PACIFIC RUBIALES ENERGY CORP.

MANAGEMENT DISCUSSION AND ANALYSIS
March 17, 2015
For the year ending December 31, 2014

Message to Shareholders

While 2014 started well, the last quarter of the year presented Pacific Rubiales and the industry with challenges not experienced for many years. Quickly recognizing the impact of a near-halving of oil prices, the Company commenced actions early in the fourth quarter to make significant adjustments in all areas of the business that will allow the Company to remain a low cost operator and weather this pricing environment. Those actions continued into 2015 and will be reflected in the financial results of 2015 and beyond as we continue to develop and produce oil and gas in Latin America.

Other than the price collapse in late 2014, the results point to another relatively good year for Pacific Rubiales, as both production and revenues continued to grow. The Company also saw important growth in production from light and medium oil exploration successes, as the production base continues to be diversified from the Rubiales field. In fact, in the past three years we have replaced production from the Rubiales field as total net production has grown from under 100,000 boe/d to current levels of just over 150,000 boe/d, despite a 14% decline in production from the Rubiales Field in 2014. As a result of making material reductions in our operating and cash costs, we are well positioned to face an ongoing weak oil price environment. We also have a flexible asset portfolio and capital expenditure program that allows the Company to adjust spending to match cash flows.

During 2014, we generated $2.5 billion in adjusted EBITDA and $2.0 billion in funds flow, on a record of $5.0 billion in revenues. For the fourth quarter of 2014, we earned revenues of $992 million and generated $419 million in adjusted EBITDA and $410 million in funds flow, including a $58 million gain from crude oil hedges. Our earnings were lower compared with the third quarter of 2014, mostly due to a non-cash impairment charge of $1.6 billion (including $193 million in exploration expenses) against our oil and gas assets and goodwill. It is important to understand that these impairments are non-cash and primarily the result of the drop in crude oil prices. Our operating netback for the year was $54.84/boe, also affected by the weakening of realized prices. We were able to partially mitigate the effect of the lower oil prices on our netback by reducing our combined operating costs to $27.28/boe in the fourth quarter ($30.51/boe for the full year), mainly attributed to our ongoing cost reduction programs and also the benefit of a weaker Colombian Peso against the U.S. Dollar. Our total unit operating costs have decreased by 25% since announcing a major program of cost reduction initiatives in 2013. We expect further operating cost reductions in 2015.

In 2014, we increased our production to 147.4 Mboe/d, a 14% growth compared with 2013, and at the low end of the Company's annual production guidance. Production at the Rubiales Field was below plan for the year, primarily impacted by limited water handling capacity and weather-related impacts on operations. However, we expect our Agrocascada reverse osmosis facility to commence operation by the second quarter of 2015, raising the water disposal capacity at the Rubiales Field by 0.5 million bwd. While the Rubiales Field was constrained, we delivered excellent exploration results with approximately 15 Mbbl/d production added from new light and medium oil discoveries. The Rubiales Field now represents approximately one-third of our total production. Net production in 2015 year-to-date has been strong, with production in the past month increasing to 152 Mboe/d, above our annual guidance target of 150 to 160 Mboe/d.

During the year we completed two transactions to monetize a portion of our infrastructure assets, being the sale of our 5% interest in the equity and capacity rights of the Ocensa pipeline for $385 million, and the sale of an interest in Pacific Midstream Ltd. ("**Pacific Midstream**") (which holds interests in pipelines and the electrical transmission line to the Rubiales and Quifa fields) for $320 million (with $240 million received late in the fourth quarter). The cash proceeds received in 2014, from these transactions, were used to pay down short-term bank loans and credit facilities. The sale of these midstream assets validate our successful strategy in investing in infrastructure projects in Colombia, and the value it generates. We expect additional sales of midstream assets during 2015.

Our financial and capital strategy remains focused on maintaining a healthy balance sheet by: (1) reducing operating and G&A costs; (2) suspending the discretionary quarterly dividend payment; (3) reducing capital expenditures to match cash flow under the prevailing oil price environment; (4) allocating capital to the most material and the highest return projects; (5) maintaining liquidity; and (6) implementing strategic liability management initiatives; all aimed at ensuring funding for future growth and generating strong returns to our shareholders. Under our current plans, we expect to see modest production growth in 2015. Our debt leverage ratio remains well below debt incurrence covenants in our senior note indentures of 3.5 times 12 month trailing debt to EBITDA and the recent successful renegotiation and relaxation of the current covenant on the $1 billion revolving credit facility and our bank debts to 4.5:1.0, is a testament to the support and confidence provided to us by our long-standing lenders.

In summary, Pacific Rubiales in 2015 is looking towards a return to a better pricing environment but is prepared and well positioned to withstand the current low oil price environment. We have a well thought out strategy of repeatable and profitable long-term growth, and the experience in executing our operating and capital programs to deliver results. We remain committed to building for the long-term benefit of our shareholders, employees, and other stakeholders, the leading independent E&P Company focused in Latin America.

Ronald Pantin
Chief Executive Officer
March 17, 2015

Content

Legal Notice – Forward-Looking Information and Statements

Certain statements in this Management, Discussion and Analysis (“**MD&A**”) constitute forward-looking statements. Often, but not always, forward-looking statements use words or phrases such as: "expects," "does not expect" 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, the 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 may be other unforeseen factors that create costs to the Company's program 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, 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 Audited Annual Consolidated Financial Statements and related notes for the years ending December 31, 2014 and December 31, 2013. 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 years ending December 31, 2014 and December 31, 2013, unless otherwise stated.

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 20.

Additional information with respect to the Company has been filed with Canadian securities regulatory authorities, including the Company's quarterly and annual financial statements and the Annual Information Form, which are available on SEDAR at www.sedar.com, SIMEV at www.superfinanciera.gov.co/web_valores/Simev, BOVESPA at www.bmfbovespa.com.br and on the Company's website at www.pacificrubiales.com. 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 translated version, the English document shall prevail and be treated as the governing version.

1. Highlights for the Year and the Quarter Ended December 31, 2014

Financial and Operating Summary

(in thousands of US$ except per share amounts or as noted)	Year Ending December 31 2014	Year Ending December 31 2013 [(1)]	Three Months Ending December 31 2014	Three Months Ending December 31 2013 [(1)]
Financials				
Oil and gas sales ($)	**$ 4,950,022**	$ 4,626,859	**$ 991,508**	$ 1,202,551
Adjusted EBITDA [(2)]	**2,484,085**	2,566,957	**419,276**	655,327
Adjusted EBITDA margin (Adjusted EBITDA/Revenues)	**50%**	55%	**42%**	54%
Per share - basic ($) [(3)]	**7.87**	7.95	**1.33**	2.02
Funds flow from operations [(2)]	**2,021,241**	1,913,112	**409,769**	476,851
Funds flow from operations margin (Funds flow from operations/Revenues)	**41%**	41%	**41%**	40%
Per share - basic ($) [(3)]	**6.41**	5.92	**1.30**	1.47
Net earnings (loss) from operations before impairment and exploration expenses [(5)]	**832,265**	1,171,889	**(40,564)**	312,520
Net (loss) earnings [(4)]	**(1,309,625)**	426,082	**(1,660,876)**	140,412
Per share - basic ($) [(3)]	**(4.15)**	1.32	**(5.26)**	0.43
Cash dividends	**207,553**	195,760	**51,687**	53,545
Cash dividends per share	**0.66**	0.61	**0.16**	0.17
Sales and Production				
Average sales volumes (boe/d)	**158,026**	134,621	**161,445**	143,864
Average oil and gas sales (boe/d)	145,941	130,789	147,208	140,465
Average trading sales (bbl/d)	12,085	3,832	14,237	3,399
Average net production (boe/d)	**147,423**	129,386	**147,075**	134,313
Average net production oil (bbl/d)	137,076	118,507	137,019	123,371
Average net production gas (boe/d)	10,347	10,879	10,056	10,942
Combined price ($/boe)	**85.35**	93.95	**65.64**	90.66
Combined netback ($/boe)	**54.84**	60.77	**38.36**	59.43
Operating Activities				
Capital expenditures	**2,382,296**	2,065,525	**757,842**	625,398
Capital expenditures for new acquisitions	**289,279**	1,133,522	**-**	1,020,475
Successful exploration, appraisal and stratigraphic drilled wells (gross)	**43**	23	**15**	12

1. Net Earnings for 2013 have been restated upon the first-time adoption of IFRS 9 – Financial Instruments. Refer to Note 30 of the Audited Annual Consolidated Financial Statements.
2. See "Additional Financial Measures" on page 36.
3. The basic weighted average number of common shares for the year ending December 31, 2014 and 2013 was 315,487,230 and 322,989,949 respectively. The same for the fourth quarter of 2014 and 2013 was 315,854,992 and 324,173,884, respectively.
4. Net (loss) earnings attributable to equity holders of the parent.
5. See additional comments on page 18.

Breakdown of Crude Oil & Gas and Trading Results

	Year Ending December 31					
	2014			2013		
	Oil & Gas	Trading	Total	Oil & Gas	Trading	Total
Volume sold (boe/d)	**145,941**	**12,085**	**158,026**	**130,789**	**3,832**	**134,621**
Average Realized Price ($/boe)	**85.35**	**91.51**	**85.82**	**93.95**	**101.40**	**94.16**
Financial Results (in thousands of US$)						
Revenues	**4,546,359**	**403,663**	**4,950,022**	**4,485,046**	**141,813**	**4,626,859**
Cost of operations oil & gas	**1,625,840**	**400,674**	**2,026,514**	**1,583,673**	**139,657**	**1,723,330**
Production cost of barrels sold	805,397	400,674	1,206,071	687,714	139,657	827,371
Transportation cost (trucking and pipeline)	690,060	-	690,060	637,302	-	637,302
Diluent cost	115,121	-	115,121	239,167	-	239,167
Other costs (Royalties paid in cash)	77,978	-	77,978	87,838	-	87,838
Overlift/Underlift	(62,716)	-	(62,716)	(68,348)	-	(68,348)
Gross margin	**2,920,519**	**2,989**	**2,923,508**	**2,901,373**	**2,156**	**2,903,529**

	Three Months Ending December 31					
	2014			2013		
	Oil & Gas	Trading	Total	Oil & Gas	Trading	Total
Volume sold (boe/d)	**147,208**	**14,237**	**161,445**	**140,465**	**3,399**	**143,864**
Average Realized Price ($/boe)	**65.64**	**78.32**	**66.75**	**90.66**	**99.11**	**90.86**
Financial Results (in thousands of US$)						
Revenues	**888,930**	**102,578**	**991,508**	**1,171,561**	**30,990**	**1,202,551**
Cost of operations oil & gas	**369,515**	**101,263**	**470,778**	**403,665**	**30,751**	**434,416**
Production cost of barrels sold	185,675	101,263	286,938	180,550	30,751	211,301
Transportation cost (trucking and pipeline)	147,885	-	147,885	158,392	-	158,392
Diluent cost	24,540	-	24,540	27,736	-	27,736
Other costs (Royalties paid in cash)	11,802	-	11,802	57,227	-	57,227
Overlift/Underlift	(387)	-	(387)	(20,240)	-	(20,240)
Gross margin	**519,415**	**1,315**	**520,730**	**767,896**	**239**	**768,135**

Highlights

Operational

- 14% increase year-over-year in net production to 147,423 boe/d, close to low end of the Company's guidance (148,000 - 162,000 boe/d). Net production for the quarter averaged 147,075 boe/d, 10% higher than the same quarter of 2013, including 123% year-over-year increases from light and medium oil fields.
- Net production from the Rubiales field decreased to 60,368 bbl/d from 70,214 bbl/d in 2013 primarily due to restricted water disposal capacity and adverse weather conditions impacting operations. The reduced production at the Rubiales field was offset with growth in light and medium oil fields, which now represent more than 40% of total net oil and gas production. The Rubiales field now represents only one-third of current production and only 41% of the total net 2014 production, down from 54% for the year 2013.
- At the Quifa SW field, net production increased to 26,079 bbl/d during the fourth quarter of 2014, 15% higher than the same period of 2013 and 10% higher than the third quarter of 2014, in part from the tie-in of additional producing wells and the impact of lower oil prices on the PAP royalty volumes.
- Phase 1 of the Central Production Facilities construction at the CPE-6 Block was completed in late 2014. These facilities are designed to process up to 8,000 bbl/d heavy oil. Year-to-date production from seven exploration and appraisal wells has averaged approximately 1.3 Mbbl/d (total gross production). Given the current low oil price environment, the Company has suspended drilling and development work in the block and will review that decision pending partner discussions and approvals, in the second half of the year.

Financial

- Revenue increased in 2014 to $5.0 billion from $4.6 billion in 2013, despite the decline in crude oil market prices throughout the second half of 2014. Average oil and gas sales (including trading) for the year were 158,026 boe/d, 17% higher compared to 134,621 boe/d for 2013, consistent with the increase in production and crude oil trading sales.
- Combined operating netback on oil and gas production for the year was $54.84/boe, lower than the $60.77/boe in 2013. The decrease was entirely attributable to the significant decline in the market prices for crude oil. At the same time, the Company achieved a significant reduction in total operating costs (including over/under lifts and other costs) by $2.67/boe to $30.51/boe, mitigating the impact from the lower realized prices and reaching the targeted guidance range of $30/boe to $33/boe.
- Adjusted EBITDA for 2014 was $2.5 billion and Funds Flow was $2.0 billion. Adjusted EBITDA was lower than the previous year primarily due to realized prices. For the fourth quarter of 2014, Adjusted EBITDA decreased by 36% to $419 million from $655 million in 2013.
- Net loss for the year was $1.3 billion, mainly as a result of the $1.3 billion non-cash impairment charge (after-tax) taken on oil and gas assets and exploration expenses ($1.6 billion before tax), reflecting the significant decline in crude oil prices. Other non-cash items affecting earnings included unrealized foreign exchange losses, deferred income taxes, and DD&A also contributed to the loss for the year.

