MANAGEMENT DISCUSSION & ANALYSIS

August 8, 2017
For the three months ended June 30, 2017

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, may 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 Frontera Energy Corporation's ("Frontera" or the "Company") 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 "Internal Control - Risks and Uncertainties" on page 23. 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. This MD&A contains certain financial terms that are not considered in IFRS (as defined below). These measures are described in greater detail under the heading "Non-IFRS Measures" on page 16.

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 and six months ended June 30, 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 June 30, 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 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 and on the Company's website at www.fronteraenergy.ca. 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

Our new progressive and disciplined approach is focused on generating and delivering value. Recent reservoir optimization of the Company's producing assets has strengthened the Company's focus on value creation to ensure that capital expenditures are deployed efficiently to produce the highest netback barrels. Importantly, as a result of our strong first half results driven by successful cost control and portfolio optimization, Frontera is increasing its 2017 Operating EBITDA guidance (in a flat $50/bbl Brent oil environment) by 10% to $275 to $300 million (from $250 to $275 million EBITDA on a consolidated basis). We have kept production flat on a quarterly basis as we focus on costs and on delivering exceptional financial performance. The results of the asset review, combined with our focus on returns and cash flow generation, means we are reducing our 2017 capex guidance by 21% to $250 to $300 million (from $325 to $375 million), and our 2017 production exit guidance by 12% to 70,000 to 75,000 boe/d (from 80,000 to 85,000 boe/d). The Company generated operating cash flow in excess of capital expenditures in the first half of 2017 and our revised guidance places Frontera's capital spending within the Operating EBITDA metric for 2017.

The remainder of 2017 will focus on continued Operating EBITDA expansion, cash flow generation, portfolio optimization, and balance sheet protection. Potential positive catalysts to unlock shareholder value include contract renegotiations, non-core asset dispositions, exploration drilling success, continued cost control, and improved financial and covenant flexibility via debt refinancing or amendments. We are also excited to implement exploration and strategic activities designed to drive growth in 2018. Our balance sheet remains extremely strong with $439 million of cash on hand and only $250 million of long term debt. We also have a strong oil hedge book with over 50% of our 2017 production hedged at a floor of approximately $50 per barrel.

During the second quarter of 2017, net production after royalties and internal consumption totalled 72,370 boe/d, which was in line with that achieved in the previous quarter. Heavy oil production from the Quifa SW field and other fields maintained production of 27,361 bbl/d compared with 28,003 bbl/d in the first quarter of 2017. Light and medium net oil and gas production in Colombia was 40,096 boe/d, compared with 40,666 boe/d in the previous quarter. The Company's net production from Peru after royalties for the second quarter of 2017 totalled 4,913 bbl/d, a 27% increase from 3,855 bbl/d in the first quarter of 2017, mainly due to Block 192's production ramp-up after the Norperuano pipeline reactivation on January 31, 2017. During the second quarter of 2017, 15 development wells were drilled in the Quifa SW field and two development wells were drilled in the Guatiquia and Mapache Blocks in Colombia.

Second quarter revenue totalled $299.5 million compared with $316.6 million in the first quarter of 2017, due to the lower volumes sold during the quarter. The Company's average sales price per barrel of crude oil and natural gas was $46.28/boe, up from $45.95/boe in the first quarter of 2017. During the second quarter of 2017, net loss attributable to equity holders of the parent was $51.5 million, compared with net income of $8.5 million in the first quarter of 2017, as a result of an impairment charge, lower risk management gain(s), and foreign exchange losses. Operating EBITDA was $86.9 million for the second quarter of 2017, lower compared with $92.4 million in the first quarter of 2017. Consolidated EBITDA for the six months ended June 30, 2017 was $202.4 million, and was on track to exceed our original 2017 guidance of $250 to $275 million. General and administrative ("**G&A**") costs (excluding restructuring and severance expenses), decreased to $26.1 million in the second quarter of 2017 from $27.7 million in the first quarter of 2017, and from $35.6 million in the second quarter of 2016. The Company continues to reduce G&A and all non-essential spending activities and look for additional streamlining and optimization opportunities to eliminate unnecessary costs.

Barry Larson
Chief Executive Officer

2. RESULTS FOR THE SECOND QUARTER OF 2017

Financial and Operating Summary

(in thousands of US$ except per share amount or as noted)	Q2 2017	Q1 2017	Q2 2016	Six months ended June 30 2017	Six months ended June 30 2016
Operating activities					
Average net production (boe/d)	72,370	72,524	127,951	72,446	135,144
Average net production oil (bbl/d)	66,448	66,035	118,526	66,242	125,191
Average net production gas (boe/d)	5,922	6,489	9,425	6,204	9,953
Average net production (boe/d) (excluding Rubiales field)	72,370	72,524	81,468	72,446	87,160
Average sales volumes (boe/d)	71,232	76,256	110,024	73,731	115,296
Average oil and gas sales (boe/d)	64,908	70,452	109,736	67,666	114,978
Oil sales (bbl/d)	59,191	64,330	100,778	61,747	105,394
Gas sales (boe/d)	5,717	6,122	8,958	5,919	9,584
Average trading sales (bbl/d)	6,324	5,804	288	6,065	318
Combined price ($/boe)	46.28	45.95	37.60	46.11	39.73
Realized oil and gas price ($/boe)	45.71	47.34	37.60	46.55	32.01
Realized hedging gain (loss) ($/boe)	0.57	(1.39)	-	(0.44)	7.72
Operating cost ($/boe)	(26.53)	(25.91)	(20.53)	(26.22)	(20.96)
Operating netback crude oil and gas ($/boe) (1)	19.75	20.04	17.07	19.89	18.77
Consolidated netback ($/boe) (1)	18.55	17.89	17.01	18.22	18.35
Cash netback ($/boe) (1)	13.53	12.57	11.47	13.06	11.45
Capital expenditures	35,907	37,578	48,349	73,485	67,153
Financials					
Total sales ($)	299,452	316,638	376,403	616,090	833,234
Net crude oil and gas sales and other income	273,377	291,367	375,438	564,744	831,354
Trading	26,075	25,271	965	51,346	1,880
Net (loss) income ($)(2)	(51,542)	8,498	(118,654)	(43,044)	(1,019,603)
Per share - basic and diluted ($)(3)	(1.03)	0.17	(37,665.40)	(0.86)	(323,661.71)
Operating EBITDA ($)(1)	86,857	92,442	120,452	179,300	310,516
Operating EBITDA margin (Operating EBITDA/revenues)	29%	29%	32%	29%	37%
Consolidated EBITDA ($)(1)	87,389	115,057	126,083	202,447	217,897
Consolidated EBITDA margin (Consolidated EBITDA/revenues)	29%	36%	33%	33%	26%
Total Assets ($)	2,621,871	2,772,423	2,990,699	2,621,871	2,990,699
Cash and cash equivalents ($)	439,479	469,974	599,410	439,479	599,410
Total Equity (Deficit) ($)	1,561,067	1,636,705	(3,962,077)	1,561,067	(3,962,077)
Debt and obligations under finance lease ($)	271,181	272,087	5,828,523	271,181	5,828,523

1. *Refer to Non-IFRS Measures on page 16.*
2. *Net (loss) income attributable to equity holders of the parent.*
3. *The basic and diluted weighted average numbers of common shares for the three months ended June 30, 2017 and 2016 were 50,005,832 and 3,150, respectively.*

Results

Operational Highlights

- Net production after royalties and internal consumption for the second quarter of 2017 totalled 72,370 boe/d, in line with that achieved in the first quarter of 2017 of 72,524 boe/d. The trucking operation that the Company developed in Peru to move production from Block 192 while the Norperuano pipeline was under repair was successful, with an average of 2,506 bbl/d transported in the quarter.
- During the six months ended June 30, 2017, the Company completed 43 development wells (of which 34 were drilled in 2017), serviced 29 wells, and completed five workovers, mainly in Colombian Blocks. The wells were focused on maintenance to keep production flat during the first half of 2017 with modest capex investment.

