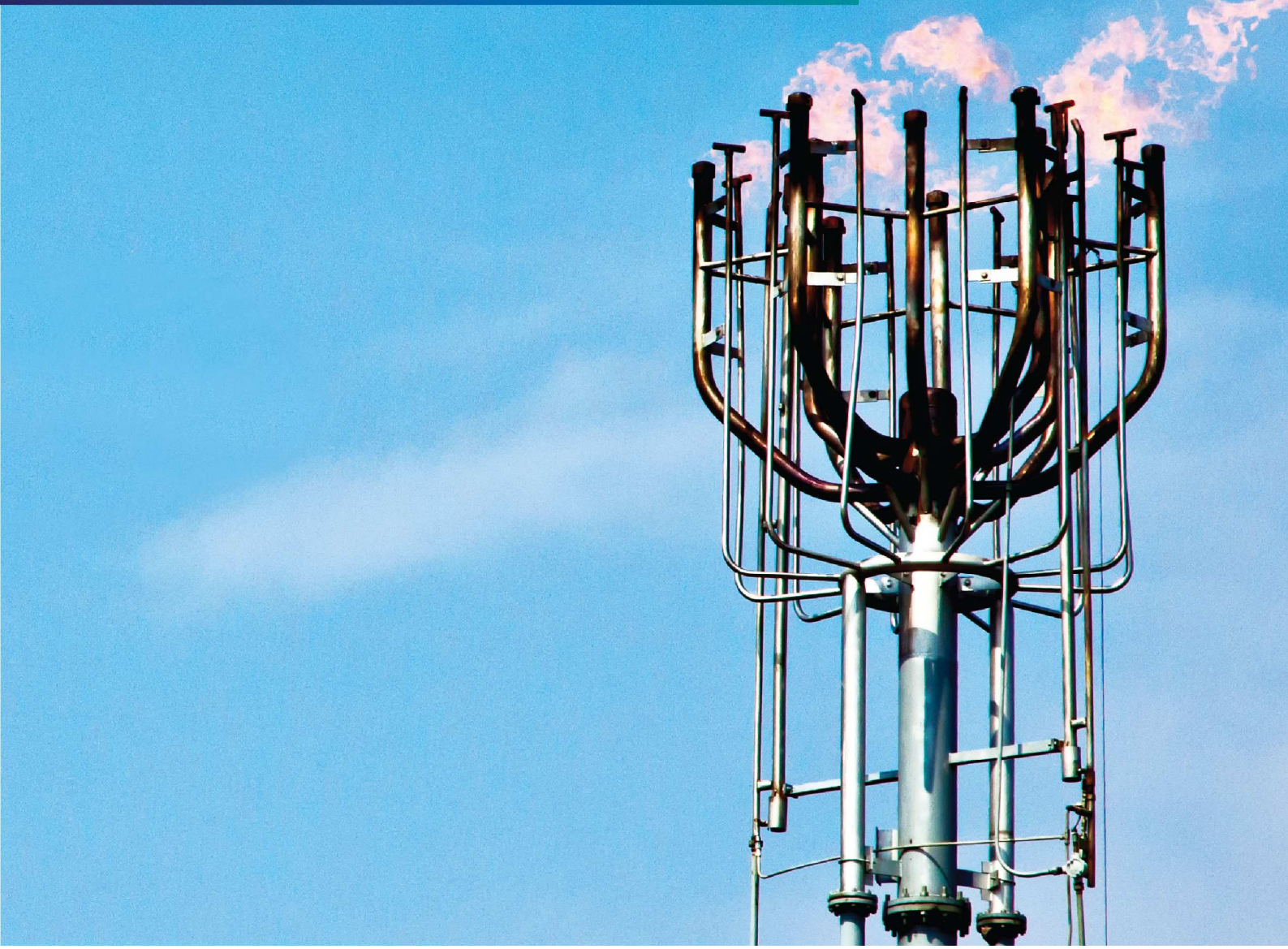
PACIFIC E&P

MANAGEMENT DISCUSSION & ANALYSIS

November 5, 2015

For the three months ended September 30, 2015



MESSAGE TO SHAREHOLDERS

The story of 2015 has been and continues to be one of low international oil prices. These prices continue to pose challenges for the industry and threaten the economic health of many companies and indeed countries. However, consistent with our strategy outlined in early 2015, we at Pacific Exploration & Production Corp. continue to deliver competitive results in this lower oil price environment.

While prices in the second quarter this year provided a glimmer of hope to the industry, the pricing downturn in the third quarter took the market and companies alike by surprise. Fortunately, we successfully executed on a hedging strategy earlier this year that has mitigated this unexpected event with significant price protection in 2015. Combined with sustainable cost reductions, focused investment and maintenance of production levels, the Company has adapted to the low oil price environment and continues to produce oil profitably.

Consistent with the previous two quarters this year, I am pleased to tell you that the Company's operations in this low oil price environment continue to deliver results. You will see that in the third quarter, the Company has maintained its drive to reduce cash operating costs to record levels and continue to control G&A spending. While these reductions cannot fully offset the significant drop in oil prices since late 2014, they have set up the base upon which to maintain the Company's profitability through the remainder of 2015 and beyond within foreseeable oil price scenarios.

The Company continues to be proactive with its liability management strategy. However, our expectation of closing the sale of our remaining equity interest in Pacific Midstream during the third quarter has not yet materialized. We will update you on further progress as appropriate as this sale is intended to bring significant cash onto the balance sheet. Also, we continue our process of strategic non-core divestures, namely, the sale of our equity interest in Puerto Bahía in 2016 and in the longer term the farm-out of part of our exploration portfolio. Focusing on high value assets allows us to optimize the use of our resources.

Our production remained stable in the third quarter of 2015, where we achieved volumes from assets in Colombia and Peru of 152,915 boe/d, including a marginal contribution from our latest addition of Block 192 in Peru. Production continues to be on track with our internal plans and within guidance of 150 to 156 Mboe/d for 2015, representing modest growth over 2014.

The Company continues to focus its production portfolio on light and medium oil assets. Exploration discoveries that were made in 2014 in the Colombian foothills continue to provide near-term production stability and growth. The modest exploration activity in 2015 has so far identified a number of other light oil prospects similar to the discoveries already made and, more importantly, our program is evaluating new light oil development drilling locations that should allow production to continue growing well into 2016.

For the third quarter of 2015, we earned revenues of $670 million and generated $272 million in Adjusted EBITDA and $197 million in funds flow from operations. Despite the drop in oil prices, our operating netback for the quarter was $30.57/boe, benefitting from reduction of total costs and the strong hedging position which generated superior realized prices.

We continued to streamline our operations and generated further cost reductions during the quarter. The Company achieved record underlying operating costs of $19.99/boe and total operating costs (including overlift and other costs) of $20.92/boe, compared with $23.71/boe and $21.08/boe, respectively, for the second quarter of 2015. Further cost savings and G&A reductions are still possible into 2016, due to additional restructuring of work processes.

There were several other positives in the quarter. These included a move to a positive working capital position. With excess cash on the balance sheet, we continuosly evaluate opportunities to effectively manage our balance sheet and deploy scarce capital as appropriate. Secondly, capital expenditures in the quarter were less than cash flow and despite the expenditures in the first half of the year being more than cash flow, we remain on track to be approximately cash flow neutral for the year. Lastly, we had the addition of five new Board of Director members, including representation from our two largest shareholders, although it did mark the retirement of one of our founders, former President Jose Francisco Arata.

While continuing to be driven to maintain focus on production levels and appropriate exploration activity, our financial and capital strategy remains focused on maintaining a healthy balance sheet by: (1) maintaining reduced operating and G&A costs; (2) reducing capital expenditures to match cash flow under the prevailing oil price environment; (3) allocating capital to the most material and highest return projects; (4) maintaining liquidity; (5) hedging adequate volumes of our production volume; and (6) implementing strategic liability management initiatives; which are all aimed at ensuring funding for future growth and generating strong returns to our Shareholders.

In summary, while these are difficult times globally for the oil industry, we are sure that the Company can weather the storm and continue to move forward with a judicious use of our resources and efficient use of our technical expertise. Despite the industry-wide move this quarter to take writedowns due to the prevailing price environment, this does not impact the long term potential of the Company's assets and the opportunities for future production growth. We are prepared for the long-term as well as for the opportunities before us and any challenges that may emerge.

Ronald Pantin
Chief Executive Officer
November 5, 2015

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" or "is expected," "anticipates" or "does not anticipate," "plans" or "planned," "estimates" or "estimated," "projects" or "projected," "forecasts" or "forecasted," "believes," "intends," "likely," "possible," "probable," "scheduled," "positioned," "goal," "objective" or 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 which may cause the actual levels of production, costs and results to be materially different from estimated levels of production, costs or results expressed or implied by such forward-looking statements. The Company believes the expectations reflected in these forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking 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 caption "Risks and Uncertainties." Although the Company has attempted to take into account important factors that could cause actual costs or operating results to differ materially, there maybe other unforeseen factors that increase costs for the Company and 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 estimates of the oil and gas that will be encountered if the property 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 of reserves and future net revenue for all properties due to the effects of aggregation.

For more information, please see the Company's Annual Information Form, dated March 17, 2015, which is 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 nine months ended September 30, 2015 and 2014. 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 three and nine months ended September 30, 2015 and 2014, 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, SIMEV at www.superfinanciera.gov.co/web_valores/Simev, and on the Company's website at www.pacific.energy. Information contained in or otherwise accessible through our website does not form a part of this MD&A and is not incorporated by reference into this MD&A.

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

1 Highlights for the Third Quarter of 2015

Financial and Operating Summary

(in thousands of US$ except per share amounts or as noted)	Q3 2015	Q2 2015	Q3 2014	Nine Months Ended September 30 2015	Nine Months Ended September 30 2014
Operating Activities					
Average sales volumes (boe/d)	**141,492**	143,225	163,617	154,792	156,873
Average oil and gas sales (boe/d)	**139,270**	132,417	148,790	145,323	145,513
Average trading sales (bbl/d)	**2,222**	10,808	14,827	9,469	11,360
Average net production (boe/d)	**152,915**	152,428	144,722	152,665	147,541
Average net production oil (bbl/d)	**143,028**	144,455	134,453	143,855	137,096
Average net production gas (boe/d)	**9,887**	7,973	10,269	8,810	10,445
Combined price ($/boe)	**51.49**	53.72	88.05	51.41	92.07
Combined netback ($/boe)	**30.57**	32.64	55.08	28.28	60.44
Combined operating cost ($/boe)	**20.92**	21.08	32.97	23.13	31.63
Capital expenditures	**154,281**	185,043	645,312	565,358	1,624,454
Financials					
Total Oil and gas sales ($)	**$ 669,995**	$ 702,733	$ 1,330,395	$ 2,172,576	$ 3,958,514
Adjusted EBITDA [1]	**271,569**	307,265	635,079	848,407	2,064,809
Adjusted EBITDA margin (Adjusted EBITDA/Revenues)	**41%**	44%	48%	39%	52%
Per share - basic ($) [2]	**0.87**	0.98	2.02	2.71	6.55
Funds flow from operations [1]	**197,203**	168,546	606,214	522,632	1,611,472
Funds flow from operations margin (Funds flow from operations/Revenues)	**29%**	24%	46%	24%	41%
Per share - basic ($) [2]	**0.63**	0.54	1.93	1.67	5.11
Net (loss) earnings from operations before impairment and exploration expenses	**(64,128)**	(101,949)	200,619	(305,009)	868,913
Net (loss) earnings [3]	**(617,318)**	(226,377)	3,484	(1,565,951)	351,251
Per share - basic ($) [2]	**(1.97)**	(0.72)	0.01	(5.00)	1.11

1. See "Additional Financial Measures" on page 32.
2. The basic weighted average numbers of common shares for the quarter ended September 30, 2015 and 2014 were 313,255,053 and 314,707,053, respectively.
3. Net (loss) earnings attributable to equity holders of the parent.

Breakdown of Oil & Gas and Trading Results

	Three Months Ended					
	September 30, 2015			September 30, 2014		
	Oil & Gas	Trading	Total	Oil & Gas	Trading	Total
Volume sold (boe/d)	**139,270**	**2,222**	**141,492**	**148,790**	**14,827**	**163,617**
Average Realized Price ($/boe)	**51.49**	**49.96**	**51.47**	**88.05**	**91.76**	**88.38**
Financial Results (in thousands of US$)						
Revenues	**659,782**	**10,213**	**669,995**	**1,205,225**	**125,170**	**1,330,395**
Cost of operations oil & gas	**268,085**	**9,660**	**277,745**	**451,321**	**125,034**	**576,355**
Production and purchase cost of barrels sold	82,436	9,660	92,096	211,877	125,034	336,911
Transportation cost (trucking and pipeline) [1]	141,718	-	141,718	180,145	-	180,145
Diluent cost	32,087	-	32,087	29,370	-	29,370
Other costs (Royalties paid in cash)	25,010	-	25,010	30,722	-	30,722
Overlift/Underlift	(13,166)	-	(13,166)	(793)	-	(793)
Gross margin	**391,697**	**553**	**392,250**	**753,904**	**136**	**754,040**

1. For the third quarter of 2015, transportation cost on a boe basis includes the Company's $16 million share of the income from equity investments in the ODL and Bicentenario pipelines. Refer to Note 17 of the Interim Condensed Consolidated Financial Statement for additional details.

