

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of Parex Resources Inc. ("Parex" or the "Company") for the three months and years ended December 31, 2015 and 2014 is dated March 8, 2016 and should be read in conjunction with the audited consolidated financial statements for the years ended December 31, 2015 and 2014. The audited consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") as issued by the International Accounting Standards Board.

Additional information related to Parex and factors that could affect the Company's operations and financial results are included in reports on file with Canadian securities regulatory authorities, including the Company's Annual Information Form dated March 19, 2015, and may be accessed through the SEDAR website at www.sedar.com.

All financial amounts are in United States (US) dollars unless otherwise stated.

Company Profile

Parex is an oil and gas company actively engaged in crude oil exploration, development and production in Colombia. Headquartered in Calgary, Canada, Parex, through its foreign subsidiaries, holds interests in onshore exploration and production blocks totaling approximately 1,870,122 gross acres. The common shares of the Company trade on the Toronto Stock Exchange ("TSX") under the symbol PXT.

Abbreviations

Refer to the final page of the MD&A for commonly used abbreviations in the document. Refer to page 19 for Reserves Information, page 19 for the Advisory on Forward-Looking Statements and page 21 for Non-GAAP Terms used.

2015 Highlights

- Annual oil production in 2015 averaged 27,434 barrels per day, an increase of 22 percent over 2014;
- Increased net working capital to \$76.7 million at December 31, 2015 compared to a net debt position of \$31.7 million at December 31, 2014, and exited 2015 with no bank debt and an available credit facility of \$200 million;
- Released an updated independently evaluated reserves assessment prepared by GLJ Petroleum Consultants Ltd with proved plus probable reserves growth of 19 percent over 2014, increasing to 81.7 million barrels of oil equivalent (98% crude oil) at December 31, 2015 from 68.4 million barrels of oil equivalent (net company working interest) at December 31, 2014 and achieved 2P reserve replacement of 232 percent with total 2015 gross reserve additions of 23.3 million barrels of oil equivalent;
- Finding, Development and Acquisition costs ("FD&A") for the year were \$2.00/bbl for proved reserves and \$3.57/bbl for proved plus probable reserves including future development capital;
- Generated year end funds flow from continuing operations of \$130.3 million (\$0.90 per share basic). Funds flow decreased from the comparative period of \$293.9 million (\$2.44 per share basic) due to lower oil prices partially offset by an increase in production volumes;
- Recorded a net loss of \$44.6 million (\$0.31 per share basic) for the year ended December 31, 2015. The net loss was primarily driven by non-cash impairment charges mainly associated with the decrease in world oil prices and expensed exploration costs;
- Completed a bought deal financing in April 2015 issuing 14.95 million shares at a price of Cdn\$9.15 per common share for gross proceeds of Cdn \$136.8 million;
- Executed a formal agreement with Empresa Colombiana de Petroleos S.A ("Ecopetrol") to operate and earn 50% working in the Aguas Blancas light oil field located in the Middle Magdalena Basin of Colombia; and
- Participated in drilling 12 gross wells in Colombia resulting in 7 oil wells, 2 disposal wells and 3 abandoned wells, for a success rate of 70 percent.

Three months ended December 31, 2015 (“fourth quarter or Q4”) Highlights

- Achieved a record quarterly oil production of 28,588 barrels per day, an increase of 8% over the prior year comparative period and 4% greater than the 2015 average oil production;
- Generated funds flow from continuing operations of \$33.6 million (\$0.22 per share basic) compared to \$49.8 million (\$0.37 per share basic) in the comparative period;
- Reduced production and transportation costs on a combined basis by 33% to \$19.03/bbl from \$28.23/bbl in the comparative period; and
- Generated free funds flow of \$10.0 million as a result of funds flow from operations being in excess of fourth quarter capital expenditures.

Financial Summary

(Financial figures in 000s except per share amounts)	For the three months ended December 31,		For the year ended December 31,		
	2015	2014	2015	2014	2013
Average daily oil production (bopd)	28,588	26,544	27,434	22,526	15,854
Realized sales price (/bbl)	\$ 36.69	\$ 60.08	\$ 46.59	\$ 87.60	\$ 104.20
Operating netback (/bbl)	\$ 15.12	\$ 25.21	\$ 21.70	\$ 47.81	\$ 62.70
Oil and natural gas revenue	\$ 107,816	\$ 160,584	\$ 521,089	\$ 752,022	\$ 636,577
Funds flow from continuing operations	\$ 33,628	\$ 49,759	\$ 130,271	\$ 293,853	\$ 271,670
Per share – basic	0.22	0.37	0.90	2.44	2.51
Per share –adjusted diluted ^{(1) (2)}	0.22	0.37	0.90	2.42	2.23
Net (loss) income	\$ (3,474)	\$ (146,612)	\$ (44,621)	\$ (108,773)	\$ 12,672
Per share – basic	(0.02)	(1.09)	(0.31)	(0.90)	0.12
Per share – diluted	(0.02)	(1.09)	(0.31)	(0.90)	0.09
Capital Expenditures, excluding corporate acquisitions	\$ 23,611	\$ 83,571	\$ 125,482	\$ 296,876	\$ 233,872
Total assets (end of period)	\$ 957,966	\$ 1,034,415	\$ 957,966	\$ 1,034,415	\$ 854,808
Working capital surplus (end of period) ⁽³⁾	\$ 76,708	\$ 3,261	\$ 76,708	\$ 3,261	\$ 24,005
Bank debt (end of period) ⁽⁴⁾	\$ -	\$ 35,000	\$ -	\$ 35,000	\$ 8,530
Weighted average shares outstanding (000s)					
Basic	150,791	134,503	145,018	120,379	108,421
Diluted	151,830	136,140	145,507	122,444	123,535
Outstanding shares (end of period) (000s)	151,489	134,690	151,489	134,690	108,712

⁽¹⁾ Non-GAAP terms. See “Non-GAAP Terms” on page 21.

⁽²⁾ Includes adjustment of debenture cash interest in the adjusted funds flow from continuing operations balance for 2014 and prior periods.

⁽³⁾ Working capital calculation does not take into consideration the undrawn amounts available under the syndicated bank credit facility.

⁽⁴⁾ Bank credit facility currently has a borrowing base of \$200.0 million as at December 31, 2015.

Strategy

The Company’s strategy is to leverage South American and Western Canadian experience and capability to create shareholder value. Jurisdictions will be targeted that have stable fiscal regimes coupled with oil-prone hydrocarbon-rich basins in under-explored areas. Parex will apply proven technology used in the Western Canada Sedimentary Basin in basins with large oil-in-place potential. The Company will focus on short cycle time from discovery to bringing new reserves on-stream and use a portfolio approach to manage subsurface and commercial risks.

Principal Properties

As at December 31, 2015, the Company's principal land holdings and interests in exploration and production blocks held by its subsidiaries were as follows:

	Working Interest	Gross Acres	Net Acres
Colombia Llanos Basin			
<i>Operated Properties</i>			
LLA-16, 20, 29 and 30	100%	201,864	201,864
LLA-57	100%	52,285	52,285
Los Ocarros	50%	31,066	15,533
El Eden	60%	6,397	3,838
Cabrestero	100%	29,562	29,562
LLA-40	50%	83,465	41,732
LLA-24	100%	147,100	147,100
LLA-26	100%	184,061	184,061
Cebucan	100%	109,185	109,185
Cerrero ⁽¹⁾	100%	83,903	83,903
Capachos ⁽¹⁾	50%	64,073	32,037
LLA-32	70%	57,040	39,928
LLA-10	50%	189,544	94,772
<i>Non-Operated Properties</i>			
LLA-34	55%	68,382	37,610
Balay	10%	4,500	450
Colombia Magdalena Basin			
<i>Operated Properties</i>			
VMM-11	100%	116,826	116,826
Morpho	100%	51,420	51,420
VIM-1	100%	223,651	223,651
VMM-9	100%	152,412	152,412
Aguas Blancas ⁽¹⁾	50%	13,386	6,693
Total		1,870,122	1,624,862

⁽¹⁾ Lands are subject to farm-in-agreement earning terms and/or regulatory approval.

Exploration properties that are deemed non-commercial will be relinquished in due course. Accordingly, the gross and net acres described above may decrease over time as lands deemed non-commercial are relinquished. For a description of blocks phase, commitments and letters of credit refer to the Annual Information Form dated March 19, 2015.

2016 Guidance

Parex expects first quarter 2016 production to exceed 28,700 bopd and 2016 full year production to be 29,000 bopd, above the 2015 average of 27,434 bopd. At Brent oil prices of \$35-\$40/bbl, 2016 capital budget and funds flow from operations is forecasted to be approximately \$40-\$80 million. Capital expenditures for 2016 consist of both maintenance and growth capital. The 2016 drilling program is expected to commence in Q2 2016 on blocks LLA-34 and Cabestero. The Company's substantial working capital could be committed to expanding the growth component of the capital program or allocated to increase the Company's land holdings and opportunity portfolio.

To provide downside crude oil price protection in 2016, the Company has transacted ICE Brent oil hedges as follows:

Period Hedged	Reference	Volume bbls/d	Sold Put	Purchased Put	Sold Call	Premium
Jan-June 2016	ICE Brent	5,000	\$47.75	\$52.50	\$70.00	\$1.00
Feb-June 2016	ICE Brent	15,000	\$25.00	\$35.00	\$45.00	\$2.08
July-Sept 2016	ICE Brent	5,000	\$30.50	\$38.00	\$47.00	\$1.00
July-Sept 2016	ICE Brent	5,000	\$34.25	\$40.25	\$49.50	\$1.00

The goal of the 2016 oil hedge strategy is to provide oil price downside protection near a \$35/bbl ICE Brent threshold.

Financial and Operational Results

Consolidated Results of Operations

Parex' operations are primarily conducted in Colombia and Canada.

	For the three months ended December 31,		For the year ended December 31,	
	2015	2014	2015	2014
Average daily production				
Colombia – oil (bopd)	28,588	26,544	27,434	22,526
Total (bopd)	28,588	26,544	27,434	22,526
Average daily sales				
Colombia – produced oil (bopd)	30,064	26,098	27,751	22,058
Colombia – purchased oil (bopd)	1,880	2,539	2,888	1,355
Total (bopd)	31,944	28,637	30,639	23,413
Operating netback (000s)				
Oil sales excluding risk management contracts	\$ 107,816	\$ 160,584	\$ 521,089	\$ 752,022
Royalties	(7,037)	(16,186)	(38,373)	(90,888)
Net revenue	100,779	144,398	482,716	661,134
Production expense	(18,176)	(26,699)	(73,499)	(90,213)
Transportation expense	(36,620)	(46,191)	(154,777)	(149,454)
Purchased oil expense	(4,667)	(12,462)	(34,630)	(33,187)
Operating netback	\$ 41,316	\$ 59,046	\$ 219,810	\$ 388,280
Operating netback (per bbl)⁽¹⁾				
Oil sales excluding risk management contracts	\$ 36.69	\$ 60.08	\$ 46.59	\$ 87.60
Royalties	(2.54)	(6.64)	(3.79)	(11.23)
Net revenue	34.15	53.44	42.80	76.37
Production expense	(6.57)	(10.95)	(7.26)	(11.15)
Transportation expense	(12.46)	(17.28)	(13.84)	(17.41)
Operating netback	\$ 15.12	\$ 25.21	\$ 21.70	\$ 47.81

⁽¹⁾ Average daily sales and the operating netback calculation include the Company's working interest sales volumes and excludes purchased oil sales volumes.

The Company's operating netback on a per barrel basis for the three months and year ended December 31, 2015 was \$15.12 (\$25.21 - three months ended December 31, 2014) and \$21.70 (\$47.81 - year ended December 31, 2014) compared to \$20.70 for the third quarter of 2015. The average realized sales price for the three months and year ended was \$36.69/bbl (\$60.08/bbl - three months ended December 31, 2014) and \$46.59/bbl (\$87.60/bbl - year ended December 31, 2014) compared to \$44.62/bbl for the third quarter of 2015.

Royalty charges for the three months and year ended December 31, 2015 were \$2.54/bbl (\$6.64/bbl - three months ended December 31, 2014) and \$3.79/bbl (\$11.23/bbl - year ended December 31, 2014).

Production expense for the three months and year ended was \$6.57/bbl (\$10.95/bbl - three months ended December 31, 2014) and \$7.26/bbl (\$11.15/bbl - year ended December 31, 2014).

Transportation expense per barrel for the three months and year ended was \$12.46/bbl (\$17.28/bbl - three months ended December 31, 2014) and \$13.84/bbl (\$17.41/bbl - year ended December 31, 2014) and compared to \$13.31/bbl for the third quarter of 2015.

Overall the price of the Company's benchmark Brent crude decreased by \$6.47/bbl in the fourth quarter as compared to the third quarter of 2015 while the operating netback declined by \$5.58/bbl in the same period, mainly as a result of cost savings from decreased transportation, production and royalty costs per barrel realized in the period partially offset by a widening of the Company's realized price as compared to the Brent reference price (see Commodity Prices).

When comparing 2015 actual results to the 2015 Guidance provided in the 2014 MD&A, actual capital expenditures were \$125.5 million compared to the budgeted amount of \$145-\$155 million. The decrease from capex guidance is a result of the Company adjusting its capital budget to keep capital expenditures

in line with funds flow in the low oil price environment. In addition, even with the reduced capital spending, the Company exceeded the 2015 forecasted production of 26,500 bopd, with actual full year 2015 production of 27,434 bopd.

Colombian Oil and Gas Sales

a) Average Daily Crude Oil Production and Sales Volumes (bopd)

	For the three months ended December 31,		For the year ended December 31,	
	2015	2014	2015	2014
Block LLA-34 (Tigana, Tua, Tarotaro & Max fields)	17,451	11,053	14,596	9,325
Block LLA-26 (Rumba, Bazar)	2,964	-	1,274	-
Block LLA-32 (Kananaskis, Carmentea, Maniceno and Bandola fields)	2,489	5,723	4,456	3,041
Block Los Ocarros (Las Maracas field)	1,140	3,201	1,692	5,000
Block Cabretero (Kitaro & Akira fields)	2,173	2,757	2,285	1,492
Block LLA-16 (Kona, Sulawesi, Java and Malawi fields)	594	1,122	722	1,935
Block LLA-30 (Adalia field)	482	1,168	704	816
Block LLA-40 (Bergonia and Celtis fields)	1,133	791	1,535	300
Other	162	729	170	617
Total Production	28,588	26,544	27,434	22,526
Inventory (build) draw and oil losses	1,476	(446)	317	(468)
Colombia average daily oil sales of produced oil	30,064	26,098	27,751	22,058
Purchased oil	1,880	2,539	2,888	1,355
Sales Volumes	31,944	28,637	30,639	23,413

Production for the fourth quarter of the year averaged 28,588 bopd, an increase of approximately 8 percent from the fourth quarter average of 2014. The fourth quarter production increase as compared to the comparative period was a result of incremental production increases attributable to Block LLA-34 and Block LLA-26. During 2015, the Company temporarily shut-in approximately 1,000 bopd of higher cost production, offset by additional production at Rumba, LLA-34 and Cabretero. Parex has increased production quarter over quarter for the last 15 quarters.

Average production in January and February 2016 is approximately 29,000 bopd, in line with Company's previously announced guidance and an increase from Q4 average production.

b) Average Reference and Realized Prices

	For the three months ended December 31,		For the year ended December 31,	
	2015	2014	2015	2014
Reference Prices				
Brent (\$/bbl)	44.69	77.07	53.57	99.56
WTI (\$/bbl)	42.16	73.20	48.76	93.20
Vasconia (\$/bbl)	37.15	71.42	47.69	93.03
Average Realized Prices				
Realized sales price (\$/bbl)	36.69	60.08	46.59	87.60
Realized oil hedging gain (\$/bbl)	1.12	2.33	0.39	0.94
Realized price after hedging (\$/bbl)	37.81	62.41	46.98	88.54
Realized price (differential) to Brent crude (\$/bbl)	(8.00)	(16.99)	(6.98)	(11.96)

During Q4 2015, the differential between Brent reference pricing and our realized sale price was \$8/bbl. The differential during Q4 was wider than historical averages. Historically the Vasconia to Brent crude differential is between \$5-\$7/bbl. In November and December 2015 the differential was approximately \$9-\$10/bbl. To date in 2016 the Vasconia differential to Brent has returned to historical norms in the \$5-\$7/bbl range.

The table below provides a quarter-by-quarter view of Parex' historical pricing in Colombia:

Average price for the period	Q4 2015	Q3 2015	Q2 2015	Q1 2015	Q4 2014
Brent (\$/bbl)	44.69	51.16	63.50	55.13	77.07
Vasconia (\$/bbl)	37.15	45.83	58.79	49.74	71.42
Parex realized sales price (\$/bbl)	36.69	44.62	56.31	49.42	60.08
Parex realized price (differential) to Brent crude (\$/bbl)	(8.00)	(6.54)	(7.19)	(5.71)	(16.99)
Parex realized price (differential) to Vasconia crude (\$/bbl)	(0.46)	(1.21)	(2.48)	(0.32)	(11.34)

Differences between Parex' realized price and Vasconia crude price is mainly related to quality adjustments and timing of oil sales compared to quarter averages. The differential between Vasconia crude pricing and Brent crude pricing also affects Parex' realized sales price and is set in liquid global markets and therefore attributed to factors that are beyond the Company's control.

c) Oil Revenue

2015 oil revenue decreased \$230.9 million or 31 percent as reconciled in the table below to 2014:

(\$000s)	
Oil revenue, year ended December 31, 2014	\$ 752,022
Sales volume of produced oil, an increase of 26% (5,693 bopd)	182,028
Sales volume of purchased oil, a increase of 113% (1,533 bopd)	49,016
Sales price decrease of 47%	(461,977)
Oil revenue, year ended December 31, 2015	\$ 521,089

d) Colombian Crude Oil Inventory in Transit

(\$000s)		For the years ended December 31,	
		2015	2014
Crude oil in transit	\$	3,207	\$ 10,959

As at December 31, 2015, the Company had 136,184 bbls of crude oil inventory in transit, which was injected into the Colombian pipelines. The inventory was valued based on direct and indirect expenditures (including production costs, certain transportation costs, depletion expense and royalty expense) at approximately \$24/bbl (\$43/bbl - 2014) incurred in bringing the crude oil to its existing condition and location. The cost per bbl of crude oil inventory has decreased largely due to a reduction in production, transportation, depletion and royalty costs per bbl from the prior period. A reconciliation of the crude oil inventory in transit volumes is provided below:

(mmbbls)		For the periods ended December 31,	
		2015	2014
Crude oil inventory in transit - beginning of the period		252.0	137.0
Oil production		10,013.4	8,222.0
Oil sales		(11,095.3)	(8,545.7)
Purchased oil		1,054.2	494.5
Delivered oil losses		(88.1)	(55.8)
Crude oil inventory in transit - end of the period		136.2	252.0

A reconciliation of quarter to quarter crude oil inventory movements is provided below:

(mmbbls)		For the periods ended			
		Dec. 31, 2015	Sept. 30, 2015	June 30, 2015	Mar. 31, 2015
Crude oil inventory in transit - beginning of the period		272.0	232.5	214.4	252.0
Oil production		2,629.9	2,518.6	2,459.3	2,405.6
Oil sales		(2,901.1)	(2,757.1)	(2,740.6)	(2,696.5)
Delivered oil losses		(37.6)	(4.7)	(24.5)	(21.3)
Purchased oil		173.0	282.7	323.9	274.6
Crude oil inventory in transit - end of the period		136.2	272.0	232.5	214.4
% of period production		5.1	10.8	9.5	9.0

Crude oil inventory build and draw down from period to period are subject to factors that the Company does not control such as timing of the number of shipments from storage to export. Crude oil inventory as a percentage of production at December 31, 2015 was 5.1%. This is lower than the historic percentage between 9% and 11% mainly due to oil export shipment timing.

e) Purchased Oil

	For the three months ended December 31,		For the year ended December 31,	
	2015	2014	2015	2014
Purchased oil expense (\$000s)	\$ 4,667	\$ 12,462	\$ 34,630	\$ 33,187

Purchased oil expense for the three months and year ended December 31, 2015 was \$4.7 million and \$34.6 million as compared to \$8.4 million in the preceding quarter and \$12.5 million and \$33.2 million for the three months and year ended December 31, 2014. Purchased oil expense has decreased as a result of the decrease in oil prices. Transportation costs are incurred by the Company to transport purchased oil to sale delivery points.

Colombian Royalties

	For the three months ended December 31,		For the year ended December 31,	
	2015	2014	2015	2014
Royalties (\$000s)	\$ 7,037	\$ 16,186	\$ 38,373	\$ 90,888
Per unit (\$/bbl)	2.54	6.64	3.79	11.23
Percentage of sales ⁽¹⁾	6.8%	10.9%	7.9%	12.6%

⁽¹⁾ Calculated based on Company working interest sales volumes excluding purchased oil volumes sold

In the three and twelve months ended December 31, 2015 royalties as a percentage of sales of 6.8% and 7.9% decreased substantially from 10.9% and 12.6% in the three and twelve months ended December 31, 2014. The third quarter of 2015 was 7.7%.

The decrease of royalties as a percentage of sales from the comparative periods is due to the High Price Royalty (HPR) being substantially lower as a result of reduced world oil prices as compared to the previous periods. The HPR comes into effect when accumulated production of any production area, inclusive of royalty volumes, exceeds 5 million barrels, and in the event international reference prices exceed pricing determined in the contract. The calculation is described as a "High Price Share" in the Company's Annual Information Form dated March 19, 2015, and may be accessed through the SEDAR website at www.sedar.com.

In the second half of 2015 both the Tua and Tigana oil fields began being subject to the HPR as they have reached cumulative production greater than 5 million barrels. Royalties however are highly dependent on the global price of crude oil as oil prices and crude quality are components of the HPR calculation. At WTI prices below \$40/bbl the HPR royalty does not come into effect.

Colombian Production Expense

	For the three months ended December 31,		For the year ended December 31,	
	2015	2014	2015	2014
Production expense (\$000s)	\$ 18,176	\$ 26,699	\$ 73,499	\$ 90,213
Per unit (\$/bbl)	6.57	10.95	7.26	11.15

A breakdown of the production expense on a per bbl basis between operated and non-operated fields are provided below:

	For the three months ended December 31,		For the year ended December 31,	
	2015	2014	2015	2014
Per unit (\$/bbl) – based on sales volumes – operated ⁽¹⁾	8.51	12.38	8.34	11.56
Per unit (\$/bbl) – based on sales volumes – non-operated ⁽¹⁾	5.26	9.07	6.25	10.64

⁽¹⁾ Calculated based on Company working interest sales volumes excluding purchased oil volumes sold.

Production expense includes the cost of activities in the field to operate wells and facilities, lift to surface, gather, process, treat and store production.

Production expense for the fourth quarter on a per barrel basis of \$6.57/bbl is lower in comparison of the third quarter of \$7.03/bbl. Operated properties production expense in the fourth quarter was \$8.51/bbl compared to \$8.12/bbl for the third quarter and non-operated properties production expense was \$5.26/bbl for the fourth quarter compared to \$5.97/bbl for the third quarter. The quarter over quarter decrease in the non-operated properties production expense relates to Block LLA-34 as fixed operating cost absorption has increased as a result of increased production from this Block.

Production expense for the year ended December 31, 2015 on a per barrel basis is \$7.26/bbl compared to \$11.15/bbl for the year ended December 31, 2014. The decrease is primarily due to the depreciation of the Colombian peso. Approximately 90% of both operated and non-operated field costs are now denominated in Colombian pesos. Other operated field cost reduction is attributed to the temporary shut-in of approximately 1,000 bopd of higher operating cost fields. This is somewhat off-set however by decreased fixed operating cost absorption on fields with decreasing production. Block LLA-34 has experienced higher fixed cost absorption as production has increased through 2015.

For 2016 the Company expects further production cost savings related to the depreciation of the Colombian peso. Further, the Company has been working with its vendors to seek price reductions in the current oil price environment and continues to temporarily shut-in higher cost production where appropriate.

Colombian Transportation Expense

	For the three months ended December 31,		For the year ended December 31,	
	2015	2014	2015	2014
Transportation expense (\$000s)	\$ 36,620	\$ 46,191	\$ 154,777	\$ 149,454
Per unit (\$/bbl)	12.46	17.28	13.84	17.41

Transportation expense includes trucking costs incurred to transport production to several offloading stations for sale and for the majority of crude volume the Ocesa pipeline tariff and offloading fee. For the three months ended December 31, 2015, the cost of transportation of \$12.46/bbl has decreased compared to the third quarter cost of \$13.31/bbl and decreased from the comparative period of \$17.28/bbl. The decrease from the comparative period is a result of decreased pipeline tariff fees and decreased trucking costs and also the depreciation of the Colombian peso compared to US\$.

On a year to date basis transportation expense has decreased to \$13.84/bbl from \$17.41/bbl in the comparative period. The main reason for this decrease relates to increased available pipeline capacity which reduced the amount of oil being trucked for export which in 2015 came at a higher cost per barrel than pipeline tariff fees. If the Colombian Peso were to continue to depreciate, trucking crude to coastal export facilities is a viable option.

The Company expects the 2016 transportation costs on a per bbl basis to be equal or lower than the fourth quarter of 2015 with variability depending on the marketing mix, delivery points and the Colombian peso/US\$ exchange rate.