Financial Highlights

- During the second quarter of 2017, revenue totalled $299.5 million compared with $316.6 million in the prior quarter, due to the lower volumes sold. Revenue decreased by $76.9 million in comparison with the second quarter of 2016 mainly due to the expiry of the Rubialies-Piriri contract in June 2016.
- Although Brent prices decreased by $3.78/bbl to $50.79/bbl in the second quarter from the first quarter, Frontera offset this with a positive hedge effect and commercial differential of $2.97/bbl. The Company's average sales price per barrel of crude oil and natural gas was $46.28/boe, up from $45.95/boe in the first quarter of 2017.
- Total operating costs, including production, transportation, and diluent costs, were within the range of the Company's guidance, increasing from $25.91/boe in the first quarter of 2017 to $26.53/boe in the second quarter of 2017. The increase was mainly attributable to the reactivation of Block 192 in Peru.
- Combined oil and gas Operating Netback for the second quarter of 2017 was $19.75/boe, 1.4% lower than the $20.04/boe in the first quarter of 2017, mainly attributable to higher operating costs related to the ramp-up of operations at Block 192.
- Consolidated Netback in the second quarter of 2017 was $18.55/boe, higher than $17.89/boe in the first quarter of 2017 and $17.01/boe in the second quarter of 2016, mainly due to cost reimbursement from the Bicentenario pipeline when third parties use the bidirectional pipeline. When the Bicentenario system is not operational the pipeline can be reversed for third party use, and the Company obtains a benefit by crediting its take-or-pay commitments.
- Operating EBITDA was $86.9 million for the second quarter of 2017, lower by 6% compared with the $92.4 million achieved in the first quarter of 2017, mainly due to lower volumes sold. In comparison with the second quarter of 2016, Operating EBITDA was lower by $33.6 million, primarily due to the expiry of the Rubiales-Piriri contract in June 2016.
- G&A costs decreased to $26.1 million in the second quarter of 2017 from $27.7 million in the first quarter of 2017, and from $35.6 million in the second quarter of 2016. The Company continues to reduce G&A costs and all non-essential spending activities. The Company will continue to look for additional opportunities to eliminate unnecessary costs.
- During the second quarter of 2017, net loss attributable to equity holders of the parent was $51.5 million, compared with a net income of $8.5 million in the first quarter of 2017, mainly due to a $23 million impairment charge, lower sales, lower unrealized risk management gain, lower gain from the equity accounted investees, and a loss on foreign exchange.
- Balance sheet remains strong as per the first quarter of 2017, underpinned by positive working capital, high liquidity and stable cash position at $541.0 million (total cash including short and long term restricted cash).
- Total capital expenditures decreased to $35.9 million in the second quarter of 2017, compared with $37.6 million in the first quarter of 2017.

Restructuring and Costs Saving Initiatives

- The Company continues to execute a hedging program designed to protect against downward oil price movements and mitigate volatility in cash flow. As of August 8, 2017, the Company has hedges in place for 1.44 MMbbl per month for the remainder of 2017 with average floor and ceiling prices of $50.65/bbl and $58.80/bbl Brent. In addition, the Company has hedged a total of 1.6 MMbbl of production in the first quarter of 2018 with average floor and ceiling prices ranging from $48.73/bbl and $55.73/bbl Brent.
- On April 3, 2017, the Company requested that the Agencia Nacional de Hidrocarburos ("**ANH**") approved the transfer of $6.0 million in commitment investment from the CPO-12 Block to two exploratory wells in the CPE-6 Block ($3.0 million for each well); the transfer is subject to approval by the ANH. The Company continues to renegotiate field commitments to focus on high-impact development drilling.
- 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 of the Company totalling $7.8 million. The agreement is subject to approval by the ANH.
- On June 1, 2017, the Company executed an assignment agreement with Petrosouth Energy Corporation pursuant to which the Company agreed to transfer its participating interest and the operatorship under the Cerrito Association Contract for $0.1 million. The Company holds an undivided 70% participating interest in the Cerrito Contract and Ecopetrol S.A. holds 30%; the assignment is subject to approval by the ANH.
- On June 2, 2017, the Agencia Nacional do Petróleo Gás Natural e Biocombustíveis ("**ANP**") approved the transfer of the Company's interest in the Queiroz Blocks in Brazil to Queiroz Galvão Exploração e Produção S.A. ("**QGEP**"). However, the transfer is subject to the replacement of standby letters of credit that the Company issued to ANP with guarantees from QGEP. Once finalized, the Company will release the outstanding $10 million owed to QGEP.

Assets Held for Sale (Executed/Closing) Summary

During the second quarter of 2017, the Company continued to monetize non-core assets and received $17.1 million on closing of the Block 131 transaction. During the first half of 2017, the Company received a total of $38.7 million from assets held for sale or sold in Peru (Blocks 126 and 131), Brazil (Karoon) and Colombia (Putumayo and Casanare Este). In addition to assets held for sale, the Company finalized an agreement with Interoil Corporation (now ExxonMobil Canada Holdings ULC) on the transfer of operating rights in Papua New Guinea for total cash consideration of $57.0 million, net of outstanding liabilities. The Company expects to receive this amount in the second half of 2017 upon receipt of regulatory approval. Below is a summary of all the non-core asset sales of exploration and production blocks executed to date; many are pending final government approvals:

