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NEWS RELEASE **November 6, 2014**

BLACKPEARL ANNOUNCES THIRD QUARTER 2014 FINANCIAL AND OPERATING RESULTS

CALGARY, ALBERTA – BlackPearl Resources Inc. ("BlackPearl" or the "Company") (TSX:PXX) (NASDAQ Stockholm:PXXS) is pleased to announce its financial and operating results for the three and nine months ended September 30, 2014.

Third quarter highlights include:

- Oil and gas production for the quarter averaged 9,248 boe/day, a 4% increase compared to the second quarter;
- At Onion Lake, construction of the first 6,000 bbl/d phase of the thermal project continued throughout the quarter including delivery of over 35% of the modules (42 of 115 units) for the central processing facilities. The drilling of the horizontal production wells and vertical injector wells also commenced during the quarter. The project is on budget and on schedule to commence steam injection in mid-2015;
- At Blackrod, production from the second pilot well pair continues to ramp-up and is currently producing in excess of 375 bbl/d at an instantaneous steam oil ratio of 3.2;
- At Mooney, a new EOR royalty incentive program implemented by the Alberta government will have a positive impact on our Mooney ASP flood and we are planning to expand the flood in early 2015;
- Lower oil prices and wider heavy oil differentials contributed to a 15% decrease in revenues in the quarter to $58.8 million compared with Q3 2013. For the first nine months of 2014, revenues increased 7% to $180.5 million compared to the first nine months of 2013;
- Funds flow from operations was $23.8 million compared to $32.6 million in Q3 2013. For the first nine months of 2014, funds flow from operations was $70.0 million, a 7% increase from the first nine months of 2013;
- Net earnings were $7.0 million in the quarter compared with $9.3 million in Q3 2013. For the first nine months of 2014, net earnings were $10.6 million, a 70% increase from the first nine months of 2013;
- A healthy balance sheet was maintained with net debt of $29.5 million and an unutilized $150 million line of credit at the end of Q3 2014.

John Festival, President of BlackPearl, commenting on Q3 2014 activities, indicated that:

"Our focus in 2014 has been on building the first phase of the thermal EOR project at Onion Lake. Construction progress to date gives us confidence that we will meet our mid-2015 target start-up date for this project.

Production growth and the steam oil ratio in the second SAGD pilot well at Blackrod continues to perform in line with our expectations. This well should reach its peak production rates in the next six to nine months. The successful pilot along with commercial development approval, which is anticipated in the next few months, significantly reduces development risk of this project, and should improve our ability to finance the commercial development of the project.

Although crude oil prices have dropped in the last few weeks, the decrease for heavy crudes has been more muted than light oil due to lower heavy oil differentials and a weaker Canadian dollar. Our wellhead price in the third quarter was in the mid-$70s/bbl, which is still above historical averages. Our current wellhead price is around $65/bbl, which is similar to the average price realized from 2010 to 2013. In addition, our current hedging program will result in 40% of our production receiving a price in excess of $70/bbl for the next six months."

Property Review

Blackrod SAGD Pilot Project

Production continues to ramp-up from the second pilot well pair at Blackrod. Steam injection and circulation in this well commenced in November 2013 and the well was converted to SAGD production in March 2014. Typically, it takes 9 to 18 months after the well is converted to production to reach peak production rates. The well pair has produced over 50,000 barrels of oil and during the third quarter production from the second well pair averaged 316 barrels of oil per day with a steam oil ratio of approximately 3.3. We are continuing to see increases in monthly production volumes; currently the well is producing over 375 barrels of oil per day with a steam oil ratio of 3.2. Recent oil analysis from the well indicates that we are still in the early stages of steam chamber development and we expect to reach our target peak production of 500 to 600 barrels of oil per day in the next six to nine months.

The initial pilot well pair continues to perform as expected and is producing approximately 175 barrels of oil per day under restricted steam injection rates.

We are continuing to work with the Alberta Energy Regulator (AER) to complete the regulatory requirements for our 80,000 barrel per day commercial development application for the Blackrod area. We received two statements of concern from stakeholders in the area regarding the development application. We are working with these groups and the AER to resolve their outstanding issues. We anticipate receiving regulatory approval for the project in the next six months.

Onion Lake

Construction of the 6,000 barrel per day thermal EOR project at Onion Lake continued throughout the quarter. The project remains on budget and on schedule for a mid-2015 start-up. At the end of September, 42 of 115 modules of the central processing facility were delivered to site and six of 12 horizontal producer wells were drilled. In addition, seven of 19 vertical injector wells and three water disposal wells were also drilled during the quarter. The remaining wells to be drilled are expected to be completed by year-end. We have also commenced construction of the 27 kilometer water source pipeline to bring source water to the steam generation facilities. Currently there are in excess of 100 construction workers on site.

In addition to construction of the thermal project, we also continued with our primary development program at Onion Lake, with 12 wells drilled during the third quarter. These wells were drilled outside of the current thermal development area.

Mooney

During the third quarter, the Alberta government implemented new royalty regulations for enhanced recovery projects, such as our ASP flood at Mooney. Generally, these new rules are positive for operators of new projects or expansion of existing projects and, as a result, we are planning to move ahead with the expansion of our ASP flood at Mooney. Under the new royalty structure, future phases of the ASP flood at Mooney are expected to pay a 5% royalty for the first eight to ten years of production. Currently, we are paying royalties of about 22% on phase 2 lands. We are completing some infrastructure improvement projects (water treatment and pipeline expansion) to accommodate expansion of the ASP flood to our phase 2 lands and expect to initiate polymer and chemical injection on these lands in early 2015. The expansion does not require drilling any additional wells; however, it will result in several existing wells being shut-in and converted to ASP injector wells. Initially this will result in a reduction in oil production of approximately 400 barrels of oil per day until we achieve a response from the ASP flood, expected in 12 to 18 months after initial injection.

Due to pressure restrictions imposed by a third party gas transmission operator in the Mooney area we are limited by the amount of solution gas we can deliver to these facilities. Limitations on gas deliveries reduces the amount of additional oil we can produce in the area. As a result, we have deferred additional drilling on the phase 3 lands at Mooney, likely until the second half of 2015. These pressure restrictions are not expected to have a significant impact on production from Phase 1 and 2 wells in the Mooney field.

Production

Oil and gas production averaged 9,248 boe per day in the third quarter of 2014 compared to 9,382 boe per day for the same period in 2013. Quarter over quarter production increased 4% from the second quarter this year. The increase reflects additional drilling at Onion Lake in the second quarter and the continued positive response from the SAGD pilot at Blackrod.

	Three months ended September 30,		**Nine months ended September 30,**	
(boe/day)	2014	2013	2014	2013
Onion Lake	4,203	4,678	4,132	4,666
Mooney	3,429	3,324	3,547	3,634
John Lake	1,025	940	1,053	841
Blackrod	478	303	332	227
Other	113	137	104	117
	9,248	9,382	9,168	9,485

Financial Results

Oil and gas revenues were $58.8 million in the third quarter compared to $69.1 million in Q3 2013. The decrease in revenues is primarily attributable to an 11% decrease in our average oil price received this quarter compared with 2013. The lower realized wellhead price reflects lower WTI reference oil prices in Q3 2014 compared with Q3 2013 (US$97.17/bbl vs US$105.83/bbl), and wider heavy oil differentials (US$20.24/bbl vs US$17.48/bbl), partially offset by a weaker Canadian dollar relative to the US dollar ($0.918 vs $0.962).

Operating costs were $26.05 per boe in Q3 2014 compared with $19.95 per boe in Q3 2013. The increase in operating costs is primarily due to the expensing of all costs associated with the first phase of the ASP flood at Mooney. During the initial re-pressurization of the reservoir these costs were being capitalized.

Funds flow from operations was $23.8 million in Q3 2014 compared to $32.6 million in the same period in 2013. The decrease in funds flow in 2014 is primarily a result of lower wellhead sales prices in Q3 2014 compared to the same period in 2013. For the nine months ended September 30, 2014 funds flow from operations was $70.0 million, a 7% increase for the same period in 2013. For the nine months ended September 30, 2014, the Company generated net income of $10.6 million compared to $6.2 million in the same period in 2013.

Financial and Operating Highlights

($000, except where noted)	Three months ended September 30 2014	2013	Nine months ended September 30 2014	2013
Daily production / sales volumes				
Oil (bbl/d) (2)	8,744	9,108	8,798	9,237
Natural gas (mcf/d)	3,024	1,643	2,222	1,491
Combined (boe/d) (1)	9,248	9,382	9,168	9,485
Product pricing ($)				
Crude oil - per bbl (before the effects of hedging)	75.89	84.85	76.89	67.57
Natural gas - per mcf	3.97	2.38	4.49	3.06
Combined - per boe	72.90	82.72	74.84	66.50
Realized loss on risk management contracts – per boe	0.58	0.00	1.65	0.00
Revenue				
Oil and gas revenue – gross	58,818	69,092	180,547	168,085
Royalties ($/boe)	12.73	17.39	14.18	12.90
Transportation costs ($/boe)	2.06	2.50	2.03	3.14
Operating costs ($/boe)	26.05	19.95	25.28	21.28
Net income for the period	7,013	9,270	10,571	6,223
Per share, basic and diluted	0.02	0.03	0.03	0.02
Funds flow from operations(3)	23,809	32,609	70,007	65,471
Capital expenditures	80,262	24,326	177,666	70,742
Working Capital (deficiency), end of period	(29,543)	(2,380)	(29,543)	(2,380)
Long term debt	-	10,000	-	10,000
Shares outstanding, end of period	335,638,226	296,305,808	335,638,226	296,305,808

(1) Boe amounts are based on a conversion ratio of 6 mcf of gas to 1 barrel of oil. Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(2) includes production from the Blackrod SAGD pilot.

(3) Funds flow from operations is a non-GAAP measure. See discussion of this term under "Non-GAAP Measures".

Guidance for the Remainder of 2014 and 2015

We expect our oil and gas production to average between 9,000 and 9,500 boe/d for 2014, unchanged from our Q2 update. Funds flow from operations for the year is anticipated to range between $80 and $85 million, again, unchanged from our Q2 2014 update. Capital spending for 2014 is expected to be between $275 and $285 million, a reduction from our Q2 update estimate of $280 to $300 million. The reduction in capital spending is a result of certain expenditures on the Onion Lake thermal project that were originally planned for the fourth quarter that will now likely occur in the first quarter of 2015 and the deferral of drilling on the Phase 3 lands at Mooney until the second half of 2015. As a result of the lower capital spending our year-end 2014 debt should be between $110 and $115 million.

In 2015, we have planned a capital expenditure program of between $80 and $85 million. Capital expenditures for 2015 will include completion of the Onion Lake thermal project, costs associated with the expansion of the ASP flood at Mooney (well conversions and initial capitalization of polymer and chemical costs), drilling horizontal wells on the phase 3 lands at Mooney, drilling 20 to 25 conventional heavy oil wells at Onion Lake and drilling up to 10 wells at John Lake and other areas.

It is expected that this capital program will be largely funded from anticipated cash flow from operations and supplemented with our existing credit facilities. Year-end 2015 debt levels are anticipated to be approximately $135 million.

Oil and gas production should average approximately 9,500 boe/d in 2015. We expect to commence steam injection at Onion Lake in mid-2015 but this thermal project is not expected to have a meaningful impact on our production levels until 2016. Exit production levels for 2015 are expected to be approximately 11,000 boe/d.

The 2014 third quarter report to shareholders, including the financial statements, management's discussion and analysis and notes to the financial statements are available on the Company's website (www.blackpearlresources.ca) or SEDAR (www.sedar.com).

Non-GAAP Measures

This news release includes terms commonly used in the oil and natural gas industry, such as "funds flow from operations" which represent cash flow from operating activities expressed before changes in non-cash working capital and "net debt" which represents borrowings under our credit facilities less working capital.. This term is used by the Company to analyze operating performance, leverage and liquidity and to provide shareholders and investors with additional information to measure the Company's performance and efficiency and its ability to fund a portion of its future activities and to service any long-term debt if incurred in the future. "Funds flow from operations" and "net debt" do not have standardized meanings prescribed by GAAP and therefore may not be comparable with the calculation of similar measures by other entities. Consequently, these are referred to as non-GAAP measures.

Forward-looking Statements

This release contains certain forward-looking statements and forward-looking information (collectively referred to as "**forward-looking statements**") within the meaning of applicable Canadian securities laws. All statements other than statements of historical fact are forward-looking statements. Forward-looking information typically contains statements with words such as "anticipate", "anticipated", "planning", "planned", "potential", "could", "continue", "continued", "continuing", "estimate", "estimates", "estimated", "forecast", "likely", "expect", "expected", "may", "intend", "intends", "intended", "intention", "deferred", "successful", "will", "project", "timing", "in the event", "move toward", "should", "scheduled", "outlook" or similar words suggesting future outcomes.