General and Administrative Expense ("G&A")

(\$000s)	For the three months ended December 31,		For the year ended December 31,	
	2015	2014	2015	2014
Gross G&A	\$ 10,999	\$ 12,125	\$ 43,347	\$ 44,037
G&A recoveries	(55)	(411)	(327)	(1,587)
Capitalized G&A	(1,354)	(2,488)	(6,122)	(8,646)
Total G&A	9,590	9,226	36,898	33,804
G&A expense reclassified to discontinued operations ⁽¹⁾	-	301	149	1,273
Net G&A expense	\$ 9,590	\$ 8,925	\$ 36,749	\$ 32,531
Per unit (\$/bbl) ⁽²⁾	\$ 3.65	\$ 3.66	\$ 3.68	\$ 3.96

⁽¹⁾ Due to the sale of Parex Resources (Trinidad) Ltd.

⁽²⁾ Calculated based on Company working interest production volumes.

Net G&A from continuing operations was \$36.7 million for the twelve months ended December 31, 2015 compared to \$32.5 million for the same period in 2014. Net G&A is impacted by both G&A recoveries and capitalized G&A which with reduced activity levels have decreased from the prior period. Gross G&A was \$43.3 million for the full year ended December 31st, 2015 (2014 - \$44.0 million). Included in gross G&A are \$5.3 million of one-time consulting costs related to process and efficiency projects carried out through 2015. A total of 279 full-time-equivalents in two locations were working for Parex as at December 31, 2015 and throughout the fourth quarter compared to 278 as at December 31, 2014 and 277 at September 30, 2015. On a per barrel basis net G&A for the year has declined 7% from the comparative year.

The Company's G&A expense is mainly denominated in local currencies of COP and Cdn dollar which have both depreciated significantly against the USD throughout 2015.

For 2016 the devaluation of the local currencies and various cost reduction efforts is expected to result in gross G&A being reduced by 10-20%.

Share-Based Compensation Expense

(\$000s)	For the three months ended December 31,		For the year ended December 31,	
	2015	2014	2015	2014
Share-based compensation expense	\$ 1,298	\$ 1,274	\$ 5,328	\$ 5,746
Restricted share units expense	1,335	925	5,060	2,745
Deferred Share units expense	635	-	635	-
Share appreciation rights expense (recovery)	1,359	(5,107)	3,806	4,005
Total (recovery) expense	\$ 4,627	\$ (2,908)	\$ 14,829	\$ 12,496
SARs (recovery) expense reclassified as discontinued operations	-	(171)	22	(171)
Total (recovery) expense – continuing operations	\$ 4,627	\$ (3,079)	\$ 14,851	\$ 12,325

Share-based compensation expense was \$14.8 million for the twelve months ended December 31, 2015 compared to \$12.5 million for the same period in 2014.

Share-based compensation expense relating to stock options was \$5.3 million for the twelve months ended December 31, 2015 compared to \$5.7 million for the same period in 2014.

Share appreciation rights (“SARs”) expense was \$1.4 million in the fourth quarter of 2015 (three months ended December 31, 2014 - \$5.1 million recovery) as a result of the share price of the company increasing in the period from Cdn\$9.25/share as at September 30, 2015 to Cdn\$10.16/share as at December 31, 2015 and the issuance of new SARs. SARs expense was \$3.8 million for the twelve months ended December 31, 2015 compared to \$4.0 million for the same period in 2014. As at December 31, 2015, the total SARs liability accrued is \$5.8 million (December 31, 2014 - \$4.4 million).

Restricted share unit (“RSUs”) expense was \$5.1 million for the twelve months ended December 31, 2015 compared to \$2.7 million for the same period in 2014. The increase is mainly related to a higher number of RSUs being issued in 2015 versus 2014.

Deferred share unit (“DSUs”) expense was \$0.6 million for the twelve months ended December 31, 2015 compared to \$nil million for the same period in 2014, as the plan did not come in effect until the current year. The DSU plan is solely for non-employee directors who will not be receiving any further RSU awards.

Depletion, Depreciation and Amortization Expense (“DD&A”)

DD&A (\$000s) total	For the three months ended December 31,		For the year ended December 31,	
	2015	2014	2015	2014
DD&A (\$000s) total	\$ 35,250	\$ 51,668	\$ 152,399	\$ 218,490
DD&A reclassified to discontinued operations	-	(3)	-	(19)
DD&A – continuing operations	\$ 35,250	\$ 51,665	\$ 152,399	\$ 218,471
Per unit (\$/bbl) ⁽¹⁾	13.40	21.16	15.22	26.56

⁽¹⁾ DDA per unit (\$/bbl) is calculated using Company working interest production volumes and does not include inventory adjustments.

Fourth quarter 2015 DD&A was \$35.3 million compared to \$51.7 million for the same period in 2014. For the year ended December 31, 2015 DD&A was \$152.4 million (\$15.22/bbl) as compared to \$218.5 million (\$26.56/bbl) for the prior year.

For the fourth quarter of 2015, future development costs of \$252.1 million (three months ended December 31, 2014 - \$360.8 million) were included in the depletion calculation. Fourth quarter 2015 DD&A of \$13.40/bbl is lower than the comparative period of \$21.16/bbl due to the significant increase in proved and probable reserves, a decrease in future development costs and a change in the CGU production mix. The decrease in full year 2015 DD&A per barrel is also a result of drilling success and increased reserves as compared to the prior period.

Foreign Exchange

	For the three months ended December 31,		For the year ended December 31,	
	2015	2014	2015	2014
Foreign exchange gain (\$000s)	\$ (5,374)	\$ (7,261)	\$ 4,996	\$ (9,742)
Foreign exchange (gain) loss reclassified to discontinued operations	-	-	-	(2)
Foreign exchange gain— continuing operations	\$ (5,374)	\$ (7,261)	\$ 4,996	\$ (9,740)
Foreign Exchange Rates				
CAD\$/USD\$	0.75	0.88	0.78	0.91
Colombian peso/USD\$	3,059	2,169	2,743	1,998

The Company's main exposure to foreign currency risk relates to the pricing of foreign currency denominated in Canadian dollars and Colombian pesos, as the Company's functional currency is the US dollar. The Company has exposure in Colombia and Canada on costs, such as capital expenditures, local wages, royalties and income taxes, all of which may be denominated in local currencies. The main driver of foreign exchange loss and gain recorded on the consolidated statements of comprehensive income (loss) is the Colombian Peso denominated tax withholdings receivable and income tax payable balances in Colombia. For the three months ended December 31, 2015, a total foreign exchange gain of \$5.4 million was recorded and for the full year 2015 a loss of \$5.0 million was recorded. The timing of payment settlements, accruals and their adjustments have impacts on foreign exchange gains/losses. Unrealized foreign exchange gains and losses may be reversed in the future as a result of fluctuations in exchange rates and are recorded in the Company's consolidated statement of comprehensive income (loss).

The Company reviews its exposure to foreign currency variations on an ongoing basis and maintains cash deposits primarily in USD denominated deposits in Canada and Barbados.

Net Finance Expense

(\$000s)	For the three months ended December 31,		For the year ended December 31,	
	2015	2014	2015	2014
Interest expense and bank charges	\$ 1,078	\$ 1,651	\$ 3,661	\$ 7,042
Accretion on decommissioning and environmental liabilities	383	334	1,588	1,127
Realized loss (gain) on foreign currency risk management contracts	-	-	1,840	2,672
Unrealized loss on foreign currency risk management contracts	99	1,975	(1,481)	1,975
Loss on disposition of tangible assets	124	136	64	731
Interest and other income	(24)	79	(579)	(1,332)
Colombian net wealth tax	-	-	3,855	-
Loss (gain) on derivative financial liability	-	-	-	23,707
Gain on settlement of convertible debentures	-	-	-	(557)
Amortization of debt issuance costs	-	-	-	475
Accretion on convertible debentures	-	-	-	3,210
Net finance expense	\$ 1,660	\$ 4,175	\$ 8,948	\$ 39,050
Finance expenses reclassified to discontinued operations	-	(138)	-	(743)
Net finance expense - continuing operations	\$ 1,660	\$ 4,037	\$ 8,948	\$ 38,307

	For the three months ended December 31,		For the year ended December 31,	
	2015	2014	2015	2014
Non-cash finance expense	\$ 606	\$ 2,445	\$ 171	\$ 30,668
Cash finance expense	1,054	1,730	8,777	8,382
Net finance expense	\$ 1,660	\$ 4,175	\$ 8,948	\$ 39,050

Interest expense in the current year relates to interest and stand-by charges on the credit facility. In the prior year these charges related to both the credit facility and the Cdn\$85.0 million Debenture which during August and September 2014, was converted for an aggregate of 8,339,991 common shares of the Company and Debentures not converted were redeemed for \$0.3 million in cash.

The non-cash components of net finance expense include the accretion on decommissioning liabilities, unrealized losses (gains) on foreign currency risk management contracts and loss on disposition of tangible assets line items.

On December 23, 2014 the Colombian government passed a law imposing a Net Wealth Tax ("NWT") levied on Colombian businesses. The tax is assessed and becomes payable on the opening equity as at January 1st of each year beginning in 2015 extending until 2017, at rates from 1.15% in 2015 to 0.4% in

2017. The Company's NWT for 2016 was \$3.9 million and was paid in two equal semi-annual installments during the year December 31, 2015. The Company's NWT for 2016 is expected to be \$2.5 million and will be paid in two equal semi-annual installments in 2016.

Risk Management

Management of cash flow variability is an integral component of Parex' business strategy. Changing business conditions are monitored regularly and, where material, reviewed with the Board of Directors to establish risk management guidelines to be used by management. The risk exposure inherent in movements in the price of crude oil, fluctuations in the US/COP exchange rate and interest rate movements are all proactively reviewed by Parex and as considered appropriate may be managed through the use of derivatives primarily with financial institutions that are members of Parex' syndicated bank credit facility. The Company considers these derivative contracts to be an effective means to manage and forecast cash flow.

Parex has elected not to apply IFRS prescribed "hedge accounting" rules and, accordingly, pursuant to IFRS the fair value of the financial contracts is recorded at each period-end. The fair value may change substantially from period to period depending on commodity and foreign exchange forward strip prices for the financial contracts outstanding at the balance sheet date. The change in fair value from period-end to period-end is reflected in the earnings for that period. As a result, earnings may fluctuate considerably based on the period-ending commodity and foreign exchange forward strip prices.

a) Risk Management Contracts – Brent Crude

The following is a summary of the ICE Brent priced crude oil risk management contracts in place for the year ended December 31, 2015:

Period Hedged	Reference	Type	Volume bbls/d	Price/bbl
March 1, 2015 to March 31, 2015	ICE Brent	Collar	5,000	\$55.00-\$66.60
March 1, 2015 to March 31, 2015	ICE Brent	Collar	3,000	\$55.00-\$68.00
April 1, 2015 to April 30, 2015	ICE Brent	Collar	5,000	\$55.00-\$68.25
April 1, 2015 to April 30, 2015	ICE Brent	Collar	3,000	\$55.00-\$69.75
April 1, 2015 to April 30, 2015	ICE Brent	Collar	2,000	\$55.00-\$67.00
May 1, 2015 to May 31, 2015	ICE Brent	Collar	5,000	\$55.00-\$68.75
May 1, 2015 to July 31, 2015	ICE Brent	Collar	5,000	\$55.00-\$65.00
June 1, 2015 to July 31, 2015	ICE Brent	Collar	2,000	\$57.50-\$69.00
August 1, 2015 to August 31, 2015	ICE Brent	Collar	3,000	\$55.00-\$76.80
August 1, 2015 to November 30, 2015	ICE Brent	Put	2,000	\$55.00
November 1, 2015 to November 30, 2015	ICE Brent	Collar	16,667	\$50.00-\$57.40

Period Hedged	Reference	Volume bbls/d	Sold Put	Purchased Put	Sold Call	Premium
January 1, 2016 to June 30, 2016	ICE Brent	5,000	\$47.75	\$52.50	\$70.00	\$1.00

The table below summarizes the (gain) on the commodity risk management contracts that were in place during the three months and years ended December 31, 2015 and 2014:

(\$000s)	For the three months ended December 31,		For the year ended December 31,	
	2015	2014	2015	2014
Realized (gain) on commodity risk management contracts	\$ (3,291)	\$ (6,232)	\$ (4,390)	\$ (8,054)
Unrealized (gain) on commodity risk management contracts	(768)	-	(2,915)	-
Total	\$ (4,059)	\$ (6,232)	\$ (7,305)	\$ (8,054)

Subsequent to December 31, 2015, Parex entered into the following ICE Brent priced crude oil risk management contracts:

Period Hedged	Reference	Volume bbls/d	Sold Put	Purchased Put	Sold Call	Premium
February 1, 2016 to June 30, 2016	ICE Brent	15,000	\$25.00	\$35.00	\$45.00	\$2.08
July 1, 2016 to September 30, 2016	ICE Brent	5,000	\$30.50	\$38.00	\$47.00	\$1.00
July 1, 2016 to September 30, 2016	ICE Brent	5,000	\$34.25	\$40.25	\$49.50	\$1.00

The Company's net unrealized derivative gain on risk management contracts for the year ended December 31, 2015 was \$2.9 million (December 31, 2014 - \$nil). The realized gain on commodity risk management contracts of \$3.3 million and \$4.4 million for the three and twelve months ended December 31, 2015 is attributed to the Company monetizing put options in the fourth quarter of 2015.

b) Risk Management Contracts – Foreign Currency

The following is a summary of the foreign currency risk management contracts in place as at December 31, 2015:

Period Hedged	Reference	Type	Amount USD	Price (COP)
September 2, 2015 to April 14, 2016	Colombian Peso	Collar	\$8 million	3,000 – 3,228
September 2, 2015 to June 14, 2016	Colombian Peso	Collar	\$8 million	3,000 – 3,228

The table below summarizes the losses (gains) on the foreign currency risk management contracts:

(\$000s)		For the three months ended December 31,		For the year ended December 31,	
		2015	2014	2015	2014
Realized loss on foreign currency risk management contracts	\$	-	\$ -	\$ 1,840	\$ 2,672
Unrealized loss (gain) on foreign currency risk management contracts		99	1,975	(1,481)	1,975
Total	\$	99	\$ 1,975	\$ 359	\$ 4,647

The realized loss represents the foreign currency risk management contracts settled during the period. The unrealized loss (gain) represents the fair value change of the underlying foreign currency risk management contracts as at the balance sheet date to be settled in the future, and also reclassification adjustments when contracts are realized and settled.

Income Tax

The components of tax expense for the three and twelve months ended December 31, 2015 and 2014 were as follows:

(\$000s)		For the three months ended December 31,		For the year ended December 31,	
		2015	2014	2015	2014
Current tax expense	\$	1,463	\$ 7,368	\$ 48,207	\$ 52,184
Deferred tax (recovery)		(21,847)	(28,022)	(54,105)	(19,539)
Total tax (recovery) expense	\$	(20,384)	\$ (20,654)	\$ (5,898)	\$ 32,645

The current tax expense and deferred tax recovery relates to the Company's operations in Colombia. Current tax in the fourth quarter was \$1.5 million as compared to \$7.4 million in the comparative three month period. In the quarter current tax expense as a percentage of Colombian cash flows was 3% compared to the company historical average being 13-15%. This decrease is mainly a result of the Company's tax restructuring completed in the third quarter of 2015 (see below).

Deferred tax in the fourth quarter of 2015 was a recovery of \$21.8 million and a recovery of \$54.1 million for the year ended December 31, 2015 (\$28.0 million and \$19.5 million recovery for the three and twelve months ended December 31, 2014), as a result of a narrowing of the book and tax basis in Colombian subsidiaries from the non-cash impairments recorded on E&E and PP&E assets and the tax restructuring completed in the third quarter of 2015 (see below). This is however partially offset by depreciation in the Colombian peso.

The calculation of current and future income tax in Colombia is based on a number of variables which can cause swings in current and future income tax. These variables include the year end producing reserves used in calculating depletion for tax purposes and the timing and number of dry hole write offs permissible for Colombian tax purposes. Accordingly estimating tax expense during the year is inherently difficult.

Tax Restructuring

Effective July 1, 2015 the Company entered into an intercompany purchase/sale agreement between two of its subsidiaries, whereby certain assets were effectively sold and consolidated. The purpose of the transaction was to make the Company's tax structure more efficient for future years. The impact of this restructuring is that the Company incurred recapture and capital gains taxes in 2015 however has gained increased tax basis, and use of loss carry-forwards in the consolidated entity.

After completing the transaction, the Company has recorded the full impact of the transaction in the third quarter of 2015 with the benefits of the restructuring beginning to be realized in the fourth quarter of 2015. For 2016, using our budget commodity price assumption of \$35-\$40/bbl, our estimated current tax

expense is expected to be less than \$5 million. The restructuring benefit is expected to reduce over time but is dependent upon global oil prices, level of capital expenditures in Colombia and other factors.

Capital Expenditures

For the year ended December 31, (\$000s)	Colombia ⁽¹⁾		Trinidad & Tobago		Canada		Total	
	2015	2014	2015	2014	2015	2014	2015	2014
Acquisition of unproved properties	15,346	14,551	-	-	-	-	15,346	14,551
Geological and geophysical	3,146	11,406	-	-	-	-	3,146	11,406
Drilling and completion	89,430	234,842	-	-	-	-	89,430	234,842
Well equipment and facilities	15,234	34,204	-	-	-	-	15,234	34,204
Other	2,112	641	-	717	214	515	2,326	1,873
Total capital expenditures	\$ 125,268	\$ 295,644	\$ -	\$ 717	\$ 214	\$ 515	\$ 125,482	\$ 296,876

⁽¹⁾ Excludes Verano and Sorgenia corporate acquisition costs.

For the three months ended December 31, (\$000s)	Colombia		Trinidad & Tobago		Canada		Total	
	2015	2014	2015	2014	2015	2014	2015	2014
Acquisition of unproved properties	5,272	7,117	-	-	-	-	5,272	7,117
Geological and geophysical	1,495	4,856	-	-	-	-	1,495	4,856
Drilling and completion	14,471	58,876	-	-	-	-	14,471	58,876
Well equipment and facilities	1,509	11,666	-	-	-	-	1,509	11,666
Other	779	88	-	551	85	417	864	1,056
Total capital expenditures	\$ 23,526	\$ 82,603	\$ -	\$ 551	\$ 85	\$ 417	\$ 23,611	\$ 83,571

Capital Expenditures Summary

During the twelve months ended December 31, 2015 the Company incurred \$125.5 million of capital expenditures compared to \$296.9 million in the same period of 2014. During 2015 the Company drilled 12 wells (9.45 net), compared to 38 wells (23.75 net) in 2014. Capital expenditures were less in 2015 as compared to 2014 due to the decrease in global oil prices reducing the Company's funds flow from operations and the Company's strategy to match capital expenditures to funds flow from operations.

In the fourth quarter of 2015 the Company drilled 1 well (1 net) in Colombia compared to 6 wells (4.15 net) in the comparative period. Drilling and completion costs during the fourth quarter totaled \$14.5 million, all of which related to drilling and completion and capitalized workover costs in Colombia. The Company also invested in building well locations for future drilling operations. Spending on well equipment and facilities was \$1.5 million in the quarter, all focused in Colombia.

The Company's Colombian operations utilized one drilling rig at the beginning of Q4 on the Rumba-4 prospect. It was rig released at the beginning of October and no other operated drilling took place in the fourth quarter. No drilling took place during Q4 on the non-operated blocks. On average, one service rig was utilized on the operated blocks in Q4, 2015 and one service rig was utilized on Block LLA-34. The level of activity decreased in the fourth quarter of 2015 from the third quarter of 2015 as Parex invested \$23.5 million in the fourth quarter as compared to \$37.7 million in the third quarter.

During the year ended December 31, 2015 capital expenditures of \$125.5 million were self funded from funds flow from operations of \$130.3 million. The Company has maintained its ability to fund growth from cash flow since 2012, excluding corporate acquisitions.

Non-cash Impairment Charges

(\$000s)	For the three months ended December 31,		For the year ended December 31,	
	2015	2014	2015	2014
Impairment of PP&E related to Llanos CGU	\$ -	\$ 113,264	\$ 31,144	\$ 113,264
Impairment of E&E assets	22,529	64,020	27,025	64,020
Total non-cash impairment charges before deferred income tax recoveries	\$ 22,529	\$ 177,284	\$ 58,169	\$ 177,284

As a result of the decrease in forecast oil prices compared to those at December 31, 2014 an indication of impairment was identified for all CGUs during 2015 and impairment tests were performed. The Company determined that the carrying amount of a CGU in the Llanos Basin exceeded its recoverable amount. An impairment of \$31.1 million (year ended December 31, 2014 - \$113.3 million) was recorded in the consolidated statement of comprehensive income (loss).

The recoverable amount was determined using fair value less costs of disposal. There are no E&E assets associated with this CGU. Future cash flows were discounted using an after tax rate of 11 percent. At December 31, 2015, the recoverable amount of the CGU was estimated to be \$nil. The impairment is due to lower crude prices assumed in the fair value calculation as compared to the prior year, there was no negative reserve report revisions or cost structure changes.

The fair value for the producing properties in this CGU was calculated based on discounted after-tax cash flows of proved and probable reserves using forecast prices and cost estimates, consistent with the Company's independent qualified reserves evaluators. This approach requires assumptions about revenue, future oil prices, tax rates and discount rates, all of which are level 3 inputs.

Prices used by Parex' independent reserve evaluator at December 31, 2015 are as follows:

	2016	2017	2018	2019	2020	Thereafter
Brent (\$US/bbl)	45.00	54.00	61.00	67.00	73.00	2% increase per year

Prices used by Parex' independent reserve evaluator at December 31, 2014 are as follows:

	2015	2016	2017	2018	2019	Thereafter
Brent (\$US/bbl)	67.50	82.50	87.50	90.00	95.00	2% increase per year

Also during 2015, the Company completed an impairment review for certain E&E assets associated primarily with Block LLA-57 in the Northern Llanos basin and determined that the carrying amount of the project assets was unlikely to be recovered by successful development or sale. The Company has acquired 3D seismic and drilled 2 exploration wells on the block. Further drilling on this block has been cancelled due to the low oil price environment. The impairment review compared the carrying value of the assets to the recoverable amount. The recoverable amount was estimated using fair value less costs of disposal (level 3 inputs). It was determined that the impairment was \$27.0 million which is recorded in the consolidated statement of comprehensive income (loss) for the year ended December 31, 2015 (year ended December 31, 2014 - \$64.0 million primarily associated with assets in Block LLA-29, LLA-40 and Trinidad assets). The recoverable amount of the blocks was determined to be \$nil.

For further information regarding the impairment charges for the years ended December 31, 2015 and 2014, refer to Note 7 "Exploration and Evaluation Assets" and Note 8 "Property, Plant and Equipment" in the financial statements.

Impairment Test of Goodwill

The Company performed its annual test for goodwill impairment at the balance sheet date in accordance with its policy described in note 3 of the audited consolidated financial statements for the years ended December 31, 2015 and 2014. The Company has allocated goodwill to the Colombia operating segment. The estimated fair value less costs of disposal of the Colombia operating segment exceeded the carrying value. As a result, no goodwill impairment was recorded. For additional information refer to Note 11 "Goodwill" in the financial statements.

Summary of Quarterly Results

Three months ended (\$000s)	Dec. 31, 2015	Sep. 30, 2015	June 30, 2015	March 31, 2015
Average daily oil production (bopd)	28,588	27,377	27,025	26,729
Realized sales price - oil (\$/bbl)	36.69	44.62	56.31	49.42
Financial (000s except per share amounts)				
Oil sales	\$ 107,816	\$ 123,249	\$ 155,717	\$ 134,307
Funds flow from continuing operations	\$ 33,628	\$ 13,448	\$ 50,237	\$ 32,958
Per share – basic	0.22	0.09	0.35	0.24
Per share – adjusted diluted ⁽¹⁾	0.22	0.09	0.34	0.24
Net (loss) income	\$ (3,474)	\$ (27,417)	\$ 1,814	\$ (15,544)
Per share – basic	(0.02)	(0.18)	0.01	(0.12)
Per share – diluted	(0.02)	(0.18)	0.01	(0.12)
Capital Expenditures, excluding corporate acquisitions	\$ 23,611	\$ 37,674	\$ 37,234	\$ 26,963
Total assets (end of period)	\$ 957,966	\$ 1,003,271	\$ 1,051,150	\$ 1,010,116
Working capital surplus (deficit) (end of period) ⁽²⁾	\$ 76,708	\$ 62,689	\$ 89,754	\$ 9,878
Bank debt (end of period)	\$ -	\$ -	\$ -	\$ 39,500

⁽¹⁾ Non-GAAP term. See “Non-GAAP Terms” below.

⁽²⁾ Working capital does not include the undrawn amount available on the credit facility.

Three months ended (\$000s)	Dec. 31, 2014	Sep. 30, 2014	June 30, 2014	March 31, 2014
Average daily oil production (bopd)	26,544	25,175	19,876	18,425
Realized sales price - oil (\$/bbl)	60.08	94.40	104.53	103.42
Financial (000s except per share amounts)				
Oil and gas sales	\$ 160,584	\$ 228,648	\$ 182,996	\$ 179,794
Funds flow from continuing operations	\$ 49,759	\$ 89,006	\$ 77,799	\$ 77,289
Per share – basic	0.37	0.70	0.70	0.71
Per share – adjusted diluted ⁽¹⁾	0.37	0.69	0.65	0.65
Net (loss) income	\$ (146,612)	\$ 16,768	\$ 11,408	\$ 9,663
Per share – basic	(1.09)	0.13	0.10	0.09
Per share – diluted	(1.09)	0.13	0.10	0.09
Capital Expenditures, excluding corporate acquisitions	\$ 83,571	\$ 56,799	\$ 95,101	\$ 61,405
Total assets (end of period)	\$ 1,034,415	\$ 1,266,610	\$ 1,226,983	\$ 882,306
Working capital surplus (deficit) (end of period) ⁽²⁾	\$ 3,261	\$ 45,321	\$ 31,189	\$ 36,957
Debentures (end of period) ⁽³⁾	\$ -	\$ -	\$ 68,375	\$ 64,728
Bank debt (end of period)	\$ 35,000	\$ 42,305	\$ 56,000	\$ 4,000

⁽¹⁾ Non-GAAP term. See “Non-GAAP Terms” below.