Proved plus Probable reserves ("2P")

- Total 2P net after royalties reserves certified at 510.9 MMboe as at December 31, 2014, 17% lower compared with 613.3 MMboe at December 31, 2013.
- Proved reserves (1P) were 315.0 MMboe as at December 31, 2014 compared with 388.6 MMboe at December 31, 2013, with the decrease primarily attributable to lower reserves at the Rubiales field.

Exploration

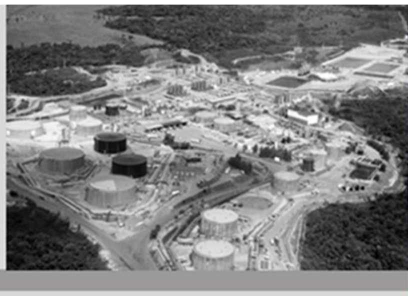
- 56 exploration wells (including stratigraphic and appraisal wells) were drilled, resulting in 43 discoveries, achieving a 77% success rate for the year.
- Exploration successes primarily located in the Central and Deep Llanos will potentially add up to 15 Mbbl/d of light oil production per day.
- In Peru, the Los Angeles well commenced long-term production testing in September 2014 and continues to produce on natural flow at approximately 2,200 bbl/d.
- In Brazil, at the non-operated shallow water offshore Block S-M-1165 (Pacific Rubiales - 35%) (Santos Basin), the 2013 Kangaroo discovery was evaluated with one exploration appraisal well and two side-track delineation wells. Drill stem testing over three oil-bearing intervals achieved a maximum oil flow rate of 3,700 bbl/d and confirmed the potential of Kangaroo as a commercial discovery.

Balance Sheet Management

- During 2014 we improved our overall liquidity by repaying the majority of our short-term debt obligations using the proceeds from the issuance of $750 million 5.625% senior notes due 2025.
- In December 2014 we agreed to sell approximately 43% of our interests in Pacific Midstream (which owns the ODL and Bicentenario Pipelines, the Petroelectrica power transmission line, and the future LNG project), to the International Finance Corporation ("**IFC**") and a consortium of investors. We received $240 million in cash in December 2014 and the remaining $80 million are expected to be received in 2015 upon completion of certain condition precedents and the completion and transfer of the LNG project.
- As part of the Company's cost cutting initiatives, the Company's depository receipts were delisted from the BOVESPA on March 17, 2015 which will result in annual savings of approximately $1 million per year in compliance and translation fees.

Business Opportunities

- In October 2014 we signed a three year Memorandum of Understanding and Cooperation with Mexico's state oil company Petróleos Mexicanos ("**Pemex**"), establishing the basis for discussions and analysis of potential oil and gas cooperation in Mexico.
- In December 2014, we also entered into a memorandum of understanding with the Mexican conglomerate Alfa S.A.B. de C.V. ("**Alfa**") to create a joint venture for bidding in the 2015 bid rounds in Mexico, the acquisition of service contracts for migration to E&P contracts, and the development of oil and gas assets and other ancillary business opportunities.



2. Operating Netbacks

Oil & Gas Operating Netback

Combined operating netbacks during 2014 and 2013 are summarized below:

	Year Ending December 31					
	2014			2013		
	Crude Oil	Natural Gas	Combined	Crude Oil	Natural Gas	Combined
Average daily volume sold (boe/day)(1)	**135,622**	**10,319**	**145,941**	**120,002**	**10,787**	**130,789**
Operating netback ($/boe)						
Crude oil and natural gas sales price	89.46	31.27	85.35	99.05	37.27	93.95
Production cost of barrels sold (2)	15.98	3.86	15.12	15.24	5.11	14.41
Transportation (trucking and pipeline) (3)	13.93	0.07	12.95	14.54	0.10	13.35
Diluent cost	2.33	-	2.16	5.46	-	5.01
Total operating cost	**32.24**	**3.93**	**30.23**	**35.24**	**5.21**	**32.77**
Other costs (4)	0.44	0.04	0.41	1.34	0.01	1.23
Royalties paid in cash	0.98	2.00	1.05	0.43	2.61	0.61
Overlift/Underlift (5)	(1.26)	(0.03)	(1.18)	(1.56)	-	(1.43)
Total operating cost including overlift/underlift, royalties paid and other costs	**32.40**	**5.94**	**30.51**	**35.45**	**7.83**	**33.18**
Operating netback crude oil and gas ($/boe)	**57.06**	**25.33**	**54.84**	**63.60**	**29.44**	**60.77**

1. Combined operating netback data is based on weighted average of daily volume sold, which includes diluents necessary for the blending of the 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 the delivery points for customers.
4. Other costs mainly correspond to inventory fluctuation, storage cost and 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 $62.7 million income during 2014 ($0.4 million income for the fourth quarter of 2014).

In 2014, the combined crude oil and gas operating netback was $54.84/boe, $5.93/boe lower compared with the same period of 2013 ($60.77/boe). Crude oil operating netback was $57.06/bbl, 10% lower compared with the same period of 2013 ($63.60/bbl). The lower netback was mainly attributable to the decline in crude oil market prices, which resulted in lower realized prices of $85.35/boe on a combined basis for 2014 compared with $93.95/boe in 2013. At the same time, the Company achieved a significant reduction in total operating costs (including over/under lifts and other costs) by $2.67/boe to $30.51/boe. Further cost reductions are expected in 2015.

Combined operating netbacks for the fourth quarter of 2014 and 2013 are summarized below:

	Three Months Ending December 31					
	2014			2013		
	Crude Oil	Natural Gas	Combined	Crude Oil	Natural Gas	Combined
Average daily volume sold (boe/day)(1)	**137,083**	**10,125**	**147,208**	**129,547**	**10,918**	**140,465**
Operating netback ($/boe)						
Crude oil and natural gas sales price	68.27	29.97	65.64	95.54	32.69	90.66
Production cost of barrels sold (2)	14.40	4.42	13.71	14.80	4.24	13.98
Transportation (trucking and pipeline) (3)	11.70	0.33	10.92	13.29	-	12.26
Diluent cost	1.95	-	1.81	2.32	-	2.14
Total operating cost	**28.05**	**4.75**	**26.44**	**30.41**	**4.24**	**28.38**
Other costs (4)	0.16	0.09	0.16	3.73	-	3.45
Royalties paid in cash	0.64	1.66	0.71	0.80	3.02	0.97
Overlift/Underlift (5)	(0.03)	0.04	(0.03)	(1.71)	0.07	(1.57)
Total operating cost including overlift/underlift, royalties paid and other costs	**28.82**	**6.54**	**27.28**	**33.23**	**7.33**	**31.23**
Operating netback crude oil and gas ($/boe)	**39.45**	**23.43**	**38.36**	**62.31**	**25.36**	**59.43**

Notes: Refer to the year basis operating netback.

For the fourth quarter 2014, the combined crude oil and gas operating netback was $38.36/boe compared with $59.43/boe for the same period in 2013. Crude oil operating netback was $39.45/bbl, 37% lower compared to the same period of 2013 ($62.31/bbl). The lower netback was entirely attributable to the decline in crude oil market prices, which resulted in significantly lower realized prices of $65.64/boe on a combined basis, compared with $90.66/boe for the fourth quarter of 2013.

The decline in oil prices was partially offset by the cost reductions achieved in 2014. The Company has reduced costs in all three underlying operating cost categories: production, transportation, and diluent. Production costs decreased from $13.98/boe in the fourth quarter of 2013 to $13.71/boe in the fourth quarter of 2014, as a result of field cost optimizations and the startup of the PEL power transmission line project. Transportation cost for the quarter decreased from $12.26/boe in 2013 to $10.92/boe for 2014 as disruptions on the Bicentenario Pipeline eased in the fourth quarter. Specifically, the pipeline was not operational for 29 days in the fourth quarter of 2014, compared with 41 days in the third quarter, 80 days in the second quarter and 52 days in the first quarter of 2014. Our diluent cost continued to decrease as we fully utilized the production of light and medium oil from prior acquisitions and new discoveries, plus accessing new lower cost diluent supply arrangements.

Trading Netback

Crude oil trading	**Year Ending December 31**		**Three Months Ending December 31**	
	2014	**2013**	**2014**	**2013**
Average daily volume sold (bbl/d)	**12,085**	**3,832**	**14,237**	**3,399**
Operating netback ($/bbl)				
Crude oil traded sales price	91.51	101.40	78.32	99.11
Cost of purchases of crude oil traded	90.84	99.86	77.31	98.35
Operating netback crude oil trading ($/bbl)	**0.67**	**1.54**	**1.01**	**0.76**

During the year 2014 the total volume of oil sold for trading increased to 4.4 MMbbl from 1.4 MMbbl during 2013. In terms of average daily volume and netback, we sold on average 12,085 bbl/d during 2014 at a netback of $0.67/bbl, compared with 3,832 bbl/d in 2013 with a netback of $1.54/bbl.

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. Further, our trading business brings two additional benefits. First, the light and medium crude being traded also act 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 in turn improve our marketing and bargaining position with respect to export cargoes.

We expect our trading volumes to continue growing in 2015 as the Bicentenario pipeline operates at a high level of utilization, as well as our market-leading position in Colombia giving us access to third party light and medium crude oil supplies.

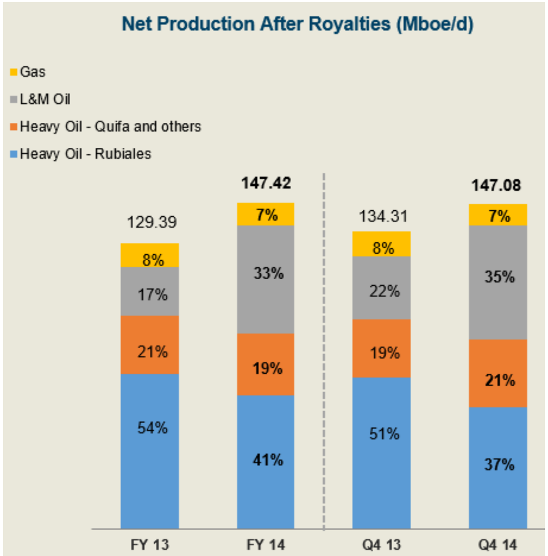
3. Operational Results

Production and Development Review

During 2014, average net production after royalties and internal consumption totaled 147,423 boe/d, representing an increase of 14% year-over-year. Average net production for the fourth quarter of 2014 reached 147,075 boe/d, 10% higher than the 134,313 boe/d for the same quarter of 2013.

We have significantly increased our light and medium oil production since 2013 through targeted acquisitions and exploration discoveries. Light and medium net oil production increased 123% year-over-year to 48,982 bbl/d from 21,948 bbl/d. There was a 78% increase in the fourth quarter of 2014 from 28,881 bbl/d in the same period of 2013. Light and medium oil production now represents 33% of our annual total net oil and gas production, while production from the Rubiales Field represented 41% of the total year net production, down from 54% for 2013.

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



Full Year 2014 Production

	Average Year Production (in boe/d)					
	Total field production		Gross share before royalties [1]		Net share after royalties	
Producing fields - Colombia	**2014**	**2013**	**2014**	**2013**	**2014**	**2013**
Rubiales / Piriri	180,519	208,763	75,460	87,768	60,368	70,214
Quifa SW [2]	56,573	55,031	33,607	32,754	23,685	23,610
	237,092	**263,794**	**109,067**	**120,522**	**84,053**	**93,824**
Other fields in Colombia						
Light and medium [3]	54,521	28,979	49,907	22,179	46,341	20,593
Gas [4]	11,372	11,183	10,347	10,879	10,347	10,879
Heavy oil [5]	6,312	4,455	4,273	3,041	4,041	2,735
	72,205	**44,617**	**64,527**	**36,099**	**60,729**	**34,207**
Total production Colombia	**309,297**	**308,411**	**173,594**	**156,621**	**144,782**	**128,031**
Producing fields in Peru						
Light and medium	5,650	2,766	2,641	1,355	2,641	1,355
	5,650	**2,766**	**2,641**	**1,355**	**2,641**	**1,355**
Total production Colombia and Peru	**314,947**	**311,177**	**176,235**	**157,976**	**147,423**	**129,386**

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 to a high-price clause 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 acquired from LAEFM Colombia Ltda. ("**LAEFM**") effective April 1, 2014 pursuant to a transaction that closed on August 12, 2014, which produced at 3,626 bbl/d. Subject to approval from Ecopetrol and the Agencia Nacional de Hidrocarburos ("**ANH**"), (if applicable), the Company is in the process of divesting its participation in the Moriche, Las Quinchas, Guasimo, Chipalo and Cerrito blocks.
4. Includes La Creciente, Dindal / Rio Seco, Abanico, Cerrito, Carbonera and other producing fields.
5. Includes Cajua, Sabanero, CPE-6, Rio Ariari, Prospecto S and Prospecto D fields.