				(in millions of US$)				
Update	Block	Country	Buyer	Net Cash Proceeds	Exploratory Commitments [1]	Enviromental Liabilities [1]	SBLC [2] / Collateral	Status
Closed	Santos Basin	Brazil	Karoon	$ 15.5	$ 50.8	$ -	$ -	Finalized
In progress	North Basin	Brazil	Queiroz	(10.0)	25.6	-	42.5	Pending replacement of SBLC
Closed	Lote 131	Peru	Cepsa	17.1	7.2	1.6	-	Finalized
In progress	Major lands	Colombia	Ecopetrol S.A	6.1	-	-	-	Under negotiation
In progress	PUT-9	Colombia	Amerisur	0.7	9.1	-	0.9	Pending Governmental approval
In progress	Mecaya	Colombia	Amerisur	0.6	5.0	0.2	0.8	Pending Governmental approval
In progress	Terecay	Colombia	Amerisur	0.1	8.1	-	0.8	Pending Governmental approval
In progress	Tacacho	Colombia	Amerisur	3.5	4.1	-	0.4	Pending Governmental approval
In progress	Casanare Este	Colombia	Gold Oil	2.0	7.9	4.1	0.8	Pending Governmental approval; 50% of cash received
In progress	Lote 126	Peru	Maple Gas	0.2	3.6	10.3	2.8	Pending Governmental approval; cash received
In progress	San Jacinto 7 block	Colombia	CNE Oil	-	7.8	-	2.5	Pending Governmental approval
In progress	Cerrito	Colombia	Petrosouth	0.1	-	0.9	-	Pending Governmental approval: cash received
				$ 35.9	**$ 129.2**	**$ 17.1**	**$ 51.5**	

1. *Estimated*
2. *Stand By Letter of Credit*

Frontera Energy Corporation – Change of Name

On June 12, 2017, the Company changed its name to Frontera Energy Corporation from Pacific Exploration & Production Corporation. The new name emphasizes the Company's strategy to focus its resources towards sustainable production through development drilling and growth with low-risk exploration. In this new era, the Company will focus its efforts to improve margins and drive higher returns for invested capital, maximizing the Company's value.

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 implementing a comprehensive financial Restructuring Transaction (the "**Restructuring Transaction**"). Pursuant to the terms of the Restructuring Transaction, the claims of certain creditors ("**Affected Creditors**") were compromised in exchange for common shares in the Company. On November 2, 2016, the Company successfully completed the implementation of its Restructuring Transaction in accordance with its plan of compromise and arrangement which was approved by both the Affected Creditors and the Ontario Superior Court of Justice (Commercial List). The Restructuring Transaction substantially changed the capital structure of the Company, reducing financial debt to $250 million, represented by five-year secured notes (the "**Exit Notes**"), and a letter of credit facility which at the time of the implementation of the Restructuring Transaction totalled $115.5 million. After completion of the Restructuring Transaction, the shareholders of the Company comprised the Affected Creditors with approximately 69.2% and Catalyst with approximately 30.8% of the common shares.

Additional information is included in Note 1 - Comprehensive Restructuring Transaction - 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 (2)	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
Cordillera-15 (3)	50.00%	Non-operated	141,308	70,654
Muisca (3)	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
CR-1	60.00%	Operated	307,384	184,431
Cerrito (4)	80.00%	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 (5)	100.00%	Operated	586,626	586,626
Tacacho (5)	50.50%	Operated	589,008	297,449
Putumayo-9 (5)	60.00%	Operated	121,452	72,871
Mecaya (5)	58.00%	Operated	74,127	42,993
Peru				
Block Z1	49.00%	Operated	554,443	271,677
Lot 126 (6)	100.00%	Operated	1,048,762	1,048,762
Lot 116 (7)	50.00%	Operated	1,628,126	814,063
Lot 192 (8)	84.00%	Operated	1,266,037	1,266,037

1. *Casanare Este Block held for sale to Gold Oil PLC Sucursal Colombia.*
2. *CPO-14 Block transfer to CEPCOLSA subject to approval by the ANH.*
3. *Includes investment in Maurel & Prom Colombia B.V. fields.*
4. *Cerrito Block held for sale to Petrosouth.*
5. *Blocks held for sale to Amerisur Exploración Colombia Limitada.*
6. *Peru block held for sale to Maple Gas Corporation del Peru SRL.*
7. *Lot 116 50% interest farmout from Maurel et Prom Perú S.A.C. is subject to Perupetro approval.*
8. *The Company is currently negotiating with Peruvian authorities on an extension of the Block 192 production contract.*

3. FINANCIAL AND OPERATIONAL RESULTS

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 Production (in boe/d)								
	Total field production		Gross share before royalties [1]		Net share after royalties				
	Three months ended							Six months ended	
Producing fields in Colombia	**June 2017**	**June 2016**	**June 2017**	**June 2016**	**June 2017**	**March 2017**	**June 2016**	**June 2017**	**June 2016**
Rubiales / Piriri	-	137,747	-	58,104	-	-	46,483	-	47,984
Quifa SW [2]	45,564	49,046	27,144	29,133	24,696	25,007	26,430	24,851	26,991
	45,564	**186,793**	**27,144**	**87,237**	**24,696**	**25,007**	**72,913**	**24,851**	**74,975**
Other fields in Colombia									
Light and medium [3]	38,797	44,938	37,169	42,383	34,174	34,177	40,352	34,175	42,777
Gas [4]	6,753	10,476	5,922	9,425	5,922	6,489	9,425	6,204	9,953
Heavy oil [5]	3,606	4,419	2,750	3,302	2,665	2,996	3,160	2,829	3,347
	49,156	**59,833**	**45,841**	**55,110**	**42,761**	**43,662**	**52,937**	**43,208**	**56,077**
Total production Colombia	**94,720**	**246,626**	**72,985**	**142,347**	**67,457**	**68,669**	**125,850**	**68,059**	**131,052**
Producing fields in Peru									
Light and medium [6]	8,385	5,223	4,913	2,101	4,913	3,855	2,101	4,387	4,092
	8,385	**5,223**	**4,913**	**2,101**	**4,913**	**3,855**	**2,101**	**4,387**	**4,092**
Total production Colombia and Peru	**103,105**	**251,849**	**77,898**	**144,448**	**72,370**	**72,524**	**127,951**	**72,446**	**135,144**
Total production excluding Rubiales/Piriri	**103,105**	**114,102**	**77,898**	**86,344**	**72,370**	**72,524**	**81,468**	**72,446**	**87,160**

1. *Share before royalties is net of internal consumption at the field and before high-price clause ("**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 the 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 field.*
5. *Includes Cajua, Sabanero, CPE-6, Rio Ariari, Prospecto S, and Prospecto D fields.*
6. *Includes Block Z1, Block 192, and Block 131, that was sold to CEPSA; production was included until May 19, 2017.*

	Three months ended			Six months ended	
Production and sales volumes reconciliation (in boe/d)	**June 2017**	**March 2017**	**June 2016**	**June 2017**	**June 2016**
D&P crude oil and natural gas production	70,797	70,992	126,521	70,894	133,716
E&E crude oil and natural gas production	1,573	1,532	1,430	1,552	1,428
Total crude oil and natural gas production	**72,370**	**72,524**	**127,951**	**72,446**	**135,144**
Crude oil inventory build	(6,357)	(1,346)	(17,015)	(3,865)	(19,692)
Average daily sales of produced crude oil and natural gas	**66,013**	**71,178**	**110,936**	**68,581**	**115,452**
Crude oil purchased	6,721	6,533	166	6,628	971
Sales from E&E assets	(1,502)	(1,455)	(1,078)	(1,478)	(1,127)
Oil and gas volumes sold, including trading	**71,232**	**76,256**	**110,024**	**73,731**	**115,296**

Net production after royalties, PAP, and internal consumption was 72,370 boe/d, in line with that of the previous. Total production for the first half 2017 was 72,446 boe/d from 135,144 boe/d in the same period of 2017, mainly due to the expiry of the Rubiales-Piriri contract. During the six months ended June 30, 2017, the Company completed 43 wells (of which 34 were drilled in 2017), serviced 29 wells, and completed five workovers, mainly in Colombian Blocks. The Company focused on wells maintenance to keep production flat during the first half of 2017 with discrete capex investment.

