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NEWS RELEASE **November 3, 2016**

BLACKPEARL ANNOUNCES THIRD QUARTER 2016 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, 2016.

Highlights include:

- After a rigorous review process, regulatory and environmental approval was received for our 80,000 barrel per day (bbl/d) SAGD commercial development application at Blackrod. With this approval and the success of our pilot, we will look at opportunities to accelerate development of this project;

- Our Onion Lake thermal project continued to demonstrate that it is a top tier thermal project with production in the quarter averaging in excess of 6,400 bbl/d with an SOR of 2.5; planning and design has begun for the phase two expansion of the project that would increase capacity to 12,000 bbl/d. In addition, project production costs continued to drop during Q3 2016, averaging $8.79/boe;

- Corporately, production averaged 10,951 barrels of oil equivalent (boe) per day in Q3 2016, a 46% increase compared to Q3 2015 volumes; the increase is attributable to the production ramp-up on the Onion Lake thermal project;

- Net debt (bank debt less working capital) was reduced to $64 million as at September 30, 2016, which represents a net debt to funds flow ratio (a non-GAAP measure) of less than 1.2 times on an annualized basis; the Company's bank debt is $30 million lower than the peak amount in the fourth quarter of 2015;

- Oil and gas revenues in Q3 2016 were $32.4 million, 56% higher than last year, and funds flow from operations (a non-GAAP measure) was $14.2 million, 40% higher than Q3 2015; year to date we have generated revenues of $74 million and funds flow from operations of $29 million;

- We continued to generate reductions in our cost structure with operating and transportation costs averaging $14.24/boe during the quarter, 32% lower than in Q3 2015.

John Festival, President of BlackPearl commenting on Q3 2016 activities stated that "Our thermal projects are some of the best in the industry. The successful start-up of our Onion Lake project as well as our SAGD pilot at Blackrod demonstrates the success of our transition to a thermal heavy oil operator. We like these thermal projects because they are low decline assets that have 20+ year project lives with very attractive operating metrics. Receiving regulatory approval for Blackrod represents a significant milestone in the development of this large resource. We have started planning the expansion at Onion Lake and expect to sanction phase two in the next few months as we finalize funding for the project. We have prudently managed our operations during the downturn and as prices recover will shift our focus to development and growth of our assets."

Financial and Operating Highlights

	Three months ended September 30, 2016	Three months ended September 30, 2015	Nine months ended September 30, 2016	Nine months ended September 30, 2015
Daily production / sales volumes				
Oil (bbl/d)	10,251	6,532	9,236	6,980
Bitumen (bbl/d)	565	583	567	534
	10,816	7,115	9,803	7,514
Natural gas (mcf/d)	815	2,178	836	2,495
Combined (boe/d) (1)	10,951	7,478	9,942	7,930
Product pricing ($) (before the effects of hedging transactions)				
Crude oil - per bbl	34.15	35.02	28.97	38.15
Natural gas - per mcf	2.10	2.88	1.72	2.69
Combined - per boe (1)	33.87	34.05	28.69	36.90
Netback ($/boe) (1) (2)				
Oil and gas sales	33.87	34.05	28.69	36.90
Realized gain (loss) on risk management contracts	2.24	12.99	3.98	13.47
Royalties	(4.30)	(6.55)	(3.61)	(6.30)
Transportation	(2.11)	(0.97)	(2.08)	(1.09)
Operating costs	(12.13)	(20.04)	(12.55)	(20.84)
	17.57	19.48	14.43	22.14
($000's, except per share amounts)				
Revenue				
Oil and gas revenue – gross	32,367	20,814	73,706	73,641
Net income (loss) for the period	556	5,402	(17,711)	(15,621)
Per share, basic and diluted	0.00	0.01	(0.05)	(0.05)
Funds flow from operations(3)	14,202	10,156	28,977	38,064
Capital expenditures	1,753	7,870	4,775	66,843
Working capital deficiency (surplus)	(3,384)	(8,254)	(3,384)	(8,254)
Bank debt	67,000	97,000	67,000	97,000
Net Debt (4)	63,616	88,746	63,616	88,746
Shares outstanding, end of period	335,646,559	335,638,226	335,646,559	335,638,226

(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)Netback is a non-GAAP measure that does not have a standardized meaning prescribed by Canadian GAAP and therefore may not be comparable to similar measures used by other companies.

(3)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 does not have a standardized meaning prescribed by Canadian GAAP and therefore may not be comparable to similar measures used by other companies. See reconciliation table between these measures under Non-GAAP Measures.

(4)Net debt is a non-GAAP measure that does not have a standardized meaning prescribed by Canadian GAAP and therefore may not be comparable to similar measures used by other companies.

Property Review

Onion Lake

Construction of the first phase of the Onion Lake thermal project was successfully completed in mid-2015 and has now been on production for just over a year. By June 2016, oil production reached name plate capacity of 6,000 bbl/d as production continued to ramp-up. During the third quarter, oil production average 6,472 bbl/d, with a steam oil ratio of 2.5. The successful start-up and on-going operations generated very good operating results, with production costs, including natural gas, under $10 per barrel during the third quarter.

We have begun planning for the expansion of the Onion Lake thermal project. The expansion would see capacity of the project doubled to 12,000 bbl/d. This expansion would include the construction of additional steam generation and oil handling facilities, water source wells, pipelines and drilling of up to 20 injection wells and 15 horizontal production wells. We estimate construction will take 12 to 15 months from the date of sanctioning and construction costs are estimated to be between $175 and $185 million, which is approximately 20% lower than the cost of the first phase of the project. The timing for sanctioning the project is dependent on finalizing funding for the project. We are currently exploring various financing options in addition to using our operating cash flows and capacity under our existing credit facility.

Blackrod

On September 16, 2016, the Alberta Energy Regulator and the Alberta government approved the Company's 80,000 bbl/d commercial development application for our Blackrod SAGD project, located in the Athabasca Oil Sands in northern Alberta. The approval represents a significant milestone for the Company and provides us with the certainty needed to plan the next steps in the development of this large resource. Blackrod is expected to be developed in phases, with the first phase likely to be between 10,000 and 20,000 bbl/d. We have not established timing for initial development of Blackrod as we need to secure financing to fund the development. We will consider taking on a joint venture partner to accelerate development. At December 31, 2015, our independent reserves evaluator assigned 180 million barrels of proved plus probable reserves and 566 million barrels of unrisked contingent resources (best estimate) to our Blackrod leases.

The existing SAGD pilot has provided us with important technical information that validated the applicability of the SAGD process on our lease, as well as providing valuable operating data for the design of a commercial project. The second pilot well pair continues to produces in excess of 500 bbl/d, with a steam oil ratio under three and, cumulatively, this well has produced over 400,000 barrels of oil.

Mooney

No new activities were undertaken at Mooney during the third quarter. The majority of the ASP flood remained shut-in during the quarter as our primary focus at Mooney has been on our cost reduction initiatives in the field. With the recent increase in crude oil prices we are in the process of selectively bringing several wells back on production in the phase one flood area.

Production

Oil and gas production averaged 10,951 barrels of oil equivalent per day in the third quarter of 2016, a 46% increase compared with the third quarter of 2015. The increase in oil production reflects the successful ramp-up of production from our Onion Lake thermal project partially offset by a reduction in our conventional oil production as a result of natural declines, limited new drilling activity and our decision earlier in the year to selectively shut-in some of our production at Onion Lake and Mooney due to low oil prices.

Average Daily Sales Volume

(boe/day)	Three months ended September 30, 2016	Three months ended September 30, 2015	Nine months ended September 30, 2016	Nine months ended September 30, 2015
Onion Lake - thermal	6,472	251	5,319	85
Onion Lake - conventional	2,162	3,285	2,177	3,621
Mooney	665	2,192	807	2,523
John Lake	885	967	872	1,000
Blackrod	565	583	567	534
Other	202	200	200	167
	10,951	7,478	9,942	7,930

Financial Results

Oil and gas revenues in Q3 2016 were $32.4 million, a 56% increase compared to the third quarter of 2015. The increase in revenues is attributable to a 46% increase in production volumes partially offset by a 3% decrease in our realized sales price.