Fourth Quarter 2014 Production

	Average Quarter Production (in boe/d)					
	Total field production		Gross share before royalties (1)		Net share after royalties	
Producing fields - Colombia	**Q4 2014**	**Q4 2013**	**Q4 2014**	**Q4 2013**	**Q4 2014**	**Q4 2013**
Rubiales / Piriri	166,052	204,308	68,864	85,571	55,091	68,456
Quifa SW (2)	60,209	55,348	35,724	32,896	26,079	22,586
	226,261	**259,656**	**104,588**	**118,467**	**81,170**	**91,042**
Other fields in Colombia						
Light and medium (3)	55,132	36,663	51,783	29,605	48,120	27,574
Gas (4)	11,304	11,581	10,056	10,942	10,056	10,942
Heavy oil (5)	6,872	5,516	4,655	3,736	4,441	3,511
	73,308	**53,760**	**66,494**	**44,283**	**62,617**	**42,027**
Total production Colombia	**299,569**	**313,416**	**171,082**	**162,750**	**143,787**	**133,069**
Producing fields in Peru						
Light and medium	7,493	2,539	3,288	1,244	3,288	1,244
	7,493	**2,539**	**3,288**	**1,244**	**3,288**	**1,244**
Total production Colombia and Peru	**307,062**	**315,955**	**174,370**	**163,994**	**147,075**	**134,313**

Notes: Refer to the Full-Year 2014 Production table on page 9.

Colombia

Net production after royalties in Colombia rose to 144,782 boe/d (309,297 boe/d total field production) in 2014 from 128,031 boe/d (308,411 boe/d total field production) in 2013, representing an increase of 13% compared to 2013, mainly as a result of:

- Light and medium oil production increased by 25,196 bbl/d in 2014 from 21,145 bbl/d in 2013, mainly attributable to the Petrominerales acquisition.
- 118 development wells that were drilled during the fourth quarter of 2014.
- A decrease in net production at the Rubiales field of 14% in comparison with 2013. 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 and the impact of the abnormal weather conditions.

During the fourth quarter of 2014, average net production after royalties in Colombia rose to 143,787 boe/d (299,569 boe/d total field production) from 133,069 boe/d (313,416 boe/d total field production) in the same period of 2013, representing an increase of 8%.

Additionally, the lower WTI prices during 2015 may increase our participation in production for the Quifa SW Field and others where the High Prices Clause (PAP) has been activated in prior periods. For instance, in Quifa SW a $60/bbl price for WTI would mean a 2.6% high price participation, a $70/bbl average would correspond to 6.5%, and a WTI of $54/bbl or less would mean 0% is paid, compared to the 8% to 15% range that was applied to that field during 2014.

Peru

Production from Peru corresponds to the 49% participating share of production from Block Z-1 and a 30% working interest in the Los Angeles discovery on Block 131. Net production after royalties for 2014 was 2,641 bbl/d (total gross field production of 5,650 bbl/d). Net production for the fourth quarter of 2014 averaged 3,288 bbl/d (total gross field 7,493 bbl/d) with gross production from Block 131 increasing by 1,849 bbl/d (553 bbl/d net) and from Block Z-1 increasing by 905 bbl/d (431 bbl/d net) compared to the third quarter of 2014.

Two new wells in the Corvina Field, CX15-10D and CX15-14D, started production in October and December respectively. These new wells added an initial production growth of 1,190 bbl/d gross. Production from Block Z-1 is expected to increase in 2015 from development drilling in the Corvina and Albacora fields.

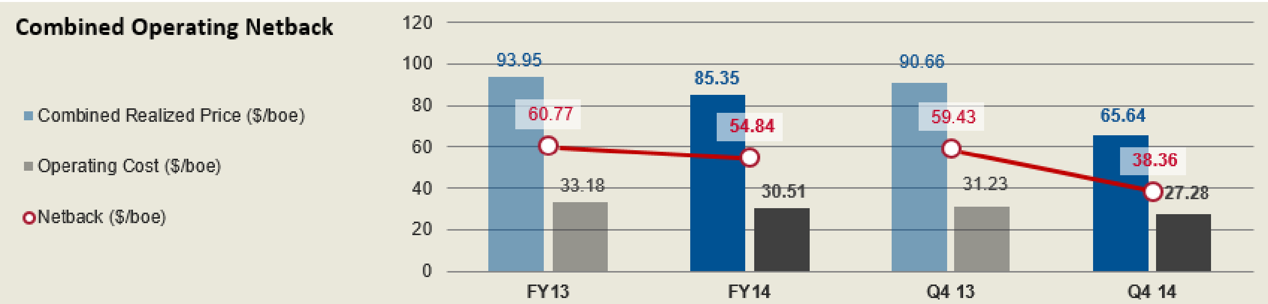
Sales, Trading and Pricing

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			
	Year Ending December 31		Three Months Ending December 31	
Colombia and Peru	**2014**	**2013**	**2014**	**2013**
Oil (bbl/d)	135,622	120,002	137,083	129,547
Gas (boe/d)	10,319	10,787	10,125	10,918
Trading (bbl/d)	12,085	3,832	14,237	3,399
Total barrels sold (in boe/d)	158,026	134,621	161,445	143,864
Realized Prices				
Oil realized price ($/bbl)	89.46	99.05	68.27	95.54
Gas realized price ($/boe)	31.27	37.27	29.97	32.69
Combined realized price oil and gas $/boe (excluding trading)	85.35	93.95	65.64	90.66
Trading realized price ($/bbl)	91.51	101.40	78.32	99.11
Reference Market Prices				
WTI NYMEX ($/bbl)	92.91	98.05	73.20	97.61
BRENT ICE ($/bbl)	99.45	108.70	77.07	109.35
Guajira Gas Price ($/MMBtu) (1)	5.65	5.81	5.67	5.65
Henry Hub average Natural Gas Price ($/MMBtu)	4.26	3.73	3.83	3.85

1. The domestic natural gas sales price is referenced to Market Reference Price ("MRP") for gas produced in La Guajira Field.

During 2014, oil and gas sales totaled 158,026 boe/d (134,621 boe/d in 2013), representing an increase of 17% year-over-year, mainly driven by an increase in oil production. Oil and gas sales for the fourth quarter of 2014 reached 161,445 boe/d, representing a 12% increase from the volumes reported for the fourth quarter of 2013 (143,864 boe/d in 2013).



In the fourth quarter of 2014, price declines reflected continued growth in U.S. oil production along with weakening outlooks for the global economy and oil demand growth. The Organization of the Petroleum Exporting Countries' ("**OPEC**") decision in late November 2014 to maintain its current crude oil production target, despite lower oil prices, put additional downward pressure on price expectations.

In the fourth quarter of 2014 ICE Brent decreased by $32.28/bbl to $77.07/bbl as compared to $109.35/bbl in the fourth quarter of 2013. Also, WTI NYMEX decreased by $24.41/bbl to $73.20/bbl as compared to $97.61/bbl in the fourth quarter of 2013.

Exploration Review and Update

During 2014, the Company drilled or was a partner in 56 wells consisting of 27 exploration wells, 25 appraisal wells and four stratigraphic wells. Of the total wells, 43 found economic hydrocarbon columns, one well encountered a thin uneconomic hydrocarbon column and 11 were abandoned as dry holes, for an overall 77% success rate. Exploration in 2014 resulted in new discoveries in the Canaguaro, Cubiro, Llanos–19, Corcel, Guatiquia, and Quifa blocks in Colombia, the PPL-475 (formally PPL-237) Block in Papua New Guinea and on Block S-M-1165 Block offshore Brazil.

In the fourth quarter of 2014, the Company drilled or participated in 17 exploration wells, including 13 wells located in Colombia, two in Peru, one in the Santos Basin of offshore Brazil and one in Papua New Guinea. The Company completed the acquisition of 12,500 kilometers of 2D seismic in offshore Guyana and completed the acquisition of 2,361 kilometers of aeromagnetic and aerogravimetric survey data in Colombia. The exploration drilling results for the year and three-month period ending December 31, 2013 and 2012 are as follows:

	Year Ending December 31		Three Months Ending December 31	
	2014	2013	2014	2013
Successful exploratory wells	15	15	8	5
Successful appraisal wells (1)	24	7	6	6
Successful stratigraphic wells	4	1	1	1
Dry wells	13	11	2	6
Total	**56**	**34**	**17**	**18**
Success rate	**77%**	**68%**	**88%**	**67%**

1. Includes horizontal appraisal wells.

Update on Wells Drilled During the Fourth Quarter of 2014

Brazil

Block S-M-1165: 35% Interest

In early November 2014, the operator of the block (Karoon Petróleo e Gas Ltda.) spudded the Kangaroo-2 appraisal well. The block is located in the offshore Santos Basin, Brazil. The Kangaroo-2 well was drilled to a TD of 7,773 feet MD, approximately four kilometers south and 820 feet up-dip from the Kangaroo-1 oil discovery made in 2013. Wireline logging in Kangaroo-2 confirmed the successful appraisal of the earlier Kangaroo-1 discovery, with five separate oil-bearing reservoir sand intervals of Paleocene and Maastrichtian age encountered, with a gross oil column thickness totaling 820 feet. Separate flow tests across three different intervals resulted in stabilized flow rates of between 1,820 bbl/d to 3,450 bbl/d with 31° to 33° API oil recovered from the Paleocene and 38° API oil recovered from the Maastrichtian. In early 2015, two successful side-track wells were drilled both up-dip and down-dip from the Kangaroo-2 wellbore, to better define potential reservoir resource size and recovery factors.

Peru

Block 131: 30% Interest

The Los Angeles-1X well in Block 131, drilled in late 2013, is a significant oil discovery in the Ucayali Basin in onshore Peru. The well encountered 62 feet of net pay in the Cretaceous-aged Cushabatay Formation. Based on initial testing, the operator (Cepsa Peru S.A.) commenced a long-term extended production test in late September 2014. The well is producing on natural flow at rates of between 2,100 and 2,300 bbl/d of 45° API oil, no watercut and a low gas oil ratio. To date the well has produced over 275 Mbbl of total cumulative oil, including earlier tests. Production from the Los Angeles-1X well is being trucked approximately 95 kilometers and sold to the Pucallpa refinery in Peru.

The Los Angeles Noi-3X exploration well spud in early December 2014 and was drilled 1.3 kilometers north of Los Angeles–1X. A TD of 8,882 feet MD in the Copacabana Formation was reached in late January. The Noi Formation was the primary target in the well. However, upon logging the only pay encountered in the well was 43 feet net pay (95 feet gross reservoir interval) in the Upper Cushabatay Formation, based on petrophysical interpretation. In early February 2015, the well was completed and tested. During a 12 hour test period under natural flow, the well tested 1,350 bbl/d with zero watercut through a 20/64” choke at 265 psi well head pressure. A total of 1.3 Mbbl of 43° to 45° API oil was produced during the test period. The Los Angeles Noi-3X well is within the same structural closure of Los Angeles-1X and validates the area of this pool to the north and confirms the continuity of the pool, with a similar oil-water contact present in both wells.

Block Z-1: 49% Interest

The Albacora Field located in offshore Peru in Block Z-1 has traditionally produced light oil from the Early Miocene Middle Zorritos sandstones at a depth of approximately 10,000 feet. Five wells (A-18DST, A-26D, A-19D, A-21D and A-27D) were drilled in 2014, also targeting deeper sandstones in a four-way closure anticline structure identified on new 3D seismic. The first three wells were completed in the deeper exploration targets and commingled with the Zorritos sandstones. Production logging test data acquired in October 2014 confirmed 35° to 36° API oil production from the deeper sandstone targets. These deeper oil-bearing sandstones have the potential to add significant production and reserves. Further analysis and testing is underway to optimize and exploit the opportunity provided by the deeper zone.

Block 116: 50% Interest

In Block 116 the Company conducted an unsuccessful test across one Tertiary age sand in the Fortuna-1XD well. The well was subsequently plugged and abandoned. Drilling challenges prevented the well from reaching the Cretaceous exploration target.

Colombia

Guatiquia Block: 100% Interest

In the Guatiquia Block, the Ardilla-1 exploration well reached total MD of 12,825 feet on October 19, 2014. Petrophysical interpretation indicates the presence of 68 feet of total net pay in the well, including seven feet in the Mirador, 17 feet in the Guadalupe and 44 feet in the Lower Sandstone-1 Unit (with no water contact present). This result is consistent with the previously drilled Ceibo-1X well, on a separate structure, which was successfully completed in the Lower Sandstone 1A unit and has produced 1.2 million barrels since February 2014. This well is currently producing over 3,800 bbl/d of oil.

As of February 28, 2015, Ardilla-1 in the LS-1 interval was producing 1,156 bbl/d of 19° API oil with a 47% watercut, a gas-oil ratio of 83 cf/bbl with a tubing head pressure of 145 psi on 60 Hz ESP artificial lift. The well has produced over 192 Mbbl of oil to date. These results continue to confirm that several potentially large but structurally separate oil accumulations are present down dip of the previously discovered Candelilla pool. The three discoveries (Ceibo, Avispa and Ardilla) are all in separate and distinct structures located along the same geological trend of Yatay and Candelilla producing oil fields. The results of our recent drilling indicate the possibility of a significantly larger petroleum accumulation at the Guadalupe Formation level than was originally anticipated. Two wells, Avispa-2 and 3, drilled during the first quarter of 2015 confirmed this concept.

The Gulupa-1 well is located in the southeast corner of the Guatiquia Block, targeting a combination structural stratigraphic trap in the Mirador and Guadalupe Formations. The Gulupa-1 well reached a TD of 10,650 feet MD on November 29, 2014. Petrophysical interpretation indicates a presence of 120 feet of net potential pay including ten feet of net pay in the Guadalupe Formation and 110 feet of potential net pay in the Mirador Formation. As of February 28, 2015, Gulupa-1 in the Guadalupe Formation was producing 201 bbl/d of 14.0° API oil, 84.8% BSW, 14 psi on 60 Hz ESP artificial lift. The well has produced over 13 Mbbl of oil to date and future production and development strategy for this discovery is currently being evaluated.