In addition, statements relating to “reserves”, “resources” or “contingent resources” are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resource described exist in the quantities predicted or estimated and can be profitably produced in the future.

In particular, but without limiting the foregoing, this report contains forward-looking statements pertaining to our business plans and strategies; capital expenditure and drilling programs including the target date of mid-2015 for completion of construction and first steam at Onion Lake and anticipated timing of initial and peak oil production rates at the Onion Lake EOR project, estimated capital costs of $210 million for the first phase of thermal development at Onion Lake, anticipated corporate production being within our production target guidelines by the end of the year, timing and expected ramp-up time to reach peak production rates of 500 to 600 barrels of oil per day for the second pilot well pair at Blackrod and the expected steam oil ratios associated with this production and our planned commercial operations, expected timing to receive regulatory approval for our commercial development application at Blackrod, anticipated expansion of the ASP flood to phase two lands at Mooney in 2015, as well as all the information contained in the Guidance for the Remainder of 2014 and 2015 section.

The forward-looking information is based on expectations and assumptions by management regarding future production levels, future oil and natural gas prices, continuation of existing tax, royalty and regulatory regimes, foreign exchange rates, estimates of future operating costs, timing and amount of capital expenditures, performance of existing and future wells, the ability to obtain financing on acceptable terms, availability of skilled labour and drilling and related equipment, general economic and financial market conditions and the ability to market oil and natural gas successfully to current and new customers. Although management considers these assumptions to be reasonable based on information currently available to it, they may prove to be incorrect.

Undue reliance should not be placed on forward-looking statements. There can be no assurance that the plans, intentions or expectations upon which forward-looking statements are based will be realized. Actual results will differ, and the differences may be material and adverse to the Company and its shareholders.

By their very nature, forward-looking statements involve inherent risks and uncertainties (both general and specific) and risks that the goals or figures contained in forward-looking statements will not be achieved. These factors include, but are not limited to, risks associated with fluctuations in market prices for crude oil, natural gas and diluent, general economic, market and business conditions, volatility of commodity inputs, substantial capital requirements, customary conditions including receipt of necessary regulatory and stock exchange approvals on the issuance of common shares, uncertainties inherent in estimating quantities of reserves and resources, extent of, and cost of compliance with, government laws and regulations and the effect of changes in such laws and regulations from time to time, the need to obtain regulatory approvals on projects before development commences, environmental risks and hazards and the cost of compliance with environmental regulations, aboriginal claims, inherent risks and hazards with operations such as fire, explosion, blowouts, mechanical or pipe failure, cratering, oil spills, vandalism and other dangerous conditions, financial loss associated with derivative risk management contracts, potential cost overruns, variations in foreign exchange rates, variations in interest rates, diluent and water supply shortages, competition for capital, equipment, new leases, pipeline capacity and skilled personnel, uncertainties inherent in the SAGD bitumen and ASP recovery process, credit risks associated with counterparties, the failure of the Company or the holder of licences, leases and permits to meet requirements of such licences, leases and permits, reliance on third parties for pipelines and other infrastructure, changes in royalty regimes, failure to accurately estimate abandonment and reclamation costs, inaccurate estimates and assumptions by management, effectiveness of internal controls, the potential lack of available drilling equipment and other restrictions, failure to obtain or keep key personnel, title deficiencies with the Company’s assets, geo-political risks, risks that the Company does not have adequate insurance coverage, risk of litigation and risks arising from future acquisition activities. Further information regarding these risk factors may be found under “Risk Factors” in the Annual Information Form.

Readers are cautioned that these factors and risks are difficult to predict and that the assumptions used in the preparation of such information, although considered reasonably accurate at the time of preparation, may prove to be incorrect. Readers are also cautioned that the foregoing list of factors is not exhaustive. Consequently, there is no representation by the Corporation that actual results achieved will be the same in whole or in part as those set out in the forward-looking information. Furthermore, the forward-looking statements contained in this report are made as of the date hereof, and the Corporation does not undertake any obligation, except as required by applicable securities legislation, to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

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BLACKPEARL RESOURCES INC.

Management's Discussion and Analysis

The following is Management's Discussion and Analysis (MD&A) of the operating and financial results of BlackPearl Resources Inc. ("BlackPearl" or "the Company") for the three and nine months ended September 30, 2014. These results are being compared with the three and nine months ended September 30, 2013. The MD&A should be read in conjunction with the Company's unaudited consolidated financial statements for the three and nine months ended September 30, 2014, together with the accompanying notes and with the Company's annual MD&A for the year ended December 31, 2013.

All dollar amounts are referenced in thousands of Canadian dollars, except where otherwise noted. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS), as is required under Canadian generally accepted accounting principles (GAAP).

Throughout this MD&A the calculation of barrels of oil equivalent (boe) is based on a conversion rate of six thousand cubic feet (mcf) of natural gas to one barrel of oil. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalence conversion method primarily applicable at the burner tip and is not intended to represent a value equivalence at the wellhead.

The following is a summary of the abbreviations that may have been used in this document:

Oil and Natural Gas Liquids		Natural Gas	
bbl	barrel	Mcf	thousand cubic feet
bbls/d	barrels per day	MMcf	million cubic feet
Mbbls/d	thousand barrels per day	Mcf/d	thousand cubic feet per day
MMbbls	million barrels	Bcf	billion cubic feet
NGLs	natural gas liquids	MMBtu	million british thermal units
boe	barrel of oil equivalent	GJ	gigajoule
boe/d	barrel of oil equivalent per day		
WTI	West Texas Intermediate (a light oil reference price)		
WCS	Western Canadian Select (a heavy oil reference price)		
SAGD	Steam Assisted Gravity Drainage (a thermal recovery process)		
ASP	Alkali, Surfactant, Polymer		
EOR	Enhanced Oil Recovery		

Non-GAAP Financial Measures

Throughout this MD&A, the Company uses terms "funds flow from operations", "funds flow from operations per share - basic", "funds flow from operations per share – diluted" and "operating netback". These terms do not have any standardized meaning as prescribed by GAAP and, therefore, may not be comparable with the calculation of similar measures presented by other issuers. These terms are used by the Company to analyze operating performance, leverage and liquidity and to provide shareholders and investors with additional information to measure the Company's performance and efficiency and its ability to fund a portion of its future activities and to service any long-term debt. Funds flow from operations is not intended to represent cash flow from operating activities or other measures of financial performance in accordance with GAAP. Operating netback is calculated as production sales less royalties, production costs and transportation costs, divided by total production for the period on a boe basis.

The following table reconciles non-GAAP measurement "Funds flow from operations" to "Cash flows from operating activities", the nearest GAAP measure. "Funds flow from operations" excludes decommissioning costs incurred and changes in non-cash working capital related to operations, while the GAAP measurement, "Cash flows from operating activities" includes these items. Funds flow from operations per share – basic & diluted is calculated as cash flow from operating activities before decommissioning costs incurred and changes in non-cash working capital related to operations divided by the average number of common shares outstanding for the period.

($000s)	2014 Q3	2014 Q2	2014 Q1	2013 Q3	Nine months ended September 30 2014	Nine months ended September 30 2013
Cash flows from operating activities [(1)]	**25,587**	24,042	18,517	33,090	**68,146**	56,926
Add (deduct):						
Decommissioning costs incurred	**213**	283	204	142	**700**	555
Changes in non-cash working capital related to operations	**(1,991)**	(1,164)	4,316	(623)	**1,161**	7,990
Funds flow from operations [(2)]	**23,809**	23,161	23,037	32,609	**70,007**	65,471

(1) Cash flow from operating activities is a GAAP measure and has a standardized meaning prescribed by Canadian GAAP.

(2) Funds flow from operations is a non-GAAP measure that represents cash flow from operating activities before decommissioning costs incurred and changes in non-cash working capital related to operations. Funds flow from operations and funds flow from operations per share do not have standardized meanings prescribed by Canadian GAAP and therefore may not be comparable to similar measures used by other companies. Management uses these non-GAAP measurements for its own performance measures and to provide its shareholders and investors with a measurement of the Company's efficiency and its ability to fund a portion of its growth expenditures.

Additional information relating to the Company, including its Annual Information Form, is available on SEDAR at www.sedar.com.

This MD&A contains forward-looking information and statements. At the end of this MD&A is an advisory on forward-looking information and statements.

The effective date of this MD&A is November 6, 2014.

OVERVIEW

BlackPearl is a Canadian-based oil and natural gas company whose common shares are traded on the Toronto Stock Exchange (TSX) under the symbol "PXX". The Corporation's Swedish Depository Receipts trade on the NASDAQ Stockholm market under the symbol "PXXS". BlackPearl's primary focus is on heavy oil and oil sands projects in Western Canada.

BlackPearl's current core properties are:

- Onion Lake, Saskatchewan – a conventional heavy oil property with a thermal EOR project under construction;
- Mooney, Alberta – a conventional heavy oil property using horizontal drilling and ASP flooding; and
- Blackrod, Alberta – a bitumen property located in the Athabasca oil sands region using the SAGD recovery process. The Company is currently operating a pilot project on this property.

These core properties provide the Company with a combination of short-term cash flow generation, medium-term reserves and production growth, and longer-term reserves and production growth on multi-phase low decline projects using both EOR and SAGD thermal recovery processes.

2014 SIGNIFICANT EVENTS

- Capital expenditures during the first nine months of 2014 were $177.7 million, with approximately $131.4 million related to the construction of the Onion Lake EOR project, $27.0 million spent at Mooney, $7.5 million spent at Onion Lake primary, $6.3 million at John Lake, $3.6 million spent at Blackrod and $1.9 million in other areas. The focus of the 2014 capital program to date has been the commercial engineering design and construction of the Onion Lake EOR project and the drilling of 18 associated wells, the drilling of 20 conventional heavy oils wells at Onion Lake, seven wells at Mooney and six horizontal wells at John Lake. In addition, 2014 capital spending to date included expansion of pipeline and road infrastructure at Mooney and the conversion of the second pilot well pair at Blackrod to the production test phase along with continued capitalization of net revenues.

- Oil and gas sales during the first nine months of 2014 were $180.5 million and funds flow from operations (non-GAAP measure) were $70.0 million. For the nine months ended September 30, 2014, net income was $10.6 million.

- During the first half of 2014 the Company issued 33,373,585 common shares at a price of $2.65 per share, for aggregate gross proceeds of $88.4 million. In addition, during the first nine months of 2014, 1,839,833 common shares were issued pursuant to the exercise of stock options which generated net proceeds of $2.0 million for the Company.

- The Company's Board of Directors approved development of the first phase of the Onion Lake EOR project. The first phase of development is being designed for production of approximately 6,000 bbls/d of oil; target date for completion of construction and first steam is mid-2015. Initial oil production from the project is expected within three months of steam injection and peak production rates are expected 9 to 12 months thereafter.

- The Company entered into a lump sum contract with Propak Systems Ltd. (Propak) for the engineering, procurement and fabrication of the central processing facilities for the Company's Onion Lake EOR project.

- At September 30, 2014, BlackPearl had working capital deficiency of $29.5 million and no long-term debt, leaving $150.0 million available to be drawn under the Company's existing credit facilities. During the second quarter of 2014 the Company's lending syndicate increased the Company's existing credit facilities from $115 million to $150 million. The Company intends to use the net proceeds from the issuance of common shares and the increased credit facilities to fund ongoing capital expenditures, including the first phase of the Onion Lake EOR project and for general corporate purposes.