Our realized oil price (before the effects of risk management activities) in Q3 2016 was $34.15 per barrel compared to $35.02 per barrel in Q3 2015. The decrease in our realized wellhead price reflects lower WTI reference oil prices in Q3 2016 compared with Q3 2015 (US$44.94/bbl vs US$46.43/bbl), and slightly wider heavy oil differentials (US$13.51/bbl vs US$13.39/bbl).

We have entered into various oil hedges to mitigate some of the negative impact of the low oil price environment in 2016. During the first nine months of 2016 we realized a gain of $10 million from our oil hedging program, which was the equivalent of adding $3.98 per barrel to our wellhead price. The table below summarizes the Company's outstanding commodity contracts as at September 30, 2016:

Subject of Contract	Volume	Term	Reference	Strike Price	Type
<u>2016</u>					
Oil	1,000 bbls/d	October 1 to December 31	CDN$ WCS	CDN$ 51.15/bbl	Swap
Oil	2,000 bbls/d	October 1 to December 31	CDN$ WCS	CDN$ 47.60/bbl	Swap
Oil	2,000 bbls/d	October 1 to December 31	US$ WTI	US$ 65.00/bbl	Sold Call
<u>2017</u>					
Oil	1,000 bbls/d	January 1 to December 31	CDN$ WCS	CDN$ 50.00/bbl	Swap
Oil	1,000 bbls/d	January 1 to December 31	CDN$ WCS	CDN$ 49.50/bbl	Swap
Oil	500 bbls/d	January 1 to June 30	CDN$ WCS	CDN$ 40.00/bbl to 52.50/bbl	Collar
Oil	500 bbls/d	January 1 to December 31	CDN$ WCS	CDN$ 40.00/bbl to 47.00/bbl	Collar
Oil	1,000 bbls/d	January 1 to December 31	US$ WTI	US$ 60.00/bbl	Sold Call
<u>2018</u>					
Oil	500 bbls/d	January 1 to December 31	US$ WTI	US$ 70.00/bbl	Sold Call

Operating costs and transportation costs in Q3 2016 were $13.6 million, or $14.24 per boe, compared to $12.8 million or $21.01/boe in Q3 2015. The increase in operating costs reflects higher production volumes. The decrease in per unit operating costs reflects the lower cost of production related to our Onion Lake thermal operations.

Higher production revenues contributed to an increase in funds flow from operations during the third quarter. Funds flow from operations increased to $14.2 million during the quarter compared to $10.2 million for the same period in 2015.

During the third quarter we continued to use our operating cash flows to reduce our debt. Bank debt as at September 30, 2016 was $67 million, $21 million lower than at the beginning of the year. Net debt (bank debt less working capital) at September 30 was $64 million. The total credit facilities available to the Company are currently $117.5 million. The lenders next review of these facilities is expected to be completed by November 30, 2016.

The 2016 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).

Guidance

Our plans are largely unchanged from guidance previously provided in the Q2 and Q1 updates. As a result of higher oil prices our estimated funds flow from operations for the year is expected to be between $42 and $45 million, up from our Q2 guidance of $35 to $40 million and year-end 2016 debt levels are anticipated to be between $52 and $55 million, down from our Q2 guidance of $60 to $65 million. We anticipate average oil and gas production in 2016 to be approximately 10,000 boe/d, an increase from our Q2 guidance of between 9,000 and 10,000 boe/d. The increase is attributable to the positive performance of the Onion Lake thermal project. Our plan for 2016 was to limit capital spending and use our operating cash flows to pay down debt and as a result capital spending for the year is now expected to be between $7 and $10 million.

Non-GAAP Measures

In this news release, the Company uses terms "funds flow from operations", "netback" and "net debt" and "net debt to funds flow ratio". These terms do not have standardized meanings 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.

The following table reconciles non-GAAP measurement "Funds flow from operations" to "Cash flow from operating activities", the nearest GAAP measure. "Funds flow from operations" represents cash flow from operating activities (the closest GAAP measure) expressed before decommissioning costs incurred and changes in non-cash working capital.

	Three months ended September 30,		Nine months ended September 30,	
($000s)	2016	2015	2016	2015
Cash flow from operating activities	16,441	14,216	27,412	50,165
Add (deduct):				
Decommissioning costs incurred	38	117	554	379
Changes in non-cash working capital related to operations	(2,277)	(4,177)	1,011	(12,480)
Funds flow from operations	14,202	10,156	28,977	38,064

"Netback" is calculated as oil and gas revenues less royalties, production costs, transportation costs and realized gains/losses on risk management contracts, divided by total production for the period on a boe basis. "Net debt" represents long term debt less working capital. "Net debt to funds flow ratio" represents net debt divided by funds flow from operations (Q3 2016 multiplied by 4 to annualize the amount).

Contingent Resources

Contingent resources are defined in the COGE Handbook as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. There is no certainty that it will be commercially viable to produce any of the contingent resources. Best estimate (P50) is a classification of estimated resources described in the COGE Handbook as being considered to be the best estimate of the quantity that will be actually recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate. Please refer to our Annual Information Form for a more detailed discussion of our contingent resources and the contingencies for each property.

All dollar amounts throughout this new release are stated in Canadian dollars unless otherwise noted.

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 historic fact are forward-looking statements. Forward-looking statements are typically identified by such words as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "potential", "targeting", "intend", "could", "might", "should", "believe" or similar words suggesting future events or future performance.

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 timing and estimated capital costs for the expansion of the Onion Lake thermal EOR project, the expectation that Blackrod will be developed in phases, with the first phase likely to be between 10,000 and 20,000 bbl/d, the estimated reserves and contingent resources associated with the Blackrod leases and all information in the Guidance section of this news release.

The forward-looking statements in this document reflect certain assumptions and expectations by management. The key assumptions that have been made in connection with these forward-looking statements include the continuation of current or, where applicable, assumed industry conditions, the continuation of existing tax, royalty and regulatory regimes, commodity price and cost assumptions, the continued availability of cash flow or financing on acceptable terms to fund the Company’s capital programs, the accuracy of the estimate of the Company’s reserves and resource volumes and that BlackPearl will conduct its operations in a manner consistent with past operations. Although management considers these assumptions to be reasonable based on information currently available to it, they may prove to be incorrect.

By their very nature, forward-looking statements involve inherent risks and uncertainties which could cause actual results to differ materially from those contained in forward-looking statements. These factors include, but are not limited to, risks associated with fluctuations in market prices for crude oil, natural gas and diluent; risks related to the exploration, development and production of crude oil, natural gas and NGLs reserves; general economic, market and business conditions; substantial capital requirements; 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; potential cost overruns; variations in foreign exchange rates; diluent supply shortages; competition for capital, equipment, new leases, pipeline capacity and skilled personnel; uncertainties inherent in the SAGD bitumen and ASP recovery processes; credit risks associated with counterparties; the failure of the Company or the holder of licenses, leases and permits to meet requirements of such licenses, 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 and others may be found under "Risk Factors" in the Annual Information Form.

Undue reliance should not be placed on these forward-looking statements. Readers are cautioned that the actual results achieved will vary from the information provided herein and the variations could be material. Readers are also cautioned that the foregoing list of assumptions, risks and factors is not exhaustive. Consequently, there is no assurance by the Company that actual results achieved will be the same in whole or in part as those set out in the forward-looking statements. Furthermore, the forward-looking statements contained in this document are made as of the date hereof, and the Company 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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The information in this release is subject to the disclosure requirements of BlackPearl Resources Inc. under the EU Market Abuse Regulation and/or the Swedish Securities Market Act. This information was publicly communicated on November 3, 2016 at 3:30 p.m. Mountain Time.

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, 2016. These results are being compared with the three and nine months ended September 30, 2015. 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, 2016, together with the accompanying notes and with the Company's annual MD&A for the year ended December 31, 2015.

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		
EBITDA (adjusted)	Comprehensive income (loss) before income tax, financing charges, non-cash items, unrealized gain or losses on risk management contracts and income/loss attributed to assets acquired or disposed as defined in the Company's lending agreement.		