Colombia

During the second quarter of 2017, light and medium net oil production in Colombia was 34,174 bbl/d, compared with 34,177 bbl/d in the previous quarter despite only one development well being drilled in each of the Guatiquia and Mapache Blocks.

Heavy oil production from Quifa SW field and other fields maintained production levels, in comparison with the previous quarter. During the second quarter of 2017, 15 development wells were drilled in the Quifa SW field, while no wells were drilled in the other heavy oil fields.

Natural gas production declined in the second quarter compared to the previous quarter reflecting the lack of capital investment as the Company evaluates future activity on the Block.

Peru

In Peru, second quarter net production after royalties was 4,913 bbl/d (8,385 bbl/d average gross production), a 27% increase from 3,855 bbl/d (7,805 bbl/d average gross production), in the first quarter of 2017, due to Block 192's production ramp-up after the reactivation of the Norperuano pipeline on January 31, 2017.

2017 Operational Update

During the second quarter of 2017, consistent with the new progressive and disciplined approach, the Company made the strategic decision to slow down production volumes at certain blocks and focus its resources on conducting reservoir studies to facilitate optimization of certain blocks over the long term. The following producing blocks were impacted:

- Quifa SW and Cajua – Reservoir studies were commenced to facilitate optimization and the placement of future development wells and evaluate the potential for more efficient well designs (multi-laterals). Now that these studies are near completion the Company will be accelerating the development program in the third quarter of 2017;
- Guatiquia – Development drilling was reduced due to reservoir studies that are required to ensure prudent reservoir management and preparations for the drilling of injector wells for reservoir pressure maintenance. The first injector well in the Ardilla Field will be drilled in the fourth quarter of 2017 in conjunction with the acceleration of the development drilling;
- CPI Blocks (Orito and Neiva) – The Company has also been re-evaluating the forward development program and is currently awaiting the results from a pilot water injection program in Neiva to enhance recovery and the completion of reservoir studies to assess the production potential of the "A" Limestone in the Orito Field. The Company expects to accelerate the development of these fields as a result of these studies; and
- Copa Field – Reservoir injectivity tests have been successfully completed, indicating that future injector wells will be able to effectively provide reservoir pressure maintenance support and immediately facilitate increased production from the Copa Field.

Inventory Movement

(in boe/d)	2017 Q2	2017 Q1	2016 Q4	2016 Q3	2016 Q2	2016 Q1
Crude oil inventory - beginning of the period	3,240	2,610	4,328	15,195	3,919	820
Crude oil and natural gas production	72,370	72,524	69,432	75,096	127,951	142,337
Crude oil and natural gas sales D&P (including trading)	(71,232)	(76,256)	(69,653)	(82,167)	(110,024)	(120,567)
Crude oil and natural gas sales E&E	(1,502)	(1,455)	(1,370)	(1,483)	(1,078)	(1,178)
Crude oil purchased	6,721	6,533	2,544	743	166	1,777
Overlift movement	(1,483)	1,505	(16)	38	(166)	(14,752)
Operational consumption	(1,576)	(1,699)	(2,054)	(1,528)	(3,610)	(2,591)
Volumetric compensation	(1,107)	(522)	(601)	(1,566)	(1,963)	(1,927)
Crude oil inventory - end of period	**5,431**	**3,240**	**2,610**	**4,328**	**15,195**	**3,919**

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 the heading entitled "Non-IFRS Measures" on page 16.

	Q2 2017	Q1 2017	Q2 2016	Six months ended June 30 2017	Six months ended June 30 2016
Average daily D&P production volume (boe/d) (1)	**70,797**	**70,992**	**126,521**	**70,892**	**114,978**
Combined Operating Netback ($/boe)					
ICE BRENT price	50.79	54.57	47.03	52.67	41.20
Crude commercial differential	(4.54)	(5.55)	(6.64)	(5.06)	(6.98)
Hedge effect	0.57	(1.39)	-	(0.44)	7.72
Gas effect and others	(0.54)	(1.68)	(2.79)	(1.06)	(2.21)
Crude oil and natural gas sales price (2)	**46.28**	**45.95**	**37.60**	**46.11**	**39.73**
Production cost of barrels	(10.91)	(10.55)	(7.56)	(10.73)	(7.56)
Transportation (trucking and pipeline)	(14.50)	(14.28)	(11.24)	(14.39)	(11.51)
Diluent cost	(1.12)	(1.08)	(1.73)	(1.10)	(1.89)
Total Operating cost (3)	**(26.53)**	**(25.91)**	**(20.53)**	**(26.22)**	**(20.96)**
Operating netback crude oil and gas ($/boe)	**19.75**	**20.04**	**17.07**	**19.89**	**18.77**
Fees paid on suspended pipeline capacity (3)	(3.45)	(4.24)	(1.57)	(3.84)	(1.79)
Share of gain of equity-accounted investees - pipelines (4)	2.25	2.09	1.51	2.17	1.37
Consolidated netback ($/boe)	**18.55**	**17.89**	**17.01**	**18.22**	**18.35**
General and administrative expenses (5)	(4.05)	(4.34)	(3.10)	(4.19)	(2.81)
Cash finance costs (6)	(0.97)	(0.98)	(2.44)	(0.97)	(4.09)
Cash netback ($/boe)	**13.53**	**12.57**	**11.47**	**13.06**	**11.45**

For reconciliation to IFRS figures:

1. *Production and development review refer to page 7.*
2. *Sales refer to page 11.*
3. *Operating costs refer to page 12.*
4. *Share of gain of equity-accounted investees refer to page 14.*
5. *General and administrative cost refer to page 13.*
6. *Finance costs refer to page 13.*

During the three and six months ended June 30, 2017, the Company's crude oil and natural gas sales price from commercial development and production fields increased to $46.28/boe and $46.11/boe, respectively, from $45.95/boe in the first quarter of 2017, and $39.73/boe in the first half of 2016, as a result of $2.97/bbl positive hedge effect and commercial differential from the first quarter of 2017, and increased comparing with the first half of 2016 due to oil market prices improvement.

Total operating costs, including production, transportation, and diluent costs, increased from $25.91/boe in the first quarter of 2017 to $26.53/boe in the second quarter of 2017. The increase was mainly attributable to higher operating costs related to the ramp-up of operations at Block 192. The Company expects future cost reductions per barrel in the block as production increases, absorbing fixed costs, and the start-up of the Norperuano pipeline. For the six months ended June 30, 2017, operating costs increased to $26.22/boe from $20.96/boe in the same period of 2016, mainly due to lower production related to the expiry of the Rubiales-Piriri contract.