Third Quarter 2015 Highlights

Operational

- In the third quarter of 2015, the Company achieved record underlying operating costs of $19.99/boe and total operating costs (including overlift and other costs) of $20.92/boe, compared with $23.71/boe and $21.08/boe, respectively, for the second quarter of 2015.
- Average daily net production after royalties was 152,915 boe/d in the third quarter of 2015, remaining stable in comparison with 152,428 boe/d in the previous quarter. This was a 6% increase compared with 144,722 boe/d for the third quarter of 2014 and was within the Company's guidance (150,000-156,000 boe/d).
- In 2015 the Company was able to maintain stable production levels in the Rubiales field despite the depletion of the field. The Company continues to optimize wells and facilities to maximize production while minimizing capital expenditures in advance of the permit approval related to the end users of Agrocascada processed water. Rubiales field production comprised 36% of the total third quarter 2015 net production. Plans are on schedule to return the field in June 2016.
- On August 30, 2015, the Company was awarded a two-year contract by Perupetro S.A. to operate Block 192, the largest producing oil block in Peru. The Block is currently producing approximately 12,000 bbl/d of an average 18° API. With this block, the Company became the largest crude oil producer in the country.
- During the third quarter of 2015, the Company received the environmental licences for the Quifa North, Arrendajo and Curito field from the Autoridad Nacional de Licencias Ambientales ("**ANLA**"). The environment licensing processes for Guama, Rio Ariari and Llanos 19 were also officially started by the ANLA.

Financial

- Net working capital improved to a positive $117.7 million as of September 30, 2015 from a negative $124.8 million at the end of the second quarter 2015, resulting from the Company's effort to manage cash flow and curtail non-essential spendings
- Revenue decreased to $670 million from the second quarter of 2015, mainly due to a lower oil for trading volume sold. Revenue included $125 million in gains realized from hedging during the quarter. Average oil and gas sales (including trading) for the third quarter of 2015 were 141,492 boe/d, 14% lower compared with 163,617 boe/d for the same period of 2014 and 1% lower than 143,225 boe/d in the second quarter of 2015.
- Combined operating netback on oil and gas for the third quarter of 2015 was $30.57/boe, 6% lower than the $32.64/boe in the second quarter of 2015. The decrease was mainly attributable to the decline in market prices for crude oil, as combined operating costs have remained stable.
- G&A expenses decreased to $53.1 million in the third quarter of 2015 from $97.0 million in the third quarter of 2014 as the Company continues to contain all non-essential spending and activities in light of the precipitous decrease in oil prices.
- Adjusted EBITDA for the third quarter of 2015 was $271.6 million and Funds Flow was $197.2 million. Adjusted EBITDA was 12% lower and Funds Flow was 17% higher respectively compared with the prior quarter.
- Net loss for the third quarter of 2015 was $617.3 million, reflecting the significant impact of the current oil price environment. Net operating earnings before impairments and DD&A totalled $280 million. Significant non-cash items affecting earnings included impairment, share-based compensation and unrealized foreign exchange losses.
- Total capital expenditures decreased to $154.3 million in the third quarter of 2015 compared with $185.0 million in the second quarter of 2015 and $645.3 million in the third quarter of 2014. Capital expenditures will continue to approximately match cash flow, with spending mainly focused on high-impact and low-risk development work.

Exploration

- Four exploration wells (including stratigraphic and appraisal wells) were drilled in the quarter and resulted in one discovery and the confirmation of three other previous discoveries for a 100% success rate in the quarter.
- Exploration successes primarily located in the Central and Deep Llanos in Colombia have added approximately 14,000 bbl/d of light oil production in the past nine months.

Balance Sheet Management

- The Company obtained a waiver from its lenders with respect to the covenant that requires the Company to maintain its consolidated net worth above U.S.$1 billion. The waiver was obtained with respect to the (1) U.S.$1 billion revolving credit and guaranty agreement with a syndicate of lenders and Bank of America, N.A. as administrative agent; (2) U.S.$250 million credit and guaranty agreement with HSBC Bank USA, N.A., as lender; (3) U.S.$109 million credit and guaranty agreement with Bank of America, N.A., as lender; and (4) U.S.$75 million master credit agreement with Banco Latino Americano de Comercio Exterior S.A. The waiver to the covenant was supported by 100% of the lending syndicate, which is comprised of 20 international and local banks. The waivers is effective immediately and will terminate on December 28, 2015. During this period, the Company will be in discussions with its lenders to address concerns during this low oil price environment.

2 Operating Netbacks

Our operating costs continued decreasing in the third quarter of 2015 as a result of strategies for streamlining production costs and optimizing field operations, and the depreciation of the Colombian peso against the U.S. dollar.

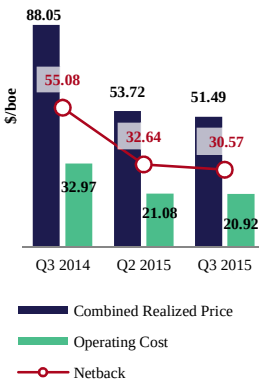
Oil & Gas Operating Netback

Combined operating netbacks during the three months ended on September 30, 2015, June 30, 2015 and September 30, 2014 are summarized below.

	Three Months Ended						
	September 30, 2015			June 30, 2015			September 30, 2014
	Crude Oil	Natural Gas	Combined	Crude Oil	Natural Gas	Combined	Combined
Average daily volume sold (boe/day)[1]	**129,591**	**9,679**	**139,270**	**124,416**	**8,001**	**132,417**	**148,790**
Operating netback ($/boe)							
Crude oil and natural gas sales price	52.94	32.17	51.49	55.04	33.34	53.72	88.05
Production cost of barrels sold [2]	6.77	1.98	6.43	9.33	2.23	8.90	15.48
Transportation (trucking and pipeline) [3]	11.87	0.20	11.06	13.73	0.85	12.95	13.16
Diluent cost	2.69	-	2.50	1.98	-	1.86	2.15
Total operating cost	**21.33**	**2.18**	**19.99**	**25.04**	**3.08**	**23.71**	**30.79**
Other costs [4]	1.08	-	1.01	0.70	0.07	0.66	1.14
Royalties paid in cash	0.85	2.18	0.95	0.56	2.05	0.65	1.10
Overlift/Underlift [5]	(1.10)	(0.11)	(1.03)	(4.20)	0.10	(3.94)	(0.06)
Total operating cost including overlift/underlift, royalties paid in cash and other costs	**22.16**	**4.25**	**20.92**	**22.10**	**5.30**	**21.08**	**32.97**
Operating netback crude oil and gas ($/boe)	**30.78**	**27.92**	**30.57**	**32.94**	**28.04**	**32.64**	**55.08**

1. Combined operating netback data is based on weighted average of daily volume sold, which includes diluents necessary for the blending of heavy crude oil and excludes oil for trading volumes.
2. Cost of production mainly includes lifting cost and other direct production costs such as fuel consumption, outsourced energy, fluid transport (oil and water) and personnel expenses, among others.
3. Includes the transport costs of crude oil and gas through pipelines and tank trucks incurred by the Company when taking the products to delivery points for customers. For the second and third quarters of 2015, transportation cost included the Company's share of the income from equity investments in the ODL and Bicentenario pipelines.
4. Other costs mainly correspond to inventory fluctuation, storage cost, the net effect of the currency hedges of operating expenses incurred in Colombian pesos during the period, and external road maintenance at the fields.
5. Corresponds to the net effect of the overlift position of $13 million income during the third quarter of 2015 ($0.8 million income for the third quarter of 2014).

COMBINED OPERATING NETBACK



During the quarter, the average combined realized price decreased to $51.49/boe from $53.72/boe in the second quarter of 2015, primarily due to the decrease in crude oil prices from an average of $55.04/bbl to $52.94/bbl. Natural gas prices also decreased, from an average of $33.34/boe in the second quarter of 2015 to $32.17/boe in the third quarter.

Total combined operating costs decreased from $21.08/boe in the second quarter to an average of $20.92/boe in the third quarter. Combined operating costs, including production, transportation, and dilution costs, decreased to $19.99/boe during the quarter from $23.71/boe in the second quarter of 2015. The decreased unit cost in the quarter is mainly a result of the continued operating cost optimization and a 21% depreciation of the Colombian peso against the U.S. dollar. During this period, there was a disruption of the Bicentenario Pipeline for 89.5 days. However, the Company was able to utilize available operational capacity in the OCENSA pipeline at comparable per unit costs.

During the third quarter of 2015, the combined crude oil and gas operating netback was $30.57/boe compared with $32.64/boe for the second quarter of 2015. The crude oil operating netback was $30.78/bbl, 7% lower compared with the second quarter of 2015 ($32.94/bbl). The decrease in netback during the third quarter of 2015 was mainly the result of a decrease in oil prices.

Combined operating netbacks for the nine months ended on September 30, of 2015 and 2014 are summarized below:

	Year to Date					
	September 30, 2015			September 30, 2014		
	Crude Oil	Natural Gas	Combined	Crude Oil	Natural Gas	Combined
Average daily volume sold (boe/day)[1]	**136,561**	**8,762**	**145,323**	**135,130**	**10,384**	**145,514**
Operating netback ($/boe)						
Crude oil and natural gas sales price	52.61	32.63	51.41	96.70	31.69	92.07
Production cost of barrels sold [2]	8.22	2.46	7.87	16.52	3.67	15.60
Transportation (trucking and pipeline) [3]	12.39	0.60	11.68	14.70	(0.02)	13.65
Diluent cost	2.14	-	2.01	2.45	-	2.28
Total operating cost	**22.75**	**3.06**	**21.56**	**33.67**	**3.65**	**31.53**
Other costs [4]	0.92	-	0.86	0.54	0.02	0.50
Royalties paid in cash	0.63	1.89	0.71	1.09	2.11	1.17
Overlift/Underlift [5]	0.01	(0.04)	-	(1.68)	(0.05)	(1.57)
Total operating cost including overlift/underlift, royalties paid in cash and other costs	**24.31**	**4.91**	**23.13**	**33.62**	**5.73**	**31.63**
Operating netback crude oil and gas ($/boe)	**28.30**	**27.72**	**28.28**	**63.08**	**25.96**	**60.44**

Notes: Refer to the operating netback table on page 4

During the nine months ended on September 30, 2015, the combined crude oil and gas operating netback was $28.28/boe, $32.16/boe lower compared with the same period of 2014 ($60.44/boe). The crude oil operating netback was $28.30/bbl, $34.78/bbl lower than the same period of 2014 ($63.08/bbl). The lower netback was entirely attributable to the decline in crude oil prices, which also resulted in the lower realized price of $51.41/boe on a combined basis for the nine months ended on September 30, 2015 compared with $92.07/boe in the same period of 2014. At the same time, the Company achieved a significant reduction in total operating costs (including over/under lifts and other costs) of $8.50/boe to $23.13/boe. Reductions in field costs were achieved through a number of initiatives including streamlining the workforce and a 21% depreciation of the Colombian Peso against U.S. dollar.

Trading Netback

	Three Months Ended		
Crude oil trading	September 30		June 30
	2015	2014	2015
Average daily volume sold (bbl/d)	**2,222**	**14,827**	**10,808**
Operating netback ($/bbl)			
Crude oil traded sales price	49.96	91.76	56.29
Cost of purchases of crude oil traded	47.26	91.66	53.63
Operating netback crude oil trading ($/bbl)	**2.70**	**0.10**	**2.66**

During the third quarter of 2015, the total volume of oil sold for trading decreased to 2,222 bbl/d from 10,808 bbl/d in the second quarter of 2015. Trading volumes vary with opportunities in the market-place and any one quarter is not a good indicator of future trading potential. Volumes sold during the third quarter of 2015 realized a netback of $2.70/bbl compared with a netback of $0.10/bbl in the same period of 2014.

The nature of our oil for trading business is opportunistic and often depends on the capacity available under our pipeline transportation agreements after our own use. Our ability to acquire crude oil for trading purposes allows us to utilize any such available capacity and sell at a positive margin to more than offset any take-or-pay fees paid. Furthermore, our trading business brings two additional benefits. First, the light and medium crude being traded acts as a diluent for our heavy oil produced, helping to reduce our overall diluent cost. Second, by maximizing the volume transported under our take-or-pay agreements with the pipelines, we improve our marketing and bargaining position with respect to export cargoes.

3 Operational Results

We have significantly increased our light and medium oil production since 2013 through targeted acquisitions and exploration discoveries.

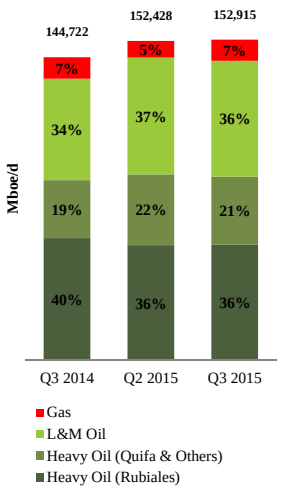
Production and Development Review

During the third quarter of 2015, net production after royalties and internal consumption totalled 152,915 boe/d, which represented an increase of 0.3% from the average net production of 152,428 boe/d reported in the previous quarter, which was higher by 8,193 boe/d in comparison with the same period of 2014.