Non-GAAP Financial Measures

Throughout this MD&A, the Company uses terms "funds flow from operations", "operating netback" and "net debt". 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 oil and gas revenues less royalties, production costs and transportation costs, divided by total production for the period on a boe basis. Net debt is calculated as long-term debt plus working capital for the period ended.

The following table reconciles non-GAAP measurement "Funds flow from operations" to "Cash flow 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 flow from operating activities" includes these items.

	2016			2015	Nine months ended September 30	
($000s)	**Q3**	Q2	Q1	Q3	**2016**	2015
Cash flow from operating activities(1)	**16,441**	7,184	3,787	14,216	**27,412**	50,165
Add (deduct):						
Decommissioning costs incurred	**38**	369	147	117	**554**	379
Changes in non-cash working capital related to operations	**(2,277)**	3,944	(656)	(4,177)	**1,011**	(12,480)
Funds flow from operations(2)	**14,202**	11,497	3,278	10,156	**28,977**	38,064

(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. Funds flow from operations 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.

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 3, 2016.

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 exchange 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 as well as a multi-phase thermal project with the first phase constructed and put on production in 2015;
- Mooney, Alberta – a conventional heavy oil property using horizontal drilling and ASP flooding; and
- Blackrod, Alberta – a bitumen property, in the exploration and evaluation phase, located in the Athabasca oil sands region. The Company is currently operating a pilot project on this property using the SAGD recovery process.

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

2016 SIGNIFICANT EVENTS

- Crude oil prices were lower in the first nine months of 2016, with WTI oil prices averaging US$41.33 per bbl during the first nine months of 2016 compared to US$51.00 per bbl during the same period in 2015.

- During the first nine months of 2016, oil and gas production averaged 9,942 boe/d; a 25% increase compared to the same period in 2015. The increase was mainly attributable to the first phase of the Onion Lake thermal project which has been on production for just over a year. During the third quarter of 2016, production from this project averaged 6,472 bbls/d, with a steam to oil ratio of 2.45.

- During the third quarter of 2016, the Company received regulatory and environmental approval from the Alberta Energy Regulator and Alberta government for its 80,000 bbls/d Blackrod SAGD commercial development application.

- Due to low oil prices, the Company limited capital spending in the first nine months of 2016 and used the majority of its cash flow from operating activities to reduce debt. Capital expenditures during the first nine months of the year were $4.8 million, with approximately $2.3 million spent at the Onion Lake thermal project related to facility improvements and planning costs for the second phase of the project, $0.6 million spent at Blackrod primarily related to continued capitalization of net revenues from operating the Blackrod pilot and $1.9 million spent in other areas. No new drilling activity occurred during the first nine months of 2016.

- Oil and gas sales during the first nine months of 2016 were $74 million and funds flow from operations (a non-GAAP measure) were $29 million. For the three months ended September 30, 2016, the Company recognized net income of $0.6 million. For the nine months ended September 30, 2016, the Company incurred a net loss of $17.7 million.

- The decline in crude oil prices was partially offset by realized gains on crude oil hedging contracts. For the nine months ended September 30, 2016, the Company realized gains of $10.2 million from these contracts.

- As a result of the Company's current cost reduction initiative, operating and transportation costs averaged $14.24/bbl in the third quarter, a 32% decrease from Q3 2015.

- During the first nine months of 2016, 8,333 common shares were issued pursuant to the exercise of stock options. The Company did not undertake any equity issuances during the first nine months of 2016.

- At September 30, 2016, BlackPearl had working capital of $3.4 million and $67 million in bank debt, leaving $50.5 million available to be drawn under the Company's existing credit facilities. The Company's bank debt is $21 million lower than at the beginning of the year.

SELECTED QUARTERLY INFORMATION

	2016			2015				2014
($000s, except where noted)	**Sep 30**	**Jun 30**	**Mar 31**	**Dec 31**	Sep 30	Jun 30	Mar 31	Dec 31
Production (boe/d) (1)	**10,951**	**9,698**	**9,166**	**9,521**	7,478	8,051	8,269	9,639
Oil and gas sales	**32,367**	**28,318**	**13,021**	**22,630**	20,814	30,712	22,115	47,798
Oil sales ($/bbl)	**34.15**	**34.44**	**16.77**	**27.65**	35.02	47.52	32.05	59.34
Gas sales ($/mcf)	**2.10**	**1.29**	**1.77**	**2.91**	2.88	2.61	2.63	3.39
Oil and gas sales ($/boe)	**33.87**	**34.03**	**16.67**	**27.45**	34.05	45.37	31.25	57.00
Production & transportation costs	**13,603**	**12,246**	**11,736**	**15,666**	12,843	14,245	16,686	22,306
Production costs ($/boe)	**12.13**	**13.23**	**12.35**	**17.77**	20.04	19.86	22.48	25.12
Transportation costs ($/boe)	**2.11**	**1.48**	**2.68**	**1.23**	0.97	1.18	1.10	1.48
Gain (loss) on risk management contracts								
Realized	**2,137**	**1,958**	**6,120**	**10,334**	7,940	5,245	13,708	5,846
Unrealized	**(538)**	**(8,597)**	**(472)**	**1,778**	11,826	(13,533)	(11,374)	20,697
Net income (loss)	**556**	**(8,945)**	**(9,322)**	**(31,172)**	5,402	(10,079)	(10,944)	16,254
Per share, basic and diluted ($)	**0.00**	**(0.03)**	**(0.03)**	**(0.09)**	0.01	(0.03)	(0.03)	0.05
Capital expenditures	**1,753**	**945**	**2,077**	**1,665**	7,870	15,992	42,981	57,700
Funds flow from operations (2)	**14,202**	**11,497**	**3,278**	**10,898**	10,156	14,968	12,940	19,716

	2016			2015				2014
($000s, except where noted)	**Sep 30**	**Jun 30**	**Mar 31**	**Dec 31**	Sep 30	Jun 30	Mar 31	Dec 31
Long-term debt	**67,000**	**80,000**	**86,000**	**88,000**	97,000	94,000	78,000	29,000
Total assets (end of period)	**773,206**	**782,591**	**795,336**	**808,344**	861,107	864,926	866,018	837,773
Shares outstanding (000s)	**335,647**	**335,647**	**335,638**	**335,638**	335,638	335,638	335,638	335,638
Weighted average shares outstanding								
Basic	**335,646**	**335,641**	**335,638**	**335,638**	335,638	335,638	335,638	335,638
Diluted	**337,959**	**335,641**	**335,638**	**335,638**	335,638	335,638	335,638	335,638

(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. Funds flow from operations 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.

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 volumes in Q4 2015 increased as a result of the start-up of commercial production from the first phase of the Onion Lake thermal project. The net loss incurred in Q4 2015 is mainly attributable to an impairment charge of $33 million taken on our Mooney CGU.

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		2016			2015			
	2016	2015	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Average Crude Oil Prices									
West Texas Intermediate (WTI) (US$/bbl)	41.33	51.00	44.94	45.59	33.45	42.18	46.43	57.94	48.63
Western Canadian Select (WCS) (Cdn$/bbl)	36.31	47.44	41.02	41.61	26.31	36.86	43.27	56.95	42.11
Differential – WCS/WTI (US$/bbl)	13.88	13.35	13.51	13.30	14.32	14.57	13.39	11.62	14.71
Differential - WCS/WTI (%)	33.6%	26.2%	30.1%	29.2%	42.8%	34.5%	28.8%	20.1%	30.2%
Average Natural Gas Prices									
AECO gas (Cdn$/GJ)	1.76	2.62	2.20	1.33	1.74	2.34	2.75	2.52	2.61
Average Foreign Exchange (US$ per Cdn$1)	0.756	0.794	0.766	0.776	0.727	0.749	0.764	0.813	0.806

Crude oil prices are based on supply and 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 the Western Canadian Select oil price, which has an average gravity of about 20.5 degrees API.

Crude oil prices were relatively flat during the third quarter of 2016 compared to the second quarter; however, prices remain lower than the comparable period in 2015. WTI oil prices averaged US$44.94 per bbl in the third quarter of 2016 compared to US$45.59 per bbl in the second quarter of 2016 and US$46.43 per bbl in the third quarter of 2015. For the first nine months of 2016 WTI oil prices averaged US$41.33 per bbl, down from US$51.00 per bbl in the same period in 2015. The improvement in third quarter crude oil pricing has been attributed to higher global demand for oil, lower production volumes, particularly in the US and the recent decision by the Organization of Petroleum Exporting Countries (OPEC) to limit production levels to between 32.5 and 33 million bbls/d of oil. OPEC has indicated that details related to the production limit are expected to be finalized at its next meeting in November.