⁽²⁾ Working capital does not include the undrawn amount available on the credit facility.

⁽³⁾ During August and September 2014, the Cdn\$85.0 million principal amount of Debentures was converted for an aggregate of 8,339,991 common shares of the Company and redeemed for \$0.3 million in cash.

Factors that Caused Variations Quarter Over Quarter

Throughout 2015 Parex grew production quarter over quarter however revenue and funds flow fluctuated significantly due to the fluctuation in world oil prices which impacted the Company’s realized sales price. In 2015, the three month period ended June 30, 2015 saw the highest oil prices and therefore the highest revenue and funds flow from operations was generated. Funds flow decreased significantly in the third quarter from the second quarter due to the decrease in oil prices and recording of the full \$31 million (\$0.21 per share basic) amount of a voluntary tax restructuring impact in the quarter.

On May 5, 2015 the Company completed a bought deal financing in the amount of \$108.7 million (net of share issue costs) which resulted in the significant increase in the Company’s cash and working capital positions from the prior quarter.

In the third quarter of 2015 the Company recorded \$4.5 million in non-cash impairments on exploration and evaluation assets in Colombia, and \$31.1 million non-cash impairments on property, plant and equipment in Colombia, resulting in a net loss of \$27.4 million for the quarter. In the fourth quarter of 2015 the Company

recorded additional \$22.5 million of non-cash impairments on exploration and evaluation assets in Colombia. This expense was partially offset by a significant deferred tax recovery in the quarter resulting from the voluntary tax restructuring, resulting in a net loss of \$3.5 million for the quarter (Refer to the “Non-cash Impairment Charges” section for additional information).

Please refer to “Financial and Operating Results” for detailed discussions on variations during the comparative quarters and to Parex’ previously issued interim and annual MD&A for further information regarding changes in prior quarters.

Fourth Quarter Results

An income statement for the three months ended December 31 is set out below:

(\$000s)			
For the three month period ended December 31,		2015	2014
Oil and gas sales	\$	107,816	\$ 160,584
Royalties		(7,037)	(16,186)
Revenue		100,779	144,398
Risk management contracts		4,059	6,232
		104,838	150,630
Expenses			
Production		18,176	26,699
Transportation		36,620	46,191
Purchased oil		4,667	12,462
General and administrative		9,590	8,925
Share-based compensation		4,627	(3,079)
Depletion, depreciation and amortization		35,250	51,665
Foreign exchange gain		(5,374)	(7,261)
Impairment of exploration and evaluation assets		22,528	44,387
Impairment of property, plant and equipment		-	113,264
Loss on settlement on decommissioning liabilities		952	7
		127,036	293,260
Finance income		(24)	79
Finance expense		1,684	3,958
Net finance expense		1,660	4,037
(Loss) from continuing operations before income taxes		(23,858)	(146,667)
Income tax expense			
Current tax expense		1,463	7,368
Deferred tax (recovery)		(21,847)	(28,022)
		(20,384)	(20,654)
Net (loss) and comprehensive income (loss) from continuing operations after income taxes	\$	(3,474)	\$ (126,013)
(Loss) from discontinued operations after income taxes		-	(20,599)
Net (loss) and comprehensive income (loss) for the period	\$	(3,474)	\$ (146,612)

Liquidity and Capital Resources

As at December 31, 2015 the Company had a working capital surplus of \$76.7 million, excluding amounts available under the credit facility, as compared to working capital surplus at September 30, 2015 of \$62.7 million and a working capital surplus of \$3.3 million at December 31, 2014. Bank debt was \$nil million compared to \$35.0 million in the comparative period. The credit facility has a current borrowing base of \$200 million and is subject to a borrowing base redetermination to be completed by the end of May, 2016. At December 31, 2015 Parex held \$94.8 million of cash, compared to \$109.3 million at September 30, 2015 and \$39.0 million at December 31, 2014. The Company’s cash balances reside in current accounts, the majority of which are held on account in Canada and Barbados. The increase in the Company’s cash and working capital positions from prior periods is a result of the May 5, 2015 bought deal financing in the amount of \$108.7 million (net of share issue costs) and the Company generating cash flow in excess of capital expenditures for the year ended December 31, 2015.

The Company values its crude oil inventory on hand using weighted average cost for the inventoried barrels. At December 31, 2015, on a fair market value basis the inventory on hand would have a value of approximately \$4.4 million or a positive fair value adjustment of approximately \$1.2 million (December 31, 2014 - value of \$13.4 million or a fair value adjustment of \$2.4 million).

Parex entered into a senior secured credit facility (“credit facility”) with a syndicate of banks led by a major Canadian bank during 2012, with a current borrowing base of \$200 million. Key covenants include a rolling four quarters total funded debt to adjusted EBITDA test of 3:50:1, and other standard business operating covenants. Given there is \$nil balance drawn on the facility as at December 31, 2015, the Company is in compliance with all covenants. The Company had the credit facilities borrowing base confirmed and redetermined at \$200 million in October 2015 during the semi-annual review. See “Contractual Obligations, Commitments and Guarantees”. The next annual review is scheduled to occur at the end of May 2016. There can be no assurance that the credit facilities will be renewed at the current borrowing base level at that time. As the Company currently has zero bank debt and no plans in 2016 to utilize the credit facility, the next re-determination is not expected to impact the Company’s current or future operations or reduce the 2016 outlook.

Outstanding Share Data

Parex is authorized to issue an unlimited number of voting common shares without nominal or par value. As at December 31, 2015 the Company had 151,489,302 common shares outstanding.

The Company has a stock option, RSU and DSU plan. The plans provide for the issuance of options, RSUs and DSUs to the Company’s directors, officers and certain employees to acquire common shares. The maximum number of options, RSUs and DSUs reserved for issuance under the three plans may not exceed 10 percent of the number of common shares issued and outstanding.

As at March 8, 2016 Parex has the following securities outstanding:

	Number	%
Common shares	151,514,066	94
Stock options	7,687,594	5
Restricted share units	2,253,949	1
Deferred share units	78,600	-
	161,534,209	100

As of the date of this MD&A, total stock options, RSUs and DSUs outstanding represent approximately 7 percent of the total issued and outstanding common shares.

Contractual Obligations, Commitments and Guarantees

In the normal course of business, Parex has entered into arrangements and incurred obligations that will affect the Company’s future operations and liquidity. These commitments primarily relate to exploration work commitments including seismic and drilling activities. The Company has discretion regarding the timing of capital spending for exploration work commitments, provided that the work is completed by the end of the exploration periods specified in the contracts or the Company can negotiate extensions of the exploration periods. Given the low oil price environment the Colombian energy regulator (“ANH”) has instituted means by which Companies can apply for extensions of phase commitments until oil prices improve. The Company has been very proactive in applying for extensions on many blocks that will assist with the Company matching cash flows from operations with capital expenditures. The Company’s exploration commitments are described in the Company’s AIF dated March 19, 2015 under “Description of Business - Principal Properties”. These obligations and commitments are considered in assessing cash requirements in the discussion of future liquidity.

In Colombia, the Company has provided guarantees to the ANH and Ecopetrol which on December 31, 2015 were \$150.3 million (September 30, 2015 - \$102.6 million) to support the exploration work commitments on its Blocks. The guarantees have been provided in the form of letters of credit for varying terms. Export Development Canada (“EDC”) has provided performance security guarantees under the Company’s \$200.0 million (September 30, 2015 - \$125.0 million) performance guarantee facility to support approximately \$123.7 million (September 30, 2015 - \$76.4 million) of the letters of credit issued on behalf of Parex. The letters of credit issued to the ANH are reduced from time to time to reflect the work performed on the various blocks.

The following table summarizes the Company’s estimated commitments as at December 31, 2015:

(\$000s)	Total	<1 year	1 – 3 years	3 – 4 years	>5 years
Exploration ⁽¹⁾	\$ 252,494	\$ 33,263	\$ 158,031	\$ 61,200	\$ -
Office and accommodations ⁽²⁾	5,338	2,220	2,178	940	-
Decommissioning expenditures	51,774	3,015	6,030	6,030	36,699
Total	\$ 309,606	\$ 38,498	\$ 166,239	\$ 68,170	\$ 36,699

⁽¹⁾ Exploration commitments do not include production bonuses and other payments that will vary depending on production levels due to the uncertainty of their amount and timing. Due to the low oil price environment, the ANH has allowed the extension of exploration commitments from time to time pursuant to a decree issued in 2015.

⁽²⁾ Includes minimum lease payment obligations associated with leases for office space and accommodations.

Decommissioning and Environmental Liabilities

	Decommissioning	Environmental	Total
Balance, December 31, 2013	\$ 13,793	\$ 7,295	\$ 21,088
Additions	9,479	3,201	12,680
Corporate acquisitions	1,300	946	2,246
Settlements of obligations during the year	(1,369)	(425)	(1,794)
Loss on settlements of obligations during the year	134	-	134
Accretion expense	864	263	1,127
Additions related to change in estimate	-	657	657
Foreign exchange (gain)	-	(1,660)	(1,660)
Decommissioning liabilities reclassified to liabilities held for sale	(389)	-	(389)
Balance, December 31, 2014	\$ 23,812	\$ 10,277	\$ 34,089
Additions	2,724	725	3,449
Settlements of obligations during the period	(193)	(246)	(439)
Accretion expense	1,162	426	1,588
Additions related to change in estimate	(694)	(140)	(834)
Foreign exchange (gain)	-	(2,454)	(2,454)
Balance, December 31, 2015	\$ 26,811	\$ 8,588	\$ 35,399
Current obligation	-	(2,102)	(2,102)
Long-term obligation	\$ 26,811	\$ 6,486	\$ 33,297

The total environmental, decommissioning and restoration obligations were determined by management based on the estimated costs to settle environmental impact obligations incurred and to reclaim and abandon the wells and well sites based on contractual requirements. The obligations are expected to be funded from the Company's internal resources available at the time of settlement.

The total decommissioning and environmental liability is estimated based on the Company's net ownership in wells drilled as at December 31, 2015, the estimated costs to abandon and reclaim the wells and well sites and the estimated timing of the costs to be paid in future periods. The total undiscounted amount of cash flows required to settle the Company's decommissioning liability is approximately \$36.7 million as at December 31, 2015 (December 31, 2014 – \$37.0 million) with the majority of these costs anticipated to occur in 2020 or later. A weighted average risk-free discount rate of 5.25 percent and an inflation rate of 2.5 percent were used in the valuation of the liabilities (December 31, 2014 – 5 percent weighted average risk-free discount rate and a 2 percent inflation rate). The discount rates used are a blend of US and Colombia risk-free rates.

The total undiscounted amount of cash flows required to settle the Company's environmental liability is approximately \$15.1 million as at December 31, 2015 (December 31, 2014 – \$14.0 million) with the majority of these costs anticipated to occur in 2016 or later in Colombia. A risk-free discount rate of 8 percent and an inflation rate of 4 percent were used in the valuation of the liabilities (December 31, 2014 – 7 percent risk-free discount rate and a 3 percent inflation rate). The discount rate used is based on a Colombia risk-free rate.

Included in the environmental liability is \$2.1 million (December 31, 2014 – \$2.1 million) that is classified as a current obligation.

Decommissioning and environmental liabilities are considered critical accounting estimates. There are significant uncertainties related to decommissioning and environmental expenditures and the impact on the financial statements could be material. The eventual timing of and costs for these expenditures could differ from current estimates. The main factors that can cause expected estimated cash flows in respect of decommissioning liabilities to change are:

- Changes in laws, legislation and regulations;
- Construction of new facilities;
- Change in commodity price;
- Change in the estimate of oil reserves and the resulting amendment to the life of reserves;
- Changes in technology; and
- Execution of decommissioning liabilities.

Reserves Information

The reserves information summarized in this MD&A is from reports prepared by our independent reserves evaluator, GLJ Petroleum Consultants Ltd. (“GLJ”), dated February 5, 2016 with an effective date of December 31, 2015, and dated February 4, 2015 with an effective date of December 31, 2014. Each of these reports was prepared in accordance with definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook (“COGE”) and National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities (“NI 51-101”). All December 31, 2015 reserves presented are based on GLJ’s forecast pricing effective January 1, 2016 and all December 31, 2014 reserves presented are based on GLJ’s forecast pricing effective January 1, 2015. Additional reserve information as required under NI 51-101 will be included in the Company’s Annual Information Form which will be filed on SEDAR by March 31, 2016.

This MD&A contains certain oil and gas metrics, including finding, development and acquisition (“FD&A”) costs, reserves replacement and reserves additions, which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included herein to provide readers with additional measures to evaluate the Company’s performance; however, such measures are not reliable indicators of the future performance of the Company and future performance may not compare to the performance in previous periods and therefore such metrics should not be unduly relied upon.

FD&A is the sum of total capital expenditures incurred in the period and the change in future development capital (“FDC”) required to develop reserves. FD&A cost per bbl is determined by dividing current period net reserve additions into the corresponding period’s FD&A cost. Total capital includes both capital expenditures incurred and changes in future development capital required to bring proved undeveloped reserves and probable reserves to production during the applicable period. Reserve additions are calculated as the change in reserves from the beginning to the end of the applicable period excluding production. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated FD&A generally will not reflect total finding and development costs related to reserves additions for that year. Changes in forecast FD&A occur annually as a result of development activities, acquisition and disposition activities and capital cost estimates that reflect our independent reserve evaluator’s best estimate of what it will cost to bring the proved undeveloped and probable reserves on production.

Reserves replacement is calculated as 23.3 million barrels of oil equivalent gross proved plus probable reserve additions (including acquisitions) during the year ended December 31, 2015 divided by current annual production of 27,434 barrels per day and expressed as a percentage. Reserve additions is calculated as the change in proved plus probable reserves from December 31, 2014 (68.4 million barrels of oil equivalent (net company working interest)) to December 31, 2015 (81.7 million barrels of oil equivalent (net company working interest)) excluding production of approximately 10 million barrels of oil equivalent (net company working interest).

Advisory on Forward-Looking Statements

Certain information regarding Parex set forth in this MD&A, including assessments by the Company’s management of the Company’s plans and future operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. The use of any of the words “plan”, “expect”, “forecast”, “project”, “intend”, “believe”, “anticipate”, “estimate” or other similar words, or statements that certain events or conditions “may” or “will” occur are intended to identify forward-looking statements. Such statements represent the Company’s internal projections, estimates or beliefs concerning, among other things, future growth, results of operations, production, future capital and other expenditures (including the amount, nature and sources of funding thereof), competitive advantages, plans for and results of drilling activity, environmental matters, business prospects and opportunities. These statements are only predictions and actual events or results may differ materially. Although the Company’s management believes that the expectations reflected in the forward-looking statements are reasonable, it cannot guarantee future results, levels of activity, performance or achievement since such expectations are inherently subject to significant business, economic, competitive, political and social uncertainties and contingencies. Many factors could cause the Company’s actual results to differ materially from those expressed or implied in any forward-looking statements made by, or on behalf of, Parex. In particular, forward-looking statements contained in this MD&A include, but are not limited to, statements with respect to:

- the Company’s operational strategy, including targeted jurisdictions and technologies used to execute its strategy;
- the Company’s approach to manage subsurface and commercial risks;
- the Company’s exploration blocks subject to farm-in and earning requirements and the effect on the Company’s land holdings as lands deemed non-commercial are released;
- activities to be undertaken in various areas including the fulfillment of exploration commitments and farm-in obligations;

- terms of exploration and production contracts and the timing of release of exploration property deemed non-commercial in respect of the exploration contracts;
- the Company's range of its capital program budget for 2016 and the Company's plans to fund its 2016 capital program from funds flow from operations;
- the Company's ability to continue to increase quarter over quarter oil production;
- the Company's forecasted 2016 oil production, capital budget and funds from operations;
- expected royalty rates and effect of changes in pricing on the Company's overall royalty as a percentage of sales and the calculation and applicability of the HPR;
- the Company's expectations regarding production cost savings related to the depreciation of the Colombian peso and the Company's plans to seek price reductions from vendors;
- expected transportation costs on a per barrel basis and effect of the marketing mix, delivery points and the Colombian peso/US\$ exchange rate on the variability of such transportation costs;
- the expected effect of devaluation of local currencies and cost reduction efforts on 2016 G&A including the anticipated reduction to G&A;
- terms and cost of stock based compensation plans, including option plan, restricted share unit plan, deferred share unit plan and share appreciation rights;
- foreign currency risk and the ability to reverse unrealized foreign exchange gains and losses in the future;
- the Company's risk management strategy and the use of derivatives primarily with financial institutions to manage movements in the price of crude oil to provide downside protection of a particular threshold, fluctuations in the US/COP exchange rate and interest rate movements;
- terms of the Company's risk management contracts and the Company's ability to manage and forecast cash flow;
- the Company's expected 2016 NWT;
- the Company's estimated full year current tax expense for 2015 and the expected reduction to the Corporation's effective current tax for 2016;
- terms of the Company's credit facility;
- terms of the Company's exploration and other contractual commitments and their timing of settlement;
- the status of the lawsuit filed against Parex, and Parex Bermuda and the Company's beliefs regarding the plaintiffs claims and plans to defend such claims;
- estimated amounts, timing and the anticipated sources of funding for the Company's environmental, decommissioning and restoration obligations;
- drilling plans including the anticipated timing the Company's drilling program for 2016 will commence and timing of drilling, completion and tie-in of wells;
- effect of business and environmental risks on the Company; and
- the statements under "Accounting Policies and Estimates".

These forward-looking statements are subject to numerous risks and uncertainties, including but not limited to: the impact of general economic conditions in Canada and Colombia; industry conditions including changes in laws and regulations including adoption of new environmental laws and regulations, and changes in how they are interpreted and enforced in Canada and Colombia; continued volatility in market prices for oil; the impact of significant declines in market prices for oil; competition; lack of availability of qualified personnel; the results of exploration and development drilling and related activities; partner approval of capital work programs and other matters requiring approval; imprecision in reserve and resource estimates; the production and growth potential of Parex' assets; obtaining required approvals of regulatory authorities in Canada and Colombia; risks associated with negotiating with foreign governments as well as country risk associated with conducting international activities; fluctuations in foreign exchange or interest rates; environmental risks; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and natural gas industry; ability to access sufficient capital from internal and external sources; risk that the Company will not be able to obtain contract extensions or fulfill the contractual obligations required to retain its rights to explore, develop and exploit any of its undeveloped properties; risk of failure to achieve the anticipated benefits associated with the acquisitions; risks related to the lawsuit brought in Texas against Parex and certain foreign subsidiaries; failure of counterparties to perform under the terms of their contracts; the risks discussed under "Risk Factors" in the Company's Annual Information Form dated March 19, 2015 and under "Decommissioning Liabilities" and "Business Environment and Risks" in this MD&A, and other factors, many of which are beyond the control of the Company. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect the Company's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com).

Although the forward-looking statements contained in this MD&A are based upon assumptions which management believes to be reasonable, the Company cannot assure investors that actual results will be consistent with these forward-looking statements. With respect to forward-looking statements contained in this MD&A, Parex has made assumptions regarding, among other things: current and future commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; uninterrupted access to areas of the Company's operations and infrastructure; future exchange rates; the price of oil; the impact of increasing competition; conditions in general economic and financial markets; availability of drilling and related equipment; effects

of regulation by governmental agencies; recoverability of reserves and future production rates; royalty rates; future operating costs; foreign exchange rates; the status of litigation; timing of drilling and completion of wells; that the Company will have sufficient cash flow, debt or equity sources or other financial resources required to fund its capital and operating expenditures and requirements as needed; that the Company's conduct and results of operations will be consistent with its expectations; that the Company will have the ability to develop the Company's oil and gas properties in the manner currently contemplated; current or, where applicable, proposed industry conditions, laws and regulations will continue in effect or as anticipated as described herein; that the estimates of the Company's reserves volumes and the assumptions related thereto (including commodity prices and development costs) are accurate in all material respects; that the Company will be able to obtain contract extensions or fulfill the contractual obligations required to retain its rights to explore, develop and exploit any of its undeveloped properties; and other matters. The ability of the Company to carry out its business plan is primarily dependent upon the continued support of its shareholders, the discovery of economically recoverable reserves and the ability of the Company to obtain financing to develop such reserves.

Forward-looking statements and other information contained in this MD&A concerning the oil and natural gas industry in the countries in which it operates and the Company's general expectations concerning this industry are based on estimates prepared by Management using data from publicly available industry sources as well as from resource reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Company believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Company is not aware of any material misstatements regarding any industry data presented herein, the oil and natural gas industry involves numerous risks and uncertainties and is subject to change based on various factors.

Management has included forward looking information and the above summary of assumptions and risks related to forward-looking information in this MD&A in order to provide shareholders with a more complete perspective on the Company's current and future operations and such information may not be appropriate for other purposes. The Company's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do, what benefits Parex will derive there from. These forward-looking statements are made as of the date of this MD&A and Parex disclaims any intent or obligation to update publicly any forward-looking statements, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

Non-GAAP Terms

This report contains financial terms that are not considered measures under GAAP such as operating netback per barrel, net debt and adjusted funds flow per share that do not have any standardized meaning under IFRS and may not be comparable to similar measures presented by other companies. Management uses these non-GAAP measures for its own performance measurement and to provide shareholders and investors with additional measurements of the Company's efficiency and its ability to fund a portion of its future capital expenditures.

Adjusted funds flow per share is calculated by dividing funds flow provided by continuing operations, adjusted in the prior period for the debenture interest expense, by the weighted average number of shares outstanding. Parex presents adjusted funds flow provided by continuing operations per share whereby per share amounts are calculated using weighted-average shares outstanding, consistent with the calculation of earnings per share. The following table shows the variables used in the calculation of adjusted funds flow per share:

(\$000s)	For the three months ended December 31,		For the year ended December 31,	
	2015	2014	2015	2014
Funds flow provided by continuing operations	\$ 33,628	\$ 49,759	\$ 130,271	\$ 293,853
Debt interest expense	-	-	-	2,948
Adjusted funds flow from continuing operations for diluted funds flow	\$ 33,628	\$ 49,759	\$ 130,271	\$ 296,801
Weighted average number of shares for the purposes of basic funds flow (\$000s)	150,791	134,503	145,018	120,379
Dilutive effect of share options on potential common shares	1,039	1,637	489	2,065
Weighted average number of shares for the purposes of diluted funds flow	\$ 151,830	\$ 136,140	\$ 145,507	\$ 122,444

Operating netback per barrel is determined by sales revenue excluding risk management contracts, less royalties, production expense and transportation expense, divided by total equivalent sales volume excluding purchased oil volumes. The Company considers operating netbacks to be a key measure as they demonstrate Parex' profitability relative to current commodity prices.

Adjusted EBITDA is defined as net income (loss) before interest, taxes, depletion and depreciation and adjusted for other non-cash items, transaction costs and extraordinary and non-recurring items.

Net debt is determined by current assets less current liabilities less long-term debt and USD face value of the convertible debenture. It is used to assess efficiency, liquidity and the Company's general financial strength. No IFRS measure is reasonably comparable to net debt.

Free cash flow (deficiency) is determined by funds flow from continuing operations less capital expenditures as follows:

(\$000s)	For the three months ended December 31,		For the year ended December 31,	
	2015	2014	2015	2014
Funds flow from continuing operations	\$ 33,628	\$ 49,759	\$ 130,271	\$ 293,853
Capital expenditures, excluding corporate acquisitions	23,611	83,571	125,482	296,876
Free cash flow (deficiency)	\$ 10,017	\$ (33,812)	\$ 4,789	\$ (3,023)

Business Environment and Risks

Overall

Parex is exposed to a variety of risks including but not limited to operational, financial, competitive, political and environmental risks. As a participant in the oil and natural gas industry, Parex is exposed to operational risks such as: unsuccessful exploration and exploitation activities, the inability to find new reserves that are commercially and economically feasible, premature declines of reservoirs, well blow-outs and other operating hazards, and lack of infrastructure or transportation to access markets and monetize reserves. The Company works to mitigate these risks by employing highly skilled personnel and utilizing available technology. The Company also maintains a corporate insurance program consistent with industry practices to protect against insurable losses.

The Company is exposed to normal financial risks inherent in the oil and natural gas industry including: commodity price risk, exchange rate risk, interest rate risk and credit risk. The Company continuously monitors opportunities to use financial instruments to manage exposure to fluctuations in commodity prices, foreign currency rates and interest rates. Parex operates the majority of its properties and, therefore, has significant control over the timing, direction and costs related to exploration commitments and development opportunities.

Foreign Jurisdictions

Parex is focused on international oil and natural gas exploration and production activities in Colombia. As such, the Company is subject to political risks such as: changes in policies and regulation related to changes in government, price controls, renegotiation of land tenure agreements, nationalization, changes in tax and royalty regulations, amendments or changes to legal systems, and complex regulatory regimes. The Company focuses its foreign operations in countries where management has prior experience and/or engages local in-country staff as soon as possible. The Company engages local, Canadian and international advisors. The Company may also, from time to time, arrange for insurance to mitigate specific risks. The Company is also exposed to potential delay of its operations due to waiting on permits or obtaining surface access to drilling locations.