Consolidated Netback in the second quarter of 2017 was $18.55/boe, higher than $17.89/boe in the first quarter of 2017 and $17.01/boe in the second quarter of 2016, mainly due to cost reimbursement from third party use of the bidirectional pipeline at Bicentenario.

During the second quarter of 2017, the Bicentenario system was not operational for 48 days; however the Company was able to source available operational capacity from the OCENSA pipeline at a lower cost per barrel. The cost redundancy from unused pipeline take-or-pay commitments impacted Consolidated Netback by $3.45/bbl in the quarter ($22.0 million).

Cash Netback increased to $13.53/boe from $12.57/boe in the first quarter of 2017 and $11.47/boe in the second quarter of 2016, as a consequence of optimization efforts to eliminate unnecessary costs and lower financing costs after the Restructuring Transaction. For the six months ended June 30, 2017, Cash Netback was $13.06/boe, higher than $11.45/boe in the same period of 2016, mainly due to lower cash finance costs.

Realized and Reference Prices

	Q2 2017	Q1 2017	Q2 2016	YTD 2017	YTD 2016
Reference prices					
ICE BRENT ($/bbl)	50.79	54.57	47.03	52.67	41.20
Realized prices					
Oil realized price ($/bbl)	48.66	48.30	38.77	48.47	41.08
Gas realized price ($/boe) (1)	21.63	21.29	24.44	21.45	24.89
Combined realized price oil and gas $/boe					
ICE BRENT	50.79	54.57	47.03	52.67	41.20
Crude commercial differential	(4.54)	(5.55)	(6.64)	(5.06)	(6.98)
Hedge effect	0.57	(1.39)	-	(0.44)	7.72
Gas effect and others	(0.54)	(1.68)	(2.79)	(1.05)	(2.21)
Combined Realized price $/boe	**46.28**	**45.95**	**37.60**	**46.12**	**39.73**

1. *Refer to the section entitled "Further Disclosures" on page 24 for conversion factor.*

Increased expectations on the effectiveness of the Organization of the Petroleum Exporting Countries ("**OPEC**") output cut agreement led to a significant crude oil price recovery during the first quarter of 2017. However, through the second quarter of the year, the OPEC deal failed to impress the market, and prices deteriorated as OPEC exports have not fallen by as much as production, while a recovery in Libyan and Nigerian output has partially upset efforts by others to reduce production. Between the first and second quarters of 2017, ICE BRENT prices decreased by $3.78/bbl to an average of $50.79/bbl.

The Company continues to execute a hedging program designed to protect against downward oil price movements and mitigate volatility in cash flow; none of these instruments were subject to hedge accounting. As of August 8, 2017, the Company has hedges in place for 1.44 MMbbl per month for the remainder of 2017 with average floor and ceiling prices of $50.65/bbl and $58.80/bbl ICE BRENT. In addition, the Company has hedged a total of 1.6 MMbbl of production in the first quarter of 2018 with average floor and ceiling prices ranging from $48.73/bbl and $55.73/bbl ICE BRENT.

Sales

(in thousands of US$)	Three Months Ended June 30 2017		Three Months Ended June 30 2016		Six Months Ended June 30 2017		Six Months Ended June 30 2016	
Net crude oil and gas sales and other income	$	270,033	$	375,438	$	570,186	$	669,788
Hedge		3,344		-		(5,442)		161,566
Trading revenue		26,075		965		51,346		1,880
Total sales	**$**	**299,452**	**$**	**376,403**	**$**	**616,090**	**$**	**833,234**
Total sales excluding trading revenue		273,377		375,438		564,744		831,354
$/per volume sold		46.28		37.60		46.11		39.73

Total sales during the second quarter of 2017 were $299.5 million, 20% lower than the same period of 2016. This reduction is the result of the expiration of the Rubiales-Piriri contract on June 30, 2016, offset by higher combined realized prices after hedging.

Revenue for the six months ended June 30, 2017 was $616.1 million, 26% lower than the same period of 2016, which had revenues of $833.2 million, mainly due to the expiry of the Rubiales-Piriri contract and higher realized gains from risk management activities.

The following is an analysis of the price and sales volume movements for the second quarter of 2017 in comparison with the same period of 2016, and for the six months ended June 30, 2016 and 2017:

(in thousands of US$)	Three Months Ended June 30 2017 - 2016	
Total sales for the three months ended June 30, 2016	$	376,403
Decrease due to lower produced and sold volume by 41% (44,828 boe/d)		(153,326)
Increase due to higher volume of trading by 6,036 bbl/d		20,208
Hedge effect		3,344
Increase due to higher realized prices by 23%		52,823
Total sales for the three months ended June 30, 2017	**$**	**299,452**

(in thousands of US$)	Six Months Ended June 30 2017 - 2016	
Total sales for the six months ended June 30, 2016	$	833,234
Decrease due to lower produced and sold volume by 41% (47,313 boe/d)		(174,393)
Increase due to higher volume of trading by 5,748 bbl/d		33,808
Hedge effect		(167,008)
Increase due to higher realized prices by 16%		90,449
Total sales for the six months ended June 30, 2017	**$**	**616,090**

Operating Costs

(in thousands of US$)	Three Months Ended June 30 2017	Three Months Ended June 30 2016	Six Months Ended June 30 2017	Six Months Ended June 30 2016
Production costs	$ 70,312	$ 87,069	$ 137,712	$ 184,022
$/per boe D&P production	10.91	7.56	10.73	7.56
Transportation costs	93,435	129,360	184,687	280,147
$/per boe D&P production	14.50	11.24	14.39	11.51
Diluent cost	7,225	19,954	14,094	45,953
$/per boe D&P production	1.12	1.73	1.10	1.89
Total operating cost	**$ 170,972**	**$ 236,383**	**$ 336,493**	**$ 510,122**
Average operating cost per boe	**$ 26.53**	**$ 20.53**	**$ 26.22**	**$ 20.96**
Fees paid on suspended pipeline capacity	22,237	18,058	49,337	43,449
$/per boe D&P production	3.45	1.57	3.84	1.79
Trading purchase cost	25,483	665	50,455	1,506
$/per bbl trading	44.28	25.35	45.96	26.04
Other costs [1]	(3,525)	(16,599)	(3,936)	(22,575)
Overlift / (underlift)	(6,433)	(145)	(25)	(34,835)
Total cost	**$ 208,734**	**$ 238,362**	**$ 432,324**	**$ 497,667**

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

Total operating costs for the three and six months ended June 30, 2017 were $171.0 million and $336.5 million, respectively, a 28% and 34% decrease from $236.4 million and $510.1 million in the same periods of 2016, mainly due to the expiry of the Rubiales-Piriri contract.

During 2017, the Company increased activities related to its oil trading business taking advantage of its transportation capacity and stronger financial position which allowed for better negotiations with suppliers.