The heavy oil differential (WTI oil prices compared to WCS oil prices) was also relatively flat in the third quarter of 2016. Heavy oil differentials averaged US$13.51 per bbl in the third quarter of 2016 compared to US$13.30 per bbl in the second quarter of 2016.

Natural gas prices decreased in the first nine months of 2016 averaging $1.76/GJ compared to $2.62/GJ in the same period in 2015. The decrease in natural gas prices during the first nine months of 2016 is attributable to higher gas storage levels due to a relatively mild winter in much of North America which reduced the demand for natural gas for heating. BlackPearl produces very little natural gas and therefore prices do not have a significant impact on our current revenues. However, we do consume relatively large amounts of gas in our Blackrod pilot operations and at our Onion Lake thermal project. Natural gas prices increased in the third quarter of 2016 averaging $2.20/GJ compared to $1.33/GJ in the second quarter of 2016. These higher natural gas prices in the third quarter of 2016 increased the operating costs in these areas.

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 reference to US benchmark prices. The Canadian dollar weakened against the US dollar in the first nine months of 2016, which partially mitigated the effect of lower crude oil prices on our revenues and cash flows. The exchange rate between the Canadian dollar and the US dollar averaged Cdn$1 = US$0.76 during the first nine months of 2016 compared to Cdn$1 = US$0.79 in the same period in 2015.

The following chart shows the Company's sensitivity to key commodity price variables. The sensitivity calculations are performed independently showing the effect of the change of one variable, with all other variables being held constant.

Estimated change in annualized funds flow from operations for 2016 [(1)]:

Key variable	Change ($)	$000s
West Texas Intermediate (WTI) (US$/bbl)	1.00	708
Realized crude oil price (Cdn$/bbl)	1.00	810
US $ to Canadian $ exchange rate	0.01	193

(1) This analysis assumes annualized estimated average production of 10,000 boe/d, current royalty rates and operating costs, no changes in working capital and includes the impact of realized risk management contracts.

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

	2016			2015	Nine months ended September 30	
	Q3	Q2	Q1	Q3	**2016**	2015
Daily production/sales volumes						
Oil (bbls/d)	**10,251**	9,004	8,442	6,532	**9,236**	6,980
Bitumen – Blackrod (bbls/d) (2)	**565**	553	584	583	**567**	534
Combined (bbls/d)	**10,816**	9,557	9,026	7,115	**9,803**	7,514
Natural gas (Mcf/d)	**815**	847	845	2,178	**836**	2,495
Total production (boe/d) (1)	**10,951**	9,698	9,166	7,478	**9,942**	7,930
Product pricing (excluding risk management activities) (2)						
Oil ($/bbl)	**34.15**	34.44	16.77	35.02	**28.97**	38.15
Natural gas ($/Mcf)	**2.10**	1.29	1.77	2.88	**1.72**	2.69
Combined ($/boe) (1)	**33.87**	34.03	16.67	34.05	**28.69**	36.90
Sales ($000s) (2)						
Oil and gas sales – gross	**32,367**	28,318	13,021	20,814	**73,706**	73,641
Royalties	**(4,111)**	(3,813)	(1,345)	(4,004)	**(9,269)**	(12,578)
Oil and gas revenues – net	**28,256**	24,505	11,676	16,810	**64,437**	61,063

(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 increased 56% in the third quarter of 2016 to $32.4 million from $20.8 million in the same period in 2015. The increase in oil and gas sales is primarily attributable to a 46% increase in production volumes (on a boe basis) in the third quarter of 2016 compared to the same period in 2015.

Production growth in the third quarter and first nine months of 2016 compared to the same periods in 2015 came from the first phase of our Onion Lake thermal project. The project has been on production for just over a year and in June production reached its design capacity of 6,000 bbls/d and production continued to ramp up. During the third quarter of 2016, production from this project averaged 6,472 bbls/d and during the nine months ended September 30, 2016, the project averaged 5,319 bbls/d.

Production in our non-thermal areas has declined from previous quarters, primarily due to natural declines combined with no new drilling activity due to low oil prices. In addition, we have selectively shut-in some of our higher cost production that is not economic in the current oil price environment. At Onion Lake, we have approximately 750 bbls of oil per day currently shut-in. As well, during the first quarter of 2016, we elected to shut-in the majority of the phase one ASP flood at Mooney, or approximately 900 bbls of oil per day. With the recent improvement in crude oil prices, we plan to selectively bring back on production at some of the shut-in wells at Mooney and Onion Lake.

On a boe basis, 99% of the Company's oil and natural gas production in the third quarter of 2016 was heavy oil or bitumen. The Onion Lake area accounted for 79% of total production in the third quarter of 2016.

	2016			2015	Nine months ended September 30	
Production by area (boe/d)	**Q3**	Q2	Q1	Q3	**2016**	2015
Onion Lake - thermal	**6,472**	5,221	4,252	251	**5,319**	85
Onion Lake - conventional	**2,162**	2,138	2,232	3,285	**2,177**	3,621
Mooney	**665**	714	1,042	2,192	**807**	2,523
John Lake	**885**	870	861	967	**872**	1,000
Blackrod	**565**	553	584	583	**567**	534
Other	**202**	202	195	200	**200**	167
Total production	**10,951**	9,698	9,166	7,478	**9,942**	7,930

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. A second pilot well pair was drilled and put on production in 2013. The pilot is being undertaken to provide operating data to design the commercial development of the Blackrod lands. The original pilot SAGD well was shut-in in August 2015. All sales and expenses from the pilot are being recorded as an adjustment to the capitalized costs of the project until commercial production commences. During the third quarter of 2016, the pilot wells produced an average of 565 bbls/d of bitumen and the net revenues capitalized for the first nine months of 2016 were a loss of $0.3 million ($1.8 million loss in the first nine months of 2015).

During the third quarter of 2016, BlackPearl received regulatory approval for its 80,000 bbls/d commercial Blackrod SAGD project. We will consider joint venture opportunities or other financing options to accelerate development of the Blackrod SAGD project.

Risk Management Activities

The Company periodically enters into risk management contracts in order to ensure a certain level of cash flow to fund planned capital projects and to maintain as much financial flexibility as possible. BlackPearl's strategy is to mainly focus on swaps, collars, calls and fixed price contracts to limit exposure to fluctuations in oil prices and revenues. The Company's risk management 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 policy permits us to hedge up to 60% of our forecast production for a period of up to 24 months.

Gains and losses on risk management contracts include both realized gains and losses representing the portion of contracts that have been settled during the year and unrealized gains and losses that represent the non-cash change in the fair values of our outstanding risk management contracts. The Company had a net gain of $1.6 million on its risk management contracts during the third quarter of 2016, consisting of a $2.1 million realized gain on the contracts and an unrealized loss of $0.5 million. The realized gain on risk management contracts was the equivalent of adding $2.24 per bbl to our wellhead price during the third quarter of 2016.