Reserves Estimates

Parex has retained an independent engineering consulting firm that assists the Company in evaluating oil and natural gas reserves on an annual basis. Reserve values are based on a number of variables and assumptions such as future commodity prices, projected production, future production costs and governmental regulations. Reserve estimates are prepared in accordance with standards and procedures set out in the COGE and NI 51-101. The reserves and recovery information contained in the independent reserve report is an estimate. The actual production and ultimate reserves from the properties may be greater or less than the estimates prepared by the independent reserve engineers.

Volatility of Commodity Prices and Foreign Exchange Rates

The Company's operational results and financial condition depend on the prices received for petroleum production. Commodity prices are determined by economic and, in some circumstances, political factors. Supply and demand factors, including weather and general economic conditions as well as conditions in other oil and natural gas regions, also influence prices. Parex is exposed to commodity price risk whereby the fair value of future cash flows will fluctuate

as a result of changes in commodity prices. Commodity prices for petroleum are affected by the global economic events that dictate the levels of supply and demand. As at the date of this MD&A, Parex has active crude oil hedges in place (see “Risk Management Contracts – Brent Crude”).

Foreign currency risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate as a result of changes in foreign currency exchange rates. The Company is exposed to foreign currency fluctuations as various portions of its cash balances and future expenses and revenues are denominated in Colombian pesos (COP\$) and Canadian dollars (Cdn\$). At the date of this MD&A, Parex had a foreign currency exchange risk management contracts in place (see “Risk Management Contracts –Foreign Exchange”).

Counterparty Risk

Credit risk is the risk of a counterparty failing to meet its obligations in accordance with the agreed upon terms. The Company may be exposed to third-party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its commodities and other parties. Parex has established credit policies and controls designed to mitigate the risk of default or non-payment with respect to oil and natural gas sales, financial hedging transactions and joint venture participants. The Company makes every effort to sell its commodities to major companies with excellent credit ratings and/or managing its crude production on a portfolio basis.

Access to Capital

From time to time, the Company may have to raise additional funds to finance business development activities. Parex’ ability to raise additional capital will depend on a number of factors such as general economic and market conditions that are beyond the Company’s control. Internally generated funds will also fluctuate with changing commodity prices. Parex currently has a \$200 million syndicated facility with three banks. The Company is required to comply with covenants under this facility and in the event it does not comply, access to capital could be restricted or repayment may be required. Parex routinely reviews the covenants based on actual and forecasted results and has the ability to make changes to development and exploration plans to comply with the covenants under the credit facility. Parex is committed to maintaining a strong balance sheet along with an adaptable capital expenditure program that can be adjusted to capitalize on, or reflect acquisition opportunities and, if necessary a tightening of liquidity sources. From the company’s founding to the date of this MD&A, Parex has had no defaults or breaches on its bank debt or any of its financial liabilities.

Operational Matters

The oil and natural gas industry is intensely competitive, with Parex competing against companies that may have greater technical and financial resources. There is competition for new exploration and development properties, for infrastructure and sales contracts, for drilling and other specialized technical equipment and for experienced key human resources. As appropriate, Parex seeks to enter into joint venture arrangements with large and/or experienced industry players in each country to improve its access to resources.

There are also extensive and varying environmental regulations imposed by the governments in the countries in which Parex operates. The Company adopts prudent and industry-recommended field operating procedures in all of its operations, as well as maintaining a health, safety and environment program.

Exploration

The Company is exposed to a high level of exploration risk. The Company’s current and future (to the extent discovered or acquired) proved reserves will decline as reserves are produced from its properties unless the Company is able to acquire or develop new reserves. The business of exploring for, developing or acquiring reserves is capital-intensive and is subject to numerous estimates and interpretations of geological and geophysical data. There can be no assurance that the Company’s future exploration, development and acquisition activities will result in material additions of proved reserves. To manage this risk, to the extent possible, Parex employs highly experienced geologists and geophysicists, uses technology such as 3D seismic as a primary exploration tool and focuses exploration efforts in known hydrocarbon-producing basins. In addition, the Company takes a portfolio approach to exploration by dispersing drilling locations among different exploration blocks and geological basins and by targeting multiple play-types. The Company may also choose to mitigate exploration risk through acquisitions that may require raising funds.

Internal Controls over Financial Reporting

Disclosure controls and procedures (“DC&P”), as defined in National Instrument 52-109 *Certification of Disclosure in Issuers’ Annual and Interim Filings*, are designed to provide reasonable assurance that information required to be disclosed in annual filings, interim filings or other reports filed, or submitted by the Company under securities legislation authorities is recorded, processed, summarized and reported within the time periods specified in the securities

legislation and include controls and procedures designed to ensure that information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the Company's management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The Chief Executive Officer and the Chief Financial Officer of Parex evaluated the effectiveness of the design and operation of the Company's DC&P. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded Parex DC&P were effective as at December 31, 2015.

Internal control over financial reporting ("ICFR"), as defined in National Instrument 52-109, includes those policies and procedures that:

- 1) Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of Parex;
- 2) Are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of Parex are being made in accordance with authorizations of management and Directors of Parex; and
- 3) Are designed to provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company's assets that could have a material effect on the annual financial statements or interim financial reports.

The Chief Executive Officer and the Chief Financial Officer are responsible for establishing and maintaining ICFR for Parex. They have, as at the financial year ended December 31, 2015, designed ICFR, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The control framework Parex officers used to design the Company's ICFR is the 2013 Internal Control - Integrated Framework ("COSO Framework") published by The Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Under the supervision of the Chief Executive Officer and the Chief Financial Officer, Parex conducted an evaluation of the effectiveness of the Company's ICFR as at December 31, 2015 based on the COSO Framework. Based on this evaluation, the officers concluded that as of December 31, 2015, Parex maintained effective ICFR. It should be noted that while Parex officers believe that the Company's controls provide a reasonable level of assurance with regard to their effectiveness, they do not expect that the DC&P and ICFR will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, but not absolute, assurance that the objectives of the control system are met.

There were no changes in Parex' ICFR during the year ended December 31, 2015 that materially affected, or are reasonably likely to materially affect, the Company's ICFR.

Off-Balance-Sheet Arrangements

The Company did not enter into any off-balance-sheet arrangements during the twelve months ended December 31, 2015.

Financial Instruments and Other Instruments

The Company's non-derivative financial instruments recognized on the consolidated balance sheet consist of cash, accounts receivable, accounts payable and accrued liabilities, and long-term debt. Non-derivative financial instruments are recognized initially at fair value. The fair values of the current financial instruments approximate their carrying value due to their short-term maturity.

Related Party Transactions

Compensation of Key Management Personnel

Key management personnel compensation, including directors, is as follows:

For the year ended December 31,		2015		2014
Salaries, directors fees and other benefits	\$	3,884	\$	3,109
Share-based compensation ⁽¹⁾		4,403		3,313
	\$	8,287	\$	6,422

⁽¹⁾ Non-cash share-based compensation expense for the year.

Key management personnel are comprised of the Company's directors and five executive officers. As at December 31, 2015, there is a \$6.2 million commitment (December 31, 2014 - \$5.8 million) relating to change of control or termination of employment of the key management personnel.

Other related party transactions

During the years ended December 31, 2015 and 2014, the Company rented office space to certain directors of the Company at market rental rates. The Company earned \$26 thousand dollars during the year ended December 31, 2015 (year ended December 31, 2014 - \$2 thousand dollars) in rental income from these related parties. At December 31, 2015, \$4 thousand dollars (December 31, 2014 - \$2 thousand dollars) of this balance was outstanding and has subsequently been collected.

Accounting Policies and Estimates

The accounting policies set out below have been applied consistently to all years presented in the consolidated financial statements, and have been applied consistently by the Company and its subsidiaries.

a) Consolidation

The consolidated financial statements include the accounts of the Company and all of its subsidiaries at December 31, 2015. The principal operating subsidiaries and their activities are:

Entity	Country of incorporation	Country of principle business activity	Ownership %	Principle business activity
Parex Resources (Colombia) Ltd.	Barbados	Colombia	100	Oil and natural gas exploration and development
Ramshorn International Limited	Bermuda	Colombia	100	Oil and natural gas exploration and development
Verano Energy (Barbados) Limited	Barbados	Colombia	100	Oil and natural gas exploration and development

The above listing does not include the wholly-owned holding company subsidiaries of Parex. All companies in the Parex group are wholly-owned subsidiaries.

On February 13, 2015, the Company sold all of the issued and outstanding shares in the capital of Parex Resources (Trinidad) Ltd to a third party. Refer to note 10 – Assets Held for Sale and Discontinued Operations.

Inter-company balances and transactions are eliminated on consolidation. Interests in joint arrangements are classified as either joint operations or joint ventures, depending on the rights and obligations of the parties to the arrangement. Joint operations arise when the Company has rights to the assets and obligations for the liabilities of the arrangement. The Company recognizes its share of assets, liabilities, revenues and expenses of a joint operation. A significant portion of the Company's operating cash flows is derived through joint operations which are involved in the development and production of crude oil in Colombia. Joint ventures arise when the Company has rights to the net assets of the arrangement. Joint ventures are accounted for under the equity method.

b) Foreign currency translation

(i) Functional and presentation currency

Items included in the consolidated financial statements are measured using the currency of the primary economic environment in which the Company operates (the "functional currency"). The consolidated financial statements are presented in United States dollars, which is the functional currency of Parex.

(ii) Transactions and balances

Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the date of the transaction. Generally, foreign exchange gains and losses resulting from the settlement of foreign currency transactions and from the translation at period-end exchange rates of monetary assets and liabilities denominated in currencies other than an operation's functional currency are recognized in the statement of comprehensive income (loss).

c) Financial instruments

The Company initially measures financial instruments at estimated fair value. The Company's loans and receivables, comprised of cash and accounts receivables, are included in current assets due to their short-term nature. Financial liabilities are categorized as "other financial liabilities" consisting of accounts payable and accrued liabilities and long-term debt.

Loans and receivables

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market and with no intention of being traded. They are included in current assets, except for maturities greater than 12 months after the balance sheet date, which are classified as non-current assets. Loans and receivables are recognized at the amount expected to be received less any discount or rebate to reduce the loan and receivables to estimated fair value. Loans and receivables are subsequently measured at amortized cost using the effective interest method. For loans and receivables that have maturity dates of less than one year, the Company estimates their carrying value approximates their fair value due to their short-term nature. Loans and receivables are comprised of cash and accounts receivable in the consolidated balance sheet.

Other financial liabilities

Other financial liabilities are financial liabilities that are not quoted on an active market and with no intention of being traded. They are included in current liabilities, except for the long-term debt as this instrument has a maturity greater than 12 months after the balance sheet date and is classified as a non-current liability. Accounts payable are initially recognized at the amount required to be paid less any discount or rebates to reduce the payables to estimated fair value. Accounts payable are subsequently measured at amortized cost using the effective interest method. For accounts payable that have maturity dates of less than one year, the Company estimates their carrying value approximates their fair value due to their short-term nature.

Derivative instruments

Derivatives may be used by the Company to manage economic exposure to market risk relating to commodity prices, foreign exchange rates and interest rates. Parex' policy is not to utilize derivative financial instruments for speculative purposes. The Company does not designate its financial derivative contracts as hedges, and as such does not apply hedge accounting. As a result, all financial derivative contracts are classified at fair value through comprehensive income (loss) and are recorded on the consolidated balance sheet at fair value.

Financial derivative contracts are initially recognized at fair value on the date a derivative contract is entered into and are remeasured at their fair value at each subsequent reporting date.

Financial derivative instruments are included in current assets (liabilities) except for those with maturities greater than 12 months after the end of the reporting period, which are classified as non-current assets (liabilities).

d) Capital assets

(i) Exploration and evaluation

All costs directly associated with the exploration and evaluation of oil and natural gas reserves are initially capitalized. E&E costs are those expenditures for an area where technical feasibility and commercial viability have not yet been determined. These costs include unproved property acquisition costs, exploration costs, geological and geophysical costs, decommissioning costs, E&E drilling, sampling and appraisals. Costs incurred prior to acquiring the legal rights to explore an area are charged directly to comprehensive income (loss) as impairment of exploration and evaluation assets.

When an area is determined to be technically feasible and commercially viable the accumulated costs are transferred to PP&E, where they are depleted. When an area is determined not to be technically feasible and commercially viable or the Company decides not to continue with its activity, the unrecoverable costs are charged to comprehensive income (loss) as impairment of exploration and evaluation assets. Net proceeds from any disposal of an intangible exploration asset are recorded as a reduction in intangible assets.

(ii) Property, plant and equipment

All costs directly associated with the development of oil and natural gas reserves are capitalized on an area-by-area basis. Development costs include expenditures for areas where technical feasibility and commercial viability have been determined. These costs include proved property acquisitions, development drilling, completion of wells, gathering facilities and infrastructure, decommissioning and restoration costs and transfers of E&E assets.

Costs accumulated within each CGU are depleted using the unit-of-production method based on proved plus probable reserves incorporating estimated future prices and costs. Costs subject to depletion include estimated future costs to be incurred in developing proved plus probable reserves. Costs of major development projects are excluded from the costs subject to depletion until they are available for use.

Costs associated with office furniture, fixtures and leasehold improvements are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from 1 to 5 years.

e) Impairment of long-term assets

The carrying amounts of the Company's long-term assets, other than E&E assets and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If an indication of impairment exists, the asset's recoverable amount is estimated. E&E assets are assessed for impairment when they are reclassified to PP&E, and, if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, assets are grouped into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs of disposal ("FVLCD").

The value in use is determined by estimating the present value of the pre-tax future net cash flows expected to be derived from the continued use of the asset or CGU. The FVLCD is based on available market information, where applicable. In the absence of such information, FVLCD is determined using discounted future after tax net cash flows of proved plus probable reserves using forecast prices and costs.

E&E assets are allocated to related CGUs where they are assessed for impairment upon their eventual reclassification to PP&E. E&E assets not reclassified to PP&E are assessed for impairment on a block by block basis.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in comprehensive income (loss). Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the units and then to reduce the carrying amounts of the other assets in the unit (group of units) on a pro-rata basis.

Impairment losses recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation or amortization, if no impairment loss had been recognized.

f) Assets held for sale

Non-current assets are classified as held for sale if their carrying amounts will be recovered through a sale transaction rather than through continuing use. This condition is met when the sale is highly probable and the asset is available for immediate sale in its present condition. For the sale to be highly probable management must be committed to a plan to sell the asset and an active program to locate a buyer and complete the plan must have been initiated. The asset must be actively marketed for sale at a price that is reasonable in relation to its current fair value and the sale should be expected to be completed within one year from the date of classification.

Non-current assets classified as held for sale are measured at the lower of the carrying amount and fair value less costs to sell, with impairments recognized in the consolidated statement of comprehensive income (loss) in the period measured. Non-current assets held for sale are presented in current assets and liabilities within the balance sheet. Assets held for sale are not depleted, depreciated or amortized.

Income and expenses related to discontinued operations are classified as income (loss) from discontinued operations within the consolidated statement of comprehensive income (loss) and the consolidated statement of cash flows.

g) Crude oil inventory

Crude oil inventory consists of crude oil in transit at the balance sheet date and is valued at the lower of cost, using the weighted average cost method, and net realizable value. Costs include direct and indirect expenditures incurred in bringing the crude oil to its existing condition and location.

h) Purchased oil

Purchased oil includes costs to buy third party oil. These costs are initially recorded in inventory until the crude oil title is transferred.

i) Goodwill

Goodwill is recorded on a business acquisition when the purchase price is in excess of the fair values assigned to assets acquired and liabilities assumed. Goodwill is not amortized and an impairment test is performed annually or as events occur that could indicate impairment. To test for impairment, goodwill is allocated to each of the Company's CGUs, groups of CGUs, or an operating segment expected to benefit from the acquisition. Goodwill is tested by combining the carrying amounts of property, plant and equipment and exploration and evaluation assets and goodwill and comparing this to the recoverable amount. Fair value less costs of disposal, is derived by estimating the discounted after-tax future net cash flows as described in the property, plant and equipment impairment test, plus the fair market value of undeveloped land, seismic and inventory. Value in use is assessed using the present value of the

expected future cash flows. Any excess of the carrying amount over the recoverable amount is recorded as impairment. Impairment charges, which are not tax affected, are recognized in comprehensive income (loss) and are not reversed. Goodwill is reported at cost less any impairment.

j) Revenue recognition

Revenue from the sale of oil and natural gas is recorded when the significant risks and rewards of ownership of the product are transferred to the buyer which is usually when legal title passes to the external party.

k) Repurchase of shares

Pursuant of the Normal Course Issuer Bid (“NCIB”), repurchased common shares reduce share capital for the average book value with any excess or deficiency charged to retained earnings (deficit).

l) Share-based compensation

The Company has an incentive stock option plan, a restricted unit plan and a deferred unit plan for certain employees, officers and directors as described in note 16. The Company records share-based compensation expense using the fair value method. The fair value of an option is calculated at the grant date using the Black-Scholes pricing model, and expensed over the vesting period of the option. The fair value of an RSU is calculated using the market price of Parex shares on the date of issuance, and expensed over the vesting period of the RSU. The fair value of a DSU is calculated using the market price of Parex shares on the date of issuance, and expensed immediately. The Company determines an appropriate forfeiture rate by examining the history of its forfeitures. The Company records the cumulative share-based compensation as contributed surplus. When options, DSUs or RSUs are exercised, contributed surplus is reduced and share capital is increased by the amount of accumulated share-based compensation for the exercised security. Any consideration received on the exercise of stock options, DSUs or RSUs is credited to share capital.

Obligations for payments of cash under the foreign subsidiaries’ SARs plan are accrued as compensation expense over the vesting period based on the fair value of SARs, subject to appreciation limits specified in the plan. The fair value of SARs is measured using the Black-Scholes pricing model. In accordance with the fair value method, increases or decreases in the fair value of the SARs result in a corresponding change in the recorded liability. The accrued compensation for a right that is forfeited is adjusted by decreasing compensation cost in the period of forfeiture.

m) Provisions

A provision is recognized if, as a result of a past event, the Company has a current legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

n) Decommissioning and environmental liabilities

The Company’s activities give rise to dismantling, decommissioning, environmental, abandonment and site disturbance remediation activities. Provisions are made for the estimated cost of the future site restoration and capitalized in the relevant asset category.

Decommissioning and environmental liabilities are measured at the present value of management’s best estimate of the cost and future timing of the expenditure required to settle the present obligation at the balance sheet date using a risk-free discount rate. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as a finance expense whereas increases (decreases) due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning and environmental liabilities are charged against the provision to the extent the provision was established.

o) Operating Segments

Management has determined the operating segments based on information regularly reviewed for the purposes of decision making, allocating resources and assessing operational performance by the Company’s chief operating decision makers. The operating segments are Canada and Colombia. The Company evaluates the financial performance of its operating segments primarily based on operating cash flow.

p) Finance income and expense

Finance expense comprises interest expense on borrowings, accretion on provisions and convertible debentures, net wealth tax, amortization of debt issuance costs, revaluation of derivative financial liabilities and impairment losses recognized on financial assets. Finance income comprises interest earned on cash and other income.

q) Cash

Cash is comprised of cash held in chartered banks in Canada and recognized financial institutions abroad with BBB+ credit ratings or higher.

r) Income taxes

Income tax expense comprises current and deferred tax. Income tax expense is recognized in comprehensive income (loss).

Current tax is the expected tax payable on taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

In general, deferred tax is recognized in respect of temporary differences arising between the tax basis of assets and liabilities and their carrying amounts in the consolidated financial statements. Deferred tax is determined on a non-discounted basis using tax rates, currency exchange rates and laws enacted or substantively enacted by the balance sheet date and expected to apply when the deferred tax asset or liability is settled. Deferred tax assets are recognized to the extent that it is probable that the assets can be recovered. Deferred tax is provided on temporary differences arising on investments in subsidiaries except, in the case of subsidiaries, where the timing of the reversal of the temporary difference is controlled by the Company and it is probable that the temporary difference will not be reversed in the foreseeable future. Deferred tax assets and liabilities are presented as non-current.

s) Per share information

Basic net income per share is calculated by dividing the income or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted net income per share is determined by adjusting the income or loss attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as options granted to employees and convertible debentures, except when the effect would be anti-dilutive.

t) New standards and interpretations not yet adopted

The standards and interpretations that are issued but not yet effective up to the date of issuance of the Company's financial statements, and that may have an impact on the disclosures and financial position of the Company, are disclosed below. The Company intends to adopt these standards and interpretations, if applicable, when they become effective.

- (i) In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers", which replaces International Accounting Standard ("IAS") 18 "Revenue", IAS 11 "Construction Contracts", and related interpretations. The standard is required to be adopted either retrospectively or using a modified transition approach for fiscal years beginning on or after January 1, 2018, with earlier adoption permitted. IFRS 15 will be applied by the Company on January 1, 2018 and the Company is currently evaluating the impact of the standard on the financial statements.
- (ii) In July 2014, the IASB completed the final elements of IFRS 9 "Financial Instruments". The standard supersedes earlier versions of IFRS 9 and completes the IASB's project to replace IAS 39 "Financial Instruments: Recognition and Measurement". IFRS 9, as amended, includes a principle-based approach for classification and measurement of financial assets, a single expected loss impairment model and a substantially-reformed approach to hedge accounting. The standard will come into effect for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. IFRS 9 will be applied by the Company on January 1, 2018 and the Company is currently evaluating the impact of the standard on the financial statements.
- (iii) In January 2016, the IASB issued IFRS 16 "Leases", which replaces IAS 17 "Leases". For lessees applying IFRS 16, a single recognition and measurement model for leases would apply, with required recognition of assets and liabilities for most leases. The standard will come into effect for annual periods beginning on or after January 1, 2019, with earlier adoption permitted if the entity is also applying IFRS 15 "Revenue from Contracts with Customers". IFRS 16 will be applied by the Company on January 1, 2019 and the Company is currently evaluating the impact of the standard on the financial statements.

Critical Accounting Estimates

The preparation of consolidated financial statements in accordance with IFRS requires management to make judgments, assumptions and estimates that affect the financial results of the Company. The following discussion outlines the accounting policies and practices involving the use of estimates that the Company believes are critical in determining Parex' financial results.

Oil and natural gas reserves

The Company retains qualified independent reserves evaluators to evaluate the Company's proved and probable oil and natural gas reserves. As at December 31, 2015 and in prior periods, Parex' reserves were evaluated by GLJ Petroleum Consultants Ltd., who are a firm of qualified independent reserves evaluators. The evaluation was conducted in accordance with the COGE handbook and NI 51-101. The Operations and Reserves Committee of the Company's Board of Directors is comprised of independent directors whose mandate is to steward the reserves evaluation process.

The estimation of reserves involves the exercise of judgment. Forecasts are based on engineering data, expected rates of production and the timing of future capital expenditures, all of which are subject to major uncertainties and interpretations. The Company expects that over time its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels. Reserve estimates can have a significant impact on net income (loss), as they are a key component in the calculation of DD&A and for determining potential asset impairment. A downward revision in reserves estimates or an increase in estimated future development costs could result in the recognition of a higher DD&A charge to net income (loss).

Oil and natural gas assets (development and producing costs) are aggregated into CGUs based on their ability to generate largely independent cash flows. If the carrying value of the CGU exceeds the recoverable amount, the CGU is written down with an impairment recognized in net income (loss). The recoverable amount of an asset or CGU is the greater of its fair value less costs to sell and its value in use. Fair value less costs to sell may be determined using discounted future net cash flows of proved plus probable reserves using forecast prices and costs. A downward revision in reserves estimates could result in the recognition of impairments charged to net income (loss).

Reversals of impairments are recognized when there has been a subsequent increase in the recoverable amount. In this event, the carrying amount of the asset or CGU is increased to its revised recoverable amount with an impairment reversal recognized in net income (loss).

Decommissioning and environmental liabilities

The Company is required to recognize a liability for future dismantling, decommissioning, environmental, abandoning and site disturbance remediation costs associated with the Company's oil and natural gas properties in accordance with existing laws, contracts or other policies. The fair value of the estimated decommissioning and environmental liability is recorded as a long-term liability, with a corresponding increase in the carrying amount of the related long-lived asset, which is depleted on a unit-of-production basis over the life of the reserves. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to net income (loss), and for revisions to the estimated future cash flows. Actual costs incurred upon settlement of the obligations are charged against the liability.

Decommissioning and environmental liabilities are determined by using management's best estimate of costs, taking into account the anticipated method and extent of restoration consistent with legal requirements, technological advances, industry practices and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying the Company's total decommissioning and environmental liability. These individual assumptions can be subject to change based on experience. Restoration technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. The Company estimates future decommissioning and environmental costs based on current estimates adjusted for inflation. This estimate for inflation is also subject to management uncertainty.

Current and Deferred tax

The Company follows the liability method of accounting for income taxes. Under this method, future tax assets and liabilities are determined based on differences between the financial reporting and tax basis of assets and liabilities and are measured using substantially enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect of a change in income tax rates on deferred tax liabilities and assets is recognized in net income (loss) in the period that the change occurs. Deferred tax assets are only recognized to the extent that it is probable that sufficient future taxable income will be available in the applicable jurisdiction to allow the deferred tax assets to be realized.