We have significantly increased our light and medium oil production through targeted acquisitions and exploration discoveries. Light and medium net oil production increased 14% from the third quarter of 2014 and remained stable compared with the second quarter of 2015, at 55,254 bbl/d. Part of the increase corresponds to production from Block 192 in Peru, which started production on August 30, 2015. Heavy oil production from Quifa and other fields also increased by 18% during the third quarter of 2015 compared with the same period in 2014. Light and medium oil and heavy crude oil (excludes Rubiales field) production now represents 36% and 21% respectively of total net oil and gas production, while production from the Rubiales field represented 36% of the quarter's total net production, down from 40% for the same period in 2014.

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

NET PRODUCTION AFTER ROYALTIES



Third Quarter 2015 Production

	Average Production (in boe/d)						
	Total field production		Gross share before royalties [1]		Net share after royalties		
Producing fields - Colombia	**Q3 2015**	**Q3 2014**	**Q3 2015**	**Q3 2014**	**Q3 2015**	**Q2 2015**	**Q3 2014**
Rubiales / Piriri	164,865	175,012	68,977	72,939	55,182	54,958	58,351
Quifa SW [2]	55,176	58,091	32,808	34,437	29,040	29,906	23,750
	220,041	**233,103**	**101,785**	**107,376**	**84,222**	**84,864**	**82,101**
Other fields in Colombia							
Light and medium [3]	56,598	52,936	53,606	49,710	49,843	52,249	46,200
Gas [4]	10,945	11,412	9,887	10,269	9,887	7,973	10,269
Heavy oil [5]	5,429	5,793	3,718	4,059	3,552	3,808	3,847
	72,972	**70,141**	**67,211**	**64,038**	**63,282**	**64,030**	**60,316**
Total production Colombia	**293,013**	**303,244**	**168,996**	**171,414**	**147,504**	**148,894**	**142,417**
Producing fields in Peru							
Light and medium [6]	9,741	4,739	5,411	2,305	5,411	3,534	2,305
	9,741	**4,739**	**5,411**	**2,305**	**5,411**	**3,534**	**2,305**
Total production Colombia and Peru	**302,754**	**307,983**	**174,407**	**173,719**	**152,915**	**152,428**	**144,722**

1. Share before royalties is net of internal consumption at the field and before PAP at the Quifa SW field.
2. The Company´s share before royalties in the Quifa SW field is 60% and decreases in accordance with a high-price clause (PAP) that assigns additional production to Ecopetrol, S.A. ("**Ecopetrol**").
3. Mainly includes Cubiro, Cravoviejo, Casanare Este, Canaguaro, Guatiquia, Casimena, Corcel, CPI Neiva, Cachicamo, Arrendajo and other producing fields. Also includes the interest in the Cubiro field, which produced at 3,626 bbl/d and was acquired from LAEFM Colombia Ltda. ("**LAEFM**") effective April 1, 2014 pursuant to a transaction that closed on August 12, 2014. The Company is in the process of divesting its participation in the Moriche, Las Quinchas, Guasimo, Chipalo and Cerrito blocks; certain divestments may be subject to approval from Ecopetrol and the Agencia Nacional de Hidrocarburos ("**ANH**").
4. Includes La Creciente, Dindal / Rio Seco, Cerrito, Carbonera and Guama fields.
5. Includes Cajua, Sabanero, CPE-6, Rio Ariari, Prospecto S and Prospecto D fields.
6. Includes 1,415 bbl/d of net production that were in the Company's possession during the second and third quarter of 2015, with respect to the receivable outstanding from BPZ Exploración y Producción S.R.L. ("**BPZ**"). Also includes Block 192, which has been operated since August 30, 2015 with 12,000 bbl/d of gross production under normal conditions.

Colombia

Net production after royalties in Colombia rose to 147,504 boe/d (293,013 boe/d total field production) in the third quarter of 2015 from 142,417 boe/d (303,244 boe/d total field production) in the same quarter of 2014; this total was slightly lower compared with the second quarter of 2015. This year, production quarter over quarter was relatively unchanged in both heavy and light/medium oil but light/medium oil production is up year over year, which has offset the decline in total heavy oil production.

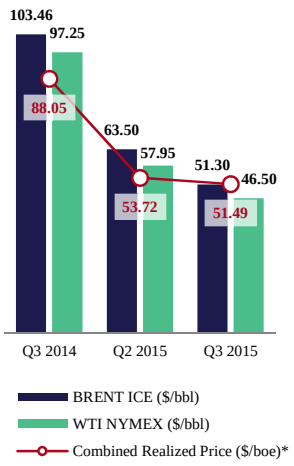
Production growth was offset by a 5% decrease in net production at the Rubiales field in comparison with the same period of 2014. Production reductions at the mature Rubiales field were primarily due to restricted water disposal capacity as a result of delays in the permitting of the Agrocascada water irrigation project.

Peru

Production from Peru corresponds to the 49% participating interest in Block Z-1, the 30% working interest in the Los Angeles discovery in Block 131 and the Block 192 operation contract. Net production after royalties for the third quarter of 2015 in Peru was 5,411 bbl/d, with increases in comparison with the previous period from additional net production from Block 192 of 1,607 bbl/d, as well as increases of 204 bbl/d from Block Z-1 of and 66 bbl/d from Block 131.

Sales, Trading and Pricing

PRICES



** Excluding Trading*

The following table highlights the average daily crude oil and gas produced and available for sale, the trading volumes sold, and the respective realized and international prices:

	Average Volume of Sales and Prices		
Colombia and Peru	**Q3 2015**	**Q2 2015**	**Q3 2014**
Oil (bbl/d)	132,492	127,738	138,667
Gas (boe/d)	9,679	8,001	10,123
Trading (bbl/d)	2,222	10,808	14,827
Total barrels sold (boe/d)	144,393	146,547	163,617
Sales from E&E assets (boe/d) [1]	(2,901)	(3,322)	-
Net barrels sold (in boe/d)	141,492	143,225	163,617
Realized Prices			
Oil realized price ($/bbl)	52.94	55.04	92.14
Gas realized price ($/boe)	32.17	33.34	31.95
Combined realized price oil and gas $/boe (excluding trading)	51.49	53.72	88.05
Trading realized price ($/bbl)	49.96	56.29	91.76
Reference Market Prices			
WTI NYMEX ($/bbl)	46.50	57.95	97.25
ICE BRENT ($/bbl)	51.30	63.50	103.46
Guajira Gas Price ($/MMBtu) [2]	5.08	5.08	5.66
Henry Hub average Natural Gas Price ($/MMBtu)	2.73	2.74	3.95

1. Includes sales from exploration and evaluation assets.
2.The domestic natural gas sales price is referenced to the Market Reference Price ("**MRP**") for gas produced in La Guajira field. Reference: Official circulars 002 and 090 of 2014, Energy and Gas Regulatory Commission ("**CREG**").

During the third quarter of 2015, oil and gas sales totalled 141,492 boe/d, which represented a decrease of 14% in comparison with 163,617 boe/d in the same period of 2014. The Company paid an overlift of approximately 231 Mbbl during the quarter, resulting in sales less than production.

The crude oil and gas combined realized price for the third quarter of 2015 reached $51.49/boe, lower by $2.23/boe as compared to the second quarter of 2015 and lower by $36.56/boe lower compared than the same period of 2014. The combined realized price of $51.49/boe, includes $9.79/boe in oil price-hedging positions realized during the quarter. See additional details under the Oil Prices Hedging section on page 16.

During the third quarter of 2015, oil prices surprises the market with a downward trend; according to the U.S. Energy Information Administration, several factors contributed to lower prices, including concerns about lower economic growth in emerging markets, expectations of higher oil exports from Iran, and continuing growth in global inventories.

In the third quarter of 2015, the price of WTI NYMEX decreased by $11.45/bbl (20%) to an average of $46.50/bbl compared with the average of $57.95/bbl in the second quarter of 2015. Likewise, the ICE BRENT price declined by $12.20/bbl (19%) to $51.30/bbl from $63.50/bbl in the second quarter of 2015.

When compared with the third quarter of 2014, the price of WTI NYMEX decreased by $50.75/bbl (52%) from $97.25/bbl to average $46.50/bbl. Similarly, the price of ICE BRENT decreased by $52.16/bbl (50%) to $51.30/bbl from $103.46/bbl in the third quarter of 2014.

Exploration Review and Update

During the third quarter of 2015, the Company drilled or was a partner in one exploration well and three appraisal wells in Colombia and Papua New Guinea. All wells encountered economic hydrocarbons, for an overall success rate of 100% for the period and 87% year to date (13 successful wells out of 15). A new discovery at the Zural-1 well in the Corcel Block, located southwest of the discovery made by the Espadarte-1 well, extended the prospectivity of this opportunity further to the southwest. Two of the appraisal wells were drilled in the Deep Llanos in Colombia and one was drilled in Papua New Guinea.

	Three Months Ended September 30		Nine Months Ended September 30	
	2015	**2014**	**2015**	**2014**
Successful exploratory wells	1	4	5	7
Successful appraisal wells [1]	3	5	8	18
Successful stratigraphic wells	-	2	-	3
Dry wells	-	3	2	11
Total	**4**	**14**	**15**	**39**
Success rate	**100%**	**79%**	**87%**	**72%**

1. Includes horizontal appraisal well.

Update on Exploration in the Third Quarter of 2015

Brazil

Blocks S-M-1165 and S-M-1102, Santos Basin: 35% Interest

Building on the exploration and appraisal success at Echidna and Kangaroo, in June 2015 Karoon Petróleo e Gás Ltda (the block operator) submitted to the ANP an amendment to the existing "Kangaroo Appraisal Plan" ("**PAD**") to the Brazilian oil and gas regulator, ANP. The amended PAD, approved in August 2015 by the ANP, comprises firm commitments to be completed by the end of December 2018 and contingent commitments which, if completed in full, would extend the PAD through 2020. The firm commitments include two appraisal wells in the Emu/Echidna area, acquisition and processing of a 3D seismic survey over the full PAD acreage, and additional 3D seismic data processing. The contingent commitments comprise the drilling of up to four wells in Kangaroo, Emu/Echidna, or Bilby, each of which would extend the PAD for six months. Appraisal drilling at Echidna is expected to better define resources and recovery factors and is a necessary first step in the staged appraisal and development program. A decision point for an early production system is planned following the 2016 appraisal drilling at Emu/Echidna.

Peru

Block 131: 30% Interest

Long term testing of the Los Angeles field has continued through the third quarter of 2015. Over 1,077 Mbbl of 45° API oil has been produced in total. Los Angeles 1X, Los Angeles Noi 3X and Los Angeles 2CD have produced over 734 Mbbl, 296 Mbbl, and 47 Mbbl of oil respectively.

Colombia

Guatiquía Block: 100% Interest

In the third quarter of 2015, the Ceibo-2 well was drilled and completed in the Lower Sand 1. The well was spudded on July 12, 2015 and reached a depth of 12,175.5 feet MD in the Gacheta Formation on August 3, 2015. Petrophysical analysis indicates 37.5 feet of net pay in the Lower Sand 1 Formation, 16.1 feet of net pay in the Upper Guadalupe Formation and 5.8 feet of net pay in the Mirador Formation. The well was completed in the Lower Sand 1 and since August 17, 2015, has produced over 88 Mbbl of 20.3° API oil at an average rate of 1,957 bbl/d with a 1.4% BSW and GOR of 53 scf/bbl through a 3-inch choke and an electro-submersible pump operating at 53 Hz.

The Avispa-6 well was spudded on August 31, 2015, and reached a depth of 12,450 feet MD on September 23, 2015. The well was not logged, so there is no petrophysical interpretation, and resolution on MWD data makes it difficult to determine if there is oil-water contact. There is an indication of productive pay in the LS1A Formation ranging from 58 feet of pay in an oil-water-contact scenario, to a maximum of 68 feet in an oil-on-rock scenario. Testing commenced October 7, 2015 and is currently in progress.

Corcel Block: 100% interest

During the third quarter of 2015, the Espadarte-2 appraisal well began testing in the Lower Guadalupe Formation. This well began drilling on March 26, 2015, and reached a total depth of 12,840 feet MD in the Gacheta Formation on April 24, 2015. In the Lower Guadalupe, 12 feet of potential petrophysical pay within a 17-foot gross interval with no evidence of fluid contact was calculated. This is correlatable and consistent with results seen at the Espadarte-1 well. This interval recovered 24° API oil in an MDT flow test with 77% water cut. From September 3 – 10, 2015, the Lower Guadalupe was tested with a total of 298 barrels of 27.7° API oil and 1,107 barrels of water recovered using artificial lift. The final 12-hour average rate was 70 bbl/d oil with a 51% water cut through a 2-inch choke.