	2016			2015	Nine months ended September 30	
($000s, except per boe)	**Q3**	Q2	Q1	Q3	**2016**	2015
Realized gain on risk management contracts	**2,137**	1,958	6,120	7,940	**10,215**	26,893
Per boe ($)	**2.24**	2.35	7.84	12.99	**3.98**	13.47
Unrealized gain (loss) on risk management contracts	**(538)**	(8,597)	(472)	11,826	**(9,607)**	(13,081)

The table below summarizes the Company's outstanding commodity contracts as at September 30, 2016:

Subject of Contract	Volume	Term	Reference	Strike Price	Type
2016					
Oil	1,000 bbls/d	October 1 to December 31	CDN$ WCS	CDN$ 51.15/bbl	Swap
Oil	2,000 bbls/d	October 1 to December 31	CDN$ WCS	CDN$ 47.60/bbl	Swap
Oil	2,000 bbls/d	October 1 to December 31	US$ WTI	US$ 65.00/bbl	Sold Call
2017					
Oil	1,000 bbls/d	January 1 to December 31	CDN$ WCS	CDN$ 50.00/bbl	Swap
Oil	1,000 bbls/d	January 1 to December 31	CDN$ WCS	CDN$ 49.50/bbl	Swap
Oil	500 bbls/d	January 1 to June 30	CDN$ WCS	CDN$ 40.00/bbl to 52.50/bbl	Collar
Oil	500 bbls/d	January 1 to June 30	CDN$ WCS	CDN$ 40.00/bbl to 47.00/bbl	Collar
Oil	1,000 bbls/d	January 1 to December 31	US$ WTI	US$ 60.00/bbl	Sold Call
2018					
Oil	500 bbls/d	January 1 to December 31	US$ WTI	US$ 70.00/bbl	Sold Call

At September 30, 2016, these contracts had a fair value of approximately $0.3 million liability. A 10% decrease to the oil price used to calculate the fair value of these contracts would result in an approximate $6.6 million increase in fair value.

Royalties

	2016			2015	Nine months ended September 30	
	Q3	Q2	Q1	Q3	**2016**	2015
Royalties ($000s)	**4,111**	3,813	1,345	4,004	**9,269**	12,578
Per boe ($)	**4.30**	4.58	1.72	6.55	**3.61**	6.30
As a percentage of oil and gas sales	**13%**	13%	10%	19%	**13%**	17%

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 were $4.1 million in the third quarter of 2016, comparable to $4.0 million in the same period in 2015. Royalties as a percentage of oil and gas sales decreased to 13% in the third quarter of 2016 from 19% of oil and gas sales in the same period in 2015. This decrease is attributable to an increase in production from the Onion Lake thermal project. Production from this project was 59% of our total production in Q3 2016 (3% in Q3 2015). During the pre-payout period the royalties from this project will be approximately 10%, which is lower than our average royalty rate for our other producing areas.

Transportation Costs

	2016			2015	Nine months ended September 30	
	Q3	Q2	Q1	Q3	**2016**	2015
Conventional Production						
Transportation costs ($000s)	**206**	127	318	595	**651**	2,176
Per boe ($)	**0.57**	0.36	0.81	0.97	**0.59**	1.09
Thermal Production						
Transportation costs ($000s)	**1,807**	1,106	1,775	-	**4,688**	-
Per boe ($)	**3.04**	2.33	4.59	-	**3.22**	-
Total Production						
Transportation costs ($000s)	**2,013**	1,233	2,093	595	**5,339**	2,176
Per boe ($)	**2.11**	1.48	2.68	0.97	**2.08**	1.09

Transportation costs are incurred to move marketable crude oil and natural gas to their selling points. Costs to ship oil/emulsion to a treating facility before it is sold are included in production expenses rather than transportation costs. Transportation costs increased in the third quarter of 2016 to $2.0 million from $0.6 million in the same period of 2015. This increase is attributable to increased production from our Onion Lake thermal project.

Production Costs

	2016			2015	Nine months ended September 30	
	Q3	Q2	Q1	Q3	**2016**	2015
Conventional Production						
Production costs ($000s)	**6,359**	6,400	5,550	12,248	**18,309**	41,598
Per boe ($)	**17.66**	17.92	14.09	20.04	**16.48**	20.84
Thermal Production						
Production costs ($000s)	**5,231**	4,613	4,093	-	**13,937**	-
Per boe ($)	**8.79**	9.71	10.58	-	**9.56**	-
Total Production						
Production costs ($000s)	**11,590**	11,013	9,643	12,248	**32,246**	41,598
Per boe ($)	**12.13**	13.23	12.35	20.04	**12.55**	20.84

Total production costs decreased 5% in the third quarter of 2016 to $11.6 million from $12.2 million in the same period in 2015. On a per boe basis, total production costs decreased 39% in the third quarter of 2016 to $12.13 per boe from $20.04 per boe in the same period in 2015. The decrease in total production costs was made up of a drop in costs related to our conventional production offset by production costs from our new thermal project at Onion Lake.

The decrease in conventional production costs in the third quarter of 2016 compared to the same period in 2015 is attributable, in part, to a 38% decrease in conventional production volumes. In addition, due to low oil prices the Company has been focusing on reducing production costs. This included negotiating lower service rates with various suppliers and contractors, deferring well servicing work and shutting-in specific wells in the Onion Lake area that are not economic at current oil prices. The Company has also temporarily shut-in the majority of the production from wells in the first phase of the Mooney ASP flood due to the continued low crude oil prices, which also contributed to the decrease in conventional production costs.

The increase in thermal production costs in the third quarter of 2016 compared to the second quarter of 2016 is primarily attributable to increased production volumes and higher gas consumption costs as a result of higher natural gas prices in the third quarter. On a boe basis however, thermal production costs decreased in the third quarter due to a 24% increase in production volumes during the third quarter.

***Operating Netback* (1)**

		2016		2015	Nine months ended September 30	
($/boe)	**Q3**	Q2	Q1	Q3	**2016**	2015
Oil and gas sales	**33.87**	34.03	16.67	34.05	**28.69**	36.90
Royalties	**4.30**	4.58	1.72	6.55	**3.61**	6.30
Transportation costs	**2.11**	1.48	2.68	0.97	**2.08**	1.09
Production costs	**12.13**	13.23	12.35	20.04	**12.55**	20.84
Operating netback before realized risk management contracts	**15.33**	14.74	(0.08)	6.49	**10.45**	8.67
Realized gain on risk management contracts	**2.24**	2.35	7.84	12.99	**3.98**	13.47
Operating netback after realized risk management contracts	**17.57**	17.09	7.76	19.48	**14.43**	22.14

(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, before realized gains on risk management activities, increased in the third quarter of 2016 to $15.33 per boe from $6.49 per boe in the same period in 2015. The increase is primarily attributable to lower royalties and production costs.

General and Administrative Expenses (G&A)

		2016		2015	Nine months ended September 30	
($000s, except per boe)	**Q3**	Q2	Q1	Q3	**2016**	2015
Gross G&A expense	**1,792**	2,009	2,129	1,944	**5,930**	6,722
Operator recoveries	**(178)**	(209)	(230)	(244)	**(617)**	(866)
Net G&A expense	**1,614**	1,800	1,899	1,700	**5,313**	5,856
Per boe ($)	**1.69**	2.16	2.43	2.78	**2.07**	2.93

General and administrative expenses consist primarily of salaries and wages of employees, office rent, computer services, legal, accounting and consulting fees. The decrease in gross G&A expenses in the first nine months of 2016 compared to the same period in 2015 reflects lower third party consultants' costs as well as lower staff compensation costs in 2016 as a result of the implementation of salary reductions and reduced work schedules for our staff during this period of low oil prices. Lower operator recoveries in the first nine months of 2016 compared to same period in 2015 is attributable to lower capital spending in 2016.

Stock-Based Compensation

		2016		2015	Nine months ended September 30	
($000s, except per boe)	**Q3**	Q2	Q1	Q3	**2016**	2015
Gross stock-based compensation	**767**	711	1,178	1,358	**2,656**	4,314
Recoveries from forfeitures	**-**	-	(48)	(10)	**(48)**	(58)
Net stock-based compensation before capitalization	**767**	711	1,130	1,348	**2,608**	4,256
Capitalized stock-based compensation	**-**	-	-	(47)	**-**	(146)
Net stock-based compensation	**767**	711	1,130	1,301	**2,608**	4,110
Per boe ($)	**0.80**	0.85	1.45	2.13	**1.02**	2.06

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 decrease in gross stock-based compensation in the first nine months of 2016 compared to the same period in 2015 is primarily attributable to a decrease in the weighted average market price of the Company's common shares during 2016. In the first nine months of 2016, 8,333 options were exercised, 125,000 options were granted, 342,669 options were forfeited and 275,000 options expired. Based on stock options outstanding as at September 30, 2016, the Company has an unamortized stock option compensation expense of approximately $1.7 million, of which $0.7 million is expected to be expensed in the remainder of 2016, $0.9 million in 2017 and $0.1 million in 2018.