The Guatiquía Block exploration well results are summarized in the following table:

Well	TD (MD)	Net Pay				Initial Test	
		Mirador	Guadalupe	Lower Sand 1	Total	Bbl/d	°API
Avispa -1	12,262	-	51	15	66	1,550	18
Ceibo -1	12,450	-	48	20	68	3,500	22
Ardilla-1	12,825	7	17	44	68	2,135	20
Gulupa-1	10,650	110	10	-	120	190	14

Corcel Block: 100% Interest

The Espadarte-1 exploration well reached a TD of 13,045 feet on November 27, 2014. The well was testing a new structural trapping concept. Petrophysical interpretation indicates the presence of 21 feet of net pay in the Lower Sandstone-1 Unit over two intervals with no water contact present. The well was tested with nitrogen injection after producing under natural flow for several weeks and is currently producing over 3,800 bbl/d of 34° API oil and 1% watercut with a tubing head pressure of 104 psi with ESP artificial lift. As of February 28, 2015, Espadarte-1 was producing 4,008 bbl/d of 33.9° API oil and 1% watercut with a tubing head pressure of 221 psi on a 44 HZ ESP artificial lift. The well has produced over 215 Mbbl of oil to date. A follow-up drilling program to delineate this discovery is currently in the planning stage.

Rio Ariari Block: 100% Interest

One exploration well was drilled on the Rio Ariari Block in the fourth quarter. Lapon-1D tested a structural high on the flank of a north-south trending Mirador paleovalley located in the eastern part of the Rio Ariari Block. The well reached a TD of 4,240 feet MD in the Paleozoic section in late December, 2014. The primary objective was the Mirador Formation and the well encountered 26 feet of petrophysically defined pay in the Upper Mirador, and 11 feet of pay in the Lower Mirador. Average porosities were estimated at 31% to 32%. The Upper Mirador was tested for eight days, producing on average 18 bbl/d of 9° API oil at a high water cut using an electro-submersible pump at variable choke sizes to optimize the production. The well is currently suspended. Lapon 1 along with the nearby previously drilled Nopal 1 demonstrates the exploration potential of this portion of the Rio Ariari Block.

Chiguiro Oeste Block: 100% Interest

Matapalos-1 is an exploration well drilled on the Chiguiro Oeste Block testing a local structural high within an aerially extensive stratigraphic closure. The well reached a TD of 5,656 feet MD in early October, 2014 and encountered 16 feet of petrophysically defined net pay in the Mirador Formation, with an average porosity of 24%. Three zones were tested in the Mirador. The interval in the Upper Mirador was tested for 30 days producing on average 51 bbl/d of 15° API oil, at a high water cut using an electro-submersible pump at variable choke sizes to optimize the production. This test was compromised by hydraulic isolation issues related to the cement bond. The well is currently suspended pending a workover, and further remediation of the well is being evaluated to optimize production.

Llanos 19 Block: 50% Interest

The Langur 1X well reached a TD of 13,717 feet on December 3, 2014. This well was testing a new exploration play in the central Llanos area of Colombia. The well encountered 14 feet of net pay in the Gacheta Formation with no water contact present. Langur 1X was tested with the assistance of nitrogen injection, yielding an average of 742 bbl/d of 25 °API oil and with a 28% watercut. After testing, the well was completed with an ESP and is currently on production at a 559 bbl/d.

Quifa Block: 60% Interest

Two exploration wells were drilled on the Quifa Block in the fourth quarter. QFN-CS-1 reached a TD of 3,428 feet and penetrated 15 feet of net pay in the Basal Sands of the Carbonera Formation. This well was completed and tested with an average flow rate of 68 bbl/d and a watercut of 55%. The stratigraphic well QFN-U1X, located four kilometers from the QFN-CS1 well, reached a TD of 5,936 feet in late December 2014. Petrophysical interpretation indicates the presence of 19 feet of net pay in the Basal Sands. These two wells have confirmed that a significant oil accumulation has been discovered on a separate structure extending the trend of the Cajua pool to the southwest.

CPE 6 Block: 50% Interest

In the Hamaca evaluation area, four appraisal horizontal wells were drilled during the fourth quarter. All four wells were drilled along the top of the Basal Sand Unit and encountered oil-saturated reservoir across horizontal net sections ranging from 215 to 984 feet. The four wells were completed with electro-submersible pumps which resulted in production rates over limited test periods ranging from 91 to 762 bbl/d oil and with watercuts ranging from 51% to 96%. The Company is evaluating plans to optimize these wells in line with recent field procedures used to minimize water and maximize oil production.

Guama Block: 100% Interest

In the Guama Block the Company continued extended testing of the Pedernalito–1X, started in late September, 2014. The well experienced stabilized flow for 44 days averaging 1.34 mmcf/d production of gas and 36 bbl/d of 54° API condensate with a 16/64” choke and 0% water cut. The follow up, well Cotorra–1X began testing on November, 17 and after 36 days was averaging 259 mcf/d of gas and 12 bbl/d of 54° API condensate with a 16/64” choke. By year-end 2014 the Company was in preparation to test the Manamo-1X appraisal well, as part of a planned extended production test program.

Guatemala

Approval of the 2014-2015 Work Plan and Budget from the Guatemalan Ministry of Energy and Mines was received in December 2014 by the operator, Compañía Petrolera del Atlántico S.A. The next planned exploration well (Choma-1X), has been hindered due to delays in service contracting.

Belize

During the fourth quarter of 2014, a 344 km 2D seismic survey was completed, and processing is under way. In addition, the interpretation of the surface geology, gravity, magnetics and geochemistry data was completed. Identification of prospects is now expected to be completed by the third quarter of 2015. This may lead to the first exploration well drilling and testing during the first quarter of 2016.

Papua New Guinea

In the Block PPL-475 (previously known as PPL-237), where the Company holds a 12.9% gross interest, the operator Interoil Corporation drilled the Raptor-1 exploration well in November 2014, which reached TD at 13,166 feet. Several attempts at testing were made without success and the well was temporarily suspended. The operator plans to return to the well in the fourth quarter of 2015.

Farm-in Transactions and Acquisitions

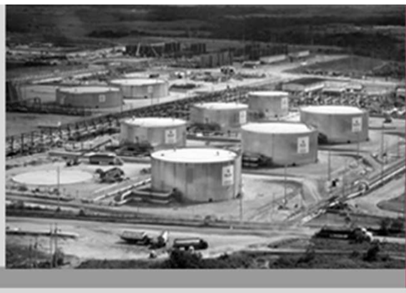
Joint Venture with ALFA to Develop Projects in Mexico

On December 3, 2014, the Company entered into a memorandum of understanding with Alfa related to a creation of a Joint Venture company in Mexico on a 50/50 basis. The Joint Venture will allow for: (i) the joint study and bidding on assets in Mexico's oil and gas bid round in 2015; (ii) the acquisition of services contracts with a view to migrating them to exploration and production contracts; (iii) the development or petroleum and natural gas assets in Mexico; and (iv) the development of any business ancillary to the petroleum business in Mexico, including mid-stream projects.

This joint venture remains subject to any applicable regulatory approvals and the determination of the Joint Venture structure pursuant to a definitive agreement.

Memorandum of Understanding signed with Pemex to Jointly Explore Oil & Gas in Mexico

On October 17, 2014, the Company has signed a three year Memorandum of Understanding and Cooperation with Mexico's state oil company, Pemex, establishing the basis for discussions and analysis of potential oil and gas cooperation in Mexico, including exploration, deep-water projects, revitalization of mature fields, heavy and extra-heavy oil onshore and offshore fields, high water production fields and other upstream activities.



4. Financial Results

Revenues

(in thousands of US$)	Year Ending December 31 2014	Year Ending December 31 2013	Three Months Ending December 31 2014	Three Months Ending December 31 2013
Net crude oil and gas sales	$ 4,546,359	$ 4,485,046	$ 888,930	$ 1,171,561
Trading revenue	403,663	141,813	102,578	30,990
Total Revenue	**$ 4,950,022**	**$ 4,626,859**	**$ 991,508**	**$ 1,202,551**
$ per boe oil and gas	85.35	93.95	65.64	90.66
$ per bbl trading	91.51	101.40	78.32	99.11
$ Total average revenue per boe	**85.82**	**94.16**	**66.75**	**90.86**

Following is an analysis of the revenue drivers of price and volume for 2014 as compared to 2013:

	Year Ending December 31 2014	2013	Difference	% Change
Total of boe sold (Mboe)	57,679	49,137	8,542	17%
Avg. Combined Price - oil & gas and trading ($/boe)	85.82	94.16	(8.34)	-9%
Total Revenue	**4,950,022**	**4,626,859**	**323,163**	**7%**

Drivers for the revenue increase:		
Due to Volume	$ 804,422	249%
Due to Price	(481,259)	-149%
	$ 323,163	

Following is an analysis of the revenue drivers of price and volume for the fourth quarter of 2014 as compared to the fourth quarter of 2013:

	Three Months Ending December 31 2014	2013	Difference	% Change
Total of boe sold (Mboe)	14,853	13,235	1,618	12%
Avg. combined price - oil & gas and trading ($/boe)	66.75	90.86	(24.11)	-27%
Total Revenue	**991,508**	**1,202,551**	**(211,043)**	**-18%**

Drivers for the revenue increase:		
Due to volume	$ 146,963	-70%
Due to price	(358,006)	170%
	$ (211,043)	

Revenues for 2014 were $5.0 billion, 7% higher as compared to 2013 revenues of $4.6 billion. The increase was driven by higher sales volumes of approximately 17% despite the significant decrease of global oil prices in the third and fourth quarters of 2014, which resulted in lower realized prices of 9%.

Revenues for the fourth quarter of 2014 were $1.0 billion, 18% lower as compared to the same quarter of 2013 revenue of $1.2 billion. This decrease is the result of lower realized prices due to the depressed fourth quarter 2014 oil prices, as production saw a healthy increase of 12% in volume.

Operating Costs

(in thousands of US$)	Year Ending December 31 2014	Year Ending December 31 2013	Three Months Ending December 31 2014	Three Months Ending December 31 2013
Production cost of barrels sold	$ 805,397	$ 687,714	$ 185,675	$ 180,550
Per boe	15.12	14.41	13.71	13.98
Transportation cost	690,060	637,302	147,885	158,392
Per boe	12.95	13.35	10.92	12.26
Diluent cost	115,121	239,167	24,540	27,736
Per boe	2.16	5.01	1.81	2.14
Other cost	22,073	58,810	2,186	44,763
Per boe	0.41	1.23	0.16	3.45
Royalties paid in cash	55,905	29,028	9,616	12,535
Per boe	1.05	0.61	0.71	0.97
Overlift/Underlift	(62,716)	(68,348)	(387)	(20,311)
Per boe	(1.18)	(1.43)	(0.03)	(1.57)
Operating cost	**1,625,840**	**$ 1,583,673**	**$ 369,515**	**$ 403,665**
Average operating cost per boe	**$ 30.51**	**$ 33.18**	**$ 27.28**	**$ 31.23**
Take-or-pay fees on disrupted transport capacity Bicentenario	78,742	-	3,117	-
Per boe	1.48	-	0.23	-
Trading purchase cost	400,674	139,657	101,263	30,751
Per boe	90.84	99.86	77.31	98.35
Total Cost	**$ 2,105,256**	**$ 1,723,330**	**$ 473,895**	**$ 434,416**

Total operating costs for 2014 were $2.1 billion, including $78.7 million in net take-or-pay fees paid to Oleoducto Bicentenario de Colombia S.A.S. ("**Bicentenario**") when the capacity was not available due to security issues. Operating costs were higher as compared to $1.7 billion in 2013, resulting from a volume increase in oil and gas produced, as the cost per boe decreased. For the fourth quarter of 2014, total operating costs were $474 million, compared to $434 million for the same period of 2013, increasing also due to the higher production achieved during the quarter, partially offset by lower unit costs.

Total cost (including operating cost, transportation and diluent plus PAP and overlift/underlift) for 2014 was $30.51/boe, 8% lower compared to $33.18/boe for 2013. For the fourth quarter of 2014, total cost for the period was $27.28/boe, 13% lower as compared to $31.23/boe for the same period of 2013. The unit costs decrease re-affirms the Company's position of a low cost producer, and positions the Company for the recent decline in world prices.

In addition, trading purchase cost increased from $140 million in 2013 to $401 million in 2014 and from $31 million to $101 million in the fourth quarter of 2014 compared with the fourth quarter of 2013, due to higher trading volumes sold during the period.

Depletion, Depreciation and Amortization

(in thousands of US$)	Year Ending December 31 2014	Year Ending December 31 2013	Three months Ending December 31 2014	Three months Ending December 31 2013
Depletion, depreciation and amortization	$ 1,641,577	$ 1,355,652	$ 479,868	$ 344,512
$/per boe sales (own production)	30.82	28.40	35.43	26.66

Depletion, depreciation and amortization ("**DD&A**") costs for 2014 and 2013 were $1.6 billion and $1.4 billion, respectively. The increase of 21% is primarily due to an increase in production, which also increased by a similar percentage. Unit DD&A for 2014 was $30.82/boe, 8% higher than the $28.40/boe for 2013.

For the fourth quarter of 2014, DD&A was $480 million, an increase of $135 million over 2013 fourth quarter DD&A of $345 million. This increase is due to both higher production of approximately 14%, decrease of proved and probable reserves, the Petrominerales acquisition and the acquisition of additional working interest in Cubiro and Arrendajo.

Impairment and Exploration Expenses

Impairment Test

(in thousands of US$)	Year Ending December 31 2014	2013	Three months Ending December 31 2014	2013
Impairment	$ 1,432,000	$ -	$ 1,432,000	$ -
Exploration expenses	193,358	23,741	189,442	94
Total	**$ 1,625,358**	**$ 23,741**	**$ 1,621,442**	**$ 94**

The Company assessed our developed and producing ("**D&P**") and exploration and evaluation ("**E&E**") assets and goodwill at the end of 2014 for impairment. In performing the impairment test, the Company estimated the recoverable amount of our D&P and E&E assets by cash generating unit ("**CGU**") based on external and internal sources of information, and goodwill at the segment level. An impairment loss is recognized when the carrying amount of our assets exceeds the recoverable amount.