The Zural-1 well began drilling on June 7, 2015, and reached a total depth of 12,779 feet MD in the Gacheta Formation on July 6, 2015. Zural-1 is located about 1 kilometre from the Espadarte-1 well on a separate structural closure. In the Lower Sands interval, petrophysical evaluation suggests the presence of 30 feet of net potential pay. In the Lower Guadalupe, 19 feet of net potential pay was encountered. Testing of the Lower Sand interval occurred from July 19 – 20, 2015 with 3,067 barrels of water recovered. Following this recovery, the Lower Guadalupe was tested with coiled tubing and nitrogen for artificial lift between July 30 and August 1, 2015. A total of 1,194 barrels of 32° API oil and 488 barrels of water were recovered. Over the period, the well produced oil at an average rate of 643 bbl/d with a water cut of 29% through a 2-inch choke. Following this short term test, the well was completed with an electro-submersible pump. To date, the well has produced 29 Mbbl of oil at an average watercut of 35% and GOR of 62 scf/bbl through a 1-inch choke.

Guama Block: 100% Interest

After the shut-down of Pedernalito-1X and Cotorra-1X, the Manamo-1X well was re-opened for extended testing on July 8, 2015. The test was conducted through the third quarter with volumes averaging 1.5 MMcf/d of gas and 55 bbl/d of 54° API condensate with no water cut on a 10/64” choke. Gas and condensate production are commercially handled at the recently installed Guama production facilities.

Papua New Guinea

In the third quarter of 2015, the Triceratops-3 appraisal well reached a total depth of 2,090 meters (6,856 feet) MDRT on August 13, 2015. The well was tested at open hole and flowed gas at 17.1 MMcf/d and condensate at an average of 200 bbl/d. Stabilized flow rates were obtained over several five-hour intervals and were measured through a 72/64" choke with the flow constrained by tubing.

The Company has withdrawn from the PRL-39 and PPL-475 licences in Papua New Guinea, after such withdrawal the Company will no longer have any blocks or interests in Papua New Guinea.

The Company's right to withdraw from PRL 39 and PRL 475 licences is in line with the July 2012 farm-in agreement pursuant to which the Company acquired a 12.903226% gross interest in such contracts for $115 million from InterOil and minority interest holders. Under the 2012 farm-in agreement, InterOil will repay the Company $96 million (to which minority interests will contribute $30 million), from net cash proceeds from the commercial sale of petroleum recovered or produced from PRL – 15 and in any event, by no later than the sixth anniversary of the withdrawal date.

Farm-in and Farm-out Transactions and Acquisitions

Pacific E&P was Awarded with the Operating Agreement for Block 192 in Peru

Through its wholly owned subsidiary, Pacific Stratus Energy Del Peru S.A., the Company was awarded a two-year contract to operate Block 192 by Perupetro S.A. and initiated operations on August 30, 2015.

This is the largest producing oil block in Peru and is located in the highly prolific Northern Marañon Basin, adjacent to the Peru-Ecuador international border. The block has been in production for 40 years, and had cumulative production of 725 MMbbl at the end of 2013. It is currently producing approximately 12,000 bbl/d and represents 17% of Peru's total oil production.

The Company's remuneration under the agreement is based on an R-factor calculation, which gives the Company a larger percentage of initial production and declines as the investment is recovered.

Farm-out Offering Portfolio Optimization

In 2014, the blocks that do not fit with the corporate strategy were identified; in 2015, the Company initiated the offering process with interested parties. Bidding offers have been received and are currently being evaluated.

4 Financial Results

Revenues

(in thousands of US$)	Three Months Ended September 30 2015	Three Months Ended September 30 2014	Nine Months Ended September 30 2015	Nine Months Ended September 30 2014
Net crude oil and gas sales	$ 659,782	$ 1,205,225	$ 2,039,461	$ 3,657,429
Trading revenue	10,213	125,170	133,115	301,085
Total Sales	**$ 669,995**	**$ 1,330,395**	**$ 2,172,576**	**$ 3,958,514**
$ per boe oil and gas	51.49	88.05	51.41	92.07
$ per bbl trading	49.96	91.76	51.49	97.09
$ Total average revenue per boe	**$ 51.47**	**$ 88.38**	**$ 51.41**	**$ 92.43**

Following is an analysis of the revenue drivers of price and volume for the third quarter of 2015 in comparison with the same period of 2014:

	Three Months Ended September 30 2015	2014	Difference	% Change
Total of boe sold (Mboe)	13,017	15,053	(2,036)	-14%
Avg. combined price - oil & gas and trading ($/boe)	51.47	88.38	(36.91)	-42%
Total Revenue	**669,995**	**1,330,395**	**(660,400)**	**-50%**

Drivers for the revenue decrease:		
Due to volume	$ (179,902)	27%
Due to price	(480,498)	73%
	$ (660,400)	

Revenues for the third quarter of 2015 were $670 million, 50% lower than the same quarter of 2014, which had revenues of $1,330 million. This decrease is the result of lower realized oil prices and lower trading volumes sold.

Revenues for the nine months ended September 30, 2015, were $2,173 million, 45% lower than the same period 2014 revenues of $3,959 million. This decrease is the result of the significant decrease in global oil prices.

Operating Costs

(in thousands of US$)	Three Months Ended September 30 2015	Three Months Ended September 30 2014	Nine Months Ended September 30 2015	Nine Months Ended September 30 2014
Production cost of barrels sold	$ 82,436	$ 211,877	$ 312,265	$ 619,722
Per boe	6.43	15.48	7.87	15.60
Transportation cost [1]	141,718	180,145	463,282	542,179
Per boe [1]	11.06	13.16	11.68	13.65
Diluent cost	32,087	29,370	79,796	90,582
Per boe	2.50	2.15	2.01	2.28
Other cost	12,880	15,664	34,199	19,878
Per boe	1.01	1.14	0.86	0.50
Royalties paid in cash	12,130	15,058	28,082	46,286
Per boe	0.95	1.10	0.71	1.17
Overlift/Underlift	(13,166)	(793)	121	(62,318)
Per boe	(1.03)	(0.06)	-	(1.57)
Operating cost	**$ 268,085**	**$ 451,321**	**917,745**	**$ 1,256,329**
Average operating cost per boe	**$ 20.92**	**$ 32.97**	**$ 23.13**	**$ 31.63**
Take-or-pay fees on disrupted transport capacity Bicentenario	51,722	21,921	81,999	75,625
Per boe	4.04	1.60	2.07	1.90
Trading purchase cost	9,660	125,034	126,423	299,407
Per bbl	47.26	91.66	48.90	96.55
Total Cost	**$ 329,467**	**$ 598,276**	**$ 1,126,167**	**$ 1,631,361**

1. For the three and nine months ended on September 30, 2015, transportation cost on a boe basis includes the Company´s $16 million and $36 million, respectively share of income from equity investments in the ODL and Bicentenario pipelines. Refer to Note 17 of the Interim Condensed Consolidated Financial Statements for additional details.

Total operating costs for the third quarter of 2015 were $329 million, which includes the Company's $16 million share of income from equity investments in the ODL and Bicentenario pipelines and $52 million ($4.04/boe) in net take-or-pay fees paid to Oleoducto Bicentenario de Colombia S.A.S. ("**Bicentenario**") when the capacity was not available. The Bicentenario pipeline was suspended for the entire third quarter due to security issues. The Company utilized a combination of available capacity on the OCENSA pipeline plus trucking to move oil to the export ports.

Operating costs, excluding take-or-pay fees paid to Bicentenario, were $268 million lower at $183 million as compared with $451 million in the same period of 2014. The reduction in costs resulted from cost optimization strategies adopted as a response to the lower oil price environment and COP depreciation against the U.S. dollar by 21% in the quarter.

In addition, trading purchase costs decreased from $125 million in the third quarter of 2014 to $10 million in the third quarter of 2015, mainly due to lower sales volume.

Depletion, Depreciation and Amortization

	Three Months Ended September 30		Nine Months Ended September 30	
(in thousands of US$)	2015	2014	2015	2014
Depletion, depreciation and amortization	$ 344,577	$ 407,280	$ 1,148,735	$ 1,165,625
$/per boe sales (own production)	26.89	29.75	28.95	29.34

DD&A costs for the third quarter of 2015 were $345 million compared to $407 million in the same period of 2014. The decrease of 15% is primarily due to the lower volume of sales in the period and a change in the estimation of DD&A for the Rubiales field to better reflect the contract expiration in June 2016. Unit DD&A for the third quarter of 2015 was $26.89/boe, 10% lower than the $29.75/boe for the third quarter of 2014.

Impairment and Exploration Expenses

	Three Months Ended September 30		Nine Months Ended September 30	
(in thousands of US$)	2015	2014	2015	2014
Impairment and exploration expenses	$ 568,013	$ -	$ 1,016,980	$ -
$/per boe sales (own production)	44.33	-	25.63	-

At the end of each reporting period, the Company assesses external and internal sources of information to decide whether there is any indication, that an asset or cash generating unit ("**CGU**") and goodwill may be impaired. Information the Company considers includes changes in the market, the economic and legal environment in which the Company operates, and other factors that are not within the Company's control and that may affect the recoverable amount of oil & gas, the value of exploration and evaluation properties, and goodwill. During the three months ended September 30, 2015, the Company, as a result of updated assumptions including oil and gas prices, discount rates, hydrocarbon reserves and resources, production, and costs, recorded a total before-tax impairment charge of $430 million ($879 million for the nine months ended September 30, 2015).

In addition, the Company recognized exploration expenses of $138 million for the three and nine months ended September 30, 2015 relating to its exploration assets in Guyana and Papua New Guinea.

General and Administrative Costs

(in thousands of US$)	Three Months Ended September 30 2015	Three Months Ended September 30 2014	Nine Months Ended September 30 2015	Nine Months Ended September 30 2014
General and administrative costs	$ 53,079	$ 97,040	$ 159,088	262,344
$/per boe sales	4.08	6.45	3.76	6.13

General and administrative ("**G&A**") costs decreased to $53 million in the third quarter of 2015 from $97 million in the same period of 2014, mainly due to the adoption of cost optimization initiatives. G&A per boe decreased by $2.37/boe to $4.08/boe from $6.45/boe in the third quarter of 2014.

As part of its strategy to adapt to the lower price environment, the Company initiated significant cost-cutting measures at the end of 2014 that carried through to early 2015. This is expected to significantly decrease the overall level of G&A in 2015 as compared with 2014.

Finance Costs and Foreign Exchange

(in thousands of US$)	Three Months Ended September 30 2015	Three Months Ended September 30 2014	Nine Months Ended September 30 2015	Nine Months Ended September 30 2014
Finance costs	$ 71,954	$ 61,412	$ 228,929	$ 187,562

Finance costs include interest on the Company's bank loans, senior notes, revolving credit facilities, working capital loans, finance leases, and fees on letters of credit, net of interest income received. For the third quarter of 2015, finance costs totalled $72 million compared with $61 million in the same period of 2014. The increase in finance costs was mainly due to the issuance of additional senior unsecured notes in September 2014 and the revolving credit draw down in early 2015.

(in thousands of US$)	Three Months Ended September 30 2015	Three Months Ended September 30 2014	Nine Months Ended September 30 2015	Nine Months Ended September 30 2014
Foreign exchange loss	$ (71,887)	$ (22,841)	$ (113,081)	$ (10,972)

The U.S. dollar is the Company's functional currency. Foreign exchange gains or losses primarily result from the movement of the Colombian peso ("**COP**") against the U.S. dollar. A significant portion of the Company's operating and capital expenditures, as well as assets and liabilities, are denominated in COP. During the third quarter of 2015, the COP depreciated against the U.S. dollar by 21% as compared with a depreciation of 8% during the same period of 2014. Foreign exchange loss for the third quarter of 2015 was $72 million compared with a loss of $23 million in the same period of 2014. The foreign exchange loss for the third quarter of 2015 was mainly due to unrealized foreign exchange translation losses from the translation of COP-denominated balances into the U.S. dollar.

Income Tax Expense

(in thousands of US$)	Three Months Ended September 30 2015	Three Months Ended September 30 2014	Nine Months Ended September 30 2015	Nine Months Ended September 30 2014
Current income tax	$ (12,124)	$ (7,898)	$ (42,317)	$ (268,133)
Deferred income tax	46,317	(171,580)	150,162	(100,200)
Total income tax recovery (expense)	**$ 34,193**	**$ (179,478)**	**$ 107,845**	**$ (368,333)**

The Canadian statutory combined income tax rate was 26.5% for the third quarter of 2015 and 2014.

The Colombian statutory tax rate for the third quarter of 2015 was 39% (2014: 34%), which includes the 25% general income tax rate and the fairness tax ("**CREE**") of 14% (2014: 9%). The Colombian Congress enacted new corporate tax rates for Colombian source income that are set to 39% in 2015, 40% in 2016, 42% in 2017, and 43% in 2018. As of January 1, 2019, the corporate tax rate will be reduced back to 34%. In addition, Congress introduced a temporary new wealth tax that accrues on net equity as of January 1, 2015, 2016, and 2017 at 1.15%, 1.00% and 0.40%, respectively.