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations from multiple jurisdictions. Rates are also affected by legislative changes. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded in the financial statements. Estimates of current income tax for interim periods are also subject to additional uncertainty. A variety of factors cannot be known until year-end and, therefore, estimates are used for interim period current tax provisions.

Share-based compensation

The Company records stock-based compensation expense using the fair value method. The fair value of an option is calculated at the grant date, and expensed equally over the vesting term of the option. The Company records the cumulative stock-based compensation as contributed surplus. When options are exercised, contributed surplus is reduced and share capital is increased by the amount of accumulated stock-based compensation for the exercised option. Any consideration received on the exercise of stock options is credited to share capital.

The determination of stock-based compensation expense is based on assumptions regarding stock volatility, risk-free interest rates and the expected life of the options. These assumptions, by their nature, are subject to measurement uncertainty.

Obligations for payments of cash under the subsidiaries' SARs plan are accrued as compensation expense over the vesting period based on the fair value of SARs, subject to appreciation limits specified in the plan. The fair value of SARs is measured using the Black-Scholes pricing model. In accordance with the fair value method, increases or decreases in the fair value of the SARs result in a corresponding change in the recorded liability. The accrued compensation for a right that is forfeited is adjusted by decreasing compensation cost in the period of forfeiture.

The determination of SARs expense is based on assumptions regarding stock volatility, risk-free interest rates and the expected life of the SAR. These assumptions, by their nature, are subject to measurement uncertainty.

The fair value of an RSU is calculated using the market price of Parex shares on the date of issuance, and expensed over the vesting period of the RSU.

The fair value of a DSU is calculated using the market price of Parex shares on the date of issuance, and expensed immediately.

Goodwill

Goodwill represents the excess of purchase price over fair value of net assets acquired, and is assessed for impairment annually at December 31 of each year. To test for impairment, goodwill is allocated to each of the Company's CGUs, or groups of CGUs, that are expected to benefit from the acquisition and is tested as described above in the Company's impairment policy. The recoverable amount of an asset or a CGU is the greater of its value in use and its FVLCD.

Value in use is determined by estimating the present value of the future net cash flows expected to be derived from the continued use of the asset or CGU. FVLCD is based on available market information, where applicable. In the absence of such information, FVLCD is determined using discounted future net cash flows of proved plus probable reserves using forecast prices and costs. A downward revision in reserves estimates could result in the recognition of a goodwill impairment charge to net earnings.

These calculations require the use of estimates and assumptions and are subject to changes as new information becomes available including information on future commodity prices, expected production volumes, quantity of reserves and discount rates as well as future development and operating costs. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGUs.

Derivative liabilities

Prior to its conversion and redemption, the convertible feature of the convertible debentures was required to be fair-valued at each balance sheet date. The fair value of this derivative liability was calculated using the Black-Scholes pricing model which is based on significant assumptions such as volatility of the market price of Parex' shares, the risk free interest rate (based on government of Canada Bonds), and the share price of Parex' stock at the measurement date.

Risk management contracts are initially recognized at fair value on the date a derivative contract is entered into and are remeasured at their fair value at each subsequent reporting date. The fair value of the risk management contract on initial recognition is normally the transaction price. Subsequent to initial recognition, the fair value are based on quoted market price where available from active markets, otherwise fair values are estimated based on market prices at the reporting date for similar assets or liabilities with similar terms and conditions.

Legal, environmental remediation and other contingent matters

In respect of these matters, the Company is required to determine both whether a loss is probable based on judgment and interpretation of laws and regulations and if such a loss can reasonably be estimated. When any such loss is determined, it is charged to net income (loss). Management continually monitors known and potential contingent matters and makes appropriate provisions by charges to net income (loss) when warranted by circumstances.


MANAGEMENT'S REPORT

Management is responsible for the reliability and integrity of the consolidated financial statements, the notes to the consolidated financial statements, and other financial information presented elsewhere in this annual report.

The consolidated financial statements were prepared by management in accordance with International Financial Reporting Standards. Since a precise determination of many assets and liabilities is dependent on future events, the timely preparation of financial statements requires that management make estimates and assumptions and use judgment. When alternative accounting methods exist, management has chosen those that it deems most appropriate in the circumstances.

PricewaterhouseCoopers LLP were appointed by the Company's shareholders to express an audit opinion on the consolidated financial statements. Their examination included such tests and procedures as they considered necessary to provide reasonable assurance that the consolidated financial statements are in accordance with International Financial Reporting Standards.

The Board of Directors is responsible for overseeing that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Finance & Audit Committee. The Finance & Audit Committee recommends appointment of the external auditors to the Board, evaluates their independence and approves their fees. The Finance & Audit Committee meets regularly with management and the external auditors to oversee that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board for approval. The external auditors have full and unrestricted access to the Finance & Audit Committee to discuss their audit and their findings.



Wayne K. Foo
President, Chief Executive Officer



Kenneth G. Pinsky
Chief Financial Officer

March 8, 2016

March 8, 2016

Independent Auditor's Report

To the Shareholders of Parex Resources Inc.

We have audited the accompanying consolidated financial statements of Parex Resources Inc. and its subsidiaries, which comprise the consolidated balance sheets as at December 31, 2015 and December 31, 2014 and the consolidated statements of comprehensive income (loss), changes in equity and cash flows for the years then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Parex Resources Inc. and its subsidiaries as at December 31, 2015 and December 31, 2014 and their financial performance and their cash flows for the years then ended in accordance with International Financial Reporting Standards, as issued by the International Accounting Standards Board.

PricewaterhouseCoopers LLP

Chartered Professional Accountants

CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Balance Sheets

As at (thousands of United States dollars)	NOTE	December 31, 2015	December 31, 2014
ASSETS			
Current assets			
Cash		\$ 94,823	\$ 39,000
Accounts receivable	5	79,855	125,262
Prepays and other current assets		8,396	8,559
Crude oil inventory	6	3,207	10,959
Derivative financial instruments	22	2,566	-
Assets held for sale	10	-	2,933
		188,847	186,713
Goodwill	11	73,452	73,452
Exploration and evaluation	7	121,354	132,048
Property, plant and equipment	8	574,313	642,202
		\$ 957,966	\$ 1,034,415
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Accounts payable and accrued liabilities		\$ 67,080	\$ 135,512
Derivative financial instruments	22	-	1,925
Current income and equity tax payable	17	42,957	43,201
Current portion of decommissioning and environmental liabilities	15	2,102	2,143
Liabilities held for sale	10	-	671
		112,139	183,452
Long-term debt	12	-	35,000
Other long-term liabilities	14	1,969	639
Decommissioning and environmental liabilities	15	33,297	31,946
Deferred tax liability	17	68,635	122,740
		216,040	373,777
Shareholders' equity			
Share capital	16	812,737	694,110
Contributed surplus		33,388	26,106
(Deficit) Retained earnings		(104,199)	(59,578)
		741,926	660,638
		\$ 957,966	\$ 1,034,415

Commitments (note 24)

Contingencies (note 26)

See accompanying Notes to the Consolidated Financial Statements

Approved by the Board:



Paul Wright
Director



Ron Miller
Director

Consolidated Statements of Comprehensive Income (Loss)

For the year ended December 31,

(thousands of United States dollars, except per share amounts)

	NOTE	2015	2014
Oil sales		\$ 521,089	\$ 752,022
Royalties		(38,373)	(90,888)
Revenue		482,716	661,134
Commodity risk management contracts	22	7,305	8,054
		490,021	669,188
Expenses			
Production		73,499	90,213
Transportation		154,777	149,454
Purchased oil		34,630	33,187
General and administrative		36,749	32,531
Transaction costs	9	-	593
Impairment of exploration and evaluation assets	7	27,025	44,387
Impairment of property, plant and equipment	8	31,144	113,264
Share-based compensation	16	14,851	12,325
Depletion, depreciation and amortization	8	152,399	218,471
Loss on settlement of decommissioning liabilities	15	741	134
Foreign exchange loss (gain)		4,996	(9,740)
		530,811	684,819
Finance (income)	13	(579)	(1,332)
Finance expense	13	9,527	39,639
Net finance expense		8,948	38,307
(Loss) from continuing operations before income taxes		(49,738)	(53,938)
Income tax expense			
Current tax expense	17	48,207	52,184
Deferred tax (recovery)	17	(54,105)	(19,539)
		(5,898)	32,645
Net (loss) and comprehensive (loss) from continuing operations after income taxes		\$ (43,840)	\$ (86,583)
(Loss) from discontinued operations after income taxes	10	(781)	(22,190)
Net (loss) and comprehensive (loss) for the year		\$ (44,621)	\$ (108,773)
Basic net (loss) per common share – continuing operations	19	\$ (0.30)	\$ (0.72)
Diluted net (loss) per common share – continuing operations	19	\$ (0.30)	\$ (0.72)
Basic and diluted net (loss) per common share – discontinued operations	19	\$ (0.01)	\$ (0.18)

See accompanying Notes to the Consolidated Financial Statements

Consolidated Statements of Changes in Equity

For the year ended December 31, (thousands of United States dollars)	NOTE	2015	2014
Share Capital			
Balance, beginning of year		\$ 694,110	\$ 414,176
Issuance of common shares under option plans		10,004	13,450
Issued on the acquisition of Verano Energy Limited (“Verano”)	9	-	169,333
Issued through bought deal financing		113,620	-
Share issue costs		(4,997)	(180)
Issued on conversion of convertible debentures	16	-	97,331
Balance, end of year		\$ 812,737	\$ 694,110
Contributed Surplus			
Balance, beginning of year		\$ 26,106	\$ 21,692
Share-based compensation		11,023	8,491
Options exercised		(3,741)	(4,077)
Balance, end of year		\$ 33,388	\$ 26,106
(Deficit) Retained Earnings			
Balance, beginning of year		\$ (59,578)	\$ 49,195
Net (loss) for the year		(44,621)	(108,773)
Balance, end of year		\$ (104,199)	\$ (59,578)
		\$ 741,926	\$ 660,638

See accompanying Notes to the Consolidated Financial Statements

Consolidated Statements of Cash Flows

For the year ended December 31,
(thousands of United States dollars)

	NOTE	2015	2014
Operating activities			
Net (loss) from continuing operations		\$ (43,840)	\$ (86,583)
Add (deduct) non-cash items			
Depletion, depreciation and amortization	8	152,399	218,471
Non-cash finance expense	13	171	29,925
Share-based compensation	16	14,851	12,325
Deferred tax (recovery)	17	(54,105)	(19,539)
Impairment of exploration and evaluation assets	7	27,025	44,387
Impairment of property, plant and equipment	8	31,144	113,264
Unrealized foreign exchange (gain) loss		8,229	(6,122)
Unrealized (gain) on commodity risk management contracts	22	(2,915)	-
Loss on settlement of decommissioning liabilities	15	741	134
Abandonment costs paid	15	(1,180)	(1,794)
Colombia equity tax paid		-	(1,667)
Stock appreciation rights paid	16	(2,249)	(2,516)
Settlement of cross currency interest rate swap	22	-	(6,432)
Funds flow provided by operating activities – continuing operations		130,271	293,853
Net change in non-cash working capital – continuing operations	19	30,881	(43,025)
Cash provided by operating activities – continuing operations		161,152	250,828
Cash (used in) operating activities – discontinued operations		(238)	(1,926)
Cash provided by operating activities		160,914	248,902
Investing activities			
Property, plant and equipment expenditures	8	(65,147)	(176,489)
Exploration and evaluation expenditures	7	(60,335)	(119,670)
Corporate and property acquisitions	9	-	(27,131)
Net change in non-cash working capital – continuing operations	19	(56,721)	23,276
Cash (used in) investing activities – continuing operations		(182,203)	(300,014)
Cash provided by investing activities – discontinued operations		1,672	118
Cash (used in) investing activities		(180,531)	(299,896)
Financing activities			
Issuance of common shares under option plans	16	6,263	9,373
Issuance of common shares through bought deal financing	16	113,620	-
Redemption of convertible debentures	13	-	(316)
Share issue costs		(4,997)	(180)
Long-term debt (repaid) issued	12	(35,000)	26,470
Cash provided by financing activities - continuing operations		79,886	35,347
Increase (decrease) in cash for the year		60,269	(15,647)
Impact of foreign exchange on foreign currency-denominated cash balances		(4,446)	(1,845)
Cash, beginning of year		39,000	56,492
Cash, end of year		\$ 94,823	\$ 39,000

Supplemental Disclosure of Cash Flow Information (note 19)

See accompanying Notes to the Consolidated Financial Statements

Notes to the Consolidated Financial Statements

For the year ended December 31, 2015

(Tabular amounts in thousands of United States dollars, unless otherwise stated. Amounts in text are in United States dollars, unless otherwise stated.)

1. Corporate Information

Parex Resources Inc. and its subsidiaries (“Parex” or “the Company”) are in the business of the exploration, development, production and marketing of oil and natural gas in South America.

Parex Resources Inc. is a publicly traded Company, incorporated and domiciled in Canada. Its registered office is at 2400, 525-8th Avenue S.W., Calgary, Alberta T2P 1G1. The Company was incorporated on August 17, 2009, pursuant to the Business Corporations Act (Alberta).

The consolidated financial statements were approved and authorized for issuance by the Board of Directors on March 8, 2016.

2. Basis of Preparation, Critical Accounting Estimates and Judgements

a) Statement of compliance

These consolidated financial statements have been prepared in accordance with IFRS, as issued by the International Accounting Standard Boards (“IASB”).

The policies applied in these consolidated financial statements are based on IFRS issued and outstanding as of March 8, 2016, the date the Board of Directors approved the consolidated financial statements.

b) Basis of measurement

The consolidated financial statements have been prepared under the historical cost convention except for derivative financial instruments and share-based compensation transactions which are measured at fair value. The methods used to measure fair values are discussed in note 4 - Determination of Fair Values.

c) Use of management estimates, judgments and measurement uncertainty

The timely preparation of the consolidated financial statements requires that management make estimates and use judgment regarding the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as at the date of the consolidated financial statements. Accordingly, actual results could differ from estimated amounts as future confirming events occur. Significant estimates and judgments made by management in the preparation of these consolidated financial statements are outlined below:

(i) Depletion, depreciation and reserves

Depletion is based on the proved plus probable reserves as evaluated in accordance with National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities* (“NI 51-101”) and incorporating the estimated future cost of developing and extracting those. The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates are based on current production forecasts, prices and economic conditions. As circumstances change and additional data becomes available, reserve estimates may also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions of reserve estimates are often required due to changes in well performance, prices, economic conditions and governmental regulations.

Although every reasonable effort is made to determine that reserve estimates are accurate, reserve estimation is an inferential science. As a result, subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices and reservoir performance. Such revisions can be either positive or negative. Changes in reserve estimates impact the financial results of the Company as reserves and estimated future development costs are used to calculate depletion and are also used in measuring fair value less costs of disposal of property, plant and equipment for impairment calculations (see note 8).

(ii) Determination of cash-generating units (“CGU”)

The determination of CGUs requires judgment in defining a group of assets that generate cash inflows that are largely independent of the cash inflows from other assets or groups of assets. CGUs are determined by similar geological structure, shared infrastructure, geographical proximity, commodity type, similar exposure to market risks and materiality.

(iii) Exploration and evaluation (“E&E”)

The decision to transfer assets from E&E to property, plant and equipment (“PP&E”) is primarily based on the estimated proved plus probable reserves used in the determination of an area’s technical feasibility and commercial viability (see note 7).

(iv) Decommissioning and environmental liabilities

Decommissioning and restoration costs will be incurred by the Company at the end of the operating life of certain of its assets. The ultimate decommissioning and restoration costs are uncertain and cost estimates can vary in response to many factors including changes to relevant legal and regulatory requirements, the emergence of new restoration techniques or experience at other production sites. The expected timing and amount of expenditure can also change in response to changes in reserves, laws and regulations or their interpretation, the timing and likelihood of the settlement of the obligation, discount rates, and future interest rates. As a result, there could be significant adjustments to the provisions established which would affect future financial results. The Company uses a risk-free discount rate.

Liabilities for environmental costs are recognized in the period in which they are incurred, normally when the asset is developed and the associated costs can be estimated. These liabilities are in addition to the decommissioning liabilities due to government regulations that require the Company to perform additional mitigation against the environmental issues attributed to water usage and deforestation from oil and gas activities performed. In addition, the timing of expected settlement of the environmental liabilities differs from the timing of expected settlement of the decommissioning liabilities. Environmental expenditures that relate to current or future revenues are expensed or capitalized as appropriate. Refer to note 15 – Decommissioning and environmental liabilities.

(v) Impairment indicators and discount rate

The recoverable amounts of CGUs and individual assets have been determined as the greater of either an asset’s or CGU’s value in use or fair value less costs of disposal. These calculations require the use of estimates and assumptions and are subject to changes as new information becomes available including information on future commodity prices, quantity of reserves and discount rates as well as future development and operating costs. It is reasonably possible that the commodity price assumptions may change, which may impact the estimated life of the oil and natural gas reserves and the recoverable economical reserves and may require a material adjustment to the carrying value of oil and natural gas assets. The Company monitors internal and external indicators of impairment relating to its property, plant and equipment, and exploration and evaluation assets. Refer to note 7 – Exploration and Evaluation Assets, note 8 – Property, Plant and Equipment and note 11 – Goodwill.

(vi) Share-based compensation

Compensation costs accrued for share-based compensation plans and the Company’s Share Appreciation Rights (“SAR”) plan are subject to the estimation of what the ultimate payout will be using the Black-Scholes pricing model which is based on significant assumptions such as the future volatility of the market price of Parex shares and expected term of the issued stock option or SAR. Compensation costs accrued for the Company’s Restricted Share Unit (“RSU”) plan and a Deferred Share Unit (“DSU”) plan are measured at fair value based on the market price of Parex shares on the date of issuance. Refer to note 16.

(vii) Derivative financial asset/liability

The estimated fair value of derivative instruments resulting derivative assets and liabilities depends on estimated forward prices and volatility in those prices and by their nature are subject to measurement uncertainty.

(viii) Income taxes

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and interpretation. As such, income taxes are subject to measurement uncertainty. The Company follows the liability method for calculating deferred taxes. Assessing the recoverability of deferred tax assets requires the Company to make significant estimates related to the expectations of future cash flows from operations and the application of existing tax laws. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of

the Company to realize the deferred tax assets and liabilities recorded at the balance sheet date could be impacted. Additionally, changes in tax laws could limit the ability of the Company to obtain tax deductions in the future.

(ix) Business combinations, corporate and property acquisitions

Business combinations, corporate and property acquisitions are accounted for using the acquisition method of accounting whereby the assets acquired and the liabilities assumed are recorded at fair values. The determination of fair value often requires management to make assumptions and estimates about future events. The fair value of property, plant and equipment (“PPE”) recognized in a business combination, corporate or property acquisition is based on market values. The market value of property, plant and equipment is the estimated amount for which PP&E could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm’s length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The market value of oil and natural gas interests (included in PP&E) are estimated with reference to the discounted cash flows expected to be derived from oil and natural gas production based on externally prepared reserve reports. The market value of E&E assets are estimated with reference to the market values of current arm’s length transactions in comparable locations. Assumptions are also required to determine the fair value of decommissioning obligations associated with the properties. Changes in any of these assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill (or gain from a bargain purchase) in the acquisition equation. Future net earnings can be affected as a result of changes in future depletion and depreciation, asset impairment or goodwill impairment.

3. Summary of Significant Accounting Policies

The accounting policies set out below have been applied consistently to all years presented in these consolidated financial statements, and have been applied consistently by the Company and its subsidiaries.

a) Consolidation

The consolidated financial statements include the accounts of the Company and all of its subsidiaries at December 31, 2015. The principal operating subsidiaries and their activities are:

Entity	Country of incorporation	Country of principle business activity	Ownership %	Principle business activity
Parex Resources (Colombia) Ltd.	Barbados	Colombia	100	Oil and natural gas exploration and development
Ramshorn International Limited	Bermuda	Colombia	100	Oil and natural gas exploration and development
Verano Energy (Barbados) Limited	Barbados	Colombia	100	Oil and natural gas exploration and development

The above listing does not include the wholly-owned holding company subsidiaries of Parex. All companies in the Parex group are wholly-owned subsidiaries.

On February 13, 2015, the Company sold all of the issued and outstanding shares in the capital of Parex Resources (Trinidad) Ltd to a third party. Refer to note 10 – Assets Held for Sale and Discontinued Operations.

Inter-company balances and transactions are eliminated on consolidation. Interests in joint arrangements are classified as either joint operations or joint ventures, depending on the rights and obligations of the parties to the arrangement. Joint operations arise when the Company has rights to the assets and obligations for the liabilities of the arrangement. The Company recognizes its share of assets, liabilities, revenues and expenses of a joint operation. A significant portion of the Company’s operating cash flows is derived through joint operations which are involved in the development and production of crude oil in Colombia. Joint ventures arise when the Company has rights to the net assets of the arrangement. Joint ventures are accounted for under the equity method.

b) Foreign currency translation

(i) Functional and presentation currency

Items included in the consolidated financial statements are measured using the currency of the primary economic environment in which the Company operates (the “functional currency”). The consolidated financial statements are presented in United States dollars, which is the functional currency of Parex.

(ii) Transactions and balances

Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the date of the transaction. Generally, foreign exchange gains and losses resulting from the settlement of foreign currency transactions and from the translation at period-end exchange rates of monetary assets and liabilities denominated in currencies other than an operation's functional currency are recognized in the statement of comprehensive income (loss).

c) Financial instruments

The Company initially measures financial instruments at estimated fair value. The Company's loans and receivables, comprised of cash and accounts receivables, are included in current assets due to their short-term nature. Financial liabilities are categorized as "other financial liabilities" consisting of accounts payable and accrued liabilities and long-term debt.

Loans and receivables

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market and with no intention of being traded. They are included in current assets, except for maturities greater than 12 months after the balance sheet date, which are classified as non-current assets. Loans and receivables are recognized at the amount expected to be received less any discount or rebate to reduce the loan and receivables to estimated fair value. Loans and receivables are subsequently measured at amortized cost using the effective interest method. For loans and receivables that have maturity dates of less than one year, the Company estimates their carrying value approximates their fair value due to their short-term nature. Loans and receivables are comprised of cash and accounts receivable in the consolidated balance sheet.

Other financial liabilities

Other financial liabilities are financial liabilities that are not quoted on an active market and with no intention of being traded. They are included in current liabilities, except for the long-term debt as this instrument has a maturity greater than 12 months after the balance sheet date and is classified as a non-current liability. Accounts payable are initially recognized at the amount required to be paid less any discount or rebates to reduce the payables to estimated fair value. Accounts payable are subsequently measured at amortized cost using the effective interest method. For accounts payable that have maturity dates of less than one year, the Company estimates their carrying value approximates their fair value due to their short-term nature.

Derivative instruments

Derivatives may be used by the Company to manage economic exposure to market risk relating to commodity prices, foreign exchange rates and interest rates. Parex' policy is not to utilize derivative financial instruments for speculative purposes. The Company does not designate its financial derivative contracts as hedges, and as such does not apply hedge accounting. As a result, all financial derivative contracts are classified at fair value through comprehensive income (loss) and are recorded on the consolidated balance sheet at fair value.

Financial derivative contracts are initially recognized at fair value on the date a derivative contract is entered into and are remeasured at their fair value at each subsequent reporting date.

Financial derivative instruments are included in current assets (liabilities) except for those with maturities greater than 12 months after the end of the reporting period, which are classified as non-current assets (liabilities).

d) Capital assets

(i) Exploration and evaluation

All costs directly associated with the exploration and evaluation of oil and natural gas reserves are initially capitalized. E&E costs are those expenditures for an area where technical feasibility and commercial viability have not yet been determined. These costs include unproved property acquisition costs, exploration costs, geological and geophysical costs, decommissioning costs, E&E drilling, sampling and appraisals. Costs incurred prior to acquiring the legal rights to explore an area are charged directly to comprehensive income (loss) as impairment of exploration and evaluation assets.

When an area is determined to be technically feasible and commercially viable the accumulated costs are transferred to PP&E, where they are depleted. When an area is determined not to be technically feasible and commercially viable or the Company decides not to continue with its activity, the unrecoverable costs are charged to comprehensive income (loss) as impairment of exploration and evaluation assets. Net proceeds from any disposal of an intangible exploration asset are recorded as a reduction in intangible assets.

(ii) Property, plant and equipment

All costs directly associated with the development of oil and natural gas reserves are capitalized on an area-by-area basis. Development costs include expenditures for areas where technical feasibility and commercial viability have been determined. These costs include proved property acquisitions, development drilling, completion of wells, gathering facilities and infrastructure, decommissioning and restoration costs and transfers of E&E assets. Costs accumulated within each CGU are depleted using the unit-of-production method based on proved plus probable reserves incorporating estimated future prices and costs. Costs subject to depletion include estimated future costs to be incurred in developing proved plus probable reserves. Costs of major development projects are excluded from the costs subject to depletion until they are available for use.

Costs associated with office furniture, fixtures and leasehold improvements are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from 1 to 5 years.

e) Impairment of long-term assets

The carrying amounts of the Company's long-term assets, other than E&E assets and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If an indication of impairment exists, the asset's recoverable amount is estimated. E&E assets are assessed for impairment when they are reclassified to PP&E, and, if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, assets are grouped into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs of disposal ("FVLCD").

The value in use is determined by estimating the present value of the pre-tax future net cash flows expected to be derived from the continued use of the asset or CGU. The FVLCD is based on available market information, where applicable. In the absence of such information, FVLCD is determined using discounted future after tax net cash flows of proved plus probable reserves using forecast prices and costs.