Finance Costs

	2016			2015	Nine months ended September 30	
($000s)	**Q3**	Q2	Q1	Q3	**2016**	2015
Gross interest & financing charges	**986**	918	835	923	**2,739**	2,568
Capitalized interest & financing charges	**-**	-	-	(786)	**-**	(2,066)
Net interest & financing charges	**986**	918	835	137	**2,739**	502
Accretion of decommissioning liabilities	**357**	361	366	431	**1,084**	1,276
Total finance costs	**1,343**	1,279	1,201	568	**3,823**	1,778

The increase in gross interest and financing charges during the first nine months of 2016 compared to the same period in 2015 is the result of higher average debt levels and slightly higher interest rates on amounts borrowed in 2016. The average interest rate on advances under the Company's credit facilities was 3.7% in the first nine months of 2016 compared to 3.4% in the first nine months of 2015. This does not include standby fees charged on unutilized amounts of the credit facilities.

All our long-term debt is floating rate debt, so the interest rate charged is based on general market conditions. Additionally, the interest rate charged on our debt is determined, in part, by our debt to EBITDA ratio (as defined in our credit agreement). The interest rate charged on our debt outstanding is expected to be 3 – 3.25% for the remainder of 2016 (assuming no other changes in market conditions) as a result of carrying a lower debt to EBITDA ratio. We have not entered into any financial instruments to fix the interest rate on our debt.

During the first nine months of 2016 we did not capitalize any interest charges. In the first nine months of 2015 we capitalized $2.1 million of interest costs related to debt incurred during the construction of the Onion Lake thermal project.

Depletion and Depreciation

	2016			2015	Nine months ended September 30	
	Q3	Q2	Q1	Q3	**2016**	2015
Depletion and depreciation ($000s)	**11,984**	10,773	10,632	12,360	**33,389**	39,078
Per boe ($)	**12.54**	12.95	13.61	20.22	**13.00**	19.58

The Company's properties are depleted on a unit of production basis based on estimated proven plus probable reserves. Depletion and depreciation expense decreased 3% in the third quarter of 2016 to $12.0 million from $12.4 million in the same period in 2015. On a boe basis, depletion and depreciation expense decreased to $12.54 per boe in the third quarter of 2016 compared to $20.22 per boe in the same period in 2015. The decrease in depletion and depletion on a boe basis is primarily attributable to a higher proportion of our production generated from the Onion Lake thermal project in 2016. The depletion rate on this project is below $10 per boe which is lower than the depletion rates for our other producing areas.

There were no impairment losses or reversals recorded for the nine months ended September 30, 2016 and 2015. However, further declines in forecast commodity prices could reduce reserve values and result in the recognition of future asset impairments. Future impairments can also result from changes to reserve estimates, future development costs and capitalized costs.

Income Taxes

BlackPearl did not pay cash income taxes in the first nine months of 2016 and does not expect to pay income taxes during the remainder of 2016 as we have sufficient tax pools to shelter expected income.

RESULTS FROM OPERATIONS

	2016			2015	Nine months ended September 30	
	Q3	Q2	Q1	Q3	**2016**	2015
Net income (loss) ($000s)	**556**	(8,945)	(9,322)	5,402	**(17,711)**	(15,621)
Per share, basic ($)	**0.00**	(0.03)	(0.03)	0.01	**(0.05)**	(0.05)
Per share, diluted ($)	**0.00**	(0.03)	(0.03)	0.01	**(0.05)**	(0.05)

For the quarter ended September 30, 2016, the Company recognized net income of $0.6 million, a decrease in net income compared to $5.4 million in the same period in 2015. This decrease in net income in 2016 is primarily a result of smaller gains on risk management contracts partially offset by higher revenues due to higher production volumes.

	2016			2015	Nine months ended September 30	
($000s)	**Q3**	Q2	Q1	Q3	**2016**	2015
Funds flow from operations (1)	**14,202**	11,497	3,278	10,156	**28,977**	38,064

(1) Funds flow from operations is a non-GAAP measure. Funds flow from operations 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.

Funds flow from operations increased 40% to $14.2 million during the third quarter of 2016 compared to $10.2 million in the same period in 2015. The increase in funds flow in 2016 is primarily a result of higher revenues due to increased production volumes partially offset by higher transportation and finance costs.

LIQUIDITY AND CAPITAL RESOURCES

($000s)	**September 30, 2016**	December 31, 2015
Working capital surplus	**(3,384)**	(11,063)
Revolving line of credit due beyond one year	**67,000**	88,000
Net debt (1)	**63,616**	76,937

(1) Net debt is a non-GAAP measure. Net debt 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.

At September 30, 2016, the Company had $67 million drawn under its existing credit facilities and issued letters of credit in the amount of $20,000; leaving $50.5 million available to be drawn under these credit facilities. 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 based on the Company's oil and gas reserves, the lending institution's forecast commodity prices, the current economic environment and other factors as determined by the syndicate of lending institutions. If the total advances made under the credit facilities are greater than the re-determined Borrowing Base, the Company has 60 days to repay the difference. The next scheduled Borrowing Base redetermination is to occur by November 30, 2016. The facilities are also subject to annual reviews by the lenders and the next scheduled review is to be completed by May 27, 2017. If the lenders elected not to renew the credit facilities during the annual review, any amounts outstanding would convert to a term loan that would be due and payable in full by May 26, 2018.

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 compared to current liabilities from the Company's consolidated balance sheet (excluding any current amounts due on credit facilities). In addition, amounts related to risk management contracts are excluded from the calculations of current assets and current liabilities. The Company had a working capital ratio of 5.0:1 at September 30, 2016 and was in compliance with this covenant at September 30, 2016.

($000s, except working capital ratio)	**September 30, 2016**	December 31, 2015
Current assets per consolidated financial statements	**16,912**	25,537
Add: amount available to be drawn on credit facilities	**50,500**	62,000
Less: current risk management assets	**(326)**	(10,548)
Current assets for working capital ratio	**67,086**	76,989
Current liabilities per consolidated financial statements	**13,528**	14,474
Less: current risk management liabilities	**-**	-
Current liabilities for working capital ratio	**13,528**	14,474
Working capital ratio	**5.0**	5.3

The next significant capital project for us is expected to be the expansion of our Onion Lake thermal project. The second phase of the Onion Lake thermal project is designed for 6,000 bbls/d of oil and capital costs are estimated to be between $175 and $185 million. We are actively exploring financing options to fund development of the second phase of the Onion Lake thermal project.

The low oil price environment in 2016 has resulted in the Company electing to defer the ongoing development of its conventional heavy oil projects at Mooney, Onion Lake and other minor project areas in order to maintain financial flexibility. If oil prices improve, we are in a position to resume our capital programs in these areas.

At September 30, 2016, there were 335,646,559 common shares issued and outstanding. In the first nine months of 2016 the Company issued 8,333 common shares pursuant to the exercise of stock options.

The Company did not pay dividends on its common shares in the first nine months of 2016 and it does not anticipate paying dividends in the near term. Dividends are at the discretion of the Company's board of directors. In addition, the terms and conditions of the Company's existing credit agreement restricts the payment of cash dividends to shareholders.

CAPITAL EXPENDITURES

Capital spending decreased in the third quarter of 2016 compared to the same period in 2015 as we adjust our activity levels to reflect a lower oil price environment and our desire to maintain financial flexibility. During the third quarter of 2016 capital spending was $1.8 million, a decrease from $7.9 million during the same period in 2015. The main component of the capital spending program during the third quarter of 2016 was facility improvements at the Onion Lake thermal project and planning for the second phase of the project. No new drilling activity occurred during the first nine months of 2016.

		2016		2015	Nine months ended September 30	
($000s)	**Q3**	Q2	Q1	Q3	**2016**	2015
Land	**302**	325	117	445	**744**	785
Seismic	**-**	-	(5)	74	**(5)**	593
Drilling and completion	**1,188**	70	1,464	1,340	**2,722**	7,128
Equipment and facilities	**204**	550	494	6,004	**1,248**	58,216
Other	**59**	-	7	7	**66**	121
Total	**1,753**	945	2,077	7,870	**4,775**	66,843
Property acquisitions	**-**	-	-	-	**-**	-
Total capital expenditures	**1,753**	945	2,077	7,870	**4,775**	66,843
Property dispositions	**-**	-	-	-	**-**	-
Net capital expenditures	**1,753**	945	2,077	7,870	**4,775**	66,843

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, 2016. These obligations are expected to be funded from cash flow from operating activities and the Company's credit facilities.