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

The Company's cumulative effective tax rate (income tax expenses as a percentage of net earnings before income tax) was 5.2% for the third quarter of 2015; the cumulative effective tax rate was 98.3% for the same period of 2014. The Company's effective tax rate differs from the statutory rate due to:

- Expenses that are not deductible for tax purposes (such as share-based compensation, foreign exchange gains or losses, and other non-deductible expenditures in both Canada and Colombia);
- Corporate expenses that result in tax loss carry-forwards, however, no deferred tax assets or recovery have been recognized. When the Company has a reasonable expectation to utilize these losses in the future, a deferred tax asset and a corresponding deferred tax recovery may be recognized, which would reduce the income tax expense;
- Foreign currency exchange rate fluctuations. The Company's functional and reporting currency is the U.S. dollar; however, the calculation of the income tax expense is based on income in the currency of the country of origin, i.e., Colombia, where the Company's assets are primarily located. As a result, the tax base of these assets is denominated in COP and the related deferred tax balances are continually subject to fluctuations in the U.S. – COP exchange rate for IFRS purposes; and
- The depreciation of the COP against the U.S. dollar by 20.8% during the third quarter of 2015, which resulted in an estimated unrealized deferred income tax expense of $223.5 million. In comparison, the Company recorded $93.8 million of unrealized deferred income tax recovery during the same period of 2014 as a result of the appreciation of the COP against the U.S. dollar by 7.8%.

Excluding the effect from the above-mentioned foreign exchange fluctuations, (the Colombian portion, where the Company's assets are primarily located) the effective tax rate for the Company would be 38.9% and the Company would have a tax recovery for the three months ended September 30, 2015:

	Three Months Ended September 30		Nine Months Ended September 30	
(in thousands of US$)	2015	2014	2015	2014
Depreciation of the COP against the U.S. dollar (%)	(20.8)%	(7.8)%	(30.5)%	(5.3)%
Net (loss) earnings before income tax	$ (663,210)	$ 182,638	$ (1,674,643)	$ 718,229
Current income tax expense	(12,124)	(7,898)	(42,317)	(268,133)
Deferred income tax recovery (expense) as reported	46,317	(171,580)	150,162	(100,200)
Total income tax recovery (expense) as reported	34,193	(179,478)	107,845	(368,333)
Excluding effect from depreciation of COP	223,531	93,786	363,397	69,965
Total income tax recovery (expense) excluding the above effects	257,724	(85,692)	471,242	(298,368)
Effective tax rate excluding effect of COP depreciation	38.9%	46.9%	28.1%	41.5%

The 2015 wealth tax payable is estimated at $39.1 million. Based on the Company's taxable base, the Company has accrued a liability for the 2015 fiscal year and will not, in the current year, make an accrual for future years, pursuant to IAS 37 and IFRIC 21.

Capital Expenditures

(in thousands of US$)	Three Months Ended September 30 2015	Three Months Ended September 30 2014	Nine Months Ended September 30 2015	Nine Months Ended September 30 2014
Production facilities [1]	$ 24,789	$ 157,210	$ 85,272	$ 380,095
Exploration activities [2]	46,271	134,671	153,388	387,658
Early facilities and others	1,793	58,936	3,642	128,560
Development drilling	73,213	268,424	287,065	647,829
Other projects	8,215	26,071	35,991	80,312
Total capital expenditures	**$ 154,281**	**$ 645,312**	**$ 565,358**	**$ 1,624,454**

1. For 2014, includes investment in Maurel & Prom Colombia B.V., in which the Company holds a 49.999% participation.
2. Exploration activities for the third quarter of 2015 include drilling, seismic and other geophysical expenditures in Colombia, Peru, Brazil, and Papua New Guinea.

Capital expenditures during the third quarter of 2015 totalled $154 million, $491 million lower than the $645 million in the same period of 2014. A total of $25 million was invested in the expansion and construction of production infrastructure, primarily in Rubiales, Quifa SW, Cubiro, Casimena and in the Block Z-1 fields; $46 million went into exploration activities including drilling, seismic and other geophysical activities in Colombia, Peru, Brazil, and Papua New Guinea; $2 million went into facilities and others; $73 million went into development drilling; and $8 million was invested in other projects.

In light of the current weak commodity price environment, our capital expenditure programs have been cut back significantly to approximately equal cash flow. Our diversified portfolio of assets has the flexibility and discretionary components to allow us to scale back capital spending while maintaining production growth (See Section 11, "Outlook," – on page 29). In addition, the Company has also been successful in obtaining a significant reduction in its exploration capital commitments to ANH, from $231 million at the end of 2014 to approximately $115 million as of the date of this report.

The following table shows the capital expenditures on acquisitions executed during the period.

(in thousands of US$)	Three Months Ended September 30 2015	Three Months Ended September 30 2014	Nine Months Ended September 30 2015	Nine Months Ended September 30 2014
Farm-in Agreement and others [1]	$ -	276,779	$ -	289,279
Total capital expenditures for new acquisitions	**$ -**	**$ 276,779**	**$ -**	**$ 289,279**

1. For the nine months ended September 30, 2014, includes the capital expenditures of $12 million to acquire a 50% participating interest in the Tinigua block onshore in Colombia.

Financial Position

Debts and Credit Instruments

The following debts were outstanding as at September 30, 2015.

Senior Unsecured Notes

The Company has a number of senior unsecured notes outstanding with an aggregate principal of $4.1 billion as at September 30, 2015. The senior notes are listed on the Official List of the Luxembourg Stock Exchange and are guaranteed by the Company's main operating subsidiaries. The maturities of the senior notes range from 2019 to 2025 and the interest rates range from 5.125% to 7.25% payable semi-annually.

Pursuant to the indentures governing the Senior Notes, the financial covenant prohibiting the incurrence of additional indebtedness of 3.5 times consolidated debt-to-EBITDA limits the Company's ability to incur additional debt, subject to various exceptions including certain refinancing transactions.

The Senior Notes represent almost 75% of the outstanding debt.

Revolving Credit Facilities

On February 5 and March 13, 2015, the Company drew down $100 million and $900 million respectively from the $1 billion unsecured revolving Credit and Guaranty Agreement (the "**Revolving Credit Facility**"). Using the proceeds from the draw down, the Company repaid short-term bank loans in the aggregate principal amount of $383.8 million. As a result of this draw down and the debt repayment, the Company increased cash on hand by $516.2 million with the next earliest principal repayment not due until October 2016.

On March 3, 2015, the Company agreed with its syndicate of lenders to amend the Revolving Credit Facility. Under the amended terms of the Revolving Credit Facility, the Company's permitted consolidated leverage ratio (debt-to-EBITDA) was increased from 3.5:1.0 to 4.5:1.0 based on a rolling four-quarter average. The other two financial covenants were not amended, being: (1) the maintenance of an interest coverage ratio of greater than 2.5; and (2) a net worth of greater than $1 billion, calculated as total assets less total liabilities, excluding those of certain subsidiaries, specifically Pacific Midstream Ltd. and Pacific Infrastructure Ventures Inc.

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

The Company was compliant with the interest coverage and debt-to-EBITDA covenants as of September 30, 2015, including (1) an actual interest coverage ratio at 4.14 times and (2) debt-to-EBITDA ratio of 4.35 times.

On September 29, 2015, the Company obtained a temporary waiver from its lenders under the Revolving Credit Facility and the other credit facilities with respect to the $1 billion net worth covenant. The waiver expires on December 28, 2015. The Company's net worth on September 30, 2015, as calculated under the credit facility (total assets less total liabilities, excluding those of excluded subsidiaries, being Pacific Midstream Ltd. and Pacific Infrastructure Ventures Inc.), was $629 million. The Company was compliant with the remainder of the covenants for which the waiver does not apply.

Letters of Credit

As at September 30, 2015, the Company had issued letters of credit and guarantees for exploration and operational commitments for a total of approximately $324 million.

Oil Price-Hedging

In the third quarter, realized gains from oil price-hedging totalled $125.5 million. This is equivalent to a $10.53/bbl increase in the selling price for the crude sales realized during the quarter. In the nine months ended September 30, 2015, cumulative realized gains from oil price hedging amounted to $156.6 million.

As of September 30, 2015, the Company had oil price derivatives on 8.7 million barrels for the fourth quarter of 2015, with average floor prices at $57.04/bbl for WTI sales and $61/bbl for Brent sales. The Company continues to be active in administering its hedging portfolio and is reacting to market conditions, aiming to increase its hedged volumes for 2016 while taking advantage of changing market conditions. Timing and flexibility in executing its hedging transactions have become instrumental in seizing opportunities from flat markets. The Company seeks to increase its hedged volumes to 40% in the first half of 2016.

Outstanding Share Data

Common Shares

As at November 3, 2015, 316,094,858 common shares were issued and outstanding.

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

Stock Options and Warrants

As at November 3, 2015, there were no warrants outstanding. 16,634,617 stock options were outstanding, of which all were exercisable. As of May 28, 2014, the Board of Directors committed to no longer granting stock options and instead has implemented a Deferred Share Unit ("**DSU**") Plan for eligible employees.

Deferred Share Units

As at November 3, 2015, there were 6,285,278 DSUs outstanding. The DSUs are cash-settled instruments that track the price of the Common Shares and are payable to eligible participants upon their retirement, resignation or termination from the Company.

Liquidity and Capital Resources

Funds flow provided by operating activities for the third quarter of 2015 totalled $197.2 million (third quarter of 2014: $606.2 million). The decrease in funds flow in the third quarter of 2015 compared with the same period of 2014 was the result of a decrease in oil prices.

As at September 30, 2015, the Company had positive working capital of $118 million, mainly comprised of $489 million in cash and cash equivalents, $10 million in restricted cash, $662 million in accounts receivable, $37 million in inventory, $190 million in income tax receivable, $7 million in prepaid expenses, $145 million in risk management asset offset by $1,220 million in accounts payable and accrued liabilities, $150 million in deferred revenue net proceeds, $35 million in risk management liability, $1 million in income tax payable, and $16 million in the current portion of obligations under finance lease.

The Company previously entered into a six-month crude sales agreement for six million barrels of oil to be delivered in six equal tranches starting in October 2015. The terms of the agreement include an advance upfront payment of $150 million to partially pre-pay the total amount expected by the Company during the crude sale contract. The final prices on the volumes delivered will be determined based on the benchmark prices at the time of delivery.

As announced in early 2015, the Company has adjusted its business plan for 2015 to reflect the lower oil prices and the forecast of operating cash flow for the year. The Company believes it will be able to fund the investment capital plan from internally generated cash flows.

Please refer to "Risk and Uncertainties" on page 35 for details relating to business uncertainties and capital structure.

5 Project Status Review

The following is an update on the current status and working-interest share of costs incurred as of September 30, 2015 for the Company's major projects.

		As of September 30, 2015		
Project	**Project financed by**	**Total cost to complete the project**	**Cost incurred to date**	**Expected future costs to incur**
Bicentenario pipeline	Equity and debt combination	747,001	716,019	30,982
PEL-Power transmission line project	Equity and debt combination	241,600	232,511	9,089
Water treatment for agricultural development	Equity and debt combination	170,000	91,000	79,000
Puerto Bahia Project	Equity and debt combination	250,733	235,739	14,994
		$ 1,409,334	**$ 1,275,269**	**$ 134,065**

Bicentenario Pipeline

As of September 30 2015, Phase One of the project is complete and approximately 31 MMbbl have been pumped through the pipeline. During the third quarter, the pipeline transported at an average rate of 4,700 bbl/d. In this quarter, the truck unloading station project in Araguaney was commissioned and it is in normal operation with a capacity of 40,000 bbl/d.

PEL – Power Transmission Line Project

The PEL power line commenced operation on January 20, 2014, and as of September 30, 2015, the line has transmitted 1,407 MWh to Rubiales and Quifa fields, the ODL pipeline and the Jagüey Substation with an availability of 99.9%. As of the date of this report, the Quifa and Jagüey substations are complete and in normal operation. The Corocora substation is 51% complete with the remainder of its construction deferred to 2016.

Studies have been completed on increasing PEL transmission capacity from 192 MW to 262 MW and the capacity has been increase was approved by Empresa de Energía de Bogotá and by Unidad de Planeación Minero Energética, subject to certain upgrades that must be performed in the national grid prior to implementation. The completion of the project is planned for 2017 and will allow for future development of the Llanos Basin.

Caribbean Floating LNG Project

As of September 2015 and due to the current oil market environment, this project has been deferred.

The regasification barge is under construction in Nantong, China with an estimated delivery date in the second half of 2016 at a total cost of $178 million. The Company has transferred its ownership of the regasification barge to Exmar in exchange for not exercising the 10% equity option in the Caribbean FLNG project.

Regarding the Caribbean FLNG barge, the Company is actively evaluating alternate locations jointly with EXMAR in international markets.

Based on an assessment performed by the Company, an impairment of $40 million has been booked for the third quarter in line with IFRS accounting rules.

Block CPE-6

In late 2014, Phase 1 of facility construction was completed, providing infrastructure to handle 25,000 bbl/d of nominal fluid capacity with a crude oil processing capacity of 8,000 bbl/d of oil. In the third quarter of 2015, production from eight exploration and appraisal wells has averaged approximately 1,238 bbl/d (total gross production). The Company through an agreement reached with the partner will start a drilling campaign in the block in the fourth quarter of 2015, and analysis is ongoing in order to optimize the long-term economic and operational viability and potential of the CPE-6 block, which contains a large amount of oil in place.