E&E assets are allocated to related CGUs where they are assessed for impairment upon their eventual reclassification to PP&E. E&E assets not reclassified to PP&E are assessed for impairment on a block by block basis.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in comprehensive income (loss). Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the units and then to reduce the carrying amounts of the other assets in the unit (group of units) on a pro-rata basis.

Impairment losses recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation or amortization, if no impairment loss had been recognized.

f) Assets held for sale

Non-current assets are classified as held for sale if their carrying amounts will be recovered through a sale transaction rather than through continuing use. This condition is met when the sale is highly probable and the asset is available for immediate sale in its present condition. For the sale to be highly probable management must be committed to a plan to sell the asset and an active program to locate a buyer and complete the plan must have been initiated. The asset must be actively marketed for sale at a price that is reasonable in relation to its current fair value and the sale should be expected to be completed within one year from the date of classification.

Non-current assets classified as held for sale are measured at the lower of the carrying amount and fair value less costs to sell, with impairments recognized in the consolidated statement of comprehensive income (loss) in the period measured. Non-current assets held for sale are presented in current assets and liabilities within the balance sheet. Assets held for sale are not depleted, depreciated or amortized.

Income and expenses related to discontinued operations are classified as income (loss) from discontinued operations within the consolidated statement of comprehensive income (loss) and the consolidated statement of cash flows.

g) Crude oil inventory

Crude oil inventory consists of crude oil in transit at the balance sheet date and is valued at the lower of cost, using the weighted average cost method, and net realizable value. Costs include direct and indirect expenditures incurred in bringing the crude oil to its existing condition and location.

h) Purchased oil

Purchased oil includes costs to buy third party oil. These costs are initially recorded in inventory until the crude oil title is transferred.

i) Goodwill

Goodwill is recorded on a business acquisition when the purchase price is in excess of the fair values assigned to assets acquired and liabilities assumed. Goodwill is not amortized and an impairment test is performed annually or as events occur that could indicate impairment. To test for impairment, goodwill is allocated to each of the Company's CGUs, groups of CGUs, or an operating segment expected to benefit from the acquisition. Goodwill is tested by combining the carrying amounts of property, plant and equipment and exploration and evaluation assets and goodwill and comparing this to the recoverable amount. Fair value less costs of disposal, is derived by estimating the discounted after-tax future net cash flows as described in the property, plant and equipment impairment test, plus the fair market value of undeveloped land, seismic and inventory. Value in use is assessed using the present value of the expected future cash flows. Any excess of the carrying amount over the recoverable amount is recorded as impairment. Impairment charges, which are not tax affected, are recognized in comprehensive income (loss) and are not reversed. Goodwill is reported at cost less any impairment.

j) Revenue recognition

Revenue from the sale of oil and natural gas is recorded when the significant risks and rewards of ownership of the product are transferred to the buyer which is usually when legal title passes to the external party.

k) Repurchase of shares

Pursuant of the Normal Course Issuer Bid ("NCIB"), repurchased common shares reduce share capital for the average book value with any excess or deficiency charged to retained earnings (deficit).

l) Share-based compensation

The Company has an incentive stock option plan, a restricted unit plan and a deferred unit plan for certain employees, officers and directors as described in note 16. The Company records share-based compensation expense using the fair value method. The fair value of an option is calculated at the grant date using the Black-Scholes pricing model, and expensed over the vesting period of the option. The fair value of an RSU is calculated using the market price of Parex shares on the date of issuance, and expensed over the vesting period of the RSU. The fair value of a DSU is calculated using the market price of Parex shares on the date of issuance, and expensed immediately. The Company determines an appropriate forfeiture rate by examining the history of its forfeitures. The Company records the cumulative share-based compensation as contributed surplus. When options, DSUs or RSUs are exercised, contributed surplus is reduced and share capital is increased by the amount of accumulated share-based compensation for the exercised security. Any consideration received on the exercise of stock options, DSUs or RSUs is credited to share capital.

Obligations for payments of cash under the foreign subsidiaries' SARs plan are accrued as compensation expense over the vesting period based on the fair value of SARs, subject to appreciation limits specified in the plan. The fair value of SARs is measured using the Black-Scholes pricing model. In accordance with the fair value method, increases or decreases in the fair value of the SARs result in a corresponding change in the recorded liability. The accrued compensation for a right that is forfeited is adjusted by decreasing compensation cost in the period of forfeiture.

m) Provisions

A provision is recognized if, as a result of a past event, the Company has a current legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

n) Decommissioning and environmental liabilities

The Company's activities give rise to dismantling, decommissioning, environmental, abandonment and site disturbance remediation activities. Provisions are made for the estimated cost of the future site restoration and capitalized in the relevant asset category.

Decommissioning and environmental liabilities are measured at the present value of management's best estimate of the cost and future timing of the expenditure required to settle the present obligation at the balance sheet date using a risk-free discount rate. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as a finance expense whereas increases (decreases) due to changes in the estimated future

cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning and environmental liabilities are charged against the provision to the extent the provision was established.

o) Operating Segments

Management has determined the operating segments based on information regularly reviewed for the purposes of decision making, allocating resources and assessing operational performance by the Company's chief operating decision makers. The operating segments are Canada and Colombia. The Company evaluates the financial performance of its operating segments primarily based on operating cash flow.

p) Finance income and expense

Finance expense comprises interest expense on borrowings, accretion on provisions and convertible debentures, net wealth tax, amortization of debt issuance costs, revaluation of derivative financial liabilities and impairment losses recognized on financial assets. Finance income comprises interest earned on cash and other income.

q) Cash

Cash is comprised of cash held in chartered banks in Canada and recognized financial institutions abroad with BBB+ credit ratings or higher.

r) Income taxes

Income tax expense comprises current and deferred tax. Income tax expense is recognized in comprehensive income (loss).

Current tax is the expected tax payable on taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

In general, deferred tax is recognized in respect of temporary differences arising between the tax basis of assets and liabilities and their carrying amounts in the consolidated financial statements. Deferred tax is determined on a non-discounted basis using tax rates, currency exchange rates and laws enacted or substantively enacted by the balance sheet date and expected to apply when the deferred tax asset or liability is settled. Deferred tax assets are recognized to the extent that it is probable that the assets can be recovered. Deferred tax is provided on temporary differences arising on investments in subsidiaries except, in the case of subsidiaries, where the timing of the reversal of the temporary difference is controlled by the Company and it is probable that the temporary difference will not be reversed in the foreseeable future. Deferred tax assets and liabilities are presented as non-current.

s) Per share information

Basic net income per share is calculated by dividing the income or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted net income per share is determined by adjusting the income or loss attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as options granted to employees and convertible debentures, except when the effect would be anti-dilutive.

t) New standards and interpretations not yet adopted

The standards and interpretations that are issued but not yet effective up to the date of issuance of the Company's financial statements, and that may have an impact on the disclosures and financial position of the Company, are disclosed below. The Company intends to adopt these standards and interpretations, if applicable, when they become effective.

- (i) In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers", which replaces International Accounting Standard ("IAS") 18 "Revenue", IAS 11 "Construction Contracts", and related interpretations. The standard is required to be adopted either retrospectively or using a modified transition approach for fiscal years beginning on or after January 1, 2018, with earlier adoption permitted. IFRS 15 will be applied by the Company on January 1, 2018 and the Company is currently evaluating the impact of the standard on the financial statements.
- (ii) In July 2014, the IASB completed the final elements of IFRS 9 "Financial Instruments". The standard supersedes earlier versions of IFRS 9 and completes the IASB's project to replace IAS 39 "Financial Instruments: Recognition and Measurement". IFRS 9, as amended, includes a principle-based approach for classification and measurement of financial assets, a single expected loss impairment model and a substantially-reformed approach to hedge accounting. The standard will come into effect for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. IFRS 9 will be applied by the Company on January 1, 2018 and the Company is currently evaluating the impact of the standard on the financial statements.

(iii) In January 2016, the IASB issued IFRS 16 “Leases”, which replaces IAS 17 “Leases”. For lessees applying IFRS 16, a single recognition and measurement model for leases would apply, with required recognition of assets and liabilities for most leases. The standard will come into effect for annual periods beginning on or after January 1, 2019, with earlier adoption permitted if the entity is also applying IFRS 15 “Revenue from Contracts with Customers”. IFRS 16 will be applied by the Company on January 1, 2019 and the Company is currently evaluating the impact of the standard on the financial statements.

4. Determination of Fair Values

A number of the Company’s accounting policies and disclosures require the determination of fair value for financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the methods below. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

a) *PP&E and intangible exploration assets*

The fair value of PP&E and intangible exploration assets are determined if there are indicators of impairment. The fair value of PP&E is the estimated amount for which PP&E could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm’s-length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The fair value of oil and natural gas assets (included in PP&E) is estimated with reference to the discounted cash flows expected to be derived from oil and natural gas production based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions. All level 3 inputs.

b) *Cash, accounts receivable, and accounts payable and accrued liabilities*

The fair value of cash, accounts receivable and accounts payable and accrued liabilities is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At December 31, 2015 and 2014 the fair value of these balances approximated their carrying value due to their short-term to maturity.

c) *Stock options*

The fair value of stock options is measured using the Black-Scholes pricing model. Measurement inputs include the share price on measurement date, exercise price of the option, expected future share price volatility, weighted average expected life of the instruments (based on historical experience and general option-holder behavior), expected dividends and the risk-free interest rate (based on Government of Canada Bonds) for the relevant expected life as described in note 16.

d) *Share appreciation rights*

The fair value of SARs is measured using the Black-Scholes pricing model. Measurement inputs include the share price on each balance sheet date, expected future share price volatility, weighted average expected life of the instruments (based on historical experience and general SAR-holder behavior), expected dividends and the risk-free interest rate (based on Government of Canada Bonds) for the relevant expected life as described in note 16.

e) *Restricted share units and deferred share units*

The fair value of stock RSUs and DSUs are measured based on the market price of Parex shares on the date of issuance. Refer to note 16.

f) *Derivative financial asset /liability*

Risk management contracts are initially recognized at fair value on the date a derivative contract is entered into and are remeasured at their fair value at each subsequent reporting date. The fair value of the risk management contract on initial recognition is normally the transaction price. Subsequent to initial recognition, the fair values are based on quoted market prices where available from active markets, otherwise fair values are estimated based on market prices at the reporting date for similar assets or liabilities with similar terms and conditions.

5. Accounts Receivable

	December 31, 2015		December 31, 2014	
Trade receivables	\$	26,395	\$	74,064
Colombia income taxes receivable		46,992		35,557
Receivables from partners		2,465		7,616
Value added taxes (VAT)		4,003		8,025
	\$	79,855	\$	125,262

Trade receivables consist primarily of oil sale receivables related to the Company's oil sales. Colombia income tax receivable is a result of withholding tax incurred on Colombia oil sales and tax installments. The balance can either be received in cash or applied to Colombian cash income tax payable. Receivables from partners consist of cash calls outstanding from joint venture partners in Colombia to recover ongoing capital costs and operating costs, or overhead recoveries outstanding from joint venture partners. VAT receivable is \$4.0 million as at December 31, 2015 (December 31, 2014 - \$8.0 million) and is recoverable in 2016. All accounts receivable are expected to be received within twelve months and are thus recognized as current assets.

6. Inventory

	December 31, 2015		December 31, 2014	
Crude oil inventory	\$	3,207	\$	10,959

Crude oil inventory consists of crude oil in transit at the balance sheet date and is valued at the lower of cost, using the weighted average cost method, and net realizable value. Costs include direct and indirect expenditures incurred in bringing the crude oil to its existing condition and location. During 2015 \$11.0 million (December 31, 2014 - \$8.7 million) of produced crude oil inventory cost was expensed to the consolidated statement of comprehensive income (loss). Purchased crude oil is sold immediately. The cost associated with purchased oil is shown in the consolidated statement of comprehensive income (loss) as purchased oil expense. At December 31, 2015 and 2014 the Company did not have any third party purchased oil in inventory.

7. Exploration and Evaluation Assets

	Colombia		Trinidad & Tobago		Total
Cost					
Balance at December 31, 2013	\$	46,769	\$	23,269	\$ 70,038
Additions		119,670		706	120,376
Transfers to PP&E		(12,457)		-	(12,457)
Disposition of tangible assets		-		(849)	(849)
Changes in decommissioning liability		5,768		-	5,768
Corporate acquisitions		15,081		-	15,081
Intercompany transfer of assets		1,604		(1,604)	-
Exploration and evaluation impairment		(44,387)		(19,633)	(64,020)
Reclassified to assets held for sale		-		(1,889)	(1,889)
Balance at December 31, 2014	\$	132,048	\$	-	\$ 132,048
Additions		60,335		-	60,335
Transfers to PP&E		(44,121)		-	(44,121)
Changes in decommissioning liability		117		-	117
Exploration and evaluation impairment		(27,025)		-	(27,025)
Balance at December 31, 2015	\$	121,354	\$	-	\$ 121,354

Additions and Transfers

E&E assets consist of the Company's exploration projects which are pending either the determination of proved or probable reserves or impairment. Additions represent the Company's share of costs incurred on E&E assets during the period. Amounts transferred to PP&E of \$44.1 million for the year ended December 31, 2015 are primarily associated with the Block LLA-26 assets. In the prior year amounts of \$12.5 million were transferred from E&E to PP&E. E&E assets increased by \$15.1 million for the year ended December 31, 2014 relating to the fair value of the assets acquired in corporate acquisitions.

2015 Impairments

During 2015, the Company completed an impairment review of E&E assets. It was determined that the carrying amount of certain E&E assets primarily associated with Block LLA-57 in the Northern Llanos basin was unlikely to be recovered by successful development or sale. The impairment review compared the carrying value of the assets to the recoverable amount. The recoverable amount was estimated using fair value less costs of disposal (level 3 inputs) and was determined to be \$nil for these assets. It was determined that the impairment was \$27.0 million which is recorded in the consolidated statement of comprehensive income (loss) for the twelve months ended December 31, 2015.

2014 Impairments

During 2014, the Company completed an impairment review for certain E&E assets associated with Block LLA-40 prior to its transfer to PP&E and determined that the carrying amount of the project assets was unlikely to be recovered by successful development or sale. The impairment review compared the carrying value of the assets to the recoverable amount. The recoverable amount was calculated based on discounted after-tax cash flows of proved and

probable reserves using forecast prices and cost estimates, consistent with the Company's independent qualified reserves evaluators. This approach requires assumptions about revenue, future oil prices, tax rates and discount rates, all of which are level 3 inputs. It was determined that the impairment was \$23.6 million which is recorded in the consolidated statement of comprehensive income (loss) for the year ended December 31, 2014. The recoverable amount was determined to be \$5.9 million using an after-tax discount rate of eleven percent, and was subsequently transferred to property, plant and equipment.

The Company also completed an impairment review for certain E&E assets associated with Block LLA-29 located in the Llanos basin in the fourth quarter of 2014 due to extended community problems that forced the block into force majeure. The impairment review compared the carrying value of assets to the recoverable amount. The recoverable amount was estimated using fair value less costs of disposal (level 3 inputs). It was determined that the impairment was \$20.8 million which is recorded in the consolidated statement of comprehensive income (loss) for the year ended December 31, 2014. The recoverable amount was determined to be \$nil as there is no certainty the block can be accessed in a normal course manner.

During the fourth quarter of 2014, the Company entered into negotiations with a third party to purchase from the Company all of the issued and outstanding shares in the capital of Parex Resources (Trinidad) Ltd, refer to note 10 - Assets Held for Sale and Discontinued Operations. Associated with this, the Company completed an impairment review of the exploration and evaluation assets in Trinidad & Tobago. The impairment review compared the carrying value of the assets to the recoverable amount. The recoverable amount was estimated using fair value less costs of disposal based on the above noted indications from third parties in the Company's interest in the assets (level 3 inputs). It was determined that the impairment was \$19.6 million on E&E assets which is recorded in the consolidated statement of comprehensive income (loss) for the year ended December 31, 2014 as part of discontinued operations. The recoverable amount of the assets was determined to be \$1.9 million, net of associated decommissioning liabilities of \$0.4 million, and was transferred to assets held for sale.

At December 31, 2015 and December 31, 2014 the Company did not have E&E assets in Canada.

8. Property, Plant and Equipment

	Canada		Colombia		Trinidad & Tobago		Total
Cost							
Balance at December 31, 2013	\$	4,781	\$	981,215	\$	318	\$ 986,314
Additions		515		175,974		11	176,500
Changes in decommissioning liability		-		7,569		-	7,569
Verano acquisition		-		247,617		-	247,617
Transfer from E&E assets		-		12,457		-	12,457
Intercompany transfer of assets		(1,903)		1,903		-	-
Dispositions		-		(624)		(91)	(715)
Balance at December 31, 2014	\$	3,393	\$	1,426,111	\$	238	\$ 1,429,742
Additions		214		64,933		-	65,147
Transfer from E&E assets		-		44,121		-	44,121
Dispositions		-		-		(238)	(238)
Changes in decommissioning liability		-		2,498		-	2,498
	\$	3,607	\$	1,537,663	\$	-	\$ 1,541,270
Accumulated Depreciation, Depletion and Amortization							
Balance at December 31, 2013	\$	2,628	\$	451,985	\$	219	\$ 454,832
Depletion and depreciation for the year		187		218,284		19	218,490
DD&A included in crude oil inventory costing		-		954		-	954
Impairment		-		113,264		-	113,264
Balance at December 31, 2014	\$	2,815	\$	784,487	\$	238	\$ 787,540
Depletion and depreciation for the year		247		152,152		-	152,399
DD&A included in crude oil inventory costing		-		(3,888)		-	(3,888)
Dispositions		-		-		(238)	(238)
Impairment		-		31,144		-	31,144
Balance at December 31, 2015	\$	3,062	\$	963,895	\$	-	\$ 966,957
Net book value:							
At December 31, 2013	\$	2,153	\$	529,230	\$	99	\$ 531,482
At December 31, 2014	\$	578	\$	641,624	\$	-	\$ 642,202
At December 31, 2015	\$	545	\$	573,768	\$	-	\$ 574,313

Additions and Transfers

During 2015, plant and equipment (“PPE”) additions mainly relate to development and appraisal expenditures in Colombia at Block LLA-32 and Block LLA-34. For the year ended December 31, 2015, \$44.1 million was transferred from E&E assets relating to Block LLA-26 (year ended December 31, 2014 - \$12.5 million transferred from E&E assets).

During 2014, additions mainly related to development expenditures in the amount of \$176.0 million in Colombia at Block LLA-32 and Block LLA-34. In the year ended December 31, 2014, \$12.5 million was transferred from E&E assets and PP&E increased by \$247.6 million relating to the fair value of the assets acquired in corporate acquisitions.

For the year ended December 31, 2015 future development costs of \$252.1 million (year ended December 31, 2014 - \$360.8 million) were included in the depletion calculation for development and production assets. For the year ended December 31, 2015 \$6.1 million of general and administrative costs (year ended December 31, 2014 - \$8.6 million) have been capitalized in respect of development and production activities during the current period.

2015 Impairments

As a result in the decrease in forecast oil prices compared to those at December 31, 2014 an indication of impairment was identified for all CGUs during 2015 and impairment tests were performed. The Company determined that the carrying amount of a CGU in the Llanos Basin exceeded its recoverable amount. An impairment of \$31.1 million was recorded in the consolidated statement of comprehensive income (loss). The recoverable amount was determined using fair value less costs of disposal.

The fair value for the producing properties in this CGU was calculated based on discounted after-tax cash flows of proved and probable reserves using forecast prices and cost estimates, consistent with the Company’s independent qualified reserves evaluators. This approach requires assumptions about revenue, future oil prices, tax rates and discount rates, all of which are level 3 inputs. Refer to note 11 – Goodwill for the future crude oil prices used by Parex’ independent reserve evaluator. There are no E&E assets associated with this CGU. Future cash flows were discounted using an after tax rate of 11 percent. As at December 31, 2015, the recoverable amount of the CGU was estimated to be \$nil. The impairment is due to lower crude prices assumed in the fair value calculation as compared to the prior year. A 1% change to the assumed discount rate or forward price estimates over the life of the reserves would have an insignificant impact on the impairment.

2014 Impairments

As a result in the decrease in forecast oil prices compared to those at December 31, 2013 an indication of impairment was identified for all CGUs during 2014 and impairment tests were performed. The Company determined that the carrying amount of a CGU in the Llanos Basin exceeded its recoverable amount. An impairment of \$113.3 million was recorded in the consolidated statement of comprehensive income (loss). The recoverable amount was determined using fair value less costs of disposal.

The fair value for the producing properties in this CGU was calculated based on discounted after-tax cash flows of proved and probable reserves using forecast prices and cost estimates, consistent with the Company’s independent qualified reserves evaluators. This approach requires assumptions about revenue, future oil prices, tax rates and discount rates, all of which are level 3 inputs. Refer to note 11 – Goodwill for the future crude oil prices used by Parex’ independent reserve evaluator. There are no E&E assets associated with this CGU. Future cash flows were discounted using an after tax rate of 11 percent. As at December 31, 2014, the recoverable amount of the CGU was estimated to be \$61.7 million. The impairment is due to lower crude prices assumed in the fair value calculation as compared to the prior year.

Changes to the assumed discount rate or forward price estimates over the life of the reserves independently would have the following impact on the impairment of the CGU at December 31, 2014:

	One Percent Increase in the Discount Rate	Five Percent Decrease in the Forward Price Estimates
Impairment of property, plant and equipment	\$ 1,807	\$ 12,838

9. Acquisitions

a) Verano acquisition

On June 25, 2014, Parex acquired all of the outstanding shares of Verano Energy Limited (“Verano”) which assets primarily consist of interests in three exploration blocks located in Colombia’s Llanos Basin (the “Verano Acquisition”). The Company paid total net consideration of \$186.2 million. The Verano Acquisition increased the Company’s working interest in Block LLA-32 to 70%, in Block LLA-17 to 63% working interest and in Block LLA-34 to 55% working interest.

The consolidated statement of comprehensive income (loss) includes results of operation of Verano since the closing date of June 25, 2014 and expensed transaction costs associated with the Verano Acquisition of \$0.6 million.

This transaction has been accounted for using the acquisition method whereby the assets acquired and the liabilities assumed are recorded at fair values. As the fair value of the identifiable assets was determined to be less than the purchase price, goodwill of \$12.2 million arose on the transaction. The following table summarizes the recognizable assets acquired and consideration paid pursuant to the acquisition:

Assets acquired and liabilities assumed⁽¹⁾

Working capital deficiency	\$	(31,537)
PP&E		247,617
E&E assets		9,863
Deferred tax liability		(50,057)
Decommissioning and environmental liabilities		(1,852)
Goodwill		12,200
	\$	186,234

Consideration for the acquisition

Issuance of common shares	\$	169,333
Cash paid		75,415
Cash acquired		(53,115)
Settlement of pre-existing relationship		(5,399)
Total net consideration paid	\$	186,234

An adjustment has been made to the fair values of assets acquired and liabilities assumed during the year ended December 31, 2014 resulting in an increased working capital deficiency and goodwill.

Included in the working capital deficiency of assets acquired are accounts receivable of \$9.1 million. The receivables are joint venture and trade receivables for which the fair value approximates carrying value.

The settlement of pre-existing relationship related to an outstanding payable balance between Verano and the Company that was no longer owed as a result of the Acquisition.

The pro forma results for period ended December 31, 2014 are shown below, as if the Verano Acquisition had occurred on January 1, 2014. Pro forma results are not indicative of actual results or future performance.

Oil sales	\$	115,889
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The consolidated statement of comprehensive income (loss) for the period ended December 31, 2014 includes \$78.3 million of oil sales attributable to the assets acquired since the Verano Acquisition. Revenue less direct costs for the period ended December 31, 2014 attributable to the assets acquired since the Verano Acquisition is \$44.8 million. The pro forma net income and pro forma net income per share, basic and diluted, are considered impracticable to calculate and therefore not included. Pro forma results are not indicative of actual results or future performance.

b) Sorgenia Acquisition

On April 7, 2014, Parex, through a foreign subsidiary, acquired Sorgenia E&P Colombia BV (“Sorgenia”) which assets primarily consist of interests in four exploration blocks located in Colombia’s Llanos Basin (the “Sorgenia Acquisition”). The Sorgenia acquisition consolidates the Company’s interests in Blocks

LLA-24 and LLA-26 to 100%. In addition, the Company acquired an additional 25% working interest in the Cerrero Block and 10% working interest in the Balay development area. Total net consideration paid was \$4.8 million in cash.

The consolidated statement of comprehensive income (loss) includes the results of operation of Sorgenia since the closing date of April 7, 2014. This transaction has been accounted for using the acquisition method whereby the assets acquired and the liabilities assumed are recorded at fair values. As the fair value of the identifiable assets was determined to equal the purchase price, no goodwill arose on the transaction. The following table summarizes the recognizable assets acquired and consideration paid pursuant to the acquisition:

Assets acquired and liabilities assumed⁽¹⁾	
Working capital surplus	\$ 7
E&E assets	5,218
Decommissioning and environmental liabilities	(394)
	\$ 4,831
Consideration for the acquisition	
Cash paid	\$ 5,000
Cash acquired	(169)
Total net consideration paid	\$ 4,831

Included in the working capital surplus of assets acquired are accounts receivable of \$0.4 million. The receivables are joint venture and trade receivables for which the fair value approximates carrying value.