SELECTED QUARTERLY INFORMATION

	2014			2013				2012
($000s, except where noted)	**Sep 30**	**Jun 30**	**Mar 31**	**Dec 31**	Sep 30	Jun 30	Mar 31	Dec 31
Production (boe/d) (1)	**9,248**	**8,897**	**9,363**	**10,454**	9,382	9,986	9,087	9,067
Oil and gas sales	**58,818**	**62,174**	**59,555**	**54,072**	69,092	58,322	40,671	47,569
Oil and gas sales ($/boe)	**72.90**	**79.53**	**72.30**	**57.67**	82.72	66.20	50.13	58.45
Production costs	**21,021**	**20,291**	**19,673**	**18,420**	16,664	18,413	18,702	14,563
Production costs ($/boe)	**26.05**	**25.96**	**23.88**	**19.65**	19.95	20.90	23.05	17.89
Gain (loss) on risk management contracts	**4,493**	**(2,571)**	**(5,967)**	**-**	-	-	-	-
Net income (loss)	**7,013**	**4,684**	**(1,126)**	**226**	9,270	2,597	(5,644)	(4,277)
Per share, basic and diluted ($)	**0.02**	**0.01**	**0.00**	**0.00**	0.03	0.01	(0.02)	(0.01)
Capital expenditures	**80,262**	**48,044**	**49,360**	**22,749**	24,326	27,315	19,101	34,635
Funds flow from operations (2)	**23,809**	**23,161**	**23,037**	**20,735**	32,609	22,823	10,039	17,684
Per share, basic and diluted ($)	**0.07**	**0.07**	**0.08**	**0.07**	0.11	0.08	0.03	0.06
Cash flow from operating activities(3)	**25,587**	**24,042**	**18,517**	**23,772**	33,090	20,592	3,244	33,973
Total assets (end of period)	**785,538**	**765,233**	**747,763**	**652,216**	648,554	647,839	613,738	620,725
Shares outstanding (000s)	**335,638**	**335,638**	**328,398**	**300,425**	296,306	296,122	296,108	295,766
Weighted average shares outstanding (000s)								
Basic	**335,638**	**334,817**	**304,841**	**298,843**	296,244	296,113	296,052	288,760
Diluted	**335,639**	**335,244**	**305,874**	**300,768**	298,584	299,693	300,768	294,525

(1) Includes test production from the Blackrod SAGD pilot. All sales and expenses from the Blackrod SAGD pilot are being recorded as an adjustment to the capitalized costs of the project until the technical feasibility and commercial viability of the project is established.
(2) Funds flow from operations is a non-GAAP measure that represents cash flow from operating activities before decommissioning costs incurred and changes in non-cash working capital related to operations. Funds flow from operations and funds flow from operations per share do not have standardized meanings prescribed by Canadian GAAP and therefore may not be comparable to similar measures used by other companies. Management uses these non-GAAP measurements for its own performance measures and to provide its shareholders and investors with a measurement of the Company's efficiency and its ability to fund a portion of its growth expenditures.
(3) Cash flow from operating activities is a GAAP measure and has a standardized meaning prescribed by Canadian GAAP.

Fluctuations in quarterly oil and gas sales and net income (loss) over the last eight quarters are primarily attributable to the volatility in crude oil prices and changes in sales volumes from new drilling activity, partially offset by natural declines in production. Production costs have increased in 2014 as the Company has begun to expense all costs related to Phase 1 of the ASP flood at Mooney. During 2013 polymer and injection costs related to Phase 1 of the ASP flood at Mooney were expensed and prior to 2013 all costs were being capitalized while the reservoir was being re-pressurized.

BUSINESS ENVIRONMENT

Fluctuations in commodity prices have a significant influence on BlackPearl's results of operation and financial condition. The following table shows selective market benchmark prices and foreign exchange rates to assist in understanding how these factors impact our performance.

Commodity Prices

	YTD		2014			2013			
	2014	2013	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Average Crude Oil Prices									
West Texas Intermediate (WTI) (US$/bbl)	99.61	98.15	97.17	102.99	98.68	97.46	105.83	94.29	94.34
Western Canadian Select (WCS) (Cdn$/bbl)	85.87	77.18	83.80	90.42	83.39	68.43	91.75	76.68	62.96
Differential – WCS/WTI (US$/bbl)	21.15	22.88	20.24	20.08	23.11	32.21	17.48	19.36	31.95
Differential - WCS/WTI (%)	21.2%	23.6%	20.8%	19.5%	23.4%	33.1%	16.5%	20.6%	33.8%
Average Natural Gas Prices									
AECO gas (Cdn$/GJ)	4.56	3.00	3.81	4.71	4.91	2.99	2.67	3.40	2.92
Average Foreign Exchange (US$ per Cdn$1)	0.914	0.976	0.918	0.917	0.906	0.950	0.962	0.977	0.991

Crude oil prices are based on demand for oil which is generally tied to global economic growth, but is also influenced by other factors such as political instability, market uncertainty, weather conditions, infrastructure constraints and government regulations. Crude oil in North America is commonly priced relative to the price of WTI oil, a light sweet crude with API gravity of about 40 degrees. Virtually all of BlackPearl's production is heavy oil and bitumen and is typically priced relative to Western Canadian Select oil prices, which have an average gravity of about 20.5 degrees API.

WCS oil prices are generally lower than WTI oil prices due to the higher cost of refining a barrel of heavy oil compared to light oil. This difference between the reference price for light oil and heavy oil is commonly referred to as the light to heavy differential.

Increased crude oil prices and tighter heavy oil differentials contributed to higher heavy oil prices for producers in the first nine months of 2014 compared to same period in 2013. The light to heavy differential narrowed during the first nine months of 2014, averaging US$21.15 per bbl compared to US$22.88 per bbl in the same period in 2013. The improvement in heavy oil prices has been attributed to increased refinery demand in the US Midwest, a continued increase in rail shipments of oil and a number of pipeline capacity improvements and expansion projects. During the first nine months of 2014, BlackPearl transported approximately 4,663 boe/d by rail, or about 51% of our total production volumes.

In addition, the weakness in the Canadian dollar also contributed to higher oil prices for Canadian producers. Changes in the value of the Canadian dollar relative to the US dollar impacts our revenues and cash flows as our oil sales price is determined by US benchmark prices. The Canadian dollar weakened against the US dollar in the first nine months of 2014 which has had a positive impact on our revenues and cash flows. The exchange rate between the Canadian dollar and the US dollar averaged Cdn$1 = US$0.91 during the first nine months of 2014 compared to Cdn$1 = US$0.94 at December 31, 2013.

Higher crude oil prices, lower differentials and the weakness in the Canadian dollar resulted in WCS oil prices averaging $85.87 per bbl during the first nine months of 2014 compared to $77.18 per the same period in 2013.

However, during the third quarter and continuing into the fourth quarter of 2014, crude oil prices have decreased significantly from prices received earlier in the year. WTI prices are currently around US$83 per bbl compared to the average of US$99.61 per bbl for the first nine months of the year. The decrease has been attributed to a number of factors including rising global oil production, particularly increases in shale production in the US, a slowdown in demand due to weaker global economic conditions, a strong US dollar and increased inventory levels. A weaker Canadian dollar and tighter heavy oil differentials has somewhat mitigated the decrease in heavy oil prices. WCS oil prices are currently around Cdn$79 per bbl.

Natural gas prices increased during the first nine months of 2014 averaging $4.56/GJ compared to $3.00/GJ during the same period in 2013. BlackPearl produces relatively small amounts of natural gas and therefore prices do not have a significant impact on our current oil and gas sales. However, we do consume gas at both our thermal projects and as we move toward commercial development of these projects the cost of gas will have a significant impact on our cost structure.

Oil and Gas Production, Oil and Gas Pricing and Oil and Gas Sales

	2014			2013	Nine months ended September 30	
	Q3	Q2	Q1	Q3	**2014**	2013
Daily production/sales volumes (1)						
Oil (bbls/d)	**8,266**	8,228	8,911	8,805	**8,466**	9,010
Natural gas (Mcf/d)	**3,024**	2,176	1,448	1,643	**2,222**	1,491
Combined (boe/d)	**8,770**	8,591	9,152	9,079	**8,836**	9,258
Bitumen – Blackrod (bbls/d) (2)	**478**	306	211	303	**332**	227
Total production (boe/d)	**9,248**	8,897	9,363	9,382	**9,168**	9,485
Product pricing (excluding risk management activities) (2)						
Oil ($/bbl)	**75.89**	81.82	73.23	84.85	**76.89**	67.57
Natural gas ($/Mcf)	**3.97**	4.61	5.41	2.38	**4.49**	3.06
Combined ($/boe)	**72.90**	79.53	72.30	82.72	**74.84**	66.50
Sales ($000s) (2)						
Oil and gas sales – gross	**58,818**	62,174	59,555	69,092	**180,547**	168,085
Royalties	**(10,273)**	(12,413)	(11,529)	(14,523)	**(34,215)**	(32,596)
Oil and gas sales – net	**48,545**	49,761	48,026	54,569	**146,332**	135,489

(1) Natural gas production converted at 6:1 (for boe figures)
(2) All sales and expenses from the Blackrod SAGD pilot are being recorded as an adjustment to the capitalized costs of the project until the technical feasibility and commercial viability of the project is established.

Oil and natural gas sales decreased 15% in the third quarter of 2014 to $58.8 million from $69.1 million in the same period in 2013. The decrease in oil and gas sales is primarily attributable to a 12% decrease in average sales prices received in Q3 2014 compared to the same period in 2013.

Lower crude oil prices and wider heavy oil differentials contributed to a decrease in our realized crude oil sales price in Q3 2014. Our average oil wellhead sales price, prior to the impact of risk management activities, was $75.89 per bbl in Q3 2014 compared with $84.85 per bbl in the same period of 2013.

For the first nine months of 2014 compared to the same period of 2013; crude oil prices were higher, the heavy oil differential narrower and the weakening of the Canadian dollar relative to the US dollar all contributed to an increase in our realized crude oil sales. Our average oil wellhead sales price, prior to the impact of risk management activities, was $76.89 per bbl for the first nine months of 2014 compared with $67.57 per bbl in the same period in 2013.

Production volumes in Q3 2014 were 9,248 boe/d, comparable to the same period in 2013. However; for the first nine months of 2014 production volumes decreased 3% to 9,168 boe/d from 9,485 boe/d in the same period in 2013. The decrease in production is attributable to natural production declines at Onion Lake, as well as, selectively shutting-in some of our wells in the area to prepare for thermal activities in certain portions of the field. The Onion Lake field is a maturing area for primary production and many of the wells drilled over the last seven years have reached or are near the end of their productive life. During 2014 we drilled 20 wells in order to flatten this production decline at the Onion Lake field and all of these wells were put on production during the third quarter. These wells were drilled in an area that is not impacted by the thermal development project.

On a boe basis, 95% of the Company's oil and natural gas production in the third quarter of 2014 was heavy oil or bitumen. The Onion Lake area accounted for 43% and the Mooney area accounted for 37% of total production in the third quarter of 2014.

	2014			2013	Nine months ended September 30	
Production by area (boe/d)	**Q3**	Q2	Q1	Q3	**2014**	2013
Onion Lake	**4,203**	3,915	4,274	4,678	**4,132**	4,666
Mooney	**3,429**	3,519	3,696	3,324	**3,547**	3,634
John Lake	**1,025**	1,065	1,069	940	**1,053**	841
Other	**113**	92	113	137	**104**	117
Blackrod	**478**	306	211	303	**332**	227
	9,248	8,897	9,363	9,382	**9,168**	9,485

In 2011, BlackPearl commenced its SAGD pilot project at Blackrod. The pilot started with a single horizontal well pair and associated steam and water handling facilities. The pilot is being undertaken to provide operating data to design the commercial development of the Blackrod lands. All sales and expenses from the pilot are being recorded as an adjustment to the capitalized costs of the project until the technical feasibility and commercial viability of the project is established. Technical feasibility and commercial viability are confirmed when reserves are recognized, regulatory approval has been obtained and our Board of Directors has sanctioned commercial development. As of September 30, 2014, BlackPearl had not received regulatory approval for the commercial Blackrod project. A second pilot well pair was drilled in 2013 and steam injection in this well pair commenced during the fourth quarter of 2013. After the initial warm up phase the well pair was converted to SAGD mode (production test phase) in March 2014. Production is expected to ramp-up to peak rates during the next twelve to fifteen months. During the third quarter of 2014, the pilot wells produced on average 478 bbls/d of bitumen and the net revenues capitalized for the first nine months of 2014 were a loss of $1.8 million (2013 - $2.2 million).

Risk Management Activities

The Company will periodically enter into risk management contracts in order to ensure a certain level of cash flow to fund planned capital projects. BlackPearl's strategy focuses on swaps and fixed price contracts to limit exposure to fluctuations in oil prices. The Company's risk management trading activities are conducted pursuant to the Company's Risk Management Policy approved by the Board of Directors and are not used for trading or speculative purposes.

The Company realized a loss of $0.5 million on its risk management contracts during the third quarter of 2014. In addition, as a result of the recent drop in crude oil prices, we recorded an unrealized gain of $5 million in Q3 2014, which represents the non-cash change in the mark-to-market values of our outstanding risk management contracts at September 30, 2014.