Agrocascada Project: Water Treatment for Agricultural Development

As of September 30, 2015, the construction of the first reverse osmosis water treatment plant was completed. The permitting process for the water concession is in progress with the local environmental authority ("**Cormacarena**"). At the end of September 2015, the Company filed additional studies required by this authority and approvals of the permits are expected in the fourth quarter of 2015.

This project represents an innovative approach for water disposal in Colombia. It benefits oil producers in terms of lowering operating costs and extending the economic life of oil fields, and it is also an excellent example of "shared value" with communities, as it brings sustainable social development to areas in need of development. In future development, the concept will be replicated by the Company in oil fields with high water production rates.

Agrocascada is expected to be operational in the first quarter of 2016 depending on the approval of the pending permits.

Pacific Infrastructure: Puerto Bahía Terminal

The Company has a 41.65% equity interest in Pacific Infrastructure Ventures Inc. ("**PII**"), a private company that is currently developing Puerto Bahía, an oil export terminal located in Cartagena Bay in Colombia. Puerto Bahía will be developed in three phases: (i) 1.7 MMbbl of oil and petroleum product storage capacity, a berthing position for vessels of up to 80K DWT, a truck loading and unloading station with a capacity of up to 30 Mbbl/d and a fixed bridge; (ii) additional storage capacity of up to 3 MMbbl, an additional berthing position for vessels of up to 150K DWT and barge handling facilities with a capacity of up to 45 Mbbl/d; and (iii) a liquids terminal with capacity of up to 4 MMbbl, containers and a berthing platform with a length of 300 metres to handle dry materials.

In May 2015, operations approval from the Minister of Energy and Mines was obtained. The port began operations in June 2015, receiving oil trucks and an oil tanker with 136,000 barrels of naphta. On August 28, 2015, the official inauguration event of the port took place with the Vice President of Colombia as well as National and Regional Authorities.

As of September 30, 2015, construction activities had progressed as follows: the liquids terminal had reached 98%, the truck loading and unloading station was at 97%, the fixed bridge was 100% complete and the multi-purpose terminal for handling bulk materials had reached 99% completion. As of the date of this report, the Company began operations in the north quayside of the liquids terminal and completed the dry dock in the multi-purpose terminal.

The operation of Puerto Bahía has generated new opportunities currently being reviewed, related to handling crude oil and products for the neighbouring Cartagena Refinery, which started operations on October 2015.

6 Commitments and Contingencies

Tax Review in Colombia

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

The DIAN has officially reassessed several value-added tax ("**IVA**") declarations on the basis that the volume of oil produced and used for internal consumption at certain fields in Colombia should have been subject to IVA. For the third quarter of 2015, the amount reassessed, including interest and penalties, is estimated at $36 million, of which, the Company estimates that $22 million should be assumed by companies that share interests in these contracts. The Company disagrees with the DIAN's reassessment and official appeals have been initiated. Several other taxation periods back to 2011 with respect to IVA on field oil consumption are also currently under review by the DIAN. For the periods that are under review, if the DIAN's views were to prevail, the Company estimates that the IVA, including interest and penalties, could range between $14 million and $76 million, of which, the Company estimates that a range of $7 million to $39 million should be assumed by other companies that share interests in these contracts.

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

The DIAN is also reviewing certain income tax deductions with respect to the special tax benefit for qualifying petroleum assets as well as other exploration expenditures. As of the date of this report, the DIAN has reassessed $56 million of tax owing, including estimated interest and penalties, with respect to the denied deductions.

As at September 30, 2015, the Company believes that the disagreements with the DIAN related to IVA and denied income tax deductions will be resolved in favour of the Company. As a result, no provision has been made in the financial statements.

Equity Tax

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

High-Price Royalty in Colombia

The Company is currently in discussion with the ANH with respect to the interpretation of the high-price participation clause in certain exploration contracts. Please refer to "PAP Disagreement with the ANH" on page 30 for details relating to this contingency.

Minimum Credit Rating Requirement

The Company has an assignment agreement with Transporte Incorporado S.A.S. ("**Transporte Incorporado**"), a Colombian company owned by an unrelated international private equity fund. Transporte Incorporado owns a 5% equity interest and capacity right in the OCENSA pipeline in Colombia. Under the assignment agreement, the Company is entitled to use Transporte Incorporado's capacity to transport crude oil through the OCENSA pipeline for a set monthly premium until 2024. Pursuant to the assignment agreement, the Company is required for the duration of the agreement to maintain a minimum credit rating of Ba3 (Moody's), which was breached in September 2015 when Moody's downgraded the Company's credit rating to B3. As a result of the downgrade and in accordance with the assignment agreement, upon giving notice to the Company, Transporte Incorporado would have the right to early-terminate the assignment agreement and the Company would be required to pay an amount determined in accordance with the agreement, estimated at $129 million. The Company has not received such notice from Transporte Incorporado, and on October 1, 2015, the Company received a waiver from Transporte Incorporado of its right to early-terminate for a period of 45 days until November 14, 2015. The Company continues to pay monthly premiums and is currently in negotiation with Transporte Incorporado regarding the terms of the agreement and the minimum credit rating requirement. No provision has been recognized in the Interim Condensed Consolidated Financial Statements as of September 30, 2015 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 2016. As part of the expansion project, the Company, through its subsidiaries Meta Petroleum and Petrominerales Colombia, entered into separate crude oil transport agreements with OCENSA for future transport capacity. The Company will start paying ship-or-pay fees once the expansion project is complete and operational. As part of the transport agreements, the Company is required to maintain minimum credit ratings of BB- (Fitch) and Ba3 (Moody's). This covenant was breached in July and September 2015 when Fitch and Moody's downgraded the Company's credit ratings to B+ and B3 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 standby 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. The Company has not received such notice from OCENSA. Furthermore, in October 2015, the Company requested in writing a waiver for the provision of the cure as required by the transport agreements for an indefinite period until the pipeline expansion project is complete and operational. The Company is currently in negotiation with OCENSA to obtain the requested waiver. No provision has been recognized in the Interim Condensed Consolidated Financial Statements as of September 30, 2015 relating to the breach of the credit rating requirement.

Commitments

As part of the normal course of business, the Company has entered into arrangements that will impact the Company's future operations and liquidity. The principal commitments of the Company are ship-or-pay arrangements on crude oil and gas transportation, asset retirement obligations, debt repayments, service contracts with suppliers in relation to the exploration and operation of oil properties, and engineering and construction contracts, among others.

Disclosures concerning the Company's significant commitments can be found in Note 23 of 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, interest rates and foreign exchange rates. 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 26 of the Interim Condensed Consolidated Financial Statements.

7 Related-Party Transactions

According to IFRS, parties are considered to be related if one party has the ability to "control" (financially or by share capital) the other party or have significant influence (management) on the other party in making financial, commercial and operational decisions. The board of directors of the Company has created the New Business Opportunities Committee ("**NBOC**") to review and approve related-party transactions. The NBOC is comprised of the following independent directors: Hernan Martinez (Chair), Alejandro Betancourt, Dennis Mills and Jesus Valdez Simancas. The NBOC is apprised of related-party transactions prior to implementation, engages independent legal counsel as needed, and meets *in camera* to deliberate. The NBOC also reviews the business rationale for each transaction and ensures that the transaction is in compliance with applicable securities laws and the Company's debt covenants.

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

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

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

a) During the three and nine months ended September 30, 2015, the Company received $43 million and $43 million respectively in accordance with its joint operations obligation associated with its 49% interest in Block Z-1 in Peru. In addition, the Company had accounts receivable of $0.5 million under the joint operation agreement from Alfa SAB de CV ("**Alfa**"), who owns a 51% working capital interest in Block Z-1 and also holds 19.2% of the issued and outstanding capital of the Company.

b) In October 2012, the Company and Ecopetrol signed two Build, Own, Manage, and Transfer ("**BOMT**") agreements with Consorcio Genser Power-Proelectrica and its subsidiaries ("**Genser-Proelectrica**") to acquire certain power generation assets for the Rubiales field. Genser-Proelectrica is a joint venture between Promotora de Energia Electrica de Cartagena & Cia S.C.A. E.S.P ("**Proelectrica**"), in which the Company has a 24.9% indirect interest and Genser Power Inc. ("**Genser**"), which is 51% owned by Pacific Power Generation Corp. ("**Pacific Power**"). On March 1, 2013, these contracts were assigned to TermoMorichal SAS ("**TermoMorichal**"), the company created to perform the agreements, in which Pacific Power has a 51% indirect interest. Total commitment under the BOMT agreements is $229.7 million over ten years. In April 2013, the Company and Ecopetrol entered into another agreement with Genser-Proelectrica to acquire additional assets for a total commitment of $57 million over ten years. At the end of the Rubiales Association Contract in 2016, the Company's obligations along with the power generation assets will be transferred to Ecopetrol. During the three and nine months ended September 30, 2015 the Company paid $8.9 million and $20.2 million (2014: $9.0 million and $9.0 million) under the Rubiales Association Contract. As at September 30, 2015, the Company had an advance of $5.8 million (December 2014: $7.6 million). As at September 30, 2015, the Company had accounts payable of $5.5 million (December 2014: $5.9 million) due to Genser-Proelectrica as at September 30, 2015. In addition, on May 5, 2014, a subsidiary of the Company provided a guarantee in favour of XM Compañia de Expertos en Mercados S.A. on behalf of Proelectrica guaranteeing obligations pursuant to an energy supply agreement in the aggregate amount of approximately $16.7 million. In December 2014, the Company entered into a new contract with Genser, related to the operation and maintenance of the power generation facility located in the Sabanero field.

In October 2013, the Company entered into connection agreements and energy supply agreements with Proelectrica for the supply of power to the oil fields in the Llanos basin. The connection agreements authorize Meta Petroleoum Corp. and Agro Cascada S.A.S. to use the connection assets of Petroelectrica for power supply at the Quifa and Rubiales fields. The agreement commenced on November 1, 2013 and will operate for 13 years. During the three and nine months ended September 30, 2015 the Company made payments of $10.3 million and $36.9 million (2014: $24.9 million and $53.9 million) under this agreement.

The Company has entered into several take-or-pay agreements as well as interruptible gas sales and transport agreements to supply gas from the La Creciente natural gas field to Proelectrica's gas-fired plant. During the three and nine months ended September 30, 2015, the Company recorded revenues of $2.2 million and $3.5 million (2014: $4.2 million and $11.2 million) from such agreements. As at September 30, 2015, the Company had trade accounts receivable of $9 million (December 2014: $7.5 million) from Proelectrica.

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

c) As at September 30, 2015, the Company had trade accounts receivable of $9 million (December 31, 2014: $7.5 million) from Proelectrica, in which the Company has a 24.9% indirect interest and which is 31.49% owned by Blue Pacific Assets Corp. ("**Blue Pacific**"). The Company and Blue Pacific's indirect interests are held through Pacific Power. Revenue from Proelectrica in the normal course of the Company's business was $2.2 million and $3.5 million for the three and nine months ended September 30, 2015 (2014: $4.2 million and $11.2 million). Two directors and officer of the Company (Serafino Iacono, Miguel de la Campa, and Laureano von Siegmund), along with Jose Francisco Arata, a director until August 14, 2015, control, or provide investment advice to the holders of approximately 76% of the shares of Blue Pacific.

d) During the three and nine months ended September 30, 2015, the Company paid $0.8 million and $3.1 million (2014: $2.1 million and $6.8 million) to Transportadora Del Meta S.A.S. ("**Transmeta**") in crude oil transportation costs. In addition, the Company had accounts receivable of $0.8 million (December 31, 2014: $1.1 million) from Transmeta and accounts payable of $0.4 million (December 31, 2014: $0.9 million) to Transmeta. Transmeta is controlled by German Efromovich, a former director of the Company until September 1, 2015.

e) As at September 30, 2015, loans receivable from related parties in the aggregate amount of $0.6 million (December 31, 2014: $0.9 million) are due from one director (Serafino Iacono) and seven officers (Carlos Perez, Luis Andres Rojas, Peter Volk, Francisco Bustillos, Luciano Biondi, Jairo Lugo and Marino Ostos) of the Company. The loans are non-interest bearing and payable in equal monthly payments over a 48-month term. In August 2015, the Company agreed to pay $8.3 million in severance to one of its officers (Jose Francisco Arata), who retired from the Company on August 14, 2015, which included $5.5 million in cash paid during the three months ended September 30, 2015, and $2.8 million payable in March 2016. In addition, the DSU entitlement for Jose Francisco Arata was paid in kind with the Company's shares held in treasury on a one-to-one basis, for a total of approximately 1.3 million common shares.

f) The Company has entered into aircraft transportation agreements with Helicopteros Nacionales de Colombia S.A.S. ("**Helicol**"), a company controlled by German Efromovich, a former director of the Company. During the three and nine months ended September 30, 2015, the Company paid $1.4 million and $5.8 million (2014: $5.5 million and $11.5 million) in fees as set out under the transportation agreements. The Company had accounts payable to Helicol as at September 30, 2015, of $1.7 million (December 31, 2014: $2.8 million).