The consolidated statement of comprehensive income (loss) for the period ended December 31, 2014 includes \$1.0 million in oil sales attributable to the assets acquired since the Sorgenia Acquisition. Revenue less direct costs for the period ended December 31, 2014 attributable to the assets acquired since the Sorgenia Acquisition is \$0.6 million. As there was no production from the assets purchased prior to the Acquisition date, pro forma revenue for the period ended December 31, 2014, as if the Sorgenia Acquisition had occurred on January 1, 2014, are the same as actual. Pro forma net income and pro forma net income per share, basic and diluted, are considered impracticable to calculate and therefore not included. Pro forma results are not indicative of actual results or future performance.

10. Assets Held for Sale and Discontinued Operations

During the year ended December 31, 2015, Parex Resources (Barbados) Ltd. ("Parex Barbados") sold to a third party all of the issued and outstanding shares of Parex Trinidad Ltd. for \$1.5 million in cash, plus the assumption of certain liabilities and adjusted working capital. The sale closed on February 19, 2015. During the reclassification of operations for sale, assets of \$20.0 million were identified as being impaired during the year ended December 31, 2014.

The combined results of the discontinued operations which have been included in the consolidated statement of comprehensive income (loss) are as follows. The comparative period income (loss) and cash flows from discontinued operations have been reclassified to include those operations classified as discontinued in the current period:

	2015	2014
Expenses	\$	\$
General and administrative	149	1,273
Share-based compensation (recovery) expense	(22)	171
Loss on settlement of other assets and liabilities	654	353
Depletion, depreciation and amortization	-	19
Loss on sale of tangible assets	-	731
Accretion on decommissioning liabilities	-	12
Foreign exchange (gain)	-	(2)
Impairment of exploration and evaluation assets	-	19,633
	\$ 781	\$ 22,190

The major classes of assets and liabilities comprising the operations classified as held for sale as at December 31, 2014 are as follows:

Assets held for sale	
Cash	\$ 286
Accounts Receivable	424
Prepays and other current assets	334
E&E assets	1,889
	\$ 2,933

Liabilities held for sale

Accounts payable and accrued liabilities	\$	270
Decommissioning liabilities		389
Long-term SARs payable		12
	\$	671

11. Goodwill

	December 31, 2015	December 31, 2014
Goodwill	\$ 73,452	\$ 73,452

Impairment test of goodwill

The Company performed its annual test for goodwill impairment at the balance sheet date in accordance with its policy described in note 3. The Company has allocated goodwill to the Colombia operating segment.

The estimated fair value less costs of disposal of the Colombia operating segment exceeded the carrying value. As a result, no goodwill impairment was recorded.

Valuation Techniques

The recoverable amount of the group of CGUs to which the goodwill was assigned is based on fair value less costs of disposal. The technique used in determining the recoverable amount is based on the net present value of the after-tax cash flows from oil and gas reserves of the group of CGU's based on reserves estimated by Parex' independent reserve evaluator and the fair value of undeveloped land based on estimates with consideration given to acquisition metrics of recent transactions completed on similar assets to those contained within the relevant group of CGU's. The discounting process uses a rate of return that is commensurate with the risk associated with the assets and the time value of money. This approach requires assumptions about revenue, future oil prices, tax rates and discount rates, all of which are level 3 inputs.

*Significant Assumptions**Oil Reserves*

Assumptions that are valid at the time of reserve estimation may change significantly when new information becomes available. Changes in forward price estimates, production costs or recovery rates may change the economic status of reserves and may ultimately result in reserves being restated.

Future Oil Prices

Oil forward price estimates are used in the cash flow model. Commodity prices have fluctuated widely in recent years due to global and regional factors including supply and demand fundamentals, inventory levels, exchange rates, weather, economic and geopolitical factors. The future oil prices used in the model are based on a forecast of crude oil prices by Parex' independent reserve evaluator.

Prices used at December 31, 2015 are as follows:

	2016	2017	2018	2019	2020	Thereafter
Brent (\$US/bbl)	45.00	54.00	61.00	67.00	73.00	2% increase per year

Prices used at December 31, 2014 are as follows:

	2015	2016	2017	2018	2019	Thereafter
Brent (\$US/bbl)	67.50	82.50	87.50	90.00	95.00	2% increase per year

Discount Rate

The Company assumed a discount rate in order to calculate the present value of its projected cash flows. The discount rate represented a weighted average cost of capital ("WACC") for comparable companies operating in similar industries, based on publicly available information. The WACC is an estimate of the overall required rate of return on an investment for both debt and equity owners and serves as the basis for developing an appropriate discount rate. Its determination requires separate analysis of the cost of equity and debt, and considers a risk premium based on an assessment of risks related to the projected cash flows of the group of Colombia based CGUs whose revenues are denominated in USD. The after tax discount rate used in performing the impairment test was 11 percent.

The fair value of the group of Colombian CGUs was in excess of its carrying value. Based on sensitivity analysis, no reasonably possible change in discount rate assumptions would cause the carrying amount of the group of Colombia CGUs to exceed its recoverable amount.

12. Long-Term Debt

	December 31, 2015	December 31, 2014
Long-term debt (syndicate credit facility)	\$ -	\$ 35,000

On May 23, 2012, Parex entered into a \$200 million senior secured credit facility (“credit facility”) with a syndicate of banks led by a major Canadian bank. At December 31, 2015, the credit facility consists of a reserve-based revolving facility of \$200 million including an operating line of \$20 million. The revolving facility is a rolling facility maturing on May 22, 2017, and may be extended for an additional 365 days after attaining syndicate approval. The credit facility is subject to re-determination of the borrowing base semi-annually on November 30 and May 31 of each year. The borrowing base is determined based on, among other things, the Company’s current reserve report, results of operations, the lenders’ view of the current and forecasted commodity prices and the current economic environment. In the event that the syndicate reduces the borrowing base below the amount drawn at the time of the redetermination, the Company has 180 days to eliminate any shortfall by providing additional security or guarantees satisfactory to the lenders or repaying amounts in excess of the new re-determined borrowing base. US base rate and LIBOR base rate loan advances under the revolving facility bear interest at rates ranging from US base rate or LIBOR plus 2.50% - 3.50% per annum, dependent on utilization. Canadian prime rate loan advances, drawn on the operating line only, bear interest at rates ranging from Canadian prime plus 1.50% - 2.50% per annum, dependent on utilization. Undrawn amounts under the revolving facility bear a commitment fee ranging from 0.5% to 0.7% per annum, dependent on utilization.

Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties. Key covenants include a rolling four quarter total funded debt to EBITDA test of 3:50: 1, and other standard business operating covenants. The authorized borrowing amount is subject to an interim review as discussed above. As at December 31, 2015, the Company is in compliance with all covenants as there is \$nil balance drawn on the facility. Security is provided for by a first fixed and floating charge debenture over all assets of Parex Resources Inc., a pledge of the shares of material subsidiaries and general assignment of book debts.

13. Net Finance Expense (Income)

For the year ended December 31,	2015	2014
Interest expense and bank charges	\$ 3,661	\$ 7,042
Accretion on decommissioning and environmental liabilities	1,588	1,127
Realized loss on foreign currency risk management contracts	1,840	2,672
Unrealized (gain) loss on foreign currency risk management contracts	(1,481)	1,975
Loss on disposition of tangible assets	64	731
Interest and other income	(579)	(1,332)
Colombian net wealth tax	3,855	-
Loss on derivative financial liability	-	23,707
Gain on settlement of convertible debentures	-	(557)
Amortization of debt issuance costs	-	475
Accretion on convertible debentures	-	3,210
Net finance expense	\$ 8,948	\$ 39,050
Finance expenses reclassified to discontinued operations	-	(743)
Net finance expense - continuing operations	\$ 8,948	\$ 38,307
For the year ended December 31,	2015	2014
Non-cash finance expense	\$ 171	\$ 30,668
Cash finance expense	8,777	8,382
Net finance expense	\$ 8,948	\$ 39,050

Convertible Debentures

On August 12, 2014 the Company issued a notice of redemption to holders of its then outstanding Cdn\$85.0 million Convertible Debentures (the “Debentures”), with the redemption date set as September 24, 2014. The Debentures had a face value of \$1,000 per debenture, and were convertible into common shares at the option of the holder at a conversion price of Cdn\$10.15 per share representing a conversion rate of approximately 98.52 common shares per Debenture. Parex had the right to redeem the Debenture at par anytime after July 1, 2014 if the volume weighted average price of a common share of the Company was in excess of 125% of the conversion price. During August and September 2014, the Cdn\$85.0 million principal amount of Debentures was converted by the Debenture holders for an aggregate of 8,339,991 common shares of the Company and Debentures not converted were redeemed for \$0.3 million in cash. The annual coupon on the debentures was 5.25 percent paid semi-annually in arrears on June 30 and December 31 of each year. The holders

of the debentures received accrued and unpaid interest for the period from July 1, 2014 to the date of conversion. A gain of \$0.6 million on the settlement of the Debentures and the related derivative financial liability was recognized in the consolidated statement of comprehensive income (loss) during the year ended December 31, 2014.

Prior to the settlement of the Debenture, the derivative financial liability was measured at fair value using the Black-Scholes valuation model, with the change to the fair value being recorded in finance expense as a loss (gain) on the derivative financial liability. For the year ended December 31, 2014, the loss on the derivative liability was \$23.7 million.

Colombian Equity Tax

On December 23, 2014 the Colombian government passed a law imposing a Net Wealth Tax (“NWT”) levied on Colombian companies. The tax is assessed and becomes payable on the opening equity as at January 1st of each year beginning in 2015 extending until 2017, at rates from 1.15% in 2015 to 0.4% in 2017. The Company’s NWT for 2015 was \$3.9 million and was paid in two equal semi-annual installments in 2015. The Company’s NWT for 2016 is expected to be \$2.5 million and will be paid in two equal semi-annual installments in 2016.

14. Other Long-Term Liabilities

Other long-term liabilities are comprised of the following:

	December 31, 2015	December 31, 2014
Long-term SARs payable	\$ 1,969	\$ 639

15. Decommissioning and Environmental Liabilities

	Decommissioning		Environmental		Total
Balance, December 31, 2013	\$	13,793	\$	7,295	\$ 21,088
Additions		9,479		3,201	12,680
Corporate acquisitions		1,300		946	2,246
Settlements of obligations during the year		(1,369)		(425)	(1,794)
Loss on settlements of obligations during the year		134		-	134
Accretion expense		864		263	1,127
Additions related to change in estimate		-		657	657
Foreign exchange (gain)		-		(1,660)	(1,660)
Decommissioning liabilities reclassified to liabilities held for sale		(389)		-	(389)
Balance, December 31, 2014	\$	23,812	\$	10,277	\$ 34,089
Additions		2,724		725	3,449
Settlements of obligations during the year		(193)		(246)	(439)
Accretion expense		1,162		426	1,588
Additions related to change in estimate		(694)		(140)	(834)
Foreign exchange (gain)		-		(2,454)	(2,454)
Balance, December 31, 2015	\$	26,811	\$	8,588	\$ 35,399
Current obligation		-		(2,102)	(2,102)
Long-term obligation	\$	26,811	\$	6,486	\$ 33,297

The total environmental, decommissioning and restoration obligations were determined by management based on the estimated costs to settle environmental impact obligations incurred and to reclaim and abandon the wells and well sites based on contractual requirements. The obligations are expected to be funded from the Company’s internal resources available at the time of settlement.

The total decommissioning and environmental liability is estimated based on the Company’s net ownership in wells drilled as at December 31, 2015, the estimated costs to abandon and reclaim the wells and well sites and the estimated timing of the costs to be paid in future periods. The total undiscounted amount of cash flows required to settle the Company’s decommissioning liability is approximately \$36.7 million as at December 31, 2015 (December 31, 2014 – \$37.0 million) with the majority of these costs anticipated to occur in 2020 or later. A weighted average risk-free discount rate of 5.25 percent and an inflation rate of 2.5 percent were used in the valuation of the liabilities (December 31, 2014 – 5 percent weighted average risk-free discount rate and a 2 percent inflation rate). The discount rates used are a blend of US and Colombia risk-free rates.

The total undiscounted amount of cash flows required to settle the Company’s environmental liability is approximately \$15.1 million as at December 31, 2015 (December 31, 2014 – \$14.0 million) with the majority of these costs anticipated to occur in 2016 or later in Colombia. A risk-free discount rate of 8 percent and an inflation rate of 4 percent were used in the valuation of the liabilities (December 31, 2014 – 7 percent risk-free discount rate and a 3 percent inflation rate). The discount rate used is based on a Colombia risk-free rate.

Included in the environmental liability is \$2.1 million (December 31, 2014 – \$2.1 million) that is classified as a current obligation.

16. Share Capital

a. Issued and outstanding common shares

	Number of shares		Amount
Balance, December 31, 2013	108,711,649	\$	414,176
Issued for cash – exercise of options and RSUs	2,949,574		9,373
Issued in Verano Acquisition	14,688,724		169,333
Issued on conversion of convertible debentures	8,339,991		97,331
Share issue costs	-		(180)
Allocation of contributed surplus – exercise of options and RSUs	-		4,077
Balance, December 31, 2014	134,689,938	\$	694,110
Issued for cash – exercise of options and RSUs	1,849,364		6,263
Issued through bought deal financing	14,950,000		113,620
Share issue costs	-		(4,997)
Allocation of contributed surplus – exercise of options and RSUs	-		3,741
Balance, December 31, 2015	151,489,302	\$	812,737

The Company has authorized an unlimited number of voting common shares without nominal or par value.

On May 5, 2015, the Company completed a bought deal financing for gross proceeds of \$113.6 million (Cdn\$136.8 million) resulting in net proceeds of \$108.6 million (Cdn\$131.3 million) after share issue costs and issued 14.95 million common shares at a price of Cdn\$9.15 per common share, which included 1.95 million common shares issued in connection with the full exercise of the underwriter's over allotment option.

In 2015, a total of 1,849,364 options were exercised for proceeds of \$6.3 million (year ended December 31, 2014 - 2,949,574 options were exercised for \$9.4 million).

On August 12, 2014 the Company issued a notice of redemption to holders of its then outstanding Cdn\$85.0 million Convertible Debentures (the "Debentures"), with the redemption date set as September 24, 2014. During August and September 2014, the Cdn\$85.0 million principal amount of Debentures was converted for an aggregate of 8,339,991 common shares of the Company and Debentures not converted were redeemed for \$0.3 million in cash.

b. Stock options

The Company has a stock option plan which provides for the issuance of options to the Company's directors, officers, and certain employees to acquire common shares. The maximum number of options reserved for issuance under the option plan may not exceed 10 percent of the number of common shares issued and outstanding. The options vest over a three-year period and expire five years from the date of grant.

	Number of options	Weighted average exercise price Cdn\$/option
Balance, December 31, 2014	7,577,010	6.78
Granted	1,991,500	10.77
Exercised	(1,564,331)	5.24
Forfeited	(149,668)	6.01
Balance, December 31, 2015	7,854,511	8.11

Stock options outstanding and the weighted average remaining life of the stock options at December 31, 2015 are as follows:

Exercise price Cdn\$	Options outstanding			Options vested		
	Number of options	Weighted average remaining life (years)	Weighted average exercise price Cdn\$/option	Number of options	Weighted average remaining life (years)	Weighted average exercise price Cdn\$/option
\$4.36 - \$6.06	708,127	1.85	4.63	626,707	1.77	4.56
\$6.07 - \$6.22	3,277,508	2.79	6.07	2,018,916	2.79	6.07
\$6.23 - \$10.59	1,863,001	3.83	9.93	585,071	3.83	10.11
\$10.60 - \$11.25	1,916,500	4.86	10.94	-	-	-
\$11.26 - \$13.93	89,375	3.63	11.86	29,791	3.63	11.86
	7,854,511	3.47	8.11	3,260,485	2.49	6.56

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions:

For the year ended December 31,	2015	2014
Risk-free interest rate (%)	0.77	1.23
Expected life (years)	4	4
Expected volatility (%)	47	46
Forfeiture rate (%)	3	3
Expected dividends	-	-

The weighted average fair value at the grant date for the year ended December 31, 2015 was Cdn\$4.04 per option (year ended December 31, 2014 – Cdn\$3.75 per option). The weighted average share price on the exercise date for options exercised in 2015 was Cdn\$10.19 (year ended December 31, 2014 – Cdn\$10.44).

c. Share appreciation rights

Parex Colombia has a SARs plan that provides for the issuance of SARs to certain employees of Parex Colombia. The plan entitles the holders to receive a cash payment equal to the excess of the market price of the Company's common shares at the time of exercise over the grant price. At any time, if the current market price of the Company's common shares exceeds four times the grant price, Parex Colombia has the option to require the holders to exercise all vested SARs. SARs typically vest over a three-year period and expire five years from the date of grant. The SARs liability cannot be settled by the issuance of common shares.

	Number of SARs	Weighted average exercise price Cdn\$/SAR
Balance, December 31, 2014	2,606,643	7.12
Granted	1,702,548	10.40
Exercised	(703,730)	5.60
Forfeited	(130,460)	7.78
Balance, December 31, 2015	3,475,001	9.01

As at December 31, 2015 893,702 SARs were vested (year ended December 31, 2014 – 730,945).

Obligations for payments of cash under the SARs plan are accrued as compensation expense over the vesting period based on the fair value of SARs, subject to appreciation limits specified in the plan. The fair value of SARs is measured using the Black-Scholes pricing model at each reporting date based on weighted average pricing assumptions noted below:

For the year ended December 31,	2015	2014
Risk-free interest rate (%)	0.55	1.11
Expected life (years)	4	4
Expected volatility (%)	47	47
Share price	10.16	7.58
Expected dividends	-	-

As at December 31, 2015, the total SARs liability accrued is \$5.8 million (December 31, 2014 - \$4.4 million) of which \$2.0 million (December 31, 2014 - \$0.6 million) is classified as long-term in accordance with the three year vesting period and \$nil (December 31, 2014 - \$0.1 mil) is classified as liabilities held for sale, refer to note 10. For the year ended December 31, 2015, Parex recorded \$3.8 million of compensation costs related to the outstanding SARs (year ended December 31, 2014 – \$4.0 million) of which \$nil (year ended December 31, 2014 – \$0.2 million) is included in loss in discontinued operations. The intrinsic value of vested SARs at December 31, 2014 was \$2.9 million (December 31, 2014 – \$1.4 million).

d. Restricted share units

The Company has in place a restricted share unit plan pursuant to which the Company may grant restricted shares to directors and certain employees. The restricted shares vest at 33 percent on each of the first, second and third anniversaries of the grant date and expire five years from date of grant.

	Number of RSU's	Weighted average exercise price Cdn\$/RSU
Balance, December 31, 2014	1,625,885	0.01
Granted	988,250	0.01
Exercised	(285,033)	0.01
Forfeited	(22,137)	0.01
Balance, December 31, 2015	2,306,965	0.01

The fair value of each RSU granted is based on the market price of Parex shares on the date of issuance. The weighted average fair value at the grant date for the year ended December 31, 2015 was Cdn\$10.80 per RSU (year ended December 31, 2014 – Cdn\$10.16 per RSU). For the year ended December 31, 2015 a weighted average forfeiture rate of 3% was applied (December 31, 2014 – 3%).

e. *Deferred share units*

The Company has in place a deferred share unit plan pursuant to which the Company may grant deferred shares to certain non-employee directors. The deferred shares vest immediately, are equivalent in value to a common share of the Company based on the market value on the date of issuance, and are settled in either common shares or cash at the discretion of the Company. DSUs can only be redeemed following departure from the Company in accordance with the terms of the DSU Plan.

	Number of DSU's	Weighted average exercise price Cdn\$/DSU
Balance, December 31, 2014	-	-
Granted	78,600	0.01
Balance, December 31, 2015	78,600	0.01

The fair value of each DSU granted is based on the market price of Parex shares on the date of issuance. The weighted average fair value at the grant date for the year ended December 31, 2015 was Cdn\$10.88 per DSU.

f. *Share-based compensation and SARs expense*

For the year ended December 31,	2015	2014
Share-based compensation expense	\$ 11,023	\$ 8,491
SARs expense	3,806	4,005
Total	\$ 14,829	\$ 12,496
SARs (expense) recovery reclassified as discontinued operations	22	(171)
Total – continuing operations	\$ 14,851	\$ 12,325

17. Income Tax

The components of tax expense for 2015 and 2014 were as follows:

For the year ended December 31,	2015	2014
Current tax expense	\$ 46,349	\$ 52,184
Adjustments in respect of prior period	1,858	-
Total current tax expense	\$ 48,207	\$ 52,184
Deferred tax expense (recovery)	(54,105)	(19,539)
Total tax expense (recovery)	\$ (5,898)	\$ 32,645

Factors affecting tax expense for the year

The standard Colombian corporate income tax rate for 2015 was 39 percent (year ended December 31, 2014 – 34 percent). The following is a reconciliation of income taxes calculated at the Colombian corporate tax rate to the tax expense for 2015 and 2014:

For the year ended December 31,	2015	2014
(Loss) before tax from continuing operations	\$ (49,738)	\$ (53,938)
(Loss) before tax multiplied by the standard rate of Colombian corporate tax of 39% (2014 – 34%)	(19,397)	(18,337)
Effects of:		
Income taxes recorded at rates different from the Colombian tax rate	17,028	5,722
Impact of Colombian rate changes	-	13,257
Impact of deferred tax rate changes	(29,386)	-
Income and Expenses taxable/deductible at different rates	(29,481)	-
Expenses not deductible for tax purposes	(15,557)	8,186
Share-based compensation	2,976	2,123
Deferred tax assets not recognized	9,150	(9,838)
Adjustment in respect of prior period	(2,286)	3,625
Foreign exchange impact on tax pools denominated in foreign currency	61,055	27,907
Total tax expense (recovery)	\$ (5,898)	\$ 32,645

The Colombian government enacted legislation in December 2014 containing tax rate changes effective January 1, 2015. Colombian current tax rates are as follows: 39% for 2015; 40% for 2016; 42% for 2017; and 43% for 2018. Under current legislation, the consolidated rate is set to revert to 34% in 2019 and onwards.

The analysis of deferred income tax liabilities (assets) as follows:

	December 31, 2015	December 31, 2014
Deferred tax (assets) to be settled within 12 months	\$ (1,384)	\$ (1,157)
Deferred tax liabilities to be settled after more than 12 months	70,019	123,897
Net deferred income tax liability	\$ 68,635	\$ 122,740

For the purposes of the above table, deferred income tax liabilities are shown net of offsetting deferred income tax assets where these occur in the same entity and jurisdiction. The deferred income tax liabilities and assets to be settled (recovered) within 12 months represents management's estimate of the timing of the reversal of temporary differences and does not correlate to the current income tax expense of the subsequent year.

The movement during the year in the deferred income tax (liabilities) assets and the net components is as follows:

Deferred Tax (Liability) Asset	December 31, 2015	(Charged) credited to the statement of comprehensive income (loss)	December 31, 2014	(Charged) credited to the statement of comprehensive income (loss)
PP&E	\$ (112,326)	30,942	(143,268)	(5,446)
Loss carry forwards	27,616	22,069	5,547	6,187
Decommissioning liability	12,233	3,141	9,092	(2,234)
SARs	1,986	316	1,670	638
Other	1,856	(2,363)	4,219	(2,139)
Balance, end of period	\$ (68,635)	54,105	(122,740)	(2,994)

The Company has losses available to reduce future taxable income, as well as other cumulative tax deductions in excess of book value in Canada, the recoverability of which is uncertain and therefore has not been recognized in the financial statements. The losses available in Colombia have been recognized in the financial statements. The Company did not recognize deferred income tax asset on the total gross temporary differences (including non-capital losses) in Canada of \$178.2 million. Losses can be carried forward indefinitely in Colombia, while in Canada they expire in 20 years. Amounts denominated in foreign currency have been translated at the December 31, 2015 exchange rate. At December 31, 2015 the Company had the following non-capital losses:

	Canada	Colombia
Expiry		
2030	5,246	-
2031	8,351	-
2032	27,271	-
2033	19,319	-
2034	2,365	-
2035	852	-
Indefinitely	-	75,284
Total	\$ 63,404	75,284

Earnings retained by subsidiaries amounted to \$108.9 million at December 31, 2015 (December 31, 2014 - \$218.5 million). No provision has been made for withholding and other taxes that would become payable on the distribution of these earnings as it is not expected that they will be remitted in the foreseeable future.

18. Net (loss) per Share

a) Basic net (loss) per share

For the year ended December 31,	2015	2014
Net (loss)		
Net (loss) for the purpose of basic net (loss) per share – continuing operations	\$ (43,840)	\$ (86,583)
Net (loss) for the purpose of basic net (loss) per share – discontinued operations	(781)	(22,190)
Net (loss) for the year	(44,621)	(108,773)
Weighted average number of shares for the purposes of basic net (loss) per share (000's)	145,018	120,379
Basic net (loss) per share – continuing operations	\$ (0.30)	\$ (0.72)
Basic net (loss) per share – discontinued operations	(0.01)	(0.18)
Basic net (loss) per share	\$ (0.31)	\$ (0.90)

b) Diluted net (loss) per share

For the year ended December 31,	2015	2014
Net (loss) – continuing operations		
Net (loss) used to calculate diluted net (loss) per share – continuing operations	\$ (43,840)	\$ (86,583)
Weighted average number of shares for the purposes of diluted net (loss) per share (000's)	145,018	120,379
Diluted net (loss) per share – continuing operations	\$ (0.30)	\$ (0.72)
Net (loss) – discontinued operations		
Net (loss) used to calculate diluted net (loss) per share – discontinued operations	\$ (781)	\$ (22,190)
Weighted average number of shares for the purposes of diluted net (loss) per share (000's)	145,018	120,379
Diluted net (loss) per share – discontinued operations	\$ (0.01)	\$ (0.18)

At December 31, 2015 3,685,542 (December 31, 2014 - 1,801,875) share options had an exercise price in excess of the average market value of the shares from the option grant date to the end of the period. The Company has reported a net loss for the years ended December 31, 2015 and 2014 and therefore stock options and the effect of Debentures that are otherwise dilutive are anti dilutive and therefore excluded from the diluted earnings per share.