Internal sources of information include the manner in which long-lived assets are being used or are expected to be used and indications of economic performance of the assets. Estimates include but are not limited to the discounted future after-tax cash flows expected to be derived from the Company's properties, costs to sell the properties and the discount rate. Assumptions used in the model to determine the recoverable amounts included:

- After-tax discount rate of 10% (12.8% before tax) as determined by the weighted average cost of capital, taking into consideration the expected return on investment by the Company's investors, the cost of debt based on the interest-bearing borrowings of the Company and segment-specific risk based on publicly available market data.

- Long-term WTI benchmark oil price of $64, $77, $83, $87 and $91 per barrel for 2015-2019 respectively and inflated by approximately 2% subsequent to that period. Prices are based on the compilation of independent industry analyst forecasts, published indices and management's own assumptions.

- Hydrocarbon reserves and resources which are estimates of the amount of hydrocarbons that can be economically and legally extracted from the Company´s oil and gas properties. The Company estimates its commercial reserves and resources based on information compiled by external reserve engineers relating to the geological and technical data on the size, depth, shape and grade of the hydrocarbon body and suitable production techniques and recovery rates. Commercial reserves are determined using estimates of oil and gas in place, recovery factors and future commodity prices, the latter having an impact on the total amount of recoverable reserves and the proportion of the gross reserves which are attributable to the host government under the terms of the agreements. Future development costs are estimated using assumptions as to the number of wells required to produce the commercial reserves, the cost of such wells and associated production facilities, and other capital costs.

- Production based on updated hydrocarbon reserve reports, recent operating and exploration results, future operating costs based on revised budgets, capital expenditures, inflation and long-term foreign exchange rates.

As at December 31, 2014, based on the impairment test performed, the carrying amounts of certain assets exceeded their recoverable amount, and as such, the Company recorded a total of $1,432 million of before-tax impairment charges. The breakdown of the charges taken is as follows:

(in thousands of US$)	Year Ending December 31 2014
Oil and gas properties	
Colombia D&P properties	$ 979,000
Exploration and evaluation properties	
Other assets	70,000
Total impairment impact E&E and D&P	1,049,000
Goodwill allocated to Colombia	375,000
Goodwill allocated to Guyana (CGX)	8,000
Total impairment before tax	1,432,000
Tax effect	332,860
Total impairment after tax	**$ 1,099,140**

The impairments recorded, excluding goodwill, may be reversed if and when the recoverable amount of the CGUs increase in future periods, as a result of higher prices.

Exploration Expenses

During the fourth quarter of 2014 the Company expensed certain previously capitalized exploration costs in Colombia and Peru for approximately $193 million, as a result of relinquishing the licenses for two blocks. Specifically these exploration expenses related to the blocks CPE-1 in Colombia and 138 in the Ucayali Basin in Peru. In March 2015 we received approval from the government of Peru permitting us to extend the exploration period of Block 138 by one year as part of our ongoing exploration campaign in the Ucayali Basin.

General and Administrative Costs

	Year Ending December 31		Three months Ending December 31	
(in thousands of US$)	2014	2013	2014	2013
General and administrative costs	$ 360,681	336,572	$ 98,337	$ 112,808
$/per boe sales	6.25	6.85	6.62	8.52

General and administrative ("**G&A**") costs increased to $360 million in 2014 from $337 million in 2013, mainly due to expanded operations and production. G&A per boe decreased by $0.60/boe from $6.85/boe to $6.25/boe compared to 2013, resulting from the increase in overall production.

For the fourth quarter of 2014, G&A was $98 million, a decrease of $15 million over the fourth quarter of 2013 ($113 million), resulting from the increase in overall production and sales and one-time corporate costs.

The Company is able to adapt to the lower price environment, and through significant cost-cutting measures is expected to significantly decrease the overall level of G&A in 2015.

Finance Costs and Foreign Exchange

	Year Ending December 31		Three Months Ending December 31	
(in thousands of US$)	2014	2013	2014	2013
Finance costs	$ 261,300	$ 162,402	$ 73,738	$ 43,298

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 year ending 2014, finance cost totaled $261 million compared to $162 million in 2013. The increase in finance costs is mainly due to the issuance of additional senior unsecured notes during 2014 and the full year impact of the notes issued at the end of the first quarter of 2013.

For the fourth quarter of 2014, interest expenses totaled $74 million compared to $43 million in 2013, a result of the aforementioned reasons.

	Year Ending December 31		Three months ending December 31	
(in thousands of US$)	2014	2013	2014	2013
Foreign exchange (loss) gain	$ (63,211)	$ 2,002	$ (52,239)	$ (7,201)

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 2014, the COP depreciated against the U.S. dollar by 23% as compared to a depreciation of 9% during 2013. Foreign exchange expense for 2014 was a $63 million loss compared to a gain of $2 million in 2013. The foreign exchange loss for 2014 was mainly due to unrealized foreign exchange translation losses from the translation of COP-denominated balances into the U.S. dollar.

For the fourth quarter of 2014, foreign exchange represented a loss of $52 million compared to a loss of $7 million in the fourth quarter of 2013. The COP depreciated against the USD by 18% in the fourth quarter of 2014 versus a depreciation of only 1% in the same quarter of the prior year.

Income Tax Expense

(in thousands of US$)	Year Ending December 31 2014	Year Ending December 31 2013	Three Months Ending December 31 2014	Three Months Ending December 31 2013
Current income tax	$ 159,387	$ 461,072	$ (108,746)	$ 89,293
Deferred income tax	29,349	43,904	(70,851)	29,936
Total income tax expense	**$ 188,736**	**$ 504,976**	**$ (179,597)**	**$ 119,229**
$ per boe	3.27	10.28	(12.09)	9.01

The Canadian statutory combined income tax rate was 26.5% for the fourth quarter of 2014 and 2013.

The Colombian statutory tax rate for the fourth quarter of 2014 was 34%, which includes the 25% general income tax rate and the fairness tax ("**CREE**") at 9%. The Colombia Congress enacted new corporate tax rates for Colombian source income of foreign corporations not attributable to a branch or permanent establishment in Colombia to 39% in 2015, 40% in 2016, 42% in 2017, and 43% in 2018. As at January 1, 2019, the corporate tax rate will reduce back to 34%. In addition, the Congress introduced a new wealth tax which accrues on net equity as at January 1, 2015, 2016, and 2017; 1.15%, 1.00% and 0.40% respectively.

The Peruvian statutory income tax rate was 30% for the year-ending 2014 and 2013. The Peruvian income tax rate for Block Z-1 was 22% for the year-ending of 2014 and 2013. The Peruvian government passed major tax reforms on December 31, 2014, including a reduction in the general corporate tax rate to 28% for 2015 – 2016; 27% for 2017 – 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 (16.5%) for the year-ending December 31, 2014, compared to 54.8% over the same cumulative year-ending December 31, 2013.
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, but for which no deferred tax assets and recovery have been recognized. When the Company has a reasonable expectation to utilize those 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 U.S. dollars; 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 as continually subject to fluctuations in the U.S. – COP exchange rate for IFRS purposes.
- The depreciation of the COP against the U.S. dollar by 18% during the fourth quarter of 2014 resulted in an estimated unrealized deferred income tax expense of $243.3 million. In comparison the Company recorded $19.7 million of unrealized income tax recovery during the same period of 2013 as a result of the depreciation of the COP agains the U.S. dollar by 1%. For the year-ending 2014, the COP depreciated against the U.S. dollar by 24% resulting in a unrealized deferred income tax expense of $313.3 million compared to 9% and a unrealized deferred income tax expense of $98.7 million for the year-ending 2013.

Excluding the effect from the above-mentioned foreign exchange fluctuations, the effective tax rate for the Company would be 46.9% and 41.5% for the three-and nine-months periods that ended December 31, 2014 and 2013, respectively:

(in thousands of US$)	Year Ending December 31 2014	2013	Three Months Ending December 31 2014	2013
Appreciation (depreciation) of the COP against U.S. dollar (%	(24.2)%	(9.0)%	(17.9)%	0.6%
Net earnings before income tax	$ (1,146,099)	$ 921,610	$ (1,864,328)	$ 257,417
Current income tax expense	(159,387)	(461,072)	108,746	(89,293)
Deferred income tax (expense) recovery as reported	(29,349)	(43,904)	70,851	(29,936)
Total income tax expense as reported	**(188,736)**	**(504,976)**	**179,597**	**(119,229)**
Exclude effect from revaluation of COP	313,304	98,667	243,339	19,742
Total income tax expense excluding the above effects	**124,568**	**(406,309)**	**422,936**	**(99,487)**
Effective tax rate excluding effect of COP revaluation	**10.9%**	**44.1%**	**22.7%**	**38.6%**

The temporary differences associated with investments in subsidiaries and joint ventures, for which a deferred tax liability has not been recognized, amounted to approximately $1.13 billion as at December 31, 2014.

Capital Expenditures

(in thousands of US$)	Year Ending December 31 2014	2013	Three Months Ending December 31 2014	2013
Production facilities [1]	$ 594,163	$ 644,062	$ 214,068	$ 202,677
Exploration activities [2]	561,130	593,023	173,472	145,123
Early facilities and others	187,900	26,367	59,340	26,367
Development drilling [1]	893,700	628,745	245,871	183,688
Other projects (STAR, Gas export, PEL)	145,403	173,328	65,091	67,543
Total capital expenditures	**$ 2,382,296**	**$ 2,065,525**	**$ 757,842**	**$ 625,398**

1. For 2013, includes investment in Maurel & Prom Colombia B.V., in which the Company holds a 49.999% participation.
2. Exploration activities for the fourth quarter of 2014 include drilling, seismic and other geophysical expenditures in Colombia, Peru, Brazil, Guatemala, Belize, and Papua New Guinea.

Capital expenditures during 2014 totaled $2.4 billion, $316 million higher compared to $2.1 billion in 2013. A total of $594 million was invested in the expansion and construction of production infrastructure, primarily in Rubiales, Quifa SW, Cubiro, Casanare Este, Guama, Cravoviejo, Sabanero, La Creciente, and in the Block Z-1 fields; $561 million went into exploration activities including drilling, seismic and other geophysical activities in Colombia, Peru, Brazil, Guatemala, Belize and Papua New Guinea; $188 million was included in early production facilities and others; $894 million went into development drilling; $145 million was invested in other projects including the small-scale LNG project and the Petroelectrica de los Llanos ("**PEL**") Power Transmission Line project.

In light of the current weaker commodity price environment, we have cut all of our capital expenditure programs. 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" – page 32).

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

(in thousands of US$)	Year Ending December 31 2014	2013	Three Months Ending December 31 2014	2013
Farm-in Agreement and others [1]	$ 289,279	$ 133,181	$ -	$ 20,134
Petrominerales (Colombia - Peru)	-	1,000,341	-	1,000,341
Total capital expenditures for new acquisitions	**$ 289,279**	**$ 1,133,522**	**$ -**	**$ 1,020,475**

1. For 2014, includes the acquisition of the remaining interest in Cubiro and Arrendajo Fields. For 2013, includes block acquisition costs in Brazil, Peru and Papua New Guinea.

Financial Position

Debts and Credit Instruments

The following debts were outstanding as at December 31, 2014:

Senior Unsecured Notes

The Company has a number of senior unsecured notes outstanding with an aggregate principal of $4.1 billion as at December 31, 2014. 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.

During the quarter, the Company closed an exchange offer (the "**Exchange Offer**") of its 7.25% senior unsecured notes due 2021 ("**7.25% Senior Notes**"). The Exchange Offer resulted in $364 million aggregate principal amount of 7.25% Senior Notes being validly tendered and accepted for exchange into 5.625% Senior Notes.

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

The financial covenants under these indentures are calculated for the most recently ended period of four consecutive fiscal quarters for which financial statements of the Company have been provided to the Senior Note trustee.

The Senior Notes represent almost 84% of the outstanding debt and have maturities that extend out from 2019 to 2025.

Amendment of Revolver Covenant and Terms

Subsequent to the fourth quarter, we agreed with our syndicate of lenders to amend the U.S.$1.0 billion senior unsecured revolving credit facility (the "Facility"). Under the amended terms of the Facility, the Company's permitted consolidated leverage ratio (debt to Adjusted EBITDA) was increased from 3.5:1.0 to 4.5:1.0 based on a rolling four quarter average. The amendments were supported by 100% of the lending syndicate comprised of 25 international and local banks. Similar amendments have been made to the following bilateral credit agreements with: (i) Bank of America, N.A. (ii) Banco Latinoamericano de Comercio Exterior, S.A. (iii) HSBC Bank USA, N.A.; and (iv) Sumitomo Mitsui Banking Corporation (the "**Credit Agreement**").

On February 5 and March 13, 2015, the Company drew down $100 million and $900 million from the Facility, respectively. Using the proceeds from the draw down, we repaid our short-term bank loans in the aggregate principal amount of $484.3 million. As a result of this draw down and the debt repayment, the Company increased cash on hand by $515.7 million with the earliest principal repayment not due until October 2016. These funds will be held in cash in order to strengthen the Company's balance sheet.

Under the terms of the Facility and the Credit Agreements, the leverage ratio covenants are "maintenance based covenants" which means that the Company must maintain compliance with the financial metrics in order to avoid default. For practical purposes, these are checked quarterly on 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, restrict the Company's ability to take on additional debt or carry out certain specified M&A operations, subject to various exemptions.