g) During the three and nine months ended September 30, 2015, the Company paid $27.3 million and $81.5 million to ODL (2014: $57.9 million and $121.1 million) for crude oil transport services under the pipeline take-or-pay agreement and had accounts payable of $10.3 million (December 31, 2014: $Nil). In addition, the Company received $0.7 million and $1.7 million from ODL during the three and nine months ended September 30, 2015 (2014: $0.7 million and $ 1.7 million) with respect to certain administrative services and rental equipment and machinery. The Company had accounts receivable from ODL as at September 30, 2015 of $0.4 million (December 31, 2014: $0.4 million).

h) During the three and nine months ended September 30, 2015, the Company paid $41.5 million and $128.4 million to Bicentenario (2014: $44.9 million and $132.5 million), a pipeline company in which the Company has a 27.6% interest, for crude oil transport services under the pipeline take-or-pay agreement. As at September 30, 2015, the balance of loans outstanding to Bicentenario was $11.8 million (December 31, 2014: $42 million). Interest income of $0.3 million and $1.3 million was recognized during the three and nine months ended September 30, 2015 (2014: $0.7 million and $2.1 million). Interest of $0.7 million and $2 million was paid on the loans during the three and nine months ended September 30, 2015, and capital of $12.9 million and $30.1 million was paid on the loans in the three and nine months ended September 30, 2015. During the three and nine months ended September 30, 2015, the Company received $Nil and $Nil (2014: $Nil and $0.5 million) with respect to certain administrative services, rental equipment and machinery. The Company had advanced $87.9 million as at September 30, 2015, (December 31, 2014: $87.9 million) to Bicentenario as a prepayment of transport tariff, which is amortized against the barrels transported. As at September 30, 2015, the Company had trade accounts receivable of $13.4 million (December 31, 2014: $13.7 million) as a short-term advance

i) The Company has established two charitable foundations in Colombia: the Pacific Rubiales Foundation and the Foundation for Social Development of Available Energy ("**FUDES**"). Both foundations have the objective of advancing social and community development projects in the country. During the three and nine months ended September 30, 2015, the Company contributed $4.3 million and $11 million respectively to these foundations (2014: $7.7 million and $28.6 million). At as September 30, 2015, the Company had accounts receivable (advances) of $3.5 million (December 31, 2014: $5.0 million) and accounts payable of $1.7 million (December 31, 2014: $8.7 million). Three of the Company's directors (Ronald Pantin, Serafino Iacono and Miguel de la Campa) and an officer of the Company (Federico Restrepo) sit on the board of directors of the Pacific Rubiales Foundation.

j) At as September 30, 2015, the Company had demand loans receivable from PII in the amount of $72.4 million (December 31, 2014: $71.4 million). The loans are guaranteed by PII's pipeline project and bear interest that ranges from LIBOR + 2% to 7% per annum. The Company owns 41.65% of PII. In addition, during the three and nine months ended September 30 2015, the Company received $3 million and $3.3 million (2014: $1.3 million and $1.3 million) from PII with respect to contract fees for advisory services and technical assistance in pipeline construction of "Oleoducto del Caribe". In addition, as at September 30, 2015, the Company had accounts receivable of $0.9 million (December 31, 2014: $1.0 million) from Pacific Infrastructure Ventures Inc., a branch of PII. As at September 30, 2015, the Company had accounts payable of $3.2 million to PII (December 31, 2014: $Nil).

In December 2012, the Company entered into a take-or-pay agreement with Sociedad Puerto Bahia S.A. ("**SPB**"), a company that is wholly owned by PII. Pursuant to the terms of the agreement, SPB will provide for the storage, transfer, loading and unloading of hydrocarbons at its port facilities. The contract term commenced in 2014 and will continue for seven years, renewable in one-year increments thereafter. These agreements may indirectly benefit Blue Pacific and other unrelated minority shareholders of PII. During the three and nine months ended September 30, 2015, the Company advanced $8.9 million and $15.3 million respectively to SPB (2014: $Nil and $Nil), of which $2.6 million and $3.4 million respectively were expensed during the three and nine months ended in September 30, 2015 in relation to services received (2014: $Nil).

k) In October 2012, the Company entered into an agreement with Pacific Coal Resources Ltd. ("**Pacific Coal**"), Blue Advanced Colloidal Fuels Corp. ("**Blue ACF**"), Alpha Ventures Finance Inc. ("**AVF**"), and an unrelated party whereby the Company acquired from Pacific Coal the right to a 5% equity interest in Blue ACF for a cash consideration of $5 million. Blue ACF is a company engaged in developing colloidal fuels; its majority shareholder is AVF, which is controlled by Blue Pacific. As part of the purchase, Pacific Coal also assigned to the Company the right to acquire up to an additional 5% equity interest in Blue ACF for an additional investment of up to $5 million. The Company currently has an 8.49% equity interest in Pacific Coal. In addition, the Company has an indirect equity interest of 10.17% in Pacific Coal through its 24.9% ownership of Pacific Power, which in turn has a 40.86% equity interest in Pacific Coal. Hernan Martinez, a director of the Company is the Executive Chairman of Pacific Coal.

l) Blue Pacific provides the Company with passenger air transport services on an as-needed basis. During the three and nine months ended September 30, 2015, the Company paid $Nil and $ Nil (2014: $Nil and $-0.2 million) for these services.

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

8 Selected Quarterly Information

	2015			2014				2013	
(in thousands of US$)	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Financials:									
Net sales	$ 669,995	$ 702,733	$ 799,848	$ 991,508	$ 1,330,395	$ 1,344,666	$ 1,283,453	$ 1,202,551	$ 1,109,973
Net (loss) earnings attributable to equity holders of the parent for the period	(617,318)	(226,377)	(722,256)	(1,660,876)	3,484	228,527	119,240	140,412	84,013
(Loss) Earnings per share									
- basic	(1.97)	(0.72)	(2.31)	(5.26)	0.01	0.73	0.38	0.43	0.26
- diluted	(1.97)	(0.72)	(2.31)	(5.26)	0.01	0.72	0.37	0.43	0.26

9 Accounting Policies, Critical Judgments, and Estimates

New Standards, Interpretations and Amendments Adopted by the Company

IFRS 3 Business Combinations

This amendment is applied prospectively and clarifies that all contingent consideration arrangements classified as liabilities (or assets) arising from a business combination should be subsequently measured at fair value through profit or loss whether or not they fall within the scope of IFRS 9 (or IAS 39, as applicable). This policy became effective for annual periods starting on or after July 1, 2014.

The adoption of IFRS 3 did not have any material impact on the Company's Interim Condensed Consolidated Financial Statements.

IFRS 8 Operating Segments

This amendment is applied retrospectively and clarifies that an entity must disclose the judgements made by management in applying the aggregation criteria, including a brief description of operating segments that have been aggregated and the economic characteristics (e.g., sales and gross margins) used to assess whether the segments are "similar".

The reconciliation of segment assets to total assets is only required to be disclosed if the reconciliation is reported to the chief operating decision maker, similar to the required disclosure for segment liabilities.

This policy became effective for annual periods starting on or after July 1, 2014.

The adoption of IFRS 8 did not have any material impact on the Company's Interim Condensed Consolidated Financial Statements.

IAS 16 Property, Plant and Equipment and IAS 38 Intangible Assets

These amendments are applied retrospectively and clarify in IAS 16 and IAS 38 that an asset may be revalued by reference to observable data on either the gross or the net carrying amount. In addition, the accumulated depreciation or amortization is the difference between the gross and carrying amounts of the asset. These policies became effective for annual periods starting on or after July 1, 2014.

The adoption of IAS 16 and IAS 38 did not have any material impact on the Company's Interim Condensed Consolidated Financial Statements.

IAS 24 Related-Party Disclosures

This amendment is applied retrospectively and clarifies that a management entity (an entity that provides key management personnel services) is a related party subject to the related-party disclosures. In addition, an entity that uses a management entity is required to disclose the expenses incurred for management services. This amendment is not relevant for the Company as it does not receive any management services from other entities.

Standards Issued but Not Yet Effective

IFRS 9 Impairment of financial instruments under IFRS 9

The impairment requirements in the new standard, IFRS 9 Financial Instruments, are based on an expected credit loss model and replace the IAS 39 Financial Instruments: Recognition and Measurement incurred loss model. The expected credit loss model applies to debt instruments recorded at amortised cost or at fair value through other comprehensive income, such as loans, debt securities and trade receivables, lease receivables and most loan commitments and financial guarantee contracts. Entities are required to recognise an allowance for either 12-month or lifetime expected credit losses ("**ECLs**"), depending on whether there has been a significant increase in credit risk since initial recognition. The ECL impairment requirements must be adopted with the other IFRS 9 requirements from 1 January 2018, with early application permitted.

IFRS 15 Revenue and Contracts with Customer´s

This amendment is applied retrospectively and clarifies the policy becomes effective from annual periods starting on or after January 1, 2018. Earlier application is permitted.

10 Internal Controls over Financial Reporting

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**"), quarterly the Company issues a "Certification of Interim Filings." This Certification requires certifying officers to state that they are responsible for establishing and maintaining Disclosure Controls and Procedures ("**DC&P**") and Internal Control Over Financial Reporting ("**ICFR**").

The Company has established a continuous control testing process with an independent auditor throughout the quarter. The process tests the value of our compliance program by:

- Performing a risk assessment to identify areas of high risk,
- Rationalizing key controls and reviewing and updating matrices,
- Increasing reliance on entity-level and automated application controls, and
- Identifying best practices and process improvement opportunities.

In the third quarter of 2015, 146 controls were tested over the 775 total controls the Company has implemented. The 775 controls will each be tested at least once in 2015. From this evaluation, the Company concluded that there are no material weaknesses or significant deficiencies in the design and effectiveness of ICFR for the financial quarter ended September 30, 2015.

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

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

The Company's internal control over financial reporting 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.

In the quarter ended September 30, 2015, there was no change in the Company's ICFR that has materially affected, or is reasonably likely to materially affect, the Company's ICFR.

11 Outlook

Pacific Exploration and Production continues to maintain a strict and disciplined approach for the year. The Company has reduced capital expenditures to approximately match cash flow in this lower oil price environment and has the flexibility and discretionary components to adjust to the external environment. In addition, cost reductions are expected to continue in 2015 through efficiency gains and operational adjustments. The outlook for 2015 was provided as guidance in mid-January 2015 and given the continuing volatility and uncertainty in oil prices was updated in August 2015 as follows:

- Net production of 150 to 156 Mboe/d, representing approximately 1% to 5% growth over 2014 production levels;
- Realized oil prices of approximately the WTI benchmark (US$/bbl);
- Expected operating costs that will continue to reflect the reductions made by the Company and are estimated at $24 to $26/boe; and
- G&A costs of $210 million, financing costs of $270 million and cash taxes of $100 million.

12 Further Disclosures

Royalties and High-Price Participation

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

Additional Production Share in the Quifa SW Field

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

Carrizales Field (Cravoviejo Block)

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

PAP Disagreement with the ANH

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

The Company disagrees with the ANH's interpretation, and asserts that in accordance with the exploration contracts, the five million barrel threshold should be applied on each of the exploitation areas within a contracted area. The Company has several contracts that are subject to the ANH high-price participation. One of these contracts is the Corcel Block, which was acquired as part of the Petrominerales acquisition and the only one for which an arbitration process has been initiated. However, the arbitration process for Corcel was under suspension at the time the Company acquired Petrominerales. The amount under arbitration is approximately $194 million plus related interest of $34 million, as at September 30, 2015. The Company also disagrees with the interest rate that the ANH has used in calculating the interest cost.

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

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

Update on Environmental Permits

Colombia

On August 24, 2015, the ANLA granted the Environmental Licence for Quifa North Field. Resolution 1027.

On September 2, 2015, the ANLA granted the Environmental Licence for Arrendajo Field. Resolution 1080.

On September 30, 2015, ANLA granted the Environmental Licence for Quifa North West Field. Resolution 1231.

Peru

During the third quarter of 2015, the Company could extend the certification of the management system through offshore operations.

Delisting from Brazil

The Company remains committed to growing its business in Brazil; however, because of the low trading volume of its BDRs on the BOVESPA, the Company announced on October 10, 2014 its intention to delist its BDRs from the BOVESPA. On February 2, 2015, the Company submitted its formal application to the CVM and BOVESPA to delist the BDRs and cancel the BDR program and received the applicable approvals from the CVM and BOVESPA on March 17, 2015.

13 Additional Financial Measures

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

Adjusted EBITDA

The Company uses the financial measure "Adjusted EBITDA" in this MD&A, whereas in the past we have used the term EBITDA. Our calculation of this measure has not changed from previous quarters, but the terminology has changed due to guidance provided by the Ontario Securities Commission. Management believes that Adjusted EBITDA is an important indicator of the Company's ability to generate liquidity through operating cash flow to fund future working capital needs, service outstanding debt, and fund future capital expenditures. The exclusion of non-cash and one-time items eliminates the impact on the Company's liquidity and normalizes the result for comparative purposes. Other issuers may calculate Adjusted EBITDA differently.