	2014			2013	Nine months ended September 30	
($000s, except per boe)	**Q3**	Q2	Q1	Q3	**2014**	2013
Realized gain (loss) on risk management contracts	**(468)**	(2,842)	(666)	-	**(3,976)**	-
Per boe ($)	**(0.58)**	(3.64)	(0.81)	-	**(1.65)**	-
Unrealized gain (loss) on risk management contracts	**4,961**	271	(5,301)	-	**(69)**	-

At September 30, 2014, the following risk management contracts were outstanding:

Subject of Contract	Volume	Term	Reference	Strike Price	Option Traded
Oil	2,500 bbls/d	October 1, 2014 to December 31, 2014	CDN$ WCS	CDN$ 82.10/bbl	Swap
Oil	1,000 bbls/d	October 1, 2014 to December 31, 2014	CDN$ WCS	CDN$ 82.00/bbl	Swap
Oil	500 bbls/d	October 1, 2014 to December 31, 2014	CDN$ WCS	CDN$ 86.05/bbl	Swap
Oil	1,500 bbls/d	January 1, 2015 to March 31, 2015	CDN$ WCS	CDN$ 80.20/bbl	Swap
Oil	2,500 bbls/d	January 1, 2015 to June 30, 2015	CDN$ WCS	CDN$ 80.00/bbl	Swap

Royalties

	2014			2013	Nine months ended September 30	
	Q3	Q2	Q1	Q3	**2014**	2013
Royalties ($000s)	**10,273**	12,413	11,529	14,523	**34,215**	32,596
Per boe ($)	**12.73**	15.88	14.00	17.39	**14.18**	12.90
As a percentage of oil and gas sales	**17%**	20%	19%	21%	**19%**	19%

BlackPearl makes royalty payments to the owners of the mineral rights on the lands we have leased. Most of the payments are to provincial governments or, in the case of our Onion Lake area production, to the Onion Lake Cree Nation. Royalties per boe decreased 27% in the third quarter of 2014 to $12.73 per boe from $17.39 per boe during the same period in 2013. The decrease in royalty per boe in the third quarter of 2014 compared to the same period of 2013 is primarily attributable to lower revenues and changes to the Alberta government's EOR royalty incentive program, which affects our Mooney area production. Under the new royalty scheme, production from the first phase of the ASP flood at Mooney will incur crown royalties under 10% for the next 8 to 10 years, effective retroactively to January 1, 2014. This resulted in a reduction in our previously paid royalties of approximately $1 million. Future expansion phases of the ASP flood will be eligible for a flat 5% royalty on production for the first 8 to 10 years of ASP flooding.

Transportation Costs

	2014			2013	Nine months ended September 30	
	Q3	Q2	Q1	Q3	**2014**	2013
Transportation costs ($000s)	**1,665**	1,688	1,539	2,086	**4,892**	7,931
Per boe ($)	**2.06**	2.16	1.87	2.50	**2.03**	3.14

Transportation costs are incurred to move marketable crude oil and natural gas to their selling points. Changes in transportation costs, on a boe basis, are generally related to moving crude oil to different sales points to capture better marketing opportunities. Transportation costs decreased 20% in the third quarter of 2014 to $1.7 million from $2.1 million in the same period in 2013. The decrease is mostly attributable to lower costs at Mooney, where we have increased the amount of production volumes we ship by rail. The travel distance to rail terminals is less than travel distance to pipeline terminals in the area resulting in lower costs.

Production Costs

	2014			2013	Nine months ended September 30	
	Q3	Q2	Q1	Q3	**2014**	2013
Production costs ($000s)	**21,021**	20,291	19,673	16,664	**60,985**	53,779
Per boe ($)	**26.05**	25.96	23.88	19.95	**25.28**	21.28

Production costs increased by 26% in the third quarter of 2014 to $21.0 million from $16.7 million in the same period in 2013. On a per boe basis, production costs increased 31% in the third quarter of 2014 to $26.05 per boe from $19.95 per boe in the same period in 2013.

The increase in production costs in the third quarter of 2014 is attributable to increased expenses at Onion Lake due to the relative maturity of the field (higher repairs, maintenance and workover costs) and the expensing, for the first time, of all operating costs associated with the first phase of the ASP flood at Mooney. Prior to 2013, all operating costs related to the ASP flood were being capitalized until the reservoir was re-pressurized. In 2013, it was evident that we were achieving a positive production response from the re-pressurization and we began to expense polymer and injection costs associated with the re-pressurization. In 2014, we began to see a consistent production response from the injection of alkali and surfactant and therefore, beginning in 2014, we began to expense all costs associated with the first phase of the ASP flood. A breakdown of the ASP related expenses is provided below.

	2014			2013	Nine months ended September 30	
($000s)	**Q3**	Q2	Q1	Q3	**2014**	2013
Polymer costs	**1,849**	1,702	1,816	1,448	**5,367**	4,957
Other chemical costs	**2,694**	2,430	1,745	2,742	**6,869**	6,962
Injection costs	**986**	1,204	1,133	481	**3,323**	2,190
Total ASP costs	**5,529**	5,336	4,694	4,671	**15,559**	14,109
ASP costs capitalized	**-**	-	-	(2,742)	**-**	(6,962)
ASP costs expensed in production costs	**5,529**	5,336	4,694	1,929	**15,559**	7,147

Operating Netback (1)

	2014			2013	Nine months ended September 30	
($/boe)	**Q3**	Q2	Q1	Q3	**2014**	2013
Revenues	**72.90**	79.53	72.30	82.72	**74.84**	66.50
Royalties	**12.73**	15.88	14.00	17.39	**14.18**	12.90
Transportation costs	**2.06**	2.16	1.87	2.50	**2.03**	3.14
Production costs	**26.05**	25.96	23.88	19.95	**25.28**	21.28
Operating netback excluding realized risk management contracts	**32.06**	35.53	32.55	42.88	**33.35**	29.18
Realized loss on risk management contracts	**(0.58)**	(3.64)	(0.81)	-	**(1.65)**	-
Operating netback including realized risk management contracts	**31.48**	31.89	31.74	42.88	**31.70**	29.18

(1) Operating netback is a non-GAAP measure. Operating netback does not have a standardized meaning prescribed by GAAP and, therefore, may not be comparable to similar measures used by other companies in the oil and gas industry.

Operating netback is the cash margin we receive from each barrel of oil equivalent sold. Operating netback, excluding realized losses on risk management activities, decreased 25% in the third quarter of 2014 to $32.06 per boe from $42.88 per boe in the same period in 2013. The decrease is primarily attributable to the decrease in realized crude oil prices and the increase in production costs, partially offset by lower royalties.

General and Administrative Expenses (G&A)

	2014			2013	Nine months ended September 30	
($000s, except per boe)	**Q3**	Q2	Q1	Q3	**2014**	2013
Gross G&A expense	**2,317**	2,228	3,625	2,375	**8,170**	7,954
Operator recoveries	**(599)**	(520)	(510)	(534)	**(1,629)**	(1,389)
Net G&A expense	**1,718**	1,708	3,115	1,841	**6,541**	6,565
Per boe ($)	**2.13**	2.18	3.78	2.20	**2.71**	2.60

General and administrative expenses consist primarily of salaries and wages of employees, office rent, computer services, legal, accounting and consulting fees. For the nine months ended September 30, 2014, gross general and administrative costs increased 3% compared to the first nine months of 2013. The increase in gross G&A expenses is primarily attributable to performance incentive payments to staff in the first quarter of 2014 as well as higher office rental expenses. Net general and administrative costs for the nine months ended September 30, 2014, were comparable to the same period in 2013 due to higher operator recoveries in 2014 as a result of increased capital spending.

Stock-Based Compensation

	2014			2013	Nine months ended September 30	
($000s, except per boe)	**Q3**	Q2	Q1	Q3	**2014**	2013
Gross stock-based compensation	**1,539**	1,480	941	1,179	**3,960**	3,556
Recoveries from forfeitures	**(9)**	(60)	(169)	(13)	**(238)**	(372)
Net stock-based compensation before capitalization	**1,530**	1,420	772	1,166	**3,721**	3,184
Capitalized stock-based compensation	**(70)**	(70)	(31)	(154)	**(171)**	(392)
Net stock-based compensation	**1,460**	1,350	741	1,012	**3,551**	2,792
Per boe ($)	**1.81**	1.73	0.90	1.21	**1.47**	1.10

Stock-based compensation costs are non-cash charges which reflect the estimated value of stock options granted. The Company uses the fair value method of accounting for stock options granted to directors, officers, employees and consultants whereby the fair value of all stock options granted is recorded as a charge to operations over the period from the grant date to the vesting date of the option. The fair value of common share options granted is estimated on the date of grant using the Black-Scholes option pricing model.

The increase in stock-based compensation expense in the third quarter of 2014 compared to the same period in 2013 reflects an increase in the number of options issued.

During the third quarter of 2014, $70,000 of stock-based compensation costs were capitalized to property, plant and equipment related to options granted to contractors who work exclusively on the development activities at the Onion Lake EOR project.

Finance Costs

		2014		2013	Nine months ended September 30	
($000s)	**Q3**	Q2	Q1	Q3	**2014**	2013
Gross interest & financing charges	**191**	496	150	290	**837**	892
Capitalized interest & financing charges	**(173)**	(118)	(89)	(31)	**(380)**	(218)
Net interest & financing charges	**18**	378	61	259	**457**	674
Accretion of decommissioning liabilities	**392**	388	371	285	**1,151**	730
Debt financing costs	**-**	-	-	1,092	**-**	1,092
Total finance costs	**410**	766	432	1,636	**1,608**	2,496

The decrease in total finance costs in the third quarter of 2014 compared to the same period in 2013 is primarily attributable to debt financing costs (primarily legal expenses) in 2013 related to the proposed $350 million second-lien senior secured term loan facility that was to be used for the development of the Onion Lake EOR project. Due to the volatility in the debt capital markets, we elected not to proceed with this financing.

The decrease in gross interest and financing charges in Q3 2014 over Q2 2014 is primarily the result of loan fees charged on the renewal and expansion of the Company's credit facilities during the second quarter.

During the third quarter of 2014, $173,000 of interest costs related to the construction of the thermal projects were capitalized.

Depletion and Depreciation

		2014		2013	Nine months ended September 30	
	Q3	Q2	Q1	Q3	**2014**	2013
Depletion and depreciation ($000s)	**16,927**	16,838	17,886	18,155	**51,651**	52,295
Per boe ($)	**20.98**	21.54	21.71	21.74	**21.41**	20.69

The Company's properties are depleted on a unit of production basis based on estimated proven plus probable reserves. Depletion and depreciation expense decreased 7% in the third quarter of 2014 to $16.9 million from $18.2 million in the same period in 2013. The decrease in depletion and depreciation was mainly attributable to the proportion change in production during Q3 2014 compared to the same period in 2013. The Onion Lake area accounted for 43% of production in Q3 2014 compared to 50% of production in Q3 2013 and Onion Lake has a higher depletion rate compared to the Company's other areas.

There were no impairment provisions recorded for the nine month period ended September 30, 2014 and September 30, 2013.

As of September 30, 2014, $148.3 million of expenditures included in property, plant and equipment that relate to the Onion Lake EOR project are not subject to depletion until production at this project begins.

Interest Income

		2014		2013	Nine months ended September 30	
($000s)	**Q3**	Q2	Q1	Q3	**2014**	2013
Interest income	**103**	383	29	19	**515**	31

Interest income consists of interest earned on excess cash held by the Company. Interest income has increased as a result of higher average cash balances maintained by the Company during the first nine months of 2014 compared to the same period in 2013. The higher average cash balances maintained during the first nine months of 2014 are due primarily to the proceeds from the issuance of common shares in 2014.

Income Taxes

		2014		2013	Nine months ended September 30	
($000s)	**Q3**	Q2	Q1	Q3	**2014**	2013
Current income tax	**19**	26	18	21	**63**	44
Deferred income tax (recovery)	**2,942**	190	(181)	3,892	**2,951**	3,380
Total income tax (recovery)	**2,961**	216	(163)	3,913	**3,014**	3,424

BlackPearl did not pay cash income taxes in the third quarter of 2014 and does not expect to pay income taxes during the remainder of 2014 as we have sufficient tax pools to shelter expected income.

During the nine months ended September 30, 2014, we recorded a tax provision of $3.0 million on earnings of $13.6 million. This low effective tax rate is due to the Company recording previously unrecognized tax benefits of $1.4 million as a result of a recent CRA tax audit of certain of the Company's prior year's tax returns.

RESULTS FROM OPERATIONS

		2014		2013	Nine months ended September 30	
	Q3	Q2	Q1	Q3	**2014**	2013
Net income (loss) ($000s)	**7,013**	4,684	(1,126)	9,270	**10,571**	6,223
Per share, basic ($)	**0.02**	0.01	(0.00)	0.03	**0.03**	0.02
Per share, diluted ($)	**0.02**	0.01	(0.00)	0.03	**0.03**	0.02

For the quarter ended September 30, 2014, the Company generated net income of $7.0 million compared to net income of $9.3 million in the same period in 2013. The decrease in income in the third quarter of 2014 compared to the same period in 2013 is primarily a result of a lower wellhead sales price and higher production costs in 2014, partially offset by lower royalties and the gain on risk management contracts.