Working Capital Loans

From time to time, the Company maintains working capital facilities with several banks. As of December 31, 2014, our current uncommitted facilities in U.S dollars were with Citibank, N.A., Bank of America, N.A., Banco Santander (Panamá) S.A, JPMorgan Chase Bank, N.A., Itau, Bank of Tokyo, HSBC, and Mercantil Commerce Bank, N.A., with interest rates ranging from LIBOR + 0.95% to LIBOR + 1. 5%. As of December 31, 2014, our current uncommitted facilities in COP are with Citibank Colombia, N.A., Banco Colpatria Multibanca Colpatria S.A. and BBVA Colombia, N.A. with interest rates ranging from 5.9% to 6%. The terms of these loans are generally less than a year.

Letters of Credit

As at December 31, 2014, the Company had issued letters of credit and guarantees for exploration and operational commitments for a total of $434 million.

Outstanding Share Data

Common Shares

As at March 13, 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 March 13, 2015, there were no warrants outstanding. 19,536,492 stock options were outstanding, of which all were exercisable. As of May 28, 2014, the Board has committed to no longer grant stock options and instead has implemented a Deferred Share Unit ("**DSU**") Plan for eligible employees.

Deferred Share Units

As at March 13, 2015, there were 7,251,719 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 Corporation.

Liquidity and Capital Resources

Funds flow provided by operating activities for 2014 totaled $2.0 billion ($1.9 billion for 2013). The increase in funds flow in 2014 was the result of an increase in production and higher sales volumes. The Company has been generating cash flows from operations from the sale of crude oil and natural gas and continues to plan for increased future production.

As of December 31, 2014, the Company had a working capital negative of $804 million, mainly comprised of $334 million of cash and cash equivalents, $904 million of account receivables, $45 million of inventory, $199 million of income tax receivable, $5 million in prepaid expenses, $1.92 billion of accounts payable and accrued liabilities, $34 million of income tax payable, $322 million of the current portion of long-term debt and $17 million of the current portion of obligations under finance lease.

The bank loans included in current liability were repaid in full with the proceeds from the drawdown of the $1 billion revolving credit facility in February and March 2015, extending the maturity of these debts.

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

5. Proved and Probable Oil and Gas Reserves

For the year ending December 31, 2014, the Company received independent certified reserves evaluation reports for all of its assets establishing that total net 2P reserves had decreased to 510.9 MMboe from 613.3 MMboe, a 17% year-on-year decline. Proved net reserves of 315.0 MMboe now represent 62% of the total 2P reserves compared to 64% in 2013.

The table below summarizes information contained in the following independent-reserves reports:

1. RPS Energy Canada Ltd. prepared: (i) the report dated March 9, 2015, effective December 31, 2014, entitled "Reserves Certification Report for the Rubiales Field, Colombia"; and (ii) the report dated March 9, 2015, effective December 31, 2014, entitled "Reserves Certification Report, Year End 2014, Quifa Field, South West Region, Colombia" (collectively, the "**RPS Report**").

2. Petrotech Engineering Ltd. prepared: (i) the report dated March 13, 2015, effective December 31, 2014, entitled "Evaluation of the Reserve of Pacific Rubiales Energy Corp. in the Guama Block in the Lower Magdalena Basin in Colombia for Year-Ending 2014"; (ii) the report dated March 13, 2015, effective December 31, 2014, entitled "Evaluation of the Reserve of Pacific Rubiales Energy Corp. in the La Creciente Block in the Lower Magdalena Basin in Colombia for Year-Ending 2014"; (iii) the report dated March 13, 2015, effective December 31, 2014, entitled "Evaluation of the Reserve of Pacific Rubiales Energy Corp. in Lote 126 in the Ucayali Basin in Offshore Peru for Year-Ending 2014"; (iv) the report dated March 13, 2015, effective December 31, 2014, entitled "Evaluation of the Heavy Oil Reserve of Pacific Rubiales Energy Corp. in Quifa Norte Block in the Eastern Llanos Basin in Colombia for Year-Ending 2014"; (v) the report dated March 13, 2015, effective December 31, 2014, entitled "Evaluation of the Heavy Oil Reserve of Pacific Rubiales Energy Corp. in CPE-6 Block in the Eastern Llanos Basin in Colombia for Year-Ending 2014"; (vi) the report dated March 13, 2015, effective December 31, 2014, entitled "Evaluation of the Heavy Oil Reserve of Pacific Rubiales Energy Corp. in Rio Ariari Block in the Eastern Llanos Basin in Colombia for Year-Ending 2014"; (vii) the report dated March 13, 2015, effective December 31, 2014, entitled "Evaluation of the Reserve of Pacific Rubiales Energy Corp. in the Z-1 Block in the Tumbles-Progreso Basin in offshore Peru for Year-Ending 2014"; (viii) the report dated March 13, 2015, effective December 31, 2014, entitled "Evaluation of the Reserve of Pacific Rubiales Energy Corp. in Cajua Field Block in the Quifa Block, Eastern Llanos Basin in Colombia for Year-Ending 2014"; (ix) the report dated March 13, 2015, effective December 31, 2014, entitled "Evaluation of the Reserve of Pacific Rubiales Energy Corp. in the Sabanero Block in the Eastern Llanos Basin in Colombia for Year-Ending 2014" (collectively, the "**Petrotech Report**").

3. Netherland Sewell & Associates, Inc. prepared the report dated March 3, 2015, effective December 31, 2014, entitled "Estimates of Reserves and Future Revenue to the Pacific Stratus Energy S.A. Interest in Certain Oil Properties Located in Albacora and Corvina Fields Offshore Peru" (the "**NSAI Report**").

4. DeGolyer and MacNaughton Limited prepared: (i) the report dated February 27, 2015, effective December 31, 2014, entitled "Appraisal Report as of December 31, 2014 on Certain Properties in Colombia for Pacific Stratus Energy, Executive Summary; and (ii) the report dated February 27, 2015, effective December 31, 2014 on Los Angeles Field in Peru for Pacific Rubiales Energy Peru Ltd., Executive Summary" (collectively, the "**D&M Report**" and together with the RPS Report, the Petrotech Report and the NSAI Report, the "**Reserves Reports**").

The Reserves Reports were prepared in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("**COGE Handbook**") and the National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**").

Additional reserves information as required under NI 51-101 are included in the Company's Annual Information Form dated March 18, 2015.

Reserves at December 31, 2014 (MMboe[1])

Country	Field	Proved (P1)		Probable (P2)		Proved + Probable (2P)		Hydrocarbon Type
		Gross	Net	Gross	Net	Gross	Net	
Colombia	Rubiales	40.2	32.1	-	-	40.2	32.1	Heavy Oil
	Quifa SW	67.3	54.4	6.4	5.1	73.7	59.5	Heavy Oil
	Other Heavy Oil Blocks[2]	58.6	50.7	103.4	90.5	162.0	141.3	Heavy Oil
	Light/Medium Oil Blocks	62.8	57.8	20.4	18.7	83.2	76.5	Light & Medium Oil, Associated Natural Gas
	Natural Gas Blocks[3]	99.4	99.4	26.4	26.4	125.8	125.8	Natural Gas
	Sub-total	**328.3**	**294.5**	**156.6**	**140.8**	**484.9**	**435.3**	Oil & Natural Gas
Peru	Light/medium oil/natural gas[4]	20.5	20.5	55.1	55.1	75.6	75.6	Oil & Natural Gas
	Total at Dec. 31, 2014	**348.8**	**315.0**	**211.7**	**195.9**	**560.5**	**510.9**	Oil & Natural Gas
	Total at Dec. 31, 2013	455.0	388.6	247.2	224.6	702.2	613.3	
	Difference	**(106.1)**	**(73.6)**	**(35.6)**	**(28.8)**	**(141.7)**	**(102.4)**	
	2014 Production	64.3	53.8	**Total Reserves Incorporate**		**(77.4)**	**(48.6)**	

1. See "Boe conversion" on the advisories section, page 41.
2. Includes Cajua, Quifa North, Sabanero, CPE-6, and Rio Ariari properties.
3. Includes La Creciente and Guama properties.
4. Includes onshore Block 131 and Block 126

In the table above, Gross refers to WI before royalties, Net refers to WI after royalties; numbers in the table may not add due to rounding differences.

6. Project Status Review

The following is an update on the current status and working-interest share of costs incurred as of December 31, 2014 for the Company's major projects:

		As of December 31, 2014		
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	774,970	706,122	68,848
PEL-Power transmission line project	Equity and debt combination	240,000	225,000	15,000
Small-scale LNG project	Equity and debt combination	278,126	59,587	218,539
Water treatment for agricultural development	Equity and debt combination	170,000	112,000	58,000
Puerto Bahia project	Equity and debt combination	246,568	186,176	60,392
OLECAR	Equity and debt combination	164,101	43,316	120,785
		$ 1,873,765	**$ 1,332,201**	**$ 541,564**

Bicentenario Pipeline

As of December 2014, Phase One of the project is completed and approximately 17.7 MMbbl has been pumped through the pipeline. During the fourth quarter, the pipeline transported an average rate of 54,476 bbl/d.

PEL – Power Transmission Line Project

The power line commenced operation on January 20, 2014, and as of December 31, 2014, the line has transmitted 772,680 MWh to the Rubiales and Quifa fields and the ODL pipeline with an availability index of 99.99%. As of the date of this report, the progress for the construction of the substations is as followsQuifa substation construction is completed and has been ready since January, the Jagüey substation is 70% complete and expected to be operational by the second quarter of 2015, and the Corocora substation is 51% completed and is expected to be finished by the third quarter of 2015.

The results from studies to increase transmission capacity from 192 MW to 262 MW have been approved by Empresa de Energía de Bogotá and the approval for the concept by Unidad de Planeación Minero Energética ("**UPME**") is expected in the first quarter of 2015. This increase in capacity will allow further future developments in the Llanos Basin.

Caribbean FLNG (World's First Floating LNG Project)

The Company is actively looking for alternate ways to monetize its existing natural gas reserves in the La Creciente and Guama fields as well as exploit its other extensive gas exploration resources in nearby fields. The Company has initiated a small-scale liquefied natural gas project ("**LNG**") that is being developed jointly with Exmar NV ("**Exmar**"), an experienced LNG/LPG transportation company based in Belgium. The project is targeting LNG supply FOB from Colombia.

The project originally comprised an 88-km, 18-inch gas pipeline from La Creciente Gas field to the Colombian Atlantic Coast and a Floating, Liquefaction and Storage Unit ("**FLSU**"). The FLSU was to be connected to a Floating Storage Unit ("**FSU**") in order to allow FOB exports to standard carriers (130,000 to 150,000 CBM). The project was nominated for an innovation prize at the last LNG World Summit.

As of December 2014, basic and detailed engineering for the gas pipeline and the offshore jetty had been completed. Port concession terms for the LNG terminal have been released and the environmental license for the onshore construction was granted by the ANLA in November 2014. The FLSU under construction in China was successfully launched last November at the Wison yard in Nantong.

Due to the current oil price environment, the project has been deferred and the Company is working with Exmar to determine the best possible use of the FLSU..

CPE-6 Block

In September 2008, and as part of the Heavy Oil Round, the CPE-6 Block (technical evaluation contract) was awarded to a joint venture made up of the Company (50%) and Talisman (Colombia) Oil & Gas Ltd. (50%), with the Company as operator.

The CPE-6 Block covers an area of over 600,000 hectares and is located approximately 70 kilometers to the southwest of the producing Rubiales and Quifa SW heavy oil fields.

In early November 2013, the Company was granted the global environmental license for the CPE-6 Block which allows for the drilling of 200 wells (including exploration, appraisal, development and injection wells) on 40 pads and also to build surface facilities for future field development expansion. In late 2013, the Company successfully tested heavy oil from two vertical exploration wells drilled into the Hamaca prospect in the northern portion of the block. During 2014, an additional 11 exploration and appraisal wells (including both vertical and horizontal) were drilled on the block.

The Company along with its partner is assessing potential plans and options for the development of the Hamaca prospect in multiple phase. In late 2014, Phase 1 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. Year-to-date 2015 production from seven exploration and appraisal wells has averaged approximately 1.3 Mbbl/d (total gross production). No new wells have been drilled year-to-date in 2015 and the Company has suspended drilling and development work in the block, given the current low oil price environment and pending partner discussions and approvals. The Company will review this decision in the second half of the year but remains confident on the long-term economic and operational viability and potential of the CPE-6 Block development, which contains a large amount of oil in place.

Agrocascada Project Water Treatment for Agricultural Development

As of December 2014, the construction of the first reverse osmosis water treatment plants reached 93% completion and the planting plan of palm oil trees was completed for the year with 200,200 plants in 1,400 hectares (ha) planted for a total of 2,700 ha.

In August 2014, the Company received the ANLA approval for the delivery of water suitable for irrigation, which had been filed on September 13, 2013. The permits for the agricultural component were filed with the environmental authority Cormacarena and the response is expected in the first half of 2015.

This project represents an innovative approach for water disposal in Colombia. It brings benefits to oil producers in terms of lower operating costs and extending the economic life of the oil fields, and is also an excellent example of “shared value” with communities, bringing sustainable development from a social point of view to areas in need of development. The concept will be replicated by the Company in future developments in oil fields with high water-production rates.

This project is expected to be operational in the second quarter of 2015.

Pacific Infrastructure: Puerto Bahía Terminal and Olecar Pipeline

As of December 31, 2014, the Company had a 41.65% interest in Pacific Infrastructure Ventures Inc. (“**Pacific Infrastructure**”), 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 meters to handle dry materials.