($000s)	2016	2017	2018	2019	2020	Thereafter
Operating leases (1)	114	960	885	687	556	545
Electrical service agreement (2)	264	1,000	585	119	119	1,987
Transportation service agreement (3)	34	135	135	135	33	-
Decommissioning liabilities (4)	349	394	456	334	8,225	72,984
Long-term debt (5)	-	-	67,000	-	-	-
Interest payments on long-term debt (5)	620	2,479	1,033	-	-	-
	1,381	4,968	70,094	1,275	8,933	75,516

(1) The Company's most significant operating lease is for office space.

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

(3) The Company entered into certain long-term agreements to transport natural gas to one of its facilities.

(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 $82.7 million as at September 30, 2016. Decommissioning programs are undertaken regularly in accordance with applicable legislative requirements.

(5) Based on the existing terms of the Company's revolving and operating lines of credit, the first possible mandatory repayment date (assuming no changes in the Borrowing Base) may come in 2018 assuming these facilities are not extended during the scheduled credit facility review in May 2017. At this time management expects the facility will be extended. Estimated future interest payments are based on rates existing at September 30, 2016.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments as at September 30, 2016 include cash and cash equivalents, trade and other receivables, deposits within prepaid expenses and deposits, accounts payable and accrued liabilities, risk management assets and liabilities and long-term debt. 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 fair value of the Company's long-term debt approximates its carrying value as the interest rates charged on this debt are comparable to current market rates. The fair values of the Company's risk management contracts are 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).

See the Company's unaudited consolidated financial statements for the three and nine months ended September 30, 2016 for details on the risks associated with these financial instruments including credit risk, liquidity risk, interest rate risk, foreign currency exchange risk and commodity price risk.

OFF-BALANCE-SHEET ARRANGEMENTS

The Company had no off-balance-sheet arrangements during the period ended September 30, 2016 or 2015. We do utilize various 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, 2016 or 2015 except for key management compensation.

OUTSTANDING SHARE DATA AND STOCK OPTIONS

As at November 3, 2016, the Company had 335,646,559 common shares outstanding and 28,980,835 stock options outstanding under its stock-based compensation program.

OUTSTANDING LONG-TERM DEBT DATA

As at November 3, 2016, the Company had $62,000,000 drawn under its existing credit facilities and had issued letters of credit in the amount of $20,000; leaving $55,480,000 available to be drawn under these credit facilities.

PROPOSED TRANSACTIONS

As of November 3, 2016, the Company does not have any significant pending transactions.

SIGNIFICANT ACCOUNTING JUDGEMENTS AND ESTIMATES

The preparation of the interim consolidated financial statements requires management to make judgements and estimates that affect the reported amounts of assets, liabilities, sales, expenses and the disclosure of contingencies. Such judgements and estimates primarily relate to unsettled transactions and events as of the date of the interim consolidated financial statements. These judgements and estimates are subject to measurement uncertainty. Actual results could differ from and affect the results reported in the 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, 2015. There have been no significant changes to the Company's critical accounting estimates as of September 30, 2016.

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

The standards and interpretations that are issued but not yet effective up to the date of issuance of the Company's financial statements are listed below.

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, 2018 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 Instruments: 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.

In January 2016, the IASB issued IFRS 16, *"Leases"* ("IFRS 16") to replace IAS 17, *"Leases."* Under IFRS 16, a single recognition and measurement model will apply for lessees which will require recognition of assets and liabilities for most leases. IFRS 16 is effective for years beginning on or after January 1, 2019 with earlier adoption permitted. The Company is currently evaluating the impact of adopting IFRS 16 on the Company's consolidated financial statements.

RISK FACTORS

Please refer to the Company's annual MD&A and Annual Information Form for the year ended December 31, 2015 for a discussion of the risks and uncertainties associated with the Company activities. Additional risk factors identified in 2016 include the following:

(a) As a result of the prolonged downturn in the oil and gas industry the number of orphan wells (wells owned by insolvent parties) has increased. The cost of abandoning orphan wells has largely been funded by industry. Accordingly, the increase in the number of orphaned wells could result in an increase in fees or assessments to other oil and gas producers, such as BlackPearl, to fund the abandonment and reclamation of these orphaned wells.

(b) In response to recent court decisions, the Alberta Energy Regulator has implemented new regulations regarding the ability to transfer leases, licenses, permits, wells and facilities between parties. The AER has increased the minimum abandonment liability rating of the buyer before they will accept a transfer of oil and gas assets. These new regulations may make it more difficult and costly for producers, such as BlackPearl, to transfer or sell assets to other parties in the future.

CONTROL CERTIFICATION

Management reported on its disclosure controls and procedures and the design of its internal control over financial reporting ("ICFR") in the annual MD&A for the year ended December 31, 2015. There have been no changes to ICFR in the nine months ended September 30, 2016 that have materially affected, or are reasonably likely to materially affect, ICFR.

Internal control systems, no matter how well conceived can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the ICFR will prevent all errors or fraud.

OUTLOOK

2016 Guidance	Initial Guidance	February Update	Q1 Update	Q2 Update	Q3 Update
Production (boe/d)					
Annual average	10,000 – 10,500	9,000 – 10,000	9,000 – 10,000	9,000 – 10,000	10,000
Funds flow from operations [(1)] ($millions)	35 – 40	5 – 10	20 – 25	35 – 40	42 – 45
Capital expenditures ($millions)	15 – 20	10 – 15	10 – 15	10 – 15	7 – 10
Year-end debt ($millions)	70 – 75	90 - 95	75 – 80	60 – 65	52 - 55
Pricing Assumptions (annual average)					
Crude oil - WTI	US $50.00	US $35.00	US $38.36	US $41.76	US$ 43.50
Light/heavy differential	US$ 15.00	US$ 14.00	US$ 14.06	US $14.04	US$ 13.81
Foreign Exchange (Cdn$ to US$)	0.75	0.71	0.76	0.76	0.76

(1) Funds flow from operations is a non-GAAP measure. Funds flow from operations 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.

Our plans for the remainder of 2016 are relatively unchanged from our Q2 2016 guidance update. We are still planning to limit capital spending and use most of our cash flow to reduce debt levels. Capital spending in 2016 is expected to be between $7 million and $10 million, down from our Q2 guidance of $10 million to $15 million. Capital spending includes preliminary planning for the second phase of the Onion Lake thermal project, continuing to operate the Blackrod SAGD pilot through the year, a small drilling program on our conventional lands and maintenance capital in all our core areas.

We anticipate oil and gas production to average approximately 10,000 boe/d in 2016, an increase from our Q2 2016 guidance of 9,000 to 10,000 boe/d. The increase is attributable to the positive performance of the Onion Lake thermal project. Funds flow from operations for 2016 is expected to be between $42 and $45 million, an increase from our Q2 guidance of $35 to $40 million and year-end 2016 debt levels are anticipated to be between $52 and $55 million, down from our Q2 guidance of $60 to $65 million. The increase in expected funds flow from operations and lower year-end debt levels is due to higher average wellhead prices and increased production than what was used in previous guidance. For budget purposes, we are using an average US$50.00/bbl WTI oil price, a heavy oil differential of US$14.19/bbl and Cdn$1 = US$0.76 foreign exchange rate for the fourth quarter of 2016.

We will continue to monitor crude oil prices and make changes to our capital spending programs and operations as we believe are necessary.

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 “anticipate”, “anticipated”, “approximately”, “plan”, “plans”, “planning”, “planned”, “could”, “continue”, “continued”, “estimate”, “estimates”, “estimated”, “forecast”, “likely”, “expect”, “expects”, “expected”, “may”, “impact”, “new”, “will”, “scheduled”, “outlook” or similar words suggesting future outcomes.