		2014		2013	Nine months ended September 30	
	Q3	Q2	Q1	Q3	**2014**	2013
Funds flow from operations (1) ($000s)	**23,809**	23,161	23,037	32,609	**70,007**	65,471
Per share, basic ($)	**0.07**	0.07	0.08	0.11	**0.22**	0.22
Per share, diluted ($)	**0.07**	0.07	0.08	0.11	**0.21**	0.22

(1) Funds flow from operations is a non-GAAP measure that represents cash flow from operating activities before decommissioning costs incurred and changes in non-cash working capital related to operations. Funds flow from operations and funds flow from operations per share do not have standardized meanings prescribed by Canadian GAAP and therefore may not be comparable to similar measures used by other companies. Management uses these non-GAAP measurements for its own performance measures and to provide its shareholders and investors with a measurement of the Company's efficiency and its ability to fund a portion of its growth expenditures.

Funds flow from operations increased by 7% to $70.0 million during the first nine months of 2014 compared to $65.5 million in the same period in 2013. The increase is funds flow in 2014 is primarily a result of higher wellhead sales prices in 2014, partially offset by higher production costs.

LIQUIDITY AND CAPITAL RESOURCES

At September 30, 2014, the Company had working capital deficiency (current assets less current liabilities) of $29.5 million. The working capital deficiency will be funded from funds flows from operating activities and the undrawn amount available on our credit facilities.

At September 30, 2014, the Company had issued letters of credit in the amount of $20,000; leaving $150 million available to be drawn under the credit facilities. The amount available under these facilities ("Borrowing Base") is re-determined by the lenders at least twice a year and is primarily based on our oil and gas reserves, forecast commodity prices, the current economic environment and other factors as determined by the lenders. The next scheduled Borrowing Base redetermination is to occur by November 30, 2014. In the event the lenders elected not to renew the credit facilities during the credit facilities review any amounts outstanding on the facilities would be due and payable in full by May 30, 2016.

Pursuant to the terms of the credit agreement, the only financial covenant in the credit facilities is to maintain a working capital ratio of 1:1 at the end of each fiscal quarter. Working capital as defined in the lending agreement is current assets, from the Company's consolidated balance sheet, plus any undrawn amount on the credit facilities compared to current liabilities from the Company's consolidated balance sheet. BlackPearl was in compliance with this covenant throughout the first nine months of 2014. The credit facilities are secured by a floating and fixed charge debenture. The terms of our credit agreement also restrict the payment of cash dividends to shareholders.

We expect to fund the ongoing development of our conventional heavy oil projects at Mooney, Onion Lake and other minor project areas from funds flow from operations and amounts available under the credit facilities. We are also able to scale back our capital expenditure program on these projects relatively easily if circumstances warrant it. The first phase of the Onion Lake EOR project is being designed for production of 6,000 bbls/d of oil and capital costs are expected to be approximately $210 million. Funding for the first phase of the project is expected to come from amounts available from our credit facilities, proceeds from share issuances earlier in the year (aggregate gross proceeds of $88.4 million) and funds flow from operations. Construction is expected to be completed in mid-2015.

The Company is planning to build the Blackrod SAGD project in phases as well, with the first phase likely to be designed for 20,000 bbls/d of oil. We have not completed detailed cost estimates for this phase but our internal estimates suggest initial capital costs will be approximately $800 million. Regulatory approval of the first phase of the Blackrod SAGD project is expected in 2014 or early 2015. Timing of development of this project is dependent on additional financing. We will consider joint venture opportunities to accelerate development of this project.

CAPITAL EXPENDITURES

During the quarter ended September 30, 2014, capital spending was $80.3 million, an increase from $24.3 million during the same period in 2013. The main components of the capital spending program during the third quarter was construction of the first phase of the Onion Lake EOR project and the drilling of 16 associated wells, the drilling of 11 conventional heavy oils wells at Onion Lake and five horizontal wells at John Lake.

					Nine months ended	
		2014		2013	September 30	
($000s)	**Q3**	Q2	Q1	Q3	**2014**	2013
Land	**233**	222	253	342	**708**	1,025
Seismic	**(36)**	(19)	(62)	41	**(117)**	991
Drilling and completion	**24,359**	7,475	19,658	14,366	**51,492**	39,687
Equipment and facilities	**55,699**	38,725	29,508	9,577	**123,932**	23,964
Other	**7**	14	3	-	**24**	18
Total	**80,262**	46,417	49,360	24,326	**176,039**	65,685
Property acquisitions	**-**	1,627	-	-	**1,627**	5,057
Total capital expenditures	**80,262**	48,044	49,360	24,326	**177,666**	70,742
Property dispositions	**-**	-	-	-	**-**	-
Net capital expenditures	**80,262**	48,044	49,360	24,326	**177,666**	70,742

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The Company has a number of financial obligations in the ordinary course of business. The following table summarizes the contractual obligations and commitments of the Company outstanding as at September 30, 2014. These obligations are expected to be funded from funds flow from operations and the Company's credit facilities.

($000s)	2014	2015	2016	2017	2018	Thereafter
Operating leases (1)	511	1,981	1,287	-	-	-
Electrical service agreements (2)	263	1,003	520	119	119	2,225
Capital commitments (3)	25,338	4,835	-	-	-	-
Decommissioning liabilities (4)	164	868	1,936	1,002	1,076	60,835
	26,276	8,687	3,743	1,121	1,195	63,063

(1) *The Company has 24 months remaining on an operating lease for office space as at September 30, 2014. The Company's office lease was executed jointly with another party. Under the terms of the lease, BlackPearl and the other party are joint and severally liable for the obligations pursuant to the lease. Accordingly, if the other party is unable to fulfill their lease obligation, BlackPearl would be required to pay a maximum additional $6.1 million (including an estimate for operating costs) over the next 24 months. At September 30, 2014, no amounts were owed (2013 – no amounts owing).*

(2) *The Company entered into certain long-term agreements to acquire electricity for one of its processing facilities.*

(3) *The Company entered into certain agreements pertaining to the construction of the Onion Lake EOR project.*

(4) *The Company also has ongoing obligations related to the decommissioning of well sites and facilities which have reached the end of their economic lives. The undiscounted estimated obligations associated with the retirement of the Company's oil and gas properties were $65.9 million as at September 30, 2014. Decommissioning programs are undertaken regularly in accordance with applicable legislative requirements.*

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments as at September 30, 2014 include cash and cash equivalents, trade and other receivables, deposits within prepaid expenses and deposits, accounts payable and accrued liabilities and risk management liabilities. The carrying value of these instruments approximates their fair value due to the short-term nature of the instruments except for risk management liabilities which are measured at fair value. The Company manages its risk through its policies and processes and starting in 2014, the Company began to use risk management contracts to manage some of these risks.

The risks associated with these financial instruments including foreign currency risk, credit risk, interest rate risk, liquidity risk and commodity price risk have not changed from December 31, 2013.

OFF-BALANCE-SHEET ARRANGEMENTS

The Company had no off-balance-sheet arrangements during the period ended September 30, 2014 or 2013. We do utilize operating leases in our normal course of business as disclosed under contractual obligations and commitments.

RELATED-PARTY TRANSACTIONS

There was no related-party transactions during the period ended September 30, 2014 or 2013.

OUTSTANDING SHARE DATA AND STOCK OPTIONS

As at November 6, 2014, the Company had 335,638,226 common shares outstanding and 19,460,836 stock options outstanding under its stock-based compensation program.

OUTSTANDING LONG-TERM DEBT DATA

As at November 6, 2014, the Company had $17,000,000 amounts drawn under its existing credit facilities and had issued letters of credit in the amount of $20,000; leaving $132,980,000 available to be drawn under these credit facilities.

PROPOSED TRANSACTIONS

As of November 6, 2014, the Company does not have any significant pending transactions.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the interim consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, sales, expenses and the disclosure of contingencies. Such estimates primarily relate to unsettled transactions and events as of the date of the interim consolidated financial statements. These estimates are subject to measurement uncertainty. Actual results could differ from and affect the results reported in these interim consolidated financial statements. Further information on the Company's critical accounting estimates can be found in the notes to the annual consolidated financial statements and annual MD&A for the year ended December 31, 2013. There have been no changes to the Company's critical accounting estimates as of September 30, 2014.

CHANGES IN ACCOUNTING POLICIES

The Company has adopted the following new and amended standards with a date of initial application of January 1, 2014.

IAS 32: Financial Instruments: Presentation – amendments to IAS 32 clarified the meaning of "currently has a legal enforceable right to set-off" and the application of the IAS 32 offsetting criteria to settlement systems which apply gross settlement mechanisms that are not simultaneous. IAS 32 amendments required minimal disclosure changes in the Company's financial statements as of January 1, 2014.

IAS 36: Impairment of Assets –amendments to IAS 36 requires entities to disclose the recoverable amount of impaired Cash Generating Units ("CGU"). IAS 36 amendments required minimal disclosure changes in the Company's financial statements as of January 1, 2014.

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In May 2014, the IASB issued IFRS 15, "*Revenue from Contracts with Customers"* ("IFRS 15") to replace IAS 11, *"Construction Contracts"*, IAS 18, *"Revenue"* and a number of revenue-related interpretations. IFRS 15 specifies how and when to recognize revenue as well as requiring entities to provide users of financial statements with more informative, relevant disclosures. IFRS 15 is effective for years beginning on or after January 1, 2017 with earlier adoption permitted. The standard may be applied retrospectively or using a modified retrospective approach. The Company is currently evaluating the impact of adopting IFRS 15 on the Company's consolidated financial statements.

In July 2014, the IASB issued IFRS 9, *"Financial Instruments"* ("IFRS 9") to replace IAS 39, *"Financial Instrument: Recognition and Measurement."* IFRS 9 is effective for years beginning on or after January 1, 2018. Early adoption is permitted if IFRS 9 is adopted in its entirety at the beginning of a fiscal period. The Company is currently evaluating the impact of adopting IFRS 9 on the Company's consolidated financial statements.

A description of standards and interpretations that will be adopted by the Company in future periods can be found in the notes to the annual consolidated financial statements for the year ended December 31, 2013.

RISKS AND UNCERTAINTIES

Please refer to the Company's annual MD&A and Annual Information Form for the year ended December 31, 2013 for a discussion of the risks and uncertainties associated with the Company activities. There have been no significant changes in these risks and uncertainties during the first nine months of 2014.

CONTROL CERTIFICATION

Management reported on its disclosure controls and procedures and the design of its internal controls over financial reporting in the annual MD&A for the year ended December 31, 2013. There have been no changes to the Company's internal controls over financial reporting ("ICFR") for the first nine months of 2014 that have materially affected, or are reasonably likely to affect, the Company's ICFR.

OUTLOOK

2014 Guidance	Initial Guidance	Q1 Update	Q2 Update	Q3 Update	Initial 2015 Guidance
Production (boe/d)					
Annual average	10,000 – 10,500	9,000 – 9,500	9,000 – 9,500	9,000 – 9,500	9,500
Funds flow from operations ($millions)	80 - 85	75 – 80	80 – 85	80 – 85	60 – 65
Capital expenditures ($millions)	260 - 270	280 – 300	280 – 300	275 – 285	80 – 85
Year-end debt ($millions)	95 - 105	135 – 140	130 – 140	110 – 115	130 – 140
Pricing Assumptions (annual average)					
Crude oil - WTI	US $92.00	US $95.50	US $99.00	US $95.00	US $85.00
Light/heavy differential	US $21.00	US $20.50	US $23.00	US $20.00	US $17.00
Foreign Exchange (Cdn$ to US$)	0.94	0.92	0.92	0.91	0.90

We expect our oil and gas production to average between 9,000 and 9,500 boe/d for 2014, unchanged from our Q2 update. Funds flow from operations for the year is anticipated to range between $80 and $85 million, again, unchanged from our Q2 2014 update. Capital spending for 2014 is expected to be between $275 and $285 million, down from our Q2 update estimate of $280 to $300 million. The reduction in capital spending is a result of certain expenditures on the Onion Lake thermal project that were originally planned for the fourth quarter now likely to be undertaken in the first quarter of 2015 and the deferral of drilling on the Phase 3 lands at Mooney until the second half of 2015. As a result of the lower capital spending our year-end 2014 debt should be between $110 and $115 million.

In 2015, we have planned a capital expenditure program of between $80 and $85 million. Capital expenditures for 2015 will include completion of the Onion Lake thermal project, costs associated with the expansion of the ASP flood at Mooney (well conversions and initial capitalization of polymer and chemical costs), drilling horizontal wells on the phase 3 lands at Mooney, drilling 20 to 25 conventional heavy oil wells at Onion Lake and drilling up to 10 wells at John Lake and other areas.

It is expected that this capital program will be largely funded from anticipated cash flow from operations and supplemented with our existing credit facilities. Year-end 2015 debt levels are anticipated to be approximately $135 million.