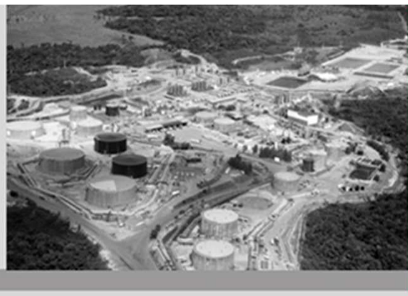
As of December 31, 2014, construction activities had progressed as follows: the liquids terminal has reached 82%, the truck loading and unloading station is at 96%, the fixed bridge was 100% completed in March 2014 and the multi-purpose terminal handling bulk materials has reached 78% completion.

Recognizing the strategic importance of the Puerto Bahía Terminal, Pacific Infrastructure signed an operation and maintenance agreement with Oiltanking International (“**Oiltanking**”). Oiltanking is recognized globally as a world-class operator of large-scale liquids terminals. During the third quarter of 2013, Pacific Infrastructure signed a credit agreement with Itau for $370 million, which was closed on February 25, 2014.

In addition to Puerto Bahía, Pacific Infrastructure is also developing the Olecar pipeline, which will connect Puerto Bahía to the oil pipeline hub at the port of Coveñas, ensuring the uninterrupted supply of crude oil for export. The Olecar project includes: (i) a pumping station at Coveñas with a capacity of 300 Mbbl/d; (ii) a 130-km, 30-inch diameter pipeline; and (iii) bidirectional connections between the Cartagena Refinery, the third largest refinery in Colombia, and Puerto Bahía.

As of the date of this report, environmental permits for the Olecar pipeline have been granted by the ANLA and right-of-way negotiations are in progress. Engineering for the Coveñas and Reficar stations are completed as well as the detailed engineering for the pipeline. Purchase orders for long-lead items are almost completed, including valves and main pumps. The Olecar project is currently 39% complete, although pipeline construction has not commenced.

7. 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 fourth quarter of 2014, the new amount reassessed, including interest and penalties, is estimated at $52.3 million. 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 $20 million and $51.8 million. 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 $67.6 million of tax owing, including estimated interest and penalties, with respect to the denied deductions.

As of December 31, 2014, 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.

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 34 for details relating to this contingency.

Commitments

As part of the Company's 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, and 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 24 of the Annual 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 27 of Annual Consolidated Financial Statements.

8. 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: Miguel Rodriguez (Chair), Dennis Mills, Victor Rivera and Hernan Martinez. 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, are considered similar to those negotiable with third parties.

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

a) In June 2007, the Company entered into a 5-year lease agreement with Blue Pacific Assets Corp. (“**Blue Pacific**”) for administrative office space in one of its Bogota, Colombia locations. Monthly rent expense of $87 thousand was payable to Blue Pacific under this agreement. Three directors and officers, as well as an executive officer, of the Company (Serafino Iacono, Miguel de la Campa, Jose Francisco Arata and Laureano von Siegmund) control, or provide investment advice to the holders of, 76% of the shares of Blue Pacific. During 2011, the lease was amended to include additional space in Bogota for a 10-year term with a monthly rent of $0.5 million and assignment of the lessor to an entity controlled by Blue Pacific. Effective January 1, 2014, Blue Pacific ceased to be a party to the lease agreements upon assigning the rights under these agreements to a third party that is not related to the Company. The Company also has a lease agreement for an office in Caracas, Venezuela for approximately $6 thousand per month. The office space is 50% owned by a family member of an executive officer of the Company (Laureano von Siegmund).

   Blue Pacific provides the Company with passenger air transport services on an as-needed basis. The Company paid $ 0.2 million in 2014 for these services (2013: $0.1 million).

b) In October 2012, the Company and Ecopetrol **(“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**”) 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 year ended December 31, 2014, those assets were under construction and the Company paid cash advances of $7.6 million, which were recorded in other assets (2013:$9.4 million). The Company has accounts payable of $5.9 million (December 2013: $0.4 million) due to Genser-Proelectrica. In addition, on May 5, 2014, a subsidiary of the Company provided a guarantee in favour of XM Compania 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. The Company has a 24.9% indirect interest in Proelectrica. 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 Proeléctrica for the supply of power to the oil fields in the Llanos basin. The connection agreements authorize Meta 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 operates for 13 years. During period ended December 31, 2014, the Company made payments of $69.1 million (2013: Nil) 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. The Company recorded revenues of $13.4 million (2013: $31.5 million), from such agreements. The Company has trade accounts receivables of $7.5 million (2013: $0.2 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 value of the energy supply agreements is $1.5 million.

c) In December 2014, the Company and TermoMorichal entered into an agreement for the construction, procurement, testing and operation of the synchronized load sharing system at the Rubiales field, which will be executed in 2015. TermoMorichal is 51% owned by Proelectrica and 49% owned by Genser.

d) As at December 31, 2014, the Company had trade accounts receivable of $7.5 million (December 31, 2013: $0.2 million) from Proelectrica, in which the Company has a 24.9% indirect interest and which is 31.49% owned by Blue Pacific. The Company's and Blue Pacific's indirect interests are held through Pacific Power. Revenue from Proelectrica in the normal course of the Company's business was $13.4 million for the year ending December 31, 2014 (2013: $31.5 million).

e) During the year ending December 31, 2014, the Company paid $7.8 million (2013: $34 million) to Transportadora Del Meta S.A.S. ("**Transmeta**") in crude oil transportation costs. In addition, the Company has accounts receivable of $1.1 million (2013: $1.5 million) from Transmeta and accounts payable of $0.9 million (2013: $1.7 million) to Transmeta as at December 31, 2014. Transmeta is controlled by German Efromovich, a director of the Company.

f) As at December 31, 2014, loans receivable from related parties in the aggregate amount of $856 thousand (December 31, 2013: $452 thousand) are due from one director and six officers (Serafino Iacono, Carlos Perez, Luis Andres Rojas, Peter Volk, Francisco Bustillos, Luciano Biondi and Jairo Lugo) (2013: two directors and six officers) of the Company. The loans are non-interest bearing and payable in equal monthly payments over a 48-month terms.

g) The Company has entered into aircraft transportation agreements with Helicopteros Nacionales de Colombia S.A.S. ("**Helicol**"), a company controlled by German Efromovich, a director of the Company. During 2014, the Company paid $15.4 million (2013: $14.9 million) in fees as set out under the transportation agreements. As at December 31, 2014, the Company had accounts payable of $2.8 million to Helicol (December 31, 2013: $2.5 million).

h) During the year ending, December 31, 2014, the Company paid $165 million to ODL (2013: $122.6 million) for crude oil transport services under the pipeline take-or-pay agreement, and has accounts payable of Nil to ODL as at December 31, 2014 (2013: $7.4 million). In addition, the Company received $2.6 million from ODL during the year ending December 31, 2014 (2013: $1.2 million) with respect to certain administrative services, rental equipment and machinery. The Company has accounts receivable from ODL as at December 31, 2014 $0.4 million (2013: $0.1 million).

i) During the year ending, December 31, 2014, the Company paid $174.4 million to Oleoducto Bicentenario de Colombia S.A.S. ("**Bicentenario**") (2013: $97.9 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 December 31, 2014 the balance of loans outstanding to Bicentenario under the agreement detailed in Note 18 (other assets – Audited Consolidated Financial Statements), is $42 million (December 31, 2013: $42 million). Interest income of $2.7 million was recognized during the year ending December 31, 2014 (2013: $2.2 million). Interest of $5.9 million was paid on the loans during the year ended December 31, 2014. The Company has received $0.6 million during the year ending December 31, 2014 (2013: $0.7 million) with respect to certain administrative services, rental equipment and machinery. The Company has advanced $87.7 million as at December 31, 2014 (December 31, 2013: $90 million) to Bicentenario as a prepayment of transport tariff, which is amortized against the barrels transported. As of December 31, 2014, the Company has an additional accounts receivable from Bicentenario of $20 million representing the return of a portion of the tariffs paid during the period of disrupted pipeline service.

j) The Company has established a charitable foundation in Colombia, Pacific Rubiales Foundation, with the objective of advancing social and community development projects in the country. During 2014, the Company contributed $43.7 million to this foundation (2013: $68 million). The Company has advances of $5.0 million (2013: $0.4 million), as the contribution is recognized when the funds are committed and/or spent. As at December 31, 2014 the Company had accounts payable of $8.7 million (2013: $0.5 million).

The Company has established a charitable foundation in Colombia called the Foundation for Social Development of Available Energy (FUDES) previously known as Vichituni Foundation (acquired as part of the Petrominerales acquisition), with the objective of advancing social and community development projects in Colombia. During 2014, the Company contributed $0.2 million to this foundation (2013: $0.2 million).The Company's Executive Committee (comprised of Ronald Pantin, José Francisco Arata, 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.

k) In October 2012, the Company entered into an agreement with Pacific Coal, Blue Advanced Colloidal Fuels Corp. ("**Blue ACF**"), Alpha Ventures Finance Inc. ("**Alpha**"), and an unrelated party whereby the Company acquired from Pacific Coal a right to a 5% equity interest in Blue ACF for cash consideration of $5 million. Blue ACF is a company engaged in developing colloidal fuels, with its majority shareholder being Alpha, which is controlled by Blue Pacific. As part of the purchase, Pacific Coal has also assigned to the Company the right to acquire up to an additional 5% equity interest in Blue ACF for additional investment of up to $5 million. The Company currently has a 13.28% equity interest in Pacific Coal.

l) As at December 31, 2014, the Company has demand loans receivable from Pacific Infrastructure Inc. *(*"**PII**") in the amount of $71.4 million (December 31, 2013: Nil). 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 year ending December 31, 2014, the Company has received $1.3 million (2013: Nil) from PII with respect to contract fees for advisory services and technical assistance in pipeline construction of "Oledoucto del Caribe". In addition, the Company has accounts receivable of $1.0 million (2013: $1.0 million) from Pacific Infrastructure Inc. Colombia.

In December 2012, the Company entered into a take-or-pay agreement with Sociedad Puerto Bahia, a company that is wholly owned by Pacific Infrastructure. Pursuant to the terms of the agreement, Sociedad Puerto Bahia will provide for the storage, transfer, loading and unloading of hydrocarbons at its port facilities. The contract term will commence in 2014 and run for seven years, renewable in one-year increments thereafter. These contracts may indirectly benefit Blue Pacific and other unrelated minority shareholders of Pacific Infrastructure

Ronald Pantin, José Francisco Arata, Serafino Iacono, Miguel de la Campa, Laureano von Siegmund and Federico Restrepo are on the board of directors of Pacific Infrastructure. Blue Pacific holds a minority interest in Pacific Infrastructure and certain other directors and officers of the Company are individual shareholders.

9. Accounting Policies, Critical Judgments, and Estimates

<u>New Standards, Interpretations and Amendments Adopted by the Company</u>

Standards Issued but Not Yet Effective

IFRS 3 Business Combinations

The 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). The Company is in the process of assessing the impact of IFRS 3 on its consolidated financial statements. This policy will become effective for annual periods starting on or after July 1, 2014.

IFRS 8 Operating Segments

The amendments are applied retrospectively and clarify that:

- An entity must disclose the judgements made by management in applying the aggregation criteria in paragraph h 12 of IFRS 8, 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.

IFRS 15 Revenue from Contracts with Customers

IFRS 15, "Revenue from Contracts with Customers" ("IFRS 15"), was issued in May 2014 and will replace IAS 11, "Construction Contracts," IAS 18, "Revenue Recognition," IFRIC 13, "Customer Loyalty Programmes," IFRIC 15, "Agreements for the Construction of Real Estate," IFRIC 18, "Transfers of Assets from Customers," and SIC-31, "Revenue – Barter Transactions Involving Advertising Services." IFRS 15 provides a single, principle-based five-step model that will apply to all contracts with customers with limited exceptions, including, but not limited to, leases within the scope of IAS 17 and financial instruments and other contractual rights or obligations within the scope of IFRS 9 "Financial Instruments," IFRS 10, "Consolidated Financial Statements" and IFRS 11, "Joint Arrangements." In addition to the five-step model, the standard specifies how to account for the incremental costs of obtaining a contract and the costs directly related to fulfilling a contract. The standard's requirements will also apply to the recognition and measurement of gains and losses on the sale of some non-financial assets that are not an output of the entity's ordinary activities. IFRS 15 is required for annual periods beginning on or after January 1, 2017; earlier adoption is permitted. The Company is in the process of assessing the impact of IFRS 15 on its consolidated financial statements.

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

The amendment is applied retrospectively and clarifies in IAS 16 and IAS 38 that the asset may be revalued by reference to observable data on either the gross or the net carrying amount. In addition, the accumulated depreciation or amortisation is the difference between the gross and carrying amounts of the asset. The Company is in the process of assessing the impact of IFRS 16 and IAS 38 on its consolidated financial statements. This policy will become effective for annual periods starting on or after January 16, 2014.

IAS 24 Related Party Disclosures

The 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. The Company is in the process of assessing the impact of IAS 24 on its consolidated financial statements. This policy will become effective for annual periods starting on or after July 1, 2014.

Amendments to IFRS 11 Joint Arrangements

The amendments to IFRS 11 require that a joint operator accounting for the acquisition of an interest in a joint operation, in which the activity of the joint operation constitutes a business must apply the relevant IFRS 3 principles for business combinations accounting. The amendments also clarify that a previously held interest in a joint operation is not remeasured on the acquisition of an additional interest in the same joint operation while joint control is retained. In addition, a scope exclusion has been added to IFRS 11 to specify that the amendments do not apply when the parties sharing joint control, including the reporting entity, are under common control of the same ultimate controlling party. The amendments apply to both the acquisition of the initial interest in a joint operation and the acquisition of any additional interests in the same joint operation and are prospectively effective for annual periods beginning on or after January 1, 2016, with early adoption permitted. The Company is in the process of assessing the impact of these amendments on its consolidated financial statements.