Depletion, Depreciation, and Amortization

(in thousands of US$)	Three Months Ended June 30 2017	Three Months Ended June 30 2016	Six Months Ended June 30 2017	Six Months Ended June 30 2016
Depletion, depreciation, and amortization	$ 97,588	$ 145,891	$ 199,382	$ 376,483
$/per boe D&P production	15.15	12.67	15.54	15.47

Depletion, depreciation, and amortization ("**DD&A**") decreased to $97.6 million in the second quarter of 2017 compared with $145.9 million in the same quarter of 2016; additionally, year-to-date DD&A decreased to $199.4 million from $376.5 million in 2016. The decrease was mainly due to the accelerated depletion of the Rubiales-Piriri contract in 2016, the lower depletable base after the impairments recorded in 2016, and the change in the depletion calculation over the Company's proved and probable reserves in 2017 (2016: proved reserves). Unit DD&A for the second quarter of 2017 was $15.15/boe or 20% higher than the same period of 2016, mainly due to lower production compared with the previous year.

Impairment and Impairment Reversal

(in thousands of US$)	Three Months Ended June 30 2017	2016	Six Months Ended June 30 2017	2016
Impairment expenses of oil & gas properties and plant and equipment	$ 23,159	$ -	$ 21,896	$ 603,998
impairment expenses (reversal) of exploration and evaluation assets	-	22,773	(10,362)	32,826
Impairment of other assets (advances and bicentenario prepayments)				52,595
Loan taxes and others	-	15	1,178	267
Total impairment and exploration expenses	**$ 23,159**	**$ 22,788**	**$ 12,712**	**$ 689,686**

During the three and six months ended June 30, 2017, the Company recognized an impairment expense of $23.2 million and $12.7 million respectively. In the second quarter of 2017, the Company continued its strategy to divest certain non-core assets. As part of this process, the Company received various offers below carrying value. In accordance with the provisions of IAS 36, Impairment of Assets, the Company considered this to be an indicator of impairment and accordingly, we were required to estimate the recoverable amount of the cash-generating unit ("**CGU**"). As a result of this analysis, an impairment charge of $23.2 million was recognized in the quarter. The Company has not categorized the assets as held-for-sale as the sale is not considered to be highly probable.

In the first quarter of 2017, the Company recognized a reversal of impairment on certain assets as held for sale of $11.6 million. The Company assessed the fair value of those assets and 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.

General and Administrative Costs

(in thousands of US$)	Three Months Ended June 30 2017	2016	Six Months Ended June 30 2017	2016
General and administrative costs	$ 26,098	$ 35,647	$ 53,804	$ 68,500
$/per boe D&P production	4.05	3.10	4.19	2.81

G&A costs for the three and six months ended June 30, 2017 decreased to $26.1 million and $53.8 million, respectively, in comparison with the same periods of 2016, mainly due to continuing efforts to minimize discretionary spending, ongoing headcount reduction and the expiry of the Rubiales-Piriri contract.

Finance Costs

(in thousands of US$)	Three Months Ended June 30 2017	2016	Six Months Ended June 30 2017	2016
Cash finance costs	$ 6,250	$ 28,141	$ 12,500	$ 99,418
Non-cash finance (cost) income	336	4,750	(1,017)	2,387
Total finance costs	**$ 6,586**	**$ 32,891**	**$ 11,483**	**$ 101,805**
Cash finance costs $/per boe D&P production	0.97	2.44	0.97	4.09

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

During the second quarter of 2017, finance costs decreased to $6.6 million from $32.9 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

	Three Months Ended June 30		Six Months Ended June 30	
(in thousands of US$)	2017	2016	2017	2016
FEC share of gain of equity-accounted investees - pipelines	$ 14,505	$ 17,419	$ 27,885	$ 33,368
Share of (loss) gain of equity-accounted investees	(4,568)	12,107	6,040	23,005
Total share of gain of equity-accounted investees	**$ 9,937**	**$ 29,526**	**$ 33,925**	**$ 56,373**
FEC share of gain of equity-accounted investees - pipelines $/per boe D&P production	2.25	1.51	2.17	1.37

During the second quarter and year to date 2017, the Company's share of gain of equity-accounted investees decreased to $9.9 million and $29.5 million, from the same periods of 2016, mainly due to the share of loss from Pacific Infrastructure related to foreign exchange fluctuations.

Foreign Exchange

	Three Months Ended June 30		Six Months Ended June 30	
(in thousands of US$)	2017	2016	2017	2016
Foreign exchange (loss) gain	$ (12,409)	$ 8,518	$ (1,163)	$ 5,179

Foreign exchange gains or losses primarily result from the movement of the Colombian peso ("**COP**") against the US dollar. A significant portion of the Company's working capital and expenditures are denominated in COP. During the second quarter of 2017 and 2016, the COP depreciated against the US dollar by 5% (foreign exchange close rates from COP – US dollar were COP$3,038.26 for the second quarter of 2017 and COP$2,880.24 for the first quarter of 2017). The foreign exchange loss in the second quarter of 2017 was $12.4 million compared with a gain of $8.5 million in the same period of 2016 primarily due to the COP depreciation impact on the translation of the Company's net working capital.

Gain (Loss) on Risk Management

	Three Months Ended June 30		Six Months Ended June 30	
(in thousands of US$)	2017	2016	2017	2016
Gain (Loss) on Risk Mangement	$ 12,434	$ 6,073	$ 52,579	$ (107,472)

As part of its risk management strategy, the Company entered into several oil price risk management contracts to hedge against oil price volatility; as of June 30, 2017, the Company had hedges for some of its production up to December 2017. The hedging portfolio consists of zero-cost collar and put spread instruments. As of June 30, 2017, the Company had outstanding finance hedge positions for approximately 7.6 MMbbl of oil with average floor and ceiling strike prices of $50.65/bbl and $58.80/bbl ICE BRENT, respectively, with a net asset of $23.4 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 June 30, 2017 have been designated as accounting hedges.

Income Tax Expense

	Three Months Ended June 30		Six Months Ended June 30	
(in thousands of US$)	2017	2016	2017	2016
Current income tax expense	$ 3,535	$ 8,594	$ 13,569	$ 20,088
Deferred income tax expense (recovery): Relating to origination and reversal of temporary differences	-	30	$ -	(1,516)
Total income tax expense	**$ 3,535**	**$ 8,624**	**$ 13,569**	**$ 18,572**

Total income tax expense was $13.6 million for the six months ended June 30, 2017, lower as compared to $18.6 million in the same period of 2016. This reduction is attributable to a decrease in overall profits, which are subject to Colombian presumptive (minimum) tax.

As of June 30, 2017, Colombian wealth tax to be paid totaled $5.9 million.

For more information please refer to Note 5 - Income Tax - Interim Condensed Consolidated Financial Statements.

Restructuring and Severance Costs

	Three Months Ended June 30		Six Months Ended June 30	
(in thousands of US$)	2017	2016	2017	2016
Restructuring cost	$ 731	$ 47,940	$ 731	$ 64,720
Severance	1,111	2,038	7,057	2,999
Total restructuring and severance costs	**$ 1,842**	**$ 49,978**	**$ 7,788**	**$ 67,719**

For the three and six months ended June 30, 2017, the Company incurred $1.8 million and $7.8 million, respectively, in costs related to restructuring and severance, lower than $50.0 million and $67.7 for the same periods in 2016, due to the closing of the Restructuring Transaction.