Oil and gas production should average approximately 9,500 boe/d in 2015. We expect to commence steam injection at Onion Lake in mid-2015 but this project is not expected to have a meaningful impact on our production levels until 2016. Exit production levels for 2015 are expected to be approximately 11,000 boe/d.

FORWARD-LOOKING STATEMENTS

This report contains certain forward-looking statements and forward-looking information (collectively referred to as "**forward-looking statements**") within the meaning of applicable Canadian securities laws. All statements other than statements of historical fact are forward-looking statements. Forward-looking information typically contains statements with words such as “anticipated”, “approximately”, “planning”, “planned”, “could”, “continued”, “estimate”, “estimates”, “estimated”, “forecast”, “likely”, “expect”, “expected”, “may”, “target”, “intends”, “intended”, “new”, “will”, “timing”, “in the event”, “move toward”, “is to occur”, “scheduled”, “outlook” or similar words suggesting future outcomes.

In addition, statements relating to “reserves”, “resources” or “contingent resources” are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resource described exist in the quantities predicted or estimated and can be profitably produced in the future.

In particular, but without limiting the foregoing, this report contains forward-looking statements pertaining to our business plans and strategies; capital expenditure and drilling programs including:

- Target date for completion of construction and first steam at the Onion Lake EOR project as discussed in the 2014 Significant Events section;
- Potential production levels and anticipated timing of initial and peak oil production at the Onion Lake EOR project as discussed in the 2014 Significant Events section;
- Future oil and gas prices and their impact on BlackPearl as discussed per the Commodity Prices section;
- Expected future gas prices and their impact on costs related to our thermal projects as discussed per the Commodity Prices section;
- Anticipated timing of peak production rates at the second pilot well pair at Blackrod as discussed in the Oil and Gas Production, Oil and Gas Pricing and Oil and Gas Sales section;
- Future expansion phases of the ASP flood at Mooney will be eligible for the Alberta government’s EOR royalty incentive program as discussed in the Royalties section;
- Expected cash taxes to be paid in 2014 in the Income Taxes section;
- The required timing of payment on any amounts outstanding on the facilities in the event the lenders elected not to renew the credit facilities as discussed in the Liquidity and Capital Resources section;
- The estimated capital costs for the first phase of thermal development at Blackrod and the first phase of thermal development at Onion Lake as discussed in the Liquidity and Capital Resources section;
- Methods, sources and timing to finance capital expenditure programs, particularly for the thermal projects at Blackrod and Onion Lake as discussed in the Liquidity and Capital resources section;
- Potential production levels for the Blackrod SAGD project and the Onion Lake thermal project in the Liquidity and Capital resources section; and
- All of the statements under the Outlook section and the table presented since they are estimates of future conditions and results.

The forward-looking information is based on expectations and assumptions by management regarding future production levels, future oil and natural gas prices, continuation of existing tax, royalty and regulatory regimes, foreign exchange rates, estimates of future operating costs, timing and amount of capital expenditures, performance of existing and future wells, the ability to obtain financing on acceptable terms, availability of skilled labour and drilling and related equipment, general economic and financial market conditions and the ability to market oil and natural gas successfully to current and new customers. Although management considers these assumptions to be reasonable based on information currently available to it, they may prove to be incorrect.

Undue reliance should not be placed on forward-looking statements. There can be no assurance that the plans, intentions or expectations upon which forward-looking statements are based will be realized. Actual results will differ, and the differences may be material and adverse to the Company and its shareholders.

By their very nature, forward-looking statements involve inherent risks and uncertainties (both general and specific) and risks that the goals or figures contained in forward-looking statements will not be achieved. These factors include, but are not limited to, risks associated with fluctuations in market prices for crude oil, natural gas and diluent, general economic, market and business conditions, volatility of commodity inputs, substantial capital requirements, customary conditions including receipt of necessary regulatory and stock exchange approvals on the issuance of common shares, uncertainties inherent in estimating quantities of reserves and resources, extent of, and cost of compliance with, government laws and regulations and the effect of changes in such laws and regulations from time to time, the need to obtain regulatory approvals on projects before development commences, environmental risks and hazards and the cost of compliance with environmental regulations, aboriginal claims, inherent risks and hazards with operations such as fire, explosion, blowouts, mechanical or pipe failure, cratering, oil spills, vandalism and other dangerous conditions, financial loss associated with risk management contracts, potential cost overruns, variations in foreign exchange rates, variations in interest rates, diluent and water supply shortages, competition for capital, equipment, new leases, pipeline capacity and skilled personnel, uncertainties inherent in the SAGD bitumen and ASP recovery process, credit risks associated with counterparties, the failure of the Company or the holder of licences, leases and permits to meet requirements of such licences, leases and permits, reliance on third parties for pipelines and other infrastructure, changes in royalty regimes, failure to accurately estimate abandonment and reclamation costs, inaccurate estimates and assumptions by management, effectiveness of internal controls, the potential lack of available drilling equipment and other restrictions, failure to obtain or keep key personnel, title deficiencies with the Company's assets, geo-political risks, risks that the Company does not have adequate insurance coverage, risk of litigation and risks arising from future acquisition activities. Further information regarding these risk factors may be found under "Risk Factors" in the Annual Information Form.

Readers are cautioned that these factors and risks are difficult to predict and that the assumptions used in the preparation of such information, although considered reasonably accurate at the time of preparation, may prove to be incorrect. Readers are also cautioned that the foregoing list of factors is not exhaustive. Consequently, there is no representation by the Corporation that actual results achieved will be the same in whole or in part as those set out in the forward-looking information. Furthermore, the forward-looking statements contained in this report are made as of the date hereof, and the Corporation does not undertake any obligation, except as required by applicable securities legislation, to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise.

Other Supplementary Information

1. List of directors and officers at November 6, 2014

a. Directors:

John Craig
John Festival
Brian Edgar
Keith Hill
Vic Luhowy

b. Officers:

John Craig, Chairman
John Festival, President and Chief Executive Officer
Don Cook, Chief Financial Officer
Chris Hogue, Vice President Operations
Ed Sobel, Vice President Exploration
Diane Phillips, Corporate Secretary

2. Financial Information

The report for the year ended December 31, 2014 is expected to be published on or before February 28, 2015.

3. Other Information

Address (Corporate head office):
BlackPearl Resources Inc.
700, 444 – 7 Avenue S.W.
Calgary, Alberta T2P 0X8
Canada
Telephone: +1.403.215.8313
Fax: +1.403.265.8324
Website: www.blackpearlresources.ca

The Canadian federal corporation number for the Company is 454611-3.

For further information, please contact:

John Festival - President and Chief Executive Officer, +1.403.215.8313
Don Cook – Chief Financial Officer, +1.403.215.8313

BLACKPEARL RESOURCES INC.

Consolidated Balance Sheets

(unaudited) (Cdn$ in thousands)	Note	September 30, 2014	December 31, 2013
Assets			
Current assets			
Cash and cash equivalents	4	**$ 12,779**	$ 8,402
Trade and other receivables	5	**20,967**	20,586
Prepaid expenses and deposits		**1,682**	963
		35,428	29,951
Trade and other receivables	5	**-**	1,038
Deferred tax assets		**-**	408
Exploration and evaluation assets	6	**167,411**	161,408
Property, plant and equipment	7	**582,699**	459,411
		$ 785,538	$ 652,216
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	8	**$ 64,051**	$ 37,895
Current portion of decommissioning liabilities	10	**851**	838
Risk management liabilities	13	**69**	-
		64,971	38,733
Decommissioning liabilities	10	**58,477**	54,546
Deferred tax liabilities		**1,736**	-
		125,184	93,279
Shareholders' equity			
Share capital	11	**970,134**	881,949
Contributed surplus		**31,360**	28,699
Deficit		**(341,140)**	(351,711)
		660,354	558,937
		$ 785,538	$ 652,216

Commitments and contingencies (note 12)

See accompanying notes to consolidated financial statements

BLACKPEARL RESOURCES INC.

Consolidated Statements of Comprehensive Income

(unaudited) **(Cdn$ in thousands, except for per share amounts)**	Note	**Three months ended September 30, 2014**	Three months ended September 30, 2013	**Nine months ended September 30, 2014**	Nine months ended September 30, 2013
Revenue					
Oil and gas sales		**$ 58,818**	$ 69,092	**$ 180,547**	$ 168,085
Royalties		**(10,273)**	(14,523)	**(34,215)**	(32,596)
Net oil and gas revenue		**48,545**	54,569	**146,332**	135,489
Gain (loss) on risk management contracts	13	**4,493**	-	**(4,045)**	-
		53,038	54,569	**142,287**	135,489
Expenses					
Production		**21,021**	16,664	**60,985**	53,779
Transportation		**1,665**	2,086	**4,892**	7,931
General and administrative		**1,718**	1,841	**6,541**	6,565
Depletion and depreciation	7	**16,927**	18,155	**51,651**	52,295
Finance costs	14	**410**	1,636	**1,608**	2,496
Stock-based compensation	11	**1,460**	1,012	**3,551**	2,792
Foreign currency exchange loss (gain)		**(34)**	11	**(11)**	15
		43,167	41,405	**129,217**	125,873
Other income					
Interest income		**103**	19	**515**	31
Income before income taxes		**9,974**	13,183	**13,585**	9,647
Income taxes					
Current income tax		**19**	21	**63**	44
Deferred income tax		**2,942**	3,892	**2,951**	3,380
		2,961	3,913	**3,014**	3,424
Net and comprehensive income for the period		**$ 7,013**	$ 9,270	**$ 10,571**	$ 6,223
Income per share					
Basic	11	**$ 0.02**	$ 0.03	**$ 0.03**	$ 0.02
Diluted	11	**$ 0.02**	$ 0.03	**$ 0.03**	$ 0.02

See accompanying notes to consolidated financial statements

BLACKPEARL RESOURCES INC.

Consolidated Statements of Changes in Equity

(unaudited)
(Cdn$ in thousands)

	Nine months ended September 30, 2014			
	Share Capital	**Contributed Surplus**	**Deficit**	**Total Equity**
Balance - January 1, 2014	$ 881,949	$ 28,699	$ (351,711)	$ 558,937
Net and comprehensive income for the period	-	-	10,571	10,571
Stock-based compensation	-	3,721	-	3,721
Shares issued on equity offering	88,440	-	-	88,440
Share issue costs	(3,361)	-	-	(3,361)
Shares issued on exercise of stock options	2,046	-	-	2,046
Transfer to share capital on exercise of stock options	1,060	(1,060)	-	-
Balance - September 30, 2014	**$ 970,134**	**$ 31,360**	**$ (341,140)**	**$ 660,354**

	Nine months ended September 30, 2013			
	Share Capital	**Contributed Surplus**	**Deficit**	**Total Equity**
Balance - January 1, 2013	$ 876,400	$ 26,762	$ (358,160)	$ 545,002
Net and comprehensive income for the period	-	-	6,223	6,223
Stock-based compensation	-	3,184	-	3,184
Shares issued on exercise of stock options	785	-	-	785
Transfer to share capital on exercise of stock options	389	(389)	-	-
Balance - September 30, 2013	$ 877,574	$ 29,557	$ (351,937)	$ 555,194

See accompanying notes to consolidated financial statements

BLACKPEARL RESOURCES INC.