IFRS 9 (2014)

On July 24, 2014 the IASB issued the final version of IFRS 9 Financial Instruments ("IFRS 9 (2014)"), bringing together the classification and measurement, impairment and hedge accounting phases of the IASB's project to replace IAS 39 Financial Instruments: Recognition and Measurement and all previous versions of IFRS 9. The standard is effective for annual periods beginning on or after January 1 2018, with early application permitted. Retrospective application will be required; however, transition reliefs are provided (including no restatement of comparative period information). The Company is in the process of assessing the impact of IFRS 9 (2014) on its consolidated financial statements.

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 across the year. The process tests the value of our compliance program by:

- Leveraging 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
- Best practice and process improvement opportunity identification.

During the fourth quarter of 2014, 276 controls were tested over the 783 total controls the Company has implemented. The 783 controls were tested at least once over the year. 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 year ended December 31, 2014.

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.

During the period ending December 31, 2014, there has been no change in the Company's ICFR that has materially affected, or is reasonably likely to materially affect, the Company's ICFR.

11. Outlook

Despite recent oil price shocks, Pacific Rubiales enters 2015 in solid standing. We have reduced our capital expenditures to match expected cash flow in a lower oil price environment and have the flexibility and further discretionary components to adjust to the external environment. In addition, we continue to reduce costs through efficiency gains and operational adjustments. The outlook for 2015 includes:

- Net production of 150 to 160 Mboe/d, a slight decrease from the previous guidance, representing approximately 1% to 8% growth over expected 2014 production levels.
- Average WTI oil price assumption of $55 to $60/bbl during the year.
- Oil price realization is expected to be $1 to $2 above the WTI benchmark price assumption.
- A significant reduction in 2015 cash costs: with operating costs estimated at $28/boe, G&A costs of $200 million, financing costs of $250 million and cash taxes of $200 million expected.
- Generating Adjusted EBITDA of $1.5 to $1.7 billion (including funds from hedging programs and dividends from affiliates), and Funds Flow (Cash Flow) of $1.1 to $1.3 billion.
- Exploration and development capital expenditures of $1.1 to $1.3 billion, the majority directed to development drilling and facilities, and a small amount to exploration.

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 2013, 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 2013, the Company initiated the delivery of the additional PAP production from the Quifa SW Field to Ecopetrol. In addition, during the second half of 2013, 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 starting at year-end 2012). During the year, the Company fully delivered the remaining balance of prior period-accumulated PAP volumes.

Carrizales Field (Cravoviejo Block)

On April 27, 2013, the exploitation area of the Carrizales Field reached five million barrels of 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

Through various business acquisitions, the Company secured certain exploration contracts where there existed outstanding disagreements with the ANH relating to the interpretation of the PAP clause. These contracts require PAP 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 exploitation 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 which is the only one for which an arbitration process has been initiated. However, the arbitration process for Corcel was under suspension at the time the Company acquired Petrominerales. The amount under arbitration was approximately $150 million plus related interest of $70 million as of December 31, 2014. 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 is over 20%. The amount under discussion with the ANH for another contract is approximately $90 million plus interest.

The Company and the ANH are currently in discussion to further understand the differences in interpretation of these exploration contracts, and expect to resolve these differences within one year. 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

During the fourth quarter of 2014, the Company received the following major environmental permits from the Environmental Authority in Colombia ("**ANLA**"):

- With Resolution 1450 of 2014, the ANLA granted the amendment of the environmental license of the Copa Field, including the concession of two underground water wells.
- With Resolution 1360 of 2014, the ANLA granted the environmental license for the underwater gas pipeline. The license contains all the permits needed to build the underwater pipeline in the Caribbean coast.
- With Resolution 1375 of 2014, the ANLA granted the amendment of the environmental license of the ground pipeline that connects La Creciente Field with the underwater pipeline.

Peru

- For the 126 Block in the Ucayali Basin, the Company received the second Environmental Impact Assessment ("**EIA**"), allowing the Company to progress the discovery to an evaluation phase.

Delisting from Brazil

Although the Company remains committed to growing its business in Brazil, because of the low trading volume of its BDRs on the BOVESPA the Company announced on October 10, 2014 its intention to delist the BDRs from the BOVESPA. On February 2, 2015, the Company submitted to the CVM and BOVESPA its formal application 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 Earnings from Operations, and Funds Flow from Operations. These non-IFRS measures do not have any standardized meaning and therefore are unlikely to be compared 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.

a) *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:

	Year Ending December 31		Three Months Ending December 31	
(in thousands of US$)	2014	2013	2014	2013
Net (loss) earnings	**$ (1,309,625)**	**$ 426,082**	**$ (1,660,876)**	**$ 140,412**
Adjustments to net (loss) earnings				
Income taxes expense	188,736	504,976	(179,597)	119,229
Foreign exchange loss (gain)	63,211	(2,002)	52,239	7,201
Finance cost	261,300	162,402	73,738	43,298
Loss (gain) on risk management contracts	7,985	2,530	17,315	(9,801)
Loss from equity investment	33,325	29,147	49,012	15,227
Other (income) expenses	(12,815)	34,461	10,018	(916)
Share-based compensation	10,243	39,416	(20,028)	(1,705)
Loss attributable to non-controlling interest	(25,210)	(9,448)	(23,855)	(2,224)
Depletion, depreciation and amortization	1,641,577	1,355,652	479,868	344,512
Impairment and exploration expenses	1,625,358	23,741	1,621,442	94
Adjusted EBITDA	**$ 2,484,085**	**$ 2,566,957**	**$ 419,276**	**$ 655,327**

b) *Funds Flow from Operations*

	Year Ending December 31		Three Months Ending December 31	
(in thousands of US$)	2014	2013	2014	2013
Cash flow from operating activities	$ 2,104,299	$ 1,637,101	$ 616,749	$ 473,683
Changes in non-cash working capital	83,058	(276,011)	206,980	(3,168)
Funds flow from operations	**$ 2,021,241**	**$ 1,913,112**	**$ 409,769**	**$ 476,851**

c) *Net Earnings from Operations*

(in thousands of US$)	Year Ending December 31 2014	2013	Three Months Ending December 31 2014	2013
Net (loss) earnings	**$ (1,309,625)**	$ 426,082	**$ (1,660,876)**	$ 140,412
Finance costs	261,300	162,402	73,738	43,298
Share of profit of equity-accounted investees	33,325	29,147	49,012	15,227
Foreign exchange loss (gain)	63,211	(2,002)	52,239	7,201
Loss (gain) on risk management	7,985	2,530	17,315	(9,801)
Other (income) expenses	(12,815)	34,461	10,018	(916)
Income tax expense	188,736	504,976	(179,597)	119,229
Loss attributable to non-controlling interest	(25,210)	(9,448)	(23,855)	(2,224)
Net (loss) earnings from operations	**$ (793,093)**	$ 1,148,148	**$ (1,662,006)**	$ 312,426

14. Sustainability Policies

After a comprehensive evaluation process, the Company was admitted to the Voluntary Principles for Security and Human Rights. As of December 2014, Pacific Rubiales is part of a select group of 27 companies that have been admitted to the Voluntary Principles, which provide a framework for companies to conduct an assessment of human rights risks associated with security, including an assessment of whether company actions might heighten or mitigate risk (directional risk analysis).

Through the implementation of these principles, we will reduce the potential for reputational concerns and address human rights risks to communities, thus contributing to greater stability of operating environments, potentially reducing exposure to litigation, enhancing the Company's reputation, and promoting Company culture and values. Following these principles closely complements our actions and enhances the corporate social license to operate. For more information visit: http://www.voluntaryprinciples.org/for-companies/.

In 2014, our Human Rights and Gender Equality Declarations were approved and are posted on our Company's website: http://www.pacificrubiales.com.co/corporate/corporate-governance.html.

Our Human Rights Declaration stems from our Sustanability Policy and is a statement of our commitment to the promotion and protection of human rights, including: freedom of association; eradication of child and forced labor; security and human rights; economic, social and cultural rights of communities; and the pursuit of gender equality. The declaration is based on due identification and analysis of potential risks and human rights, adequate management thereof and the definition of action plans according to the needs and the political and socioeconomic context of the zones in which we operate, with special emphasis on those that are in a high-risk situation.

Our Gender Equality Declaration also stems from our Sustanability Policy, recognizes "Diversity and Inclusion", and focuses on the principle that gender equality is a guaranty of progress, competitiveness and added value for the Company and its stakeholders. It advocates and promotes the rights of the women and men that work for Pacific Rubiales and those who belong to the communities and ethnicities neighbouring our operations.

In 2014 the sustainability department trained 463 public and private security force officials, from the Bogota offices and seven of the Company's major fields, in human rights and sustainability concepts, increasing the level of participation by 50% in comparison to 2012 and 2013. .

Additionally the sustainability department carried out 98 training sessions on the concepts of sustainability and shared value across the Company and its fields. These were conducted solely by members of the sustainability department and incurred no additional costs for the Company.

According to the sustainability analysts Sustainalytics, Pacific Rubiales is number one amongst 167 peers in the industry in sustainability performance. They have been tracking the Company since 2012, monitoring our continued improvement. Amongst our highest ratings are:

95 points (out of 100) in social perfomance,
93 points in governance perfomance, and
87 points in overall Environmental, Social and Governance (ESG) perfomance.

The Annual and Sustainability Report for 2014 will be published in late April 2015 on our website.

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 concurrently with this MD&A 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.

Discussed below are specific risks or uncertainties that could impact the Company's financial condition, changes in financial condition and results of operations. The Company has a robust Enterprise Risk Management program that identifies, assesses and provides action plans and controls to mitigate the occurrence of the risks described below, as well as other risks and uncertainties the Company faces.

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 our 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 our operational and financial results. The Company believes that it has the operational and financial flexibility to weather the current low price oil and gas environment in which it operates.

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 Rubiales is working on several ways to identify the potential for 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 we operate.

Production growth depends on our 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 include:
1. Joint venture contracts with our partners to achieve our goals.
2. High competition for attractive acquisitions.
3. Renewal and repositioning of opportunities in our portfolio to enhance recovery.
4. Ability to solve problems related to obtaining environmental permits.

Mitigation activities include a plan of reserves incorporation through exploration, acquisitions, enhanced oil recovery, and negotiations with governments and other stakeholders. In addition, capital projects for production and transportation systems are continuously evaluated and executed.

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

Pacific Rubiales faces many challenges, including uncertain geology, frontier conditions, availability of engineering resources, and technical, fiscal and regulatory constraints. These challenges are relevant when the Company operates in remote areas, which require industrial services, as well as access roads, extensive planning, production facilities, electrical generation and transmission, treating capacity and disposal of production water, storage and port facilities, and gas compression capacity, among others, to timely execute our business plan. Our ability to execute these projects depends on, among other things, the availability of sufficient capital and the efficient allocation of that capital.

Major water disposal projects delivery

Successful execution of the water disposal projects requires, among other things, the existence and availability of necessary technology, engineering resources and environmental licenses to increase production in the Llanos Basin reservoirs. Several projects to manage this increasing volume of water are being executed, as described in this MD&A.

The nature of our operations exposes us to a wide range of health, safety and environmental risks

Given the geographic range, operational diversity, and technical complexity of our 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 our assets.
- Performance of safety risks assessments on a regular basis in our fields and operational facilities.
- 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 our business and our main production asset means we hire significant number of contractors. The Company always maintains the highest standards in the industry and exceeds local regulations in order to ensure that we are in compliance with all HSE standards.

The ability to achieve our strategic objectives depends on how we strengthen stakeholder relationships

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

Human talent attraction, retention and succession planning

One of the key success factors for the Company is its people. Attraction and retention of talent are essential to the Company's growth and sustainability, especially technical personnel and experienced management to deliver and execute the Company's business plan.

The nature of our operations exposes us to a wide range of political developments and changes to regulatory environment and law

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

Our operations can be exposed to security issues

We operate in different geographies were social, civil unrest and security events are not within in the control of the Company. Our portfolio in the different countries can be exposed to these events, impacting our business strategy. In order to minimize the collateral damage should these risks materialize, the Company has set up a plan to protect the assets and people, with proper business continuity plans and management crisis plans.

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

The Company is committed for working with high ethical standards, within an ethical culture and with transparency, based on our Code of Conduct and Ethics. A program for the prevention of fraud and corruption is in place with the objective of strengthening the knowledge of this policy, covering all employees and contractors. In addition, the Company has its delegation of authority procedures that are continuously updated, as well as its Code of Ethics and Conduct, in order to enhance the control environment. As well, an annual assessment of fraud and corruption risk is performed according to the guidelines of the Canadian Corruption of Foreign Public Officials Act.

If any of these risks, or the risks identified in the Annual Information Form, materialize into actual events or circumstances or other possible additional risks and uncertainties of which the Company is currently unaware or which it considers not to be material in relation to the Company's business, actually occur, the Company's assets, liabilities, financial condition, results of operations (including future results of operations), business and business prospects, are likely to be materially and adversely affected. In such circumstances, the price of the Company's securities could decline and investors may lose all or part of their investment. For more information, please see the Company's Annual Information Form, which is available at www.sedar.com.

16. Advisories

Finding Costs

The aggregate of the finding costs incurred in the most recent financial year and the change during that year in estimated future finding costs will generally not reflect total finding costs related to reserves additions for that year.

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, we have expressed boe 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, 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 was 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.

Translations

This MD&A was prepared originally in the English language and subsequently translated into Spanish. In the case of any differences between the English version and its 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
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
MMcf/d	Million cubic feet per day
MD	Measured depth
MMbbl	Million barrels
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