A reconciliation of Net Earnings to Adjusted EBITDA follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(in thousands of US$)	2015	2014	2015	2014
Net (loss) earnings [1]	**$ (617,318)**	**$ 3,484**	**$ (1,565,951)**	**$ 351,251**
Adjustments to net (loss) earnings				
Income tax (recovery) expense	(34,193)	179,478	(107,845)	368,333
Foreign exchange loss	71,887	22,841	113,081	10,972
Finance cost	71,954	61,412	228,929	187,562
Gain on risk management contracts	(136,558)	(8,005)	(67,921)	(9,330)
Loss (gain) of equity-accounted investees	17,692	(284)	(13,662)	(15,687)
Other expenses (income)	6,094	(57,983)	53,078	(22,833)
Share-based compensation	(8,880)	27,180	4,681	30,271
Equity tax	-	-	39,149	-
(Loss) attributable to non-controlling interest	(11,699)	(324)	(847)	(1,355)
Depletion, depreciation and amortization	344,577	407,280	1,148,735	1,165,625
Impairment and exploration expenses	568,013	-	1,016,980	-
Adjusted EBITDA	**$ 271,569**	**$ 635,079**	**$ 848,407**	**$ 2,064,809**

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

Funds Flow from Operations

	Three Months Ended September 30		Nine Months Ended September 30	
(in thousands of US$)	2015	2014	2015	2014
Cash flow from operating activities	$ (57,861)	$ 599,067	$ 138,396	$ 1,487,550
Changes in non-cash working capital	205,064	7,147	533,391	123,922
Deferred revenue net proceeds	50,000	-	(149,155)	-
Funds flow from operations	**$ 197,203**	**$ 606,214**	**$ 522,632**	**$ 1,611,472**

Net (Loss) Earnings from Operations

(in thousands of US$)	Three Months Ended September 30 2015	Three Months Ended September 30 2014	Nine Months Ended September 30 2015	Nine Months Ended September 30 2014
Net (loss) earnings [1]	$ (617,318)	$ 3,484	$ (1,565,951)	$ 351,251
Finance costs	71,954	61,412	228,929	187,562
Loss (gain) of equity-accounted investees	17,692	(284)	(13,662)	(15,687)
Equity tax	-	-	39,149	-
Foreign exchange loss	71,887	22,841	113,081	10,972
Gain on risk management contracts	(136,558)	(8,005)	(67,921)	(9,330)
Other expenses (income)	6,094	(57,983)	53,078	(22,833)
Income tax (recovery) expense	(34,193)	179,478	(107,845)	368,333
Loss attributable to non-controlling interest	(11,699)	(324)	(847)	(1,355)
Net (loss) earnings from operations	**$ (632,141)**	**$ 200,619**	**$ (1,321,989)**	**$ 868,913**

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

14 Sustainability Policies

For the third year in a row, Pacific E&P was included amongst the members of the North American Dow Jones Sustainability Index ("**DJSI**"). With this recognition, Pacific E&P reaffirms its position as an industry leader in sustainability along with a select group of nine companies that were chosen from a total of 34 that participated.

The criteria in which Pacific E&P scored above 80 in the DJSI, in many cases 10-20 percentile points above industry average, were: Code of Conduct, Payment Transparency, Supply Chain Management, Biodiversity, Environmental Policy and Management Systems, Water-Related Risks (100 points), Labour Practice Indicators and Human Rights, Occupational Health and Safety, Social Impacts on Communities, Social Reporting, Stakeholder Engagement and Talent Attraction and Retention.

The Company highlights the above because of the impacts associated with obtaining high scores on criteria that embody some of the industry's biggest challenges. The Company recognizes the importance of ensuring that its social, economic, governance and environmental dimensions continue performing in line with the highest standards.

The process of being awarded Block 192 in Peru was a challenge that was framed not only by the milestones in profitability and operations that the selected company would need to commit to, but also how it would manage relationships with the indigenous groups surrounding the block. The company used its Sustainability, Stakeholder Engagement, Human Rights and Gender declarations as well as its Social Investment Plan as part of its strategy to prioritize the wellbeing and development of these groups, which was well-received by the Peruvian stakeholders.

The Company is committed to leading energy efficiency processes, so in 2015 the Company re-certified its reinjection PADS in the Rubiales and Quifa fields under ISO 50001. The initiative was recognized by ANDESCO, the Colombian association for public services and communications, during September. The Company sees this recognition as an incentive to continue working with its Agrocascada and Petroelectrica de los Llanos projects in order to guarantee that they contribute to reducing the country's environmental footprint and expenses.

Pacific E&P also recertified its fields under the ISO 9001, ISO 14001 and OSHAS 18001 norms, consolidating its commitment to incident-free operations. In 2014, the Company reduced disabling injuries by 81%.

In light of the renewed Sustainable Development Goals, during the third quarter of 2015, Pacific E&P actively collaborated with the UN Global Compact Business for Peace platform Advisory Group to construct a paper on "Advancing Sustainable Development Goals by Supporting Peace: How Business Can Contribute." The paper reflects the Company's vision as to the mechanisms businesses can use to support peace-building efforts in its countries of operations.

In line with its Gender Equality Declaration and Five-Year Action Plan, Pacific E&P launched its "virtual office" pilot where employees could work 2-3 days a week from home, prioritizing those with family situations requiring increased location flexibility. The Company exposed its pilot in "Telework Week," an event sponsored by the Colombian Labour and Technology Ministries. Through this initiative, the Company reaffirms its commitment to improving the quality of life and productivity of its employees.

15 Risks and Uncertainties

The business, operations and earnings of the Company could be impacted by the occurrence of risks of all kinds, including financial, operational, technological, and political, that might affect the oil and gas industry generally or the Company specifically. The Company's Annual Information Form, filed on March 17, 2015, and available at www.sedar.com, contains a complete discussion of the risks and uncertainties that could have an effect on the business and operations of the Company.

Operational and financial performance are exposed to the fluctuations of WTI prices and foreign exchange

The Company is exposed to the uncertainty of the financial and economic global environment, and certain risks like liquidity and price volatility may affect the cash flow required to finance the growth of the business. In addition to the cash it generates, the Company uses debt instruments and has implemented hedging activities on WTI and foreign exchange to protect part of the capital at risk to ensure operational sustainability and to confront extreme situations in a challenging economic environment for short periods of time. Prolonged periods of low WTI prices or rising costs could result in projects being delayed or cancelled or in a charge for impairment that could have a significant effect on operational and financial results. The Company believes that it has the operational and financial flexibility to weather the current low oil and gas price environment in which it operates.

The Company will continue to monitor its working capital balances and commitments as changing economic and risk conditions emerge. As announced in early 2015, the Company has adjusted its business plan for 2015 to reflect the lower oil prices and the forecast of operating cash flow for the year. The Company believes it will be able to fund the investment capital plan from internally generated cash flows.

Business Uncertainties and Capital Structure

The Company's financial position has been significantly impacted by the significant decline in the price of oil and the pending loss of production from the Rubiales Field in June 2016. The Company has significant financial obligations and will face difficulties and challenges financing any Mexican assets independently given current industry and economic conditions.

The Company's current debt structure and limited access to additional financing due to restrictions associated with the terms of its long-term debt arrangements create material uncertainties that may cast doubt on the Company's ability to access capital.

On March 3, 2015, the Company agreed with its syndicate of lenders to amend the Revolving Credit Facility. Under the amended terms of the Revolving Credit Facility, the Company's permitted consolidated leverage ratio (debt-to-EBITDA) was increased from 3.5:1.0 to 4.5:1.0 based on a rolling four-quarter average. The other two financial covenants were not amended, being: (1) maintaining an interest coverage ratio of greater than 2.5; and (2) a net worth of greater than $1 billion, calculated as total assets less total liabilities, excluding those of excluded subsidiaries, being Pacific Midstream Ltd. and Pacific Infrastructure Ventures Inc. The amendments were supported by 100% of the lending syndicate, which is comprised of 20 international and local banks. Similar amendments have been made to the Credit Agreements. The Company was with the consolidated leverage and interest coverage covenants during the third quarter of 2015, including: (1) actual interest coverage ratio of 4.14 and (2) debt-to-EBITDA ratio of 4.35.

On September 29, 2015 the Company obtained a temporary waiver from its lenders under the Revolving Credit Facility in respect of the $1 billion net worth covenant, for a period of 90 days up to and including December 28, 2015. The Company's net worth, as calculated above, was $629 million as of September 30, 2015.

Efficiency and cost control are necessary to assure competitiveness

In this time of high volatility in the market, efficiency and cost control are key to business success. The Company's costs need to be managed in an efficient manner for capital and operational expenditures. Pacific E&P is working on several ways to identify potential improvements, including analysis to reduce G&A and lifting costs, to be more efficient. The Company is also working on synergies in supply chain management to maximize savings in long-term contracts with suppliers in the different countries in which it operates.

Production growth depends on the Company's ability to replace proved oil and gas reserves

The medium-term production growth plan requires adding reserves to replace production and increase the proved reserves and resources. The risks associated with this growth plan include:

- Disagreements in the joint venture agreements with partners in achieving the Company's goals,
- High competition for attractive resources acquisitions,
- Renew and reposition of opportunities portfolio to enhance recovery, and
- Delays in obtaining environmental permits.

Mitigation activities include a plan of reserves incorporation through exploration, acquisitions, enhanced oil recovery, and negotiations with governments and other stakeholders with diverse portfolios in terms of country and geological risk. In addition, capital projects for production and transportation systems will be continuously executed.

Major water disposal projects delivery

Successful execution of water disposal requires, among other things, the existence and availability of the necessary technology, engineering resources, and environmental licences to increase production in the Llanos Basin reservoirs. Several projects to manage this increasing volume of water are being initiated.

The nature of the Company's operations exposes it to a wide range of health, safety and environmental risks

Given the geographic range, operational diversity, and technical complexity of its operations, the Company is potentially exposed to Health, Safety and Environment ("**HSE**") risks. The Company has established, among other things:

- Procedures to select and evaluate contractors on their compliance with the Company's HSE guidelines;
- Improvements on and implementation of reliability and maintenance programs for operational facilities and equipment in order to guarantee the integrity of the company's assets;
- Performance of safety risk assessments on a regular basis in fields and operational facilities; and
- Emergency Response Plans in conjunction with partners and other operators in nearby areas, including reacting under simulated hazards.

A common practice in the oil and gas industry is to work with contractors, and the nature of the Company's business and its main production asset means it hires a significant number of contractors. The Company always maintains the highest standards in the industry and exceeds local regulations in order to ensure that it is in compliance with all HSE standards.

The ability to achieve the Company´s strategic objectives depends on how it strengthen stakeholder relationships

Keeping strong relationships with its main stakeholders in the regions where the Company operates is a key component of its strategy for sustainable growth. To help address the expectations of stakeholders, the Company has designed a plan that includes social investment projects in order to strengthen the existing Corporate Social Responsibility initiatives in the communities where it operate.

HR attraction, retention and succession planning as one of the core targets of the Company

One of the key success factors for Pacific E&P is the people. Attraction and retention of talent are essential to the Company's growth and sustainability, especially in terms of technical personnel and experienced management who can deliver on the needs of the business and answer the challenges that the Company is currently facing.

The nature of the Company's operations exposes it to a wide range of political developments and changes to regulatory environment and law.

The Company has operations in countries where political, economic and social transitions are taking place. These countries have experienced changes to the regulatory environment, changes on taxation, strikes, acts of war, and insurrections. All applicable events that may have a significant impact on the Company's activities and results have been identified and analyzed.

Operations can be exposed to security issues

The Company operates in different geographies where social or civil unrest or security events may not be within the control of the Company. The Company's portfolio in these countries can be exposed to these and other events, which may impact the business strategy. In order to minimize the collateral damage of the materialization of these risks, the Company has set up plans to protect its assets and people including formal Business Continuity Plans and Crisis Management Plans.

Fraud and corruption control is one of the main objectives of the Company

The Company is committed to working with transparency and with high ethical standards. A strong culture of ethics and transparency has been developed based on the Code of Ethics and Conduct. An assessment of fraud and corruption risk is performed annually according to the guidelines of Canada's Corruption of Foreign Public Officials Act ("**CFPOA**"), and an update of the Prevention of Asset Laundering and Terrorist Financing System is also performed. A program covering all employees and contractors for the prevention of money laundering is in place with the objective of strengthening the knowledge of this policy. In addition, in order to enhance the control environment, the Company continuously updates its Delegations of Authority procedures and the Code of Ethics and Conduct.

Future production growth depends on the delivery of large and complex infrastructure projects

Pacific E&P faces many challenges, including uncertain geology, frontier conditions, engineering resources, and restrictive technical, fiscal and regulatory conditions. These challenges are especially relevant when the Company operates in remote areas that require industrial services as well as extensive planning, access roads, production facilities, electrical generation and transmission, treating capacity and disposal of production water, storage and port facilities, and gas compression capacity, among other requirements, in order to deliver timely production in line with the Business Plan.

16 Advisories

Boe Conversion

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

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

Prospective Resources

Readers should give attention to the estimates of individual classes of resources and appreciate the differing probabilities of recovery associated with each class. Estimates of remaining (un-risked) recoverable resources include prospective resources that have not been adjusted for risk based on the chance of discovery or the chance of development and contingent resources that have not been adjusted for risk based on the chance of development. It is not an estimate of volumes that may be recovered. Actual recovery is likely to be less and may be substantially less or zero.

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates, assuming their discovery and development, and may be sub-classified based on project maturity. There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that any discovery will be technically or economically viable in order to produce any portion of the resources.

Translation

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

17 Abbreviations

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

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