Capital Expenditures

	Three Months Ended June 30		Six Months Ended June 30	
(in thousands of US$)	2017	2016	2017	2016
Production facilities	$ 3,834	$ 15,379	$ 5,254	$ 19,826
Exploration activities	1,215	22,861	2,186	24,985
Development drilling	30,801	6,649	65,918	15,615
Other projects	57	3,460	127	6,727
Total capital expenditures	**$ 35,907**	**$ 48,349**	**$ 73,485**	**$ 67,153**

During the second quarter of 2017, capital expenditures totalled $35.9 million, compared with $48.3 million in the second quarter of 2016. During the second quarter of 2017, a total of $3.8 million was invested in the expansion and construction of production infrastructure, primarily in the Cajua, La Creciente, Cravoviejo, and Guaduas blocks; $1.2 million was invested in exploration activities, mainly in Peru and Colombia; and $30.8 million went into development drilling, mainly in the Quifa SW, Guatiquia, Mapache, Corcel, Orito, Casimena, and Cubiro Blocks.

Selected Quarterly Information

(in thousands of US$ except as noted)	2017 Q2	2017 Q1	2016 Q4	2016 Q3	2016 Q2	2016 Q1	2015 Q4	2015 Q3
Financial and Operational results:								
Average daily oil and natural gas production (boe/d)	72,370	72,524	69,432	75,096	127,951	142,337	159,831	152,915
Average daily oil production (boe/d)	66,448	66,035	62,229	67,128	118,526	131,856	149,368	143,028
Average daily natural gas production (boe/d)	5,922	6,489	7,203	7,968	9,425	10,481	10,463	9,887
Net oil and natural gas sales (boe/d)	64,908	70,452	67,470	81,877	109,736	120,220	171,039	139,270
Combined realized sales price – oil and natural gas ($/boe)	46.28	45.95	41.92	40.83	37.60	41.67	41.22	51.49
Realized oil and gas price ($/boe)	45.71	47.34	43.44	40.83	37.60	26.90	32.75	41.70
Realized oil hedging ($/boe)	0.57	(1.39)	(1.52)	-	-	14.77	8.47	9.79
ICE BRENT ($/bbl)	50.79	54.57	51.06	46.99	47.03	35.21	44.69	51.30
Operating cost ($/boe)	26.53	25.91	(27.98)	(24.54)	(20.53)	(21.35)	(22.01)	(20.93)
Operating netback crude oil and gas ($/boe) (1)	19.75	20.04	13.94	16.29	17.07	20.32	19.21	30.56
Consolidated netback crude oil and gas ($/boe) (1)	18.55	17.89	13.30	12.35	17.01	19.58	17.41	27.93
Cash netback crude oil and gas ($/boe) (1)	13.53	12.57	5.46	4.77	11.47	11.46	9.70	19.51
Total sales ($)	299,452	316,638	269,772	308,705	376,403	456,831	651,970	669,995
Net (loss) income attributable to equity holders of the parent for the period ($)	(51,542)	8,498	4,025,194	(557,068)	(118,654)	(900,949)	(3,895,908)	(617,318)
- basic ($)	(1.03)	0.17	80.50	(176,835)	(37,665)	(285,996)	(12.37)	(1.97)
Operating EBITDA ($) (1)	86,857	92,442	44,275	89,846	120,452	190,064	224,911	331,974
Consolidated EBITDA ($) (1)	87,389	115,057	(1,967)	37,689	126,083	91,814	257,584	414,550
Capital expenditures ($)	35,907	37,578	64,248	30,061	48,349	18,804	160,154	154,281
Total assets (end of period) ($)	2,621,871	2,772,423	2,741,719	2,403,602	2,990,699	2,687,858	3,986,121	8,290,772

1. *Refer to Non-IFRS Measures.*

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 June 30		Six Months Ended June 30	
(in thousands of US$)	2017	2016	2017	2016
Net loss [(1)]	**$ (51,542)**	**$ (118,654)**	**$ (43,044)**	**$ (1,019,603)**
Adjustments				
Income tax expense	3,535	8,624	13,569	18,572
Depletion, depreciation and amortization	97,588	145,891	199,382	376,483
Impairment and exploration expenses	23,159	22,788	12,712	689,686
Finance costs	6,586	32,891	11,483	101,805
Restructuring and severance costs	1,842	49,978	7,788	67,719
Equity tax	-	-	11,694	26,901
Other income	(5,350)	(2,210)	(7,848)	(44,420)
Foreign exchange unrealized loss (gain)	11,571	(13,225)	(3,289)	754
Consolidated EBITDA	**87,389**	**126,083**	**202,447**	**217,897**
(Gain) loss valuation of unrealized hedge contracts	(12,434)	(6,073)	(52,579)	107,472
Share of gain in equity-accounted investees	(9,937)	(29,526)	(33,925)	(56,373)
Gain attributable to non-controlling interest	(1,469)	12,500	9,314	12,507
Share based compensation	233	(5,297)	253	(8,503)
Foreign exchange realized loss (gain)	838	4,707	4,453	(5,933)
Fees paid on suspended pipeline capacity	22,237	18,058	49,337	43,449
Operating EBITDA	**$ 86,857**	**$ 120,452**	**$ 179,300**	**$ 310,516**

1. *Net 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 9.

Financial Position

Upon completion of the Restructuring Transaction and as of June 30, 2017, the only long-term borrowing of the Company consisted of Exit Notes due in 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)	< 2.5 : 1.0
Consolidated Fixed Charge (2)	> 3.25 : 1.0

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, declare dividends, and enter into lease-back transactions, among others.

Letters of Credit

The Company has various guarantees in place in the normal course of business. As at June 30, 2017, the Company had issued letters of credit and guarantees for exploration and operational commitments for a total of $154.5 million.

Outstanding Share Data

Common Shares

As at August 1, 2017, 50,005,832 common shares were issued and outstanding.
The Company does not have shares subject to escrow restrictions or pooling agreements.

Deferred Share Units ("DSUs")

As at August 1, 2017, there were 39,338 DSUs outstanding. DSUs are instruments that may be settled in cash or common shares and are payable to eligible participants (limited to directors of the Company) upon their departure from the Board of Directors of the Company.

Liquidity and Capital Resources

As at June 30, 2017, the Company had positive working capital of $342.3 million, comprised of $439.5 million in cash and cash equivalents, $34.3 million in restricted cash, $286.1 million in accounts receivable, $43.5 million in inventory, $60.2 million in income tax receivable, $1.3 million in prepaid expenses, $25.3 million in assets held for sale, $23.4 million in risk management assets, $536.9 million in accounts payable and accrued liabilities, $2.7 million in risk management liability, $3.9 million in income tax payable, $4.0 million in the current portion of obligations under finance lease, and $23.6 million in asset retirement obligations.