19. Supplemental Disclosure of Cash Flow Information

a) Net change in non-cash working capital

For the year ended December 31,	2015	2014
Accounts receivable	\$ 45,407	\$ (3,293)
Prepays and other current assets	163	(3,679)
Crude oil inventory	7,752	(2,264)
Accounts payable and accrued liabilities	(75,296)	17,972
Depletion related to crude oil inventory	(3,866)	954
Net non-cash working capital on assets held for sale - note 10	-	(3,310)
Net non-cash working capital on corporate acquisitions - note 9	-	(26,129)
Net change in non-cash working capital	\$ (25,840)	\$ (19,749)
Operating	\$ 30,881	\$ (43,025)
Investing	(56,721)	23,276
Financing	-	-
Net change in non-cash working capital	\$ (25,840)	\$ (19,749)

b) Interest and taxes paid

For the year ended December 31,	2015	2014
Cash interest paid	\$ 808	\$ 4,340
Cash income and equity taxes paid	\$ 24,755	\$ 47,298

20. Employee Salaries and Benefit Expenses

For the year ended December 31,	2015		2014	
Salaries, bonuses and other short term benefits	\$	28,058	\$	31,349
Share-based compensation expense		11,023		8,491
SARs expense		3,806		4,005
	\$	42,887	\$	43,845

Employee salaries, bonuses and short-term benefits are included in general and administrative expenses in the consolidated statement of comprehensive income (loss). Stock-based compensation, SARs, RSUs and DSUs expense is included in share-based compensation expense in the consolidated statement of comprehensive income (loss).

21. Capital Management

The Company's strategy is to maintain a strong capital base in order to provide flexibility in the future development of the business and maintain the confidence of investors and capital markets.

The Company manages its capital to achieve the following:

- Maintain balance sheet strength in order to meet the Company's strategic growth objectives; and
- Ensure financial capacity is available to fund the Company's exploration commitments.

Parex has a senior secured credit facility (see note 12- Long-Term Debt) which as at December 31, 2015 had a borrowing base in the amount of \$200.0 million. The credit facility is intended to serve as means to increase liquidity and fund cash needs as they arise. As at December 31, 2015 \$nil (December 31, 2014 - \$35.0 million) was drawn on the credit facility.

The Company has also provided a general security agreement to Export Development Canada ("EDC") in connection with the performance security guarantees that support letters of credit provided to the Colombian National Hydrocarbon Agency ("ANH") and Empresa Colombiana de Petroleos S.A. ("Ecopetrol") related to the exploration work commitments on its Colombian concessions (see note 24 - Commitments). This performance guarantee facility has a limit of \$200.0 million (December 31, 2014 – limit of \$125.0 million) of which \$123.7 million (December 31, 2014 - \$73.4 million) is utilized at December 31, 2015.

As at December 31, 2015, the Company's net working capital surplus is \$76.7 million (December 31, 2014 – \$3.3 million), of which \$94.8 million is cash.

Parex has the ability to adjust its capital structure by issuing new equity or debt and making adjustments to its capital expenditure program to the extent the capital expenditures are not committed. The Company considers its capital structure at this time to include shareholders' equity and the credit facility. As at December 31, 2015, shareholders' equity was \$741.9 million (December 31, 2014 - \$660.6 million).

22. Financial Instruments and Risk Management

The Company's non-derivative financial instruments recognized on the consolidated balance sheet consist of cash, accounts receivable, accounts payable and accrued liabilities, and long-term debt. Non-derivative financial instruments are recognized initially at fair value. The fair values of the current financial instruments approximate their carrying value due to their short-term maturity. The fair value of the revolving credit facility is equal to its carrying amount as the facility bears interest at floating rates and the credit spreads within the facility are indicative of market rates.

Long-term financial instruments of the Company carried on the consolidated balance sheet are carried at amortized cost with the exception of financial derivative instruments, specifically fixed price contracts and foreign currency risk management contracts, which are carried at fair value. There are no significant differences between the carrying amount of derivative financial instruments and their estimated fair values as at December 31, 2015.

The fair value of the Company's financial derivative instruments are quoted in active markets. The Company classifies the fair value of these transactions according to the following hierarchy.

Level 1 – quoted prices in active markets for identical financial instruments.

Level 2 – quoted prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model-derived valuations in which all significant inputs and significant value drivers are observable in active markets.

Level 3 – valuations derived from valuation techniques in which one or more significant inputs or significant value drivers are unobservable.

The Company's financial derivative instruments have been classified as level 2 based on the fair value hierarchy described above. The Company used the following techniques to determine the fair value measurements:

Crude oil contracts are recorded at their estimated fair value based on the difference between the contracted price and the period end forward price for the same commodity, using quoted market prices or the period end forward price for the same commodity extrapolated to the end of the contract term.

The fair value of foreign currency risk management contracts is determined using forward exchange rates at each measurement date.

Prior to the extinguishment of the Cross Currency Interest Rate Swap ("CCIRS") during the year ended December 31, 2014, the fair value was determined using the forward exchange rates at each measurement date.

Prior to its redemption in the year ended December 31, 2014, the convertible debenture had two components of value – a conventional bond and a call on the equity of the Company through conversion. The conversion option was an embedded derivative and had been separated from the host contract and classified as a financial liability through profit and loss.

a) Credit risk

Credit risk is the risk of loss associated with the inability of a third party to fulfill its payment obligations. The Company is exposed to the risk that third parties that owe it money do not meet their obligations. The Company assesses the financial strength of its joint venture partners and oil marketing counterparties in its management of credit exposure.

The Company for the year ended December 31, 2015 had the majority of its oil sales to 10 counterparties. Accounts receivable balance as at December 31, 2015 are substantially made up of receivables with customers in the oil and gas industry and are subject to normal industry credit risks. The Company historically has not experienced any collection issues with its crude oil customers. At December 31, 2015 there are \$1.1 million of accounts receivable past due, all of which are considered collectible (December 31, 2014 - \$0.5 million).

As at December 31, 2015 and 2014 the Company's accounts receivable are aged as follows:

For the year ended December 31,	2015		2014	
Current (less than 90 days)	\$	78,710	\$	124,720
Past due (more than 90 days)		1,145		542
Total	\$	79,855	\$	125,262

None of the Company's receivables are impaired at December 31, 2015. The maximum credit risk exposure associated with accounts receivable is the total carrying value.

b) Liquidity risk

The Company's approach to managing liquidity risk is to have sufficient cash and/or credit facilities to meet its obligations when due. Management typically forecasts cash flows for a period of 12 to 36 months to identify any financing requirements. Liquidity is managed through daily and longer-term cash, debt and equity management strategies. These include estimating future cash generated from operations based on reasonable production and pricing assumptions, estimating future discretionary and non-discretionary capital expenditures and assessing the amount of equity or debt financing available. The Company is committed to maintaining a strong balance sheet and has the ability to change its capital program based on expected operating cash flows. The balance drawn on the Company's \$200 million credit facility at December 31, 2015 was \$nil.

The following are the contractual maturities of financial liabilities at December 31, 2015:

	Less than 1 year	2-3 Years	4-5 Years	Thereafter	Total
Accounts payable and accrued liabilities	\$ 63,224	-	-	-	\$ 63,224
SARs payable	3,856	1,969	-	-	5,825
Total	\$ 67,080	1,969	-	-	\$ 69,049

The following are the contractual maturities of financial liabilities at December 31, 2014:

	Less than 1 year	2-3 Years	4-5 Years	Thereafter	Total
Accounts payable and accrued liabilities	\$ 133,826	-	-	-	\$ 133,826
SARs payable	3,611	639	-	-	4,250
Current income and equity tax payable ⁽¹⁾	7,156	-	-	-	7,156
Credit Facility including interest ⁽²⁾	1,050	36,050	-	-	37,100
Total	\$ 145,643	36,689	-	-	\$ 182,332

⁽¹⁾ Net of withholding tax receivable in the amount of \$35.6 million.

⁽²⁾ Balances denominated in Canadian dollars have been translated at the December 31, 2014 exchange rate.

c) Commodity price risk

The Company is exposed to commodity price movements as part of its operations, particularly in relation to the prices received for its oil production. Crude oil is sensitive to numerous worldwide factors, many of which are beyond the Company's control. Changes in global supply and demand fundamentals in the crude oil market and geopolitical events can significantly affect crude oil prices. Consequently, these changes could also affect the value of the Company's properties, the level of spending for exploration and development and the ability to meet obligations as they come due. The Company's oil production is sold under short-term contracts, exposing it to the risk of near-term price movements.

As at December 31, 2015 the Company had outstanding risk management contracts which are used to manage its exposure to fluctuations in the price of crude oil.

The following is a summary of the ICE Brent priced crude oil risk management contracts in place for the year ended December 31, 2015:

Period Hedged	Reference	Type	Volume bbls/d	Price/bbl
March 1, 2015 to March 31, 2015	ICE Brent	Collar	5,000	\$55.00-\$66.60
March 1, 2015 to March 31, 2015	ICE Brent	Collar	3,000	\$55.00-\$68.00
April 1, 2015 to April 30, 2015	ICE Brent	Collar	5,000	\$55.00-\$68.25
April 1, 2015 to April 30, 2015	ICE Brent	Collar	3,000	\$55.00-\$69.75
April 1, 2015 to April 30, 2015	ICE Brent	Collar	2,000	\$55.00-\$67.00
May 1, 2015 to May 31, 2015	ICE Brent	Collar	5,000	\$55.00-\$68.75
May 1, 2015 to July 31, 2015	ICE Brent	Collar	5,000	\$55.00-\$65.00
June 1, 2015 to July 31, 2015	ICE Brent	Collar	2,000	\$57.50-\$69.00
August 1, 2015 to August 31, 2015	ICE Brent	Collar	3,000	\$55.00-\$76.80
August 1, 2015 to November 30, 2015	ICE Brent	Put	2,000	\$55.00
November 1, 2015 to November 30, 2015	ICE Brent	Collar	16,667	\$50.00-\$57.40

Period Hedged	Reference	Volume bbls/d	Sold Put	Purchased Put	Sold Call	Premium
January 1, 2016 to June 30, 2016	ICE Brent	5,000	\$47.75	\$52.50	\$70.00	\$1.00

The fair value of the ICE Brent priced crude oil risk management contracts of \$2.6 million receivable (December 31, 2014 – liability of \$1.9 million) is recorded in the financial statement line item “Derivative financial instruments” in the consolidated balance sheet.

The table below summarizes (gain) loss on the commodity risk management contracts that were in place during the year ended December 31, 2015 and 2014:

For the year ended December 31,	2015	2014
Realized (gain) on commodity risk management contracts	\$ (4,390)	\$ (8,054)
Unrealized (gain) on commodity risk management contracts	(2,915)	-
Total	\$ (7,305)	\$ (8,054)

As shown in the table above, as at December 31, 2015, Parex had committed to the future sale of 930,000 barrels of oil with a 3-way collar from Brent oil prices of \$47.75 to \$70.00 per bbl. The following sensitivity shows the resulting unrealized loss (gain) and impact on (loss) income before tax for the oil hedged contracts if Brent oil price were to increase/decrease by \$10/bbl from the spot rate as at December 31, 2015:

	Brent Price	Impact for the year ended December 31, 2015	
		Increase of \$10/bbl	Decrease of \$10/bbl
Oil hedged contract loss (gain)	Period end	\$ 1,568	\$ (371)

Subsequent to December 31, 2015, Parex entered into the following ICE Brent priced crude oil risk management contracts:

Period Hedged	Reference	Volume bbls/d	Sold Put	Purchased Put	Sold Call	Premium
February 1, 2016 to June 30, 2016	ICE Brent	15,000	\$25.00	\$35.00	\$45.00	\$2.08
July 1, 2016 to September 30, 2016	ICE Brent	5,000	\$30.50	\$38.00	\$47.00	\$1.00
July 1, 2016 to September 30, 2016	ICE Brent	5,000	\$34.25	\$40.25	\$49.50	\$1.00

d) Foreign currency risk

The Company is exposed to foreign currency risk as various portions of its cash balances are held in Canadian dollars (Cdn\$) and Colombian pesos (COP\$) while its committed capital expenditures are expected to be primarily denominated in US dollars.

The following is a summary of the foreign currency risk management contracts settled during the year ended December 31, 2015:

Period Hedged	Reference	Type	Amount USD	Price (COP)
September 5, 2014 to April 30, 2015	Colombian Peso	Collar	\$15 million	1,850 – 2,100

The following is a summary of the foreign currency risk management contracts in place as at December 31, 2015:

Period Hedged	Reference	Type	Amount USD	Price (COP)
September 2, 2015 to April 14, 2016	Colombian Peso	Collar	\$8 million	3,000 – 3,228
September 2, 2015 to June 14, 2016	Colombian Peso	Collar	\$8 million	3,000 – 3,228

Associated with the Cdn\$85.0 million of Debentures, on December 30, 2012 the Company entered into a Cross Currency Interest Rate Swap (“CCIRS”) with two financial institutions who are members of the Company’s credit facility. Under the terms of the CCIRS, the US dollar amount of the Debenture was fixed for purposes of interest and principal repayment at a notional amount of \$85.7 million as follows:

	Type	Receive Notional Principal (Cdn\$)	Fixed annual rate (Cdn%)	Pay Notional Principal (US\$)	Fixed annual rate (US%)
December 30, 2012 – June 30, 2016	Swap	85,000,000	5.25%	85,685,565	4.45%

In association with the settlement of the Debenture during the year ended December 31, 2014, the CCIRS was also terminated during the prior year.

The table below summarizes the (gain) loss on the foreign currency risk management contracts:

For the year ended December 31,	2015	2014
Realized loss on foreign currency risk management contracts	\$ 1,840	\$ 2,672
Unrealized (gain) loss on foreign currency risk management contracts	(1,481)	1,975
Total	\$ 359	\$ 4,647

The Company recorded a \$0.4 million loss on these contracts in the year ended December 31, 2015 (year ended December 31, 2014 - \$4.6 million loss) which is recorded in the financial statement line item “Finance expense” in the consolidated statements of comprehensive income (loss). Refer to note 13.

The following sensitivity show the resulting unrealized loss (gain) and impact on (loss) income before tax for the foreign exchange risk management contracts for the respective changes in the period end foreign exchange rates at December 31, 2015:

Exchange Rate USD/COP	Impact for the year ended December 31, 2015	
	Increase of 10%	Decrease of 10%
Total	\$ 1,097	\$ (1,311)

e) Interest rate risk

The Company is exposed to interest rate risk in relation to interest expense on its credit facility. Currently the Company has not entered into any agreements to manage this risk. The following sensitivity shows the resulting loss (gain) on (loss) income before tax if the interest rate increased /decreased by 1% for the year ended December 31, 2015:

Interest rate	Impact for the year ended December 31, 2015	
	Increase of 1%	Decrease of 1%
Total	\$ 270	\$ (270)

23. Segmented Information

The Company has foreign subsidiaries and the following segmented information is provided:

For the year ended December 31, 2015

	Canada		Colombia		Trinidad &		Total
	\$	\$	\$	\$	\$	\$	\$
Oil sales	-	-	521,089	-	-	-	521,089
Royalties	-	-	(38,373)	-	-	-	(38,373)
Revenue	-	-	482,716	-	-	-	482,716
Commodity risk management contracts	-	-	7,305	-	-	-	7,305
Expenses	-	-	490,021	-	-	-	490,021
Production	-	-	73,499	-	-	-	73,499
Transportation	-	-	154,777	-	-	-	154,777
Purchased oil	-	-	34,630	-	-	-	34,630
General and administrative	15,319	-	21,430	-	-	-	36,749
Share-based compensation	11,023	-	3,828	-	-	-	14,851
Depletion, depreciation and amortization	248	-	152,151	-	-	-	152,399
Loss on settlement of decommissioning liabilities	-	-	741	-	-	-	741
Foreign exchange loss	781	-	4,215	-	-	-	4,996
Impairment of property, plant and equipment	-	-	31,144	-	-	-	31,144
Impairment of exploration and evaluation assets	-	-	27,025	-	-	-	27,025
Finance (income)	-	27,371	-	503,440	-	-	530,811
Finance expense	(620)	-	41	-	-	-	(579)
Net finance expense	4,182	3,562	5,345	-	-	-	9,527
Net (loss) before taxes	-	(30,933)	-	(18,805)	-	-	(49,738)
Current tax expense	-	-	-	48,207	-	-	48,207
Deferred tax (recovery)	-	-	-	(54,105)	-	-	(54,105)
Net (loss) from continuing operations	\$	(30,933)	\$	(12,907)	\$	-	\$ (43,840)
Net (loss) from discontinued operations	-	-	-	-	(781)	-	(781)
Net (loss)	\$	(30,933)	\$	(12,907)	\$	(781)	\$ (44,621)
Capital assets (end of year)	\$	545	\$	695,122	\$	-	\$ 695,667
Capital expenditures	\$	214	\$	125,268	\$	-	\$ 125,482
Total assets (end of year)	\$	75,914	\$	882,052	\$	-	\$ 957,966

For the year ended December 31, 2014

	Canada		Colombia		Trinidad &		Total
	\$	\$	\$	\$	\$	\$	\$
Oil sales	-	-	752,022	-	-	-	752,022
Royalties	-	-	(90,888)	-	-	-	(90,888)
Revenue	-	-	661,134	-	-	-	661,134
Risk management contracts	877	-	7,177	-	-	-	8,054
Expenses	-	877	668,311	-	-	-	669,188
Production	-	-	90,213	-	-	-	90,213
Transportation	-	-	149,454	-	-	-	149,454
Purchased oil	-	-	33,187	-	-	-	33,187
General and administrative	15,351	-	17,180	-	-	-	32,531
Share-based compensation	8,491	-	3,834	-	-	-	12,325
Depletion, depreciation and amortization	186	-	218,285	-	-	-	218,471
Transaction costs	593	-	-	-	-	-	593
Foreign exchange gain	(3,459)	-	(6,281)	-	-	-	(9,740)
Loss on settlement of decommissioning liabilities	-	-	134	-	-	-	134
Exploration and evaluation impairment	-	-	44,387	-	-	-	44,387
Property, plant and equipment impairment	-	-	113,264	-	-	-	113,264
Finance (income)	-	21,162	-	663,657	-	-	684,819
Finance expense	(20)	34,836	(1,312)	4,803	-	-	(1,332)
Net income (loss) before taxes from continuing operations	34,816	34,816	3,491	-	-	-	38,307
Current tax expense	-	(55,101)	1,163	-	-	-	(53,938)
Deferred tax (recovery)	-	-	52,184	-	-	-	52,184
Net (loss) from continuing operations	\$	(55,101)	\$	(31,482)	\$	-	\$ (86,583)
Net (loss) from discontinued operations	-	-	-	-	(22,190)	-	(22,190)
Net (loss)	\$	(55,101)	\$	(31,482)	\$	(22,190)	\$ (108,773)
Capital assets (end of year)	\$	578	\$	773,672	\$	-	\$ 774,250
Capital expenditures, excluding corporate acquisitions	\$	515	\$	295,644	\$	717	\$ 296,876
Total assets (end of year)	\$	8,097	\$	1,023,385	\$	2,933	\$ 1,034,415

In Colombia in the year 2015 the majority of oil sales were with ten counterparties (year ended December 31, 2014 – fourteen counterparties) in the oil and gas industry and are subject to normal industry credit risks.

24. Commitments

a) Colombia

At December 31, 2015 performance guarantees are in place with the ANH and Ecopetrol for the Capachos and Aguas Blancas farm-in blocks. The guarantees are in the form of issued letters of credit totaling \$150.3 million (December 31, 2014 - \$103.4 million) to support the exploration work commitments in respect of the 23 blocks in Colombia.

At December 31, 2015 EDC has provided the Company's bank with performance security guarantees to support approximately \$123.7 million (December 31, 2014 - \$73.4 million) of the letters of credit issued on behalf of Parex. The EDC guarantees have been secured by a general security agreement issued by Parex in favour of EDC. The letters of credit issued to the ANH and Ecopetrol are reduced from time to time to reflect completed work on an ongoing basis.

The value of the Company's exploration commitments as at December 31, 2015 in respect of the Colombia blocks are estimated to be as follows:

(000s)		
2016	\$	33,263
2017		151,281
Thereafter		67,950
	\$	252,494

b) Operating leases

In the normal course of business, Parex has entered into arrangements and incurred obligations that will impact the Company's future operations and liquidity. These commitments include leases for office space and accommodations.

The existing minimum lease payments for office space and accommodations at December 31, 2015 are as follows:

(000s)	Total	2016	2017	2018	2019	Thereafter
Office and accommodations	\$ 5,338	2,220	1,166	1,012	940	-

25. Related Party Disclosures

a) Significant Subsidiaries

The consolidated financial statements include the financial statements of Parex Resources Inc. at December 31, 2015 and 2014. Transactions between subsidiaries are eliminated upon consolidation.

b) Compensation of Key Management Personnel

Key management personnel compensation, including directors, is as follows:

For the year ended December 31,		2015	2014
Salaries, directors fees and other benefits	\$	3,884	\$ 3,109
Share-based compensation ⁽¹⁾		4,403	3,313
	\$	8,287	\$ 6,422

⁽¹⁾ Non-cash share-based compensation expense for the year.

Key management personnel are comprised of the Company's directors and five executive officers. As at December 31, 2015, there is a \$6.2 million commitment (December 31, 2014 - \$5.8 million) relating to change of control or termination of employment of the key management personnel.

c) Other transactions

During the years ended December 31, 2015 and 2014, the Company rented office space to certain directors of the Company at market rental rates. The Company earned \$26 thousand dollars during the year ended December 31, 2015 (year ended December 31, 2014 - \$2 thousand dollars) in rental income from these related parties. At December 31, 2015, \$4 thousand dollars (December 31, 2014 - \$2 thousand dollars) of this balance was outstanding and has subsequently been collected.

Other than the above noted transaction, the Company did not have any related party transactions with entities outside the consolidated group for the years ended December 31, 2015 and 2014.

26. Contingencies

As previously disclosed in Parex' Annual Information Form for the 2014 fiscal year, the Alberta Statement of Claim relates to a share purchase agreement the Plaintiff entered into with Nabors Global Holdings II Limited (the "Seller") respecting the Plaintiff's proposed purchase of all of the Class A Shares (the "Ramshorn Shares") of Ramshorn International Limited ("Ramshorn") owned by the Seller (which agreement was entered into prior to the agreement Parex Bermuda and the Seller entered into for the purchase of the Ramshorn Shares), which prior agreement the Plaintiff claims the Seller improperly terminated with the unlawful interference and inducement of Parex, Parex Bermuda and RBC. The Plaintiff has agreed to not take any steps against Parex or Parex Bermuda without reasonable prior notice. The Plaintiff is seeking specific performance remedies, or, in the alternative, actual and exemplary damages, however the Plaintiff has not yet identified or disclosed its actual damages (if any), or described the methodology by which it intends to calculate its alleged damages, nor has it been required to do so. On April 30, 2015 the Plaintiff filed for Chapter 11 Bankruptcy in the Northern District of Texas. In the bankruptcy, the Plaintiff has proposed to sell up to all of its operating assets in order to fund amounts owing to its creditors. It is not presently known what, if any, impact the Plaintiff's bankruptcy might have on the Alberta litigation. On October 23, 2015, the Texas Supreme Court granted all parties' Petitions For Review, and set oral argument for December 10, 2015. At the present time it is unknown how the Texas Supreme Court will ultimately rule on the jurisdictional issues or when any such ruling will be issued by the Texas Supreme Court. The claims against Ramshorn have been effectively abated until such time that the Texas Supreme Court issues its rulings. Parex and Parex Bermuda believe that the Plaintiff's claims against them set forth in the Alberta Statement of Claim are baseless and without merit and they intend on vigorously defending such claims if they are ultimately pursued by the Plaintiff in Alberta.

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Chairman of the Board

Curtis D. Bartlett

John F. Bechtold

Lisa Colnett

Robert J. Engbloom

Wayne K. Foo

Ron D. Miller

Paul D. Wright

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Chief Executive Officer

David R. Taylor
President

Kenneth G. Pinsky
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ABBREVIATIONS

Oil and Natural Gas Liquids

bbbls	barrels
mbbls	one thousand barrels
mmbbls	one million barrels
NGLs	natural gas liquids
bbbls/d or bopd	barrels of oil per day
mbbls/d	one thousand barrels per day
BOE or boe	barrel of oil equivalent, using the conversion factor of 6 Mcf: 1 bbl
mboe	one thousand barrels of oil equivalent
mmboe	one million barrels of oil equivalent
bfpd	barrels of fluid per day
boe/d	barrels of oil equivalent per day

Other

WTI	West Texas Intermediate
Brent	Brent Ice

"BOEs" may be misleading, particularly if used in isolation. A BOE conversion ratio of nine thousand cubic feet of natural gas to one barrel of oil equivalent (6 mcf: 1 bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.