Consolidated Statements of Cash Flows

(unaudited) **(Cdn$ in thousands)**	Note	**Three months ended September 30, 2014**	Three months ended September 30, 2013	**Nine months ended September 30, 2014**	Nine months ended September 30, 2013
Operating activities					
Net and comprehensive income for the period		**$ 7,013**	$ 9,270	**$ 10,571**	$ 6,223
Items not involving cash:					
Depletion and depreciation	7	**16,927**	18,155	**51,651**	52,295
Accretion of decommissioning liabilities	14	**392**	285	**1,151**	730
Stock-based compensation	11	**1,460**	1,012	**3,551**	2,792
Foreign exchange loss (gain)		**36**	(5)	**63**	51
Deferred income tax		**2,942**	3,892	**2,951**	3,380
Unrealized loss (gain) on risk management contracts	13	**(4,961)**	-	**69**	-
Decommissioning costs incurred	10	**(213)**	(142)	**(700)**	(555)
Changes in non-cash working capital	14	**1,991**	623	**(1,161)**	(7,990)
Cash flow from operating activities		**25,587**	33,090	**68,146**	56,926
Financing activities					
Proceeds on issue of common shares, net of costs	11	**-**	264	**86,316**	785
Proceeds on issue of long-term debt		**-**	-	**-**	25,000
Repayment of long-term debt		**-**	(15,000)	**-**	(15,000)
Cash flow from (used in) financing activities		**-**	(14,736)	**86,316**	10,785
Investing activities					
Capital expenditures - exploration and evaluation assets	6	**(404)**	(2,405)	**(5,553)**	(23,859)
Capital expenditures - property, plant and equipment	7	**(79,571)**	(21,765)	**(171,725)**	(46,382)
Changes in non-cash working capital	14	**13,224**	4,672	**27,267**	(6,166)
Cash flow used in investing activities		**(66,751)**	(19,498)	**(150,011)**	(76,407)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**(70)**	16	**(74)**	(36)
Increase (decrease) in cash and cash equivalents		**(41,234)**	(1,128)	**4,377**	(8,732)
Cash and cash equivalents, beginning of period		**54,013**	9,373	**8,402**	16,977
Cash and cash equivalents, end of period		**$ 12,779**	$ 8,245	**$ 12,779**	$ 8,245

See accompanying notes to consolidated financial statements

BLACKPEARL RESOURCES INC.
Notes to the Consolidated Financial Statements
(tabular amounts in thousands of Cdn$, except as noted)
(unaudited)

1. GENERAL INFORMATION

BlackPearl Resources Inc. (collectively with its subsidiaries, the “Company” or “BlackPearl”) is engaged in the business of oil and gas exploration, development and production in North America. The Company’s primary focus is on heavy oil and oil sands projects in Western Canada. The Company is listed and traded on the TSX Exchange under the trading symbol “PXX”. The Company’s Swedish Depository Receipts trade on the NASDAQ Stockholm market under the symbol “PXXS”. BlackPearl is incorporated and located in Canada. The address of its registered office is 700, 444 – 7th Avenue SW, Calgary, Alberta, T2P 0X8.

2. BASIS OF PREPARATION

These condensed unaudited interim consolidated financial statements for the three and nine months ended September 30, 2014 have been prepared in accordance with IAS 34, Interim Financial Reporting under International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board (“IASB”) and have been prepared following the same accounting policies and method of computation as the annual consolidated financial statements for the year ended December 31, 2013 except for standards applicable for the first time and new standards and amendments effective for the first time from January 1, 2014 as disclosed in note 3 and the calculation of income taxes. Income taxes on earnings or loss in the interim periods are accrued using the income tax rate that would be applicable to the expected total annual earnings or loss.

The policies applied in these condensed interim consolidated financial statements are based on IFRS issued, outstanding and effective as of November 6, 2014, the date they were approved and authorized for issuance by the Company’s Board of Directors (“the Board”). Any subsequent changes to IFRS that are given effect in the Company’s annual consolidated financial statements for the year ended December 31, 2014 could result in restatement of these interim consolidated financial statements.

The disclosures provided below are incremental to those included with the annual consolidated financial statements. Certain information and disclosures normally included in the notes to the annual consolidated financial statements have been condensed or have been disclosed on an annual basis only. Accordingly, these interim consolidated financial statements should be read in conjunction with the annual consolidated financial statements for the year ended December 31, 2013 which have been prepared in accordance with IFRS as issued by the IASB.

3. SIGNIFICANT ACCOUNTING POLICIES

New standards and amendments effective for the first time from January 1, 2014

Certain pronouncements were issued that are mandatory for accounting periods beginning before or on January 1, 2014. The following new standards and amendments have been adopted in these interim financial statements.

IAS 32: Financial Instruments: Presentation – amendments to IAS 32 clarified the meaning of “currently has a legal enforceable right to set-off” and the application of the IAS 32 offsetting criteria to settlement systems which apply gross settlement mechanisms that are not simultaneous. IAS 32 amendments required minimal disclosure changes in the Company’s financial statements as of January 1, 2014.

IAS 36: Impairment of Assets –amendments to IAS 36 requires entities to disclose the recoverable amount of impaired Cash Generating Units (“CGU”). IAS 36 amendments required minimal disclosure changes in the Company’s financial statements as of January 1, 2014.

Accounting standards issued but not yet applied

In May 2014, the IASB issued IFRS 15, “*Revenue from Contracts with Customers”* (“IFRS 15”) to replace IAS 11, *“Construction Contracts”*, IAS 18, *“Revenue”* and a number of revenue-related interpretations. IFRS 15 specifies how and when to recognize revenue as well as requiring entities to provide users of financial statements with more informative, relevant disclosures. IFRS 15 is effective for years beginning on or after January 1, 2017 with earlier adoption permitted. The standard may be applied retrospectively or using a modified retrospective approach. The Company is currently evaluating the impact of adopting IFRS 15 on the Company's consolidated financial statements.

In July 2014, the IASB issued IFRS 9, *"Financial Instruments"* ("IFRS 9") to replace IAS 39, *"Financial Instrument: Recognition and Measurement."* IFRS 9 is effective for years beginning on or after January 1, 2018. Early adoption is permitted if IFRS 9 is adopted in its entirety at the beginning of a fiscal period. The Company is currently evaluating the impact of adopting IFRS 9 on the Company's consolidated financial statements.

A description of standards and interpretations that will be adopted by the Company in future periods can be found in the notes to the annual consolidated financial statements for the year ended December 31, 2013.

4. CASH AND CASH EQUIVALENTS

		September 30, 2014		December 31, 2013
Cash at banks	**$**	**2,555**	$	8,402
Short-term deposits		**10,224**		-
	$	**12,779**	$	8,402

Cash at banks earn interest at floating rates based on daily bank deposit rates. As of September 30, 2014, US $1.5 million (2013 – US $1.1 million) is included in cash at banks. The Company only deposits cash with major banks of high quality credit ratings.

5. TRADE AND OTHER RECEIVABLES

		September 30, 2014		December 31, 2013
Trade accounts receivable	**$**	**18,548**	$	16,845
Receivables from joint venturers		**302**		305
Allowance for doubtful accounts		**(285)**		(285)
Net accounts receivable		**18,565**		16,865
Royalty reimbursement from enhanced oil recovery incentive programs		**1,038**		4,072
Other receivables		**1,364**		687
Total trade and other receivables		**20,967**		21,624
Less non-current portion of royalty reimbursement from enhanced oil recovery incentive programs		**-**		(1,038)
Current portion of trade and other receivables	**$**	**20,967**	$	20,586

Aging of trade accounts receivables are as follows:

		September 30, 2014		December 31, 2013
Current	**$**	**18,347**	$	16,443
31 to 60 days		**184**		322
61 to 90 days		**28**		46
Over 90 days		**6**		34
	$	**18,565**	$	16,845

6. EXPLORATION AND EVALUATION ASSETS

At January 1, 2013	$ 134,721
Expenditures	24,181
Acquisition	2,094
Capitalized stock-based compensation	148
Change in decommissioning provision	264
At December 31, 2013	161,408
Expenditures	3,926
Acquisition	1,627
Change in decommissioning provision	450
At September 30, 2014	$ 167,411

The Company's exploration and evaluation assets consist predominately of costs pertaining to the Blackrod SAGD project in northern Alberta. These assets are not subject to depletion or depreciation but they are reviewed for possible impairment. During the first nine months of 2014, no assets were considered to be impaired.

The net operating revenues of the Blackrod SAGD pilot are being capitalized until the decision to transfer exploration and evaluation assets to property, plant and equipment is made. The decision to transfer exploration and evaluation assets to property, plant and equipment occurs when commercial viability and technical feasibility is established, regulatory and Board approval is received and management has determined to pursue commercial development which is based, in part, on proved and probable reserves recognized for the asset. During the nine months ended September 30, 2014, the Company capitalized net operating revenues totalling a loss of $1.8 million (2013 - $2.2 million). The Company did not capitalize any general and administrative costs related to exploration activities during the nine months ended September 30, 2014 (2013 - $Nil).

7. PROPERTY, PLANT AND EQUIPMENT

	Petroleum and natural gas properties	**Corporate**	**Total**
Cost			
At January 1, 2013	$ 848,108	$ 3,352	$ 851,460
Expenditures	63,755	90	63,845
Acquisitions	2,963	-	2,963
Capitalized stock-based compensation	260	-	260
Change in decommissioning provision	22,279	-	22,279
Disposals	(2,302)	-	(2,302)
At December 31, 2013	935,063	3,442	938,505
Expenditures	171,701	24	171,725
Capitalized stock-based compensation	171	-	171
Change in decommissioning provision	3,043	-	3,043
At September 30, 2014	$ 1,109,978	$ 3,466	$ 1,113,444
Accumulated depletion and depreciation			
At January 1, 2013	$ 402,256	$ 1,905	$ 404,161
Depletion and depreciation	71,870	213	72,083
Impairment	3,000	-	3,000
Disposals	(150)	-	(150)
At December 31, 2013	476,976	2,118	479,094
Depletion and depreciation	51,503	148	51,651
At September 30, 2014	$ 528,479	$ 2,266	$ 530,745
Net book value			
December 31, 2013	$ 458,087	$ 1,324	$ 459,411
September 30, 2014	$ 581,499	$ 1,200	$ 582,699

During the nine months ended September 30, 2014, the Company capitalized borrowing costs of $0.4 million (2013 - $0.2 million) to development activities. The Company did not capitalize any general and administrative costs related to development activities during the nine months ended September 30, 2014 (2013 - $Nil).

Property, plant and equipment at September 30, 2014 includes $148.3 million (December 31, 2013 - $16.0 million) of assets under construction pertaining to the Onion Lake Enhanced Oil Recovery (EOR) project that are not subject to depletion and depreciation.

The Company performed review tests at September 30, 2014 for any indication of impairment. No assets were considered to be impaired and no impairment was recorded during the nine months ended September 30, 2014 (2013 - $Nil).

At September 30, 2014, the potential recoverable amount of the Company's previously impaired CGU was $0.1 million at the Salt Lake CGU in Saskatchewan.

8. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

		September 30, 2014		December 31, 2013
Trade payables and accrued liabilities	**$**	**63,082**	$	37,159
Payables to joint venturers		**534**		359
Other payables		**435**		377
	$	**64,051**	$	37,895

Trade payables are non-interest bearing and are normally settled on a 30 to 60 day term.

9. LONG-TERM DEBT

At September 30, 2014 the Company's credit facilities consist of a $140 million syndicated revolving line of credit (2013 - $105 million) and a non-syndicated operating line of credit of $10 million (2013 - $10 million). The facilities are secured by a floating and fixed charge debenture on the assets of the Company. The amount available under these facilities ("Borrowing Base") is re-determined at least twice a year and is primarily based on the Company's oil and gas reserves, forecast commodity prices, the current economic environment and other factors as determined by the syndicate of lending institutions. The next scheduled Borrowing Base redetermination is to occur by November 30, 2014. The facilities are also subject to annual reviews by the lenders and the next scheduled review is to be completed by May 31, 2015. In the event the lenders elected not to renew the credit facilities during the annual review, any amounts outstanding on the facilities would be due and payable in full by May 30, 2016.

Pursuant to the lending agreement, advances may be made, at the Company's option, as direct advances, LIBOR advances, banker's acceptances or standby letters of credit/guarantees. These advances bear interest depending on the type of advancement at the lender's prime rate, banker's acceptance rate or LIBOR rates, plus applicable margins. The applicable margin charged by the lender is dependent upon the Company's debt to EBITDA ratio calculated at the Company's previous fiscal quarter end. The lending agreement defines debt as any advances outstanding on the credit facilities plus any outstanding letters of credit/guarantee as per the Company's consolidated balance sheet. The lending agreement defines EBITDA as comprehensive income before income tax, financing charges, non-cash items deducted in determining comprehensive income and any income/losses attributable to assets acquired or disposed of when determining net comprehensive income for the period as per the Company's consolidated statement of comprehensive income. The Company also incurs a standby fee for undrawn amounts.

At September 30, 2014, no amounts were drawn under these facilities; however, the Company has issued a $20,000 letter of credit; leaving $150 million available to be drawn under the credit facilities. Pursuant to the terms of the credit agreement, the Company is required to maintain a working capital ratio of 1:1 at the end of each fiscal quarter. Working capital as defined in the lending agreement is current assets, as indicated on the Company's consolidated balance sheet, plus any undrawn amount on the credit facilities as compared to current liabilities from the Company's consolidated balance sheet. The Company had a working capital ratio of 2.9:1 at September 30, 2014 (2013 – 3.8:1) and is in compliance with this covenant at September 30, 2014.

10. DECOMMISSIONING LIABILITIES

The Company's decommissioning liability is an estimate of the reclamation and abandonment costs arising from the Company's ownership interest in oil and gas assets, including well sites, gathering systems, batteries and processing facilities. The total undiscounted amount of the estimated cash flows required to settle the liability is approximately $65.9 million (December 31, 2013 - $63.9 million). The estimated net present value of the decommissioning liability was calculated using an inflation factor of 2% (December 31, 2013 - 2%) and discounted using a risk-free rate of 2.58% (December 31, 2013 - 2.55%). Settlement of the liability, which may extend up to 40 years in the future, is expected to be funded from general corporate funds at the time of retirement.