Refer to "Internal Control - Risks and Uncertainties" on page 23 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. Because the outcome of these matters is uncertain, there can be no assurance that such matters will be resolved in the Company's favour. 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.

Except as noted below, no material changes have occurred with respect to the matters disclosed in Note 25 "Contingencies and Commitments" of the Company's annual consolidated financial statements for the year ended December 31, 2016, and no new contingencies have occurred that are material to the Company since the issuance of those financial statements.

Minimum Credit Rating Requirement

In Colombia, the Company is participating as a shipper in a project to expand the OCENSA pipeline, which was completed and commenced operations in July 2017. As part of the expansion project, the Company, through its subsidiaries Meta Petroleum Corp. and Petrominerales Colombia Corp., entered into separate crude oil transport agreements with OCENSA for future transport capacity. The Company started paying ship-or-pay fees once the expansion project was completed and operational. As part of the expansion project agreements, the Company is required to maintain minimum credit ratings of BB- (Fitch) and Ba3 (Moody's) or to evidence compliance of net assets and working capital tests. The Company met the tests requirements based on the net assets and working capital and submitted them to OCENSA upon filing of the 2016 financial statements.

5. RELATED-PARTY TRANSACTIONS

The following table provides the total balances, loans, interest balance outstanding and commitments with related parties as at June 30, 2017 and December 31, 2016:

		Accounts Receivables	Accounts Payables	Commitments	Cash Advance	Loans	Interest Balance	Convertible Debentures
Oleoducto de los Llanos (ODL)	2017	$ -	$ 3,582	$ 156,253	$ -	$ -	$ -	$ -
	2016	638	341	176,442	-	-	-	-
Oleoducto Bicentenario de Colombia S.A.S.	2017	13,473	570	971,164	87,753	-	-	-
	2016	13,400	-	1,164,251	87,753	-	-	-
Pacific Infrastructure Ventures Inc.-Sociedad Portuaria Puerto Bahia S.A. (1)	2017	898	1,557	173,663	-	76,552	22,148	-
	2016	828	905	199,859	-	74,279	18,097	-
Interamerican Energy - Consorcio Genser Power - Proelectrica	2017	-	111	-	-	-	-	-
	2016	174	555	-	-	-	-	-
Paye Foundation (2)	2017	-	81	-	-	-	-	-
	2016	-	1,737	-	-	-	-	-
CGX Energy Inc.	2017	64	-	-	-	12,866	1,515	1,500
	2016	-	-	-	-	10,000	1,500	1,500
Fupepco Foundation (3)	2017	-	30	-	-	-	-	-

1. *Please refer to Note 12: Other Assets from the Interim Condensed Consolidated Financial Statements.*
2. *Formerly Pacific Rubiales Foundation.*
3. *The Company established a charitable foundation Fupepco Foundation in Colombia in 2017. The foundation has the objective of advancing social and community development projects in the country.*

The following table provides the total amount of transactions that had been entered into, and interest income earned, with related parties during the three and six months ended June 30, 2017 and 2016:

		Three months ended June 30			Six months ended June 30		
		Sales	Purchases / Services	Interest Income	Sales	Purchases / Services	Interest Income
Oleoducto de los Llanos (ODL)	2017	$ -	$ 12,508	$ -	$ -	$ 21,295	$ -
	2016	124	21,817	-	217	51,466	-
Oleoducto Bicentenario de Colombia S.A.S.	2017	-	33,929	-	-	66,205	-
	2016	-	29,067	-	-	79,318	-
Pacific Infrastructure Ventures Inc.-Sociedad Portuaria Puerto Bahia S.A.	2017	-	9,982	2,063	-	19,971	4,050
	2016	509	9,823	1,263	2,592	20,064	2,527
Interamerican Energy - Consorcio Genser Power - Proelectrica	2017		19	-	338	19	-
	2016	1,764	9,206	-	7,660	15,194	-
Paye Foundation	2017	-	-	-	-	1,715	-
	2016	-	1,727	-	-	5,284	-
Fupepco Foundation	2017	-	10	-	-	54	-

On April 26, 2017, the Company entered into a secured bridge loan facility with CGX Energy Inc. ("**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% and is secured by the assets of CGX. During the quarter ended June 30, 2017, the Company advanced $1.8 million under this facility.

6. ACCOUNTING POLICIES, CRITICAL JUDGMENTS, AND ESTIMATES

Basis of Presentation

The Interim Condensed Consolidated Financial Statements for the three and six months ended June 30, 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 Audited Annual Financial Statements.

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. As of January 1, 2017, oil and gas properties were depleted over proved and probable reserves, compared 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 used in preparation of the Interim Condensed Consolidated Financial Statements, other than as noted in Note 2.1, 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.

IFRS 9 Financial Instruments

The Company previously adopted IFRS 9 (2013) and will adopt the amendments to IFRS 9 (2014) as of the effective date of January 1, 2018. The amendments primarily relate to a new "expected credit loss" impairment model. The Company does not expect this standard to have an impact given that sales are almost exclusively to large organizations and governmental entities with strong credit ratings and the negligible historical level of customer default.

IFRS 15 Revenue from Contracts with Customers

The Company will adopt IFRS 15 as of January 1, 2018. The Company has completed the scoping phase of this project which included an evaluation of each revenue stream by legal entity. This assessment included a detailed review of all contracts, including those relating to infrastructure assets, using the five-step model under the new standard. Based on the assessment to date, the Company does not expect a material change to the amount of revenue recognized and believes the impact will be limited to additional disclosure requirements. The Company is expecting to complete our assessment and final conclusions during the third quarter.

IFRS 16 Leases

The Company will adopt IFRS 16 as of January 1, 2019 and is currently developing an implementation plan to assess the impact on its consolidated financial statements.

IFRIC 23 - Uncertainty over Income Tax Treatments

In June 2017, the IASB issued IFRIC 23 to clarify the accounting for uncertainties in income taxes. The interpretation provides guidance and clarifies the application of the recognition and measurement criteria in IAS 12 Income Taxes when there is uncertainty over income tax treatments. The interpretation is effective for annual periods beginning on January 1, 2019 and the Company is currently assessing the impact of IFRIC 23 on its consolidated financial statements.

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, 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.

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.
- 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.

There have been no significant changes during the six months ended June 30, 2017 to the risks and uncertainties identified in the Company's Annual Information Form ("**AIF**") for the period ended December 31, 2016, and dated March 14, 2017. 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	**Mboe**	Thousand barrels of oil equivalent
2P	Proved reserves + Probable reserves	**Mboe/d**	Thousand barrels of oil equivalent per day
bbl	Barrels	**MMbbl**	Million barrels
bbl/d	Barrels per day	**MMbbl/d**	Million barrels of oil per day
boe	Barrels of oil equivalent	**MMboe**	Million barrels of oil equivalent
boe/d	Barrels of oil equivalent per day		
D&P	Development and producing		
E&E	Exploration and evaluation		
Mbbl	Thousand barrels		
Mbbl/d	Thousand barrels per day		