Changes to the decommissioning liability were as follows:

		Nine months ended September 30, 2014		Year ended December 31, 2013
Decommissioning liability, beginning of period	**$**	**55,384**	$	33,372
New liabilities recognized		**3,289**		2,103
Liabilities acquired		**469**		6,589
Reduction in liabilities due to asset dispositions		**(157)**		(789)
Decommissioning costs incurred		**(700)**		(849)
Change in estimated costs of decommissioning		**-**		14,815
Change in discount rate		**(108)**		(951)
Accretion expense		**1,151**		1,094
Decommissioning liability, end of period		**59,328**		55,384
Less current portion of decommissioning liability		**(851)**		(838)
Non-current portion of decommissioning liability	**$**	**58,477**	$	54,546

11. SHARE CAPITAL

(a) Authorized

The Company is authorized to issue an unlimited number of common shares.

(b) Common Shares Issued

	Number of Shares	**Attributed Value**
Balance as at January 1, 2013	295,765,808	$ 876,400
Shares issued on exercise of stock options	4,659,000	3,659
Transferred from contributed surplus on exercise of stock options	-	1,890
Balance as at December 31, 2013	300,424,808	881,949
Shares issued on equity offering	33,373,585	88,440
Share issue costs, net of tax benefits of $809	-	(3,361)
Shares issued on exercise of stock options	1,839,833	2,046
Transferred from contributed surplus on exercise of stock options	-	1,060
Balance as at September 30, 2014	335,638,226	$ 970,134

(c) Stock Options Outstanding

The Company has a stock option plan (the "Plan") available to directors, officers, employees and certain consultants of the Company and its subsidiaries. Under the Plan, the number of common shares to be reserved and authorized for issuance pursuant to options granted under the Plan cannot exceed 10% of the total number of issued and outstanding shares in the Company. The term and the vesting period of any options granted are determined at the discretion of the Board. The maximum term for options granted is ten years; however, all of the options granted by the Company have a term of five years or less and vest at a rate of one third on each of the three anniversaries from the date of the grant.

The exercise price of the option cannot be less than the five-day volume weighted average trading price of the common shares immediately preceding the day the option is granted.

The following table summarizes stock options outstanding:

	Number of Options	**Weighted Average Exercise Price ($)**
Outstanding at January 1, 2013	17,382,999	2.81
Granted	3,545,500	2.39
Exercised	(4,659,000)	0.79
Forfeited	(1,638,000)	3.69
Expired	(25,000)	1.75
Outstanding at December 31, 2013	14,606,499	3.26
Granted	8,006,000	2.65
Exercised	(1,839,833)	1.11
Forfeited	(1,066,833)	3.78
Outstanding at September 30, 2014	19,705,833	3.18

Options outstanding and exercisable as at September 30, 2014 are summarized below:

	Options Outstanding			**Options Exercisable**		
Range of Exercise Prices ($)	**Number of Options**	**Weighted-Average Exercise Price ($)**	**Weighted-Average Remaining Life (Years)**	**Number of Options**	**Weighted-Average Exercise Price ($)**	**Weighted-Average Remaining Life (Years)**
1.89 – 3.00	13,576,833	2.51	3.35	3,569,533	2.28	0.90
3.01 – 4.50	1,941,500	3.68	2.68	1,168,688	3.73	2.58
4.51 – 6.00	3,872,500	5.01	1.63	3,227,684	5.02	1.53
6.01 – 7.66	315,000	6.91	1.69	315,000	6.91	1.69
	19,705,833	3.18	2.92	8,280,905	3.73	1.41

The fair value of common share options granted is estimated on the date of grant using the Black-Scholes option pricing model. During the nine months ended September 30, 2014, 8,006,000 options were granted (2013 - 3,045,500).

The fair value of these options was estimated using the following weighted average assumptions:

	Three months ended September 30		Nine months ended September 30	
Assumptions	**2014**	2013	**2014**	2013
Risk free interest rate (%)	**1.3**	1.4	**1.3**	1.1
Expected life (years)	**3.7**	3.5	**3.6**	3.5
Expected volatility (%)	**50.2**	51.1	**50.7**	49.3
Forfeiture rate (%)	**14.4**	14.6	**15.1**	14.2
Weighted average fair value of options	**$ 0.88**	$ 0.71	**$ 1.02**	$ 0.90

(d) Stock-based Compensation

	Three months ended September 30		Nine months ended September 30	
	2014	2013	**2014**	2013
Gross stock-based compensation	**$ 1,539**	$ 1,179	**$ 3,960**	$ 3,556
Recoveries from forfeitures	**(9)**	(13)	**(238)**	(372)
Net stock-based compensation before capitalization	**1,530**	1,166	**3,721**	3,184
Stock-based compensation capitalized to exploration and evaluation assets	**-**	-	**-**	(148)
Stock-based compensation capitalized to property, plant and equipment	**(70)**	(154)	**(171)**	(244)
Net stock-based compensation	**$ 1,460**	$ 1,012	**$ 3,551**	$ 2,792

(e) Income per Share

Basic income per share amounts are calculated by dividing net and comprehensive income for the period by the weighted average number of common shares outstanding during the period.

The following table shows the calculation of basic and diluted income per share for the periods ended:

	Three months ended September 30		Nine months ended September 30	
	2014	2013	**2014**	2013
Net and comprehensive income	**$ 7,013**	$ 9,270	**$ 10,571**	$ 6,223
Weighted average number of common shares - basic	**335,638**	296,244	**325,167**	296,137
Dilutive effect:				
Outstanding options	**1**	2,340	**482**	3,799
Weighted average number of common shares – diluted	**335,639**	298,584	**325,650**	299,936
Basic income per share	**$ 0.02**	$ 0.03	**$ 0.03**	$ 0.02
Diluted income per share	**$ 0.02**	$ 0.03	**$ 0.03**	$ 0.02

For the nine months ended September 30, 2014, the Company used an average market price of $2.44 (2013 - $2.20) per share to calculate the dilutive effect of stock options. For the nine months ended September 30, 2014, 15,541,775 options were anti-dilutive (2013 – 12,882,898) and were not included in the calculation of diluted income per share.

12. COMMITMENTS AND CONTINGENCIES

	2014	2015	2016	2017	2018	Thereafter
Operating leases (1)	$ 511	$ 1,981	$ 1,287	$ -	$ -	$ -
Electrical service agreement (2)	263	1,003	520	119	119	2,225
Capital commitments (3)	25,338	4,835	-	-	-	-
	$ 26,112	$ 7,819	$ 1,807	$ 119	$ 119	$ 2,225

(1) The Company has 24 months remaining on an operating lease for office space as at September 30, 2014. The Company's office lease was executed jointly with another party. Under the terms of the lease, BlackPearl and the other party are joint and severally liable for the obligations pursuant to the lease. Accordingly, if the other party is unable to fulfill their lease obligation, BlackPearl would be required to pay a maximum additional amount of $6.1 million (including an estimate for operating costs) over the next 24 months. At September 30, 2014, no amounts were owed (2013 – no amounts owing).

(2) The Company entered into certain long-term agreements to acquire electricity for one of its processing facilities.

(3) The Company entered into certain agreements pertaining to the construction of the Onion Lake EOR project.

13. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments as at September 30, 2014 include cash and cash equivalents, trade and other receivables, deposits within prepaid expenses and deposits, accounts payable and accrued liabilities and risk management liabilities.

(a) Fair value of financial instruments

The following table summarizes the carrying value of the Company's financial assets and liabilities compared to their respective fair values.

	September 30, 2014		December 31, 2013	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Financial Assets				
Loans and receivables:				
Cash and cash equivalents	$ 12,779	$ 12,779	$ 8,402	$ 8,402
Trade and other receivables	$ 20,967	$ 20,967	$ 17,552	$ 17,552
Deposits	$ 414	$ 414	$ 413	$ 413
Financial liabilities				
Financial liabilities at amortized cost:				
Accounts payable and accrued liabilities	$ 64,051	$ 64,051	$ 37,895	$ 37,895
Financial liabilities at fair value through profit or loss:				
Risk management liabilities	$ 69	$ 69	$ -	$ -

The fair value of cash and cash equivalents, trade and other receivables, deposits and accounts payable and accrued liabilities approximate their carrying amount due to the short-term nature of the instruments. The Company's risk management liabilities are carried at fair value. The Company manages its risk through its policies and processes and starting in 2014, the Company began to use risk management contracts to manage some of these risks.

The risks associated with these financial instruments including credit risk, liquidity risk, interest rate risk, foreign currency exchange risk and commodity price risk have not changed from December 31, 2013.

(b) Risk management

The Company enters into certain risk management contracts in order to manage the exposure to market risks from fluctuations in commodity prices. These risk management contracts are not used for trading or speculative purposes. The Company has not designated its risk management contracts as effective accounting hedges, and thus has not applied hedge accounting, even though the Company considers all risk management contracts to be economic hedges. As a result, all risk management contracts are recorded at fair value at each reporting period with the change in fair value being recognized as an unrealized gain or loss on the statement of comprehensive income.

The fair value of swaps is determined by discounting the difference between the contracted prices and published forward price curves as at the consolidated balance sheet date, using the remaining contracted oil volumes and a risk-free interest rate (based on published government rates). These swap contracts are considered level two under the fair value hierarchy.

Risk management amounts recognized during 2014 were as follows:

	Three months ended September 30		Nine months ended September 30	
	2014	2013	**2014**	2013
Realized gain (loss) on risk management contracts	**$ (468)**	$ -	**$ (3,976)**	$ -
Unrealized gain (loss) on risk management contracts	**4,961**	-	**(69)**	-
Gain (loss) on risk management contracts	**$ 4,493**	$ -	**$ (4,045)**	$ -

As at September 30, 2014, the Company held the following commodity contracts:

Subject of Contract	Volume	Term	Reference	Strike Price	Option Traded
Oil	2,500 bbls/d	October 1, 2014 to December 31, 2014	CDN$ WCS	CDN$ 82.10/bbl	Swap
Oil	1,000 bbls/d	October 1, 2014 to December 31, 2014	CDN$ WCS	CDN$ 82.00/bbl	Swap
Oil	500 bbls/d	October 1, 2014 to December 31, 2014	CDN$ WCS	CDN$ 86.05/bbl	Swap
Oil	1,500 bbls/d	January 1, 2015 to March 31, 2015	CDN$ WCS	CDN$ 80.20/bbl	Swap
Oil	2,500 bbls/d	January 1, 2015 to June 30, 2015	CDN$ WCS	CDN$ 80.00/bbl	Swap

As at September 30, 2014, a 10% decrease in the CDN$ WCS forward benchmark price used to calculate unrealized gains and losses for the risk management contracts above would result in an $7.7 million increase in after tax net income.

14. SUPPLEMENTARY INFORMATION

(a) The following table summarizes the cash interest and taxes paid:

	Three months ended September 30		Nine months ended September 30	
	2014	2013	**2014**	2013
Cash interest paid	**$ 191**	$ 290	**$ 837**	$ 892
Cash taxes paid	**$ 19**	$ 21	**$ 63**	$ 44

(b) The following table summarizes finance costs included on the statement of comprehensive income:

	Three months ended September 30		Nine months ended September 30	
	2014	2013	**2014**	2013
Gross interest and financing charges	**$ 191**	$ 290	**$ 837**	$ 892
Capitalized interest and financing charges	**(173)**	(31)	**(380)**	(218)
Net interest and financing charges	**18**	259	**457**	674
Accretion of decommissioning liabilities	**392**	285	**1,151**	730
Debt financing costs	**-**	1,092	**-**	1,092
Finance costs	**$ 410**	$ 1,636	**$ 1,608**	$ 2,496

(c) The following table reconciles the changes in non-cash working capital as disclosed in the consolidated statements of cash flows:

	Three months ended September 30		Nine months ended September 30	
	2014	2013	**2014**	2013
Changes in non-cash working capital:				
Trade and other receivables	**$ 1,748**	$ (730)	**$ 657**	$ (9,329)
Inventory	**-**	423	**-**	(275)
Prepaid expenses and deposits	**482**	1,036	**(719)**	(644)
Accounts payable and accrued liabilities	**12,985**	4,566	**26,168**	(3,908)
	$ 15,215	$ 5,295	**$ 26,106**	$ (14,156)
Relating to:				
Operating activities	**$ 1,991**	$ 623	**$ (1,161)**	$ (7,990)
Investing activities	**13,224**	4,672	**27,267**	(6,166)
Changes in non-cash working capital	**$ 15,215**	$ 5,295	**$ 26,106**	$ (14,156)