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 expected production limits to be set by OPEC at its next meeting in November as discussed in the Commodity Prices section;
- The estimated change in annualized funds flow from operations for 2016 due to changes in key variables as discussed in the Commodity Prices section;
- With the recent improvement in crude oil prices, the Company plans to put some of the shut-in wells back on production at Mooney and Onion Lake as discussed in the Oil and Gas Production, Oil and Gas Pricing and Oil and Gas sales section;
- Exploring financing options to accelerate development of the Blackrod SAGD project as discussed in the Oil and Gas Production, Oil and Gas Pricing and Oil and Gas sales section;
- Expected stock-based compensation expense for the remainder of 2016, 2017 and 2018 as discussed in the Stock-based Compensation section;
- The expected interest rate charged on our debt outstanding for the remainder of 2016 as discussed in the Finance Costs section;
- Potential future asset impairments as discussed in the Depletion and Depreciation section;
- Expected cash taxes to be paid for the remainder of 2016 in the Income Taxes section;
- Exploring financing options and estimated costs to expand our Onion Lake thermal project as discussed in the Liquidity and Capital Resources section;
- Expectation that if oil prices improve, the Company would be in a position to resume our capital programs as discussed in the Liquidity and Capital Resources section;
- The Company’s expectation that it will not be paying dividends in the near term as discussed in the Liquidity and Capital resources section;
- The Company’s expectation that the revolving and operating lines of credit will be extended at the next review as discussed in the Contractual Obligations and Commitments 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 statements in this document reflect certain assumptions and expectations by management. The key assumptions that have been made in connection with these forward-looking statements include the continuation of current or, where applicable, assumed industry conditions, the continuation of existing tax, royalty and regulatory regimes, commodity price and cost assumptions, the continued availability of cash flow or financing on acceptable terms to fund the Company's capital programs, the accuracy of the estimate of the Company's reserves and resource volumes and that BlackPearl will conduct its operations in a manner consistent with past operations. Although management considers these assumptions to be reasonable based on information currently available to it, they may prove to be incorrect.

By their very nature, forward-looking statements involve inherent risks and uncertainties which could cause actual results to differ materially from those contained in forward-looking statements. These factors include, but are not limited to, risks associated with fluctuations in market prices for crude oil, natural gas and diluent; risks related to the exploration, development and production of crude oil, natural gas and NGLs reserves; general economic, market and business conditions; substantial capital requirements; 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; potential cost overruns; variations in foreign exchange rates; diluent supply shortages; competition for capital, equipment, new leases, pipeline capacity and skilled personnel; uncertainties inherent in the SAGD bitumen and ASP recovery processes; credit risks associated with counterparties; the failure of the Company or the holder of licenses, leases and permits to meet requirements of such licenses, 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 and others may be found under "Risk Factors" in the Annual Information Form.

Undue reliance should not be placed on these forward-looking statements. Readers are cautioned that the actual results achieved will vary from the information provided herein and the variations could be material. Readers are also cautioned that the foregoing list of assumptions, risks and factors is not exhaustive. Consequently, there is no assurance by the Company that actual results achieved will be the same in whole or in part as those set out in the forward-looking statements. Furthermore, the forward-looking statements contained in this document are made as of the date hereof, and the Company 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.

Other Supplementary Information

1. **List of directors and officers at November 3, 2016**
   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 and Corporate Secretary
      Chris Hogue, Vice President Operations
      Ed Sobel, Vice President Exploration

2. **Financial Information**
   The report for the year ended December 31, 2016 is expected to be published on or before February 28, 2017.

3. **Other Information**
   Address (Corporate head office):
   BlackPearl Resources Inc.
   900, 215 – 9th Avenue S.W.
   Calgary, Alberta T2P 1K3
   Canada
   Telephone: +1.403.215.8313
   Fax: +1.403.265.5359
   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, 2016**		December 31, 2015
Assets					
Current assets					
Cash and cash equivalents	4	**$**	**3,528**	$	2,300
Trade and other receivables	5		**11,670**		10,801
Inventory			**88**		605
Prepaid expenses and deposits			**1,300**		1,283
Fair value of risk management assets	13		**326**		10,548
			16,912		25,537
Exploration and evaluation assets	6		**170,491**		169,493
Property, plant and equipment	7		**585,803**		613,314
		$	**773,206**	$	808,344
Liabilities					
Current liabilities					
Accounts payable and accrued liabilities	8	**$**	**12,883**	$	13,939
Current portion of decommissioning liabilities	9		**645**		535
			13,528		14,474
Fair value of risk management liabilities	13		**609**		1,223
Decommissioning liabilities	9		**68,911**		66,392
Long-term debt	10		**67,000**		88,000
			150,048		170,089
Shareholders' equity					
Share capital	11		**970,142**		970,134
Contributed surplus			**42,406**		39,800
Deficit			**(389,390)**		(371,679)
			623,158		638,255
		$	**773,206**	$	808,344

Commitments and contingencies (note 12)

See accompanying notes to consolidated financial statements

BLACKPEARL RESOURCES INC.

Consolidated Statements of Comprehensive Income (Loss)

(unaudited) **(Cdn$ in thousands, except for per share amounts)**	Note	**Three months ended September 30, 2016**	Three months ended September 30, 2015	**Nine months ended September 30, 2016**	Nine months ended September 30, 2015
Revenue					
Oil and gas sales		**$ 32,367**	$ 20,814	**$ 73,706**	$ 73,641
Royalties		**(4,111)**	(4,004)	**(9,269)**	(12,578)
Net oil and gas revenue		**28,256**	16,810	**64,437**	61,063
Gain on risk management contracts	13	**1,599**	19,766	**608**	13,812
		29,855	36,576	**65,045**	74,875
Expenses					
Production		**11,590**	12,248	**32,246**	41,598
Transportation		**2,013**	595	**5,339**	2,176
General and administrative		**1,614**	1,700	**5,313**	5,856
Depletion and depreciation	7	**11,984**	12,360	**33,389**	39,078
Finance costs	14	**1,343**	568	**3,823**	1,778
Stock-based compensation	11	**767**	1,301	**2,608**	4,110
Foreign currency exchange loss (gain)		**(12)**	(37)	**40**	(95)
		29,299	28,735	**82,758**	94,501
Other income					
Interest income		**-**	4	**2**	50
Income (loss) before income taxes		**556**	7,845	**(17,711)**	(19,576)
Income taxes					
Deferred income tax (recovery)		**-**	2,443	**-**	(3,955)
Net and comprehensive income (loss) for the period		**$ 556**	$ 5,402	**$ (17,711)**	$ (15,621)
Income (loss) per share					
Basic	11	**$ 0.00**	$ 0.01	**$ (0.05)**	$ (0.05)
Diluted	11	**$ 0.00**	$ 0.01	**$ (0.05)**	$ (0.05)

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, 2016			
	Share Capital	**Contributed Surplus**	**Deficit**	**Total Equity**
Balance - January 1, 2016	$ 970,134	$ 39,800	$ (371,679)	$ 638,255
Net and comprehensive loss for the period	-	-	(17,711)	(17,711)
Stock-based compensation	-	2,608	-	2,608
Shares issued on exercise of stock options	6	-	-	6
Transfer to share capital on exercise of stock options	2	(2)	-	-
Balance - September 30, 2016	**$ 970,142**	**$ 42,406**	**$ (389,390)**	**$ 623,158**

	Nine months ended September 30, 2015			
	Share Capital	**Contributed Surplus**	**Deficit**	**Total Equity**
Balance - January 1, 2015	$ 970,134	$ 33,788	$ (324,886)	$ 679,036
Net and comprehensive loss for the period	-	-	(15,621)	(15,621)
Stock-based compensation	-	4,256	-	4,256
Balance - September 30, 2015	$ 970,134	$ 38,044	$ (340,507)	$ 667,671

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, 2016**	Three months ended September 30, 2015	**Nine months ended September 30, 2016**	Nine months ended September 30, 2015
Operating activities					
Net and comprehensive income (loss) for the period		**$ 556**	$ 5,402	**$ (17,711)**	$ (15,621)
Items not involving cash:					
Depletion and depreciation	7	**11,984**	12,360	**33,389**	39,078
Accretion of decommissioning liabilities	14	**357**	431	**1,084**	1,276
Stock-based compensation	11	**767**	1,301	**2,608**	4,110
Foreign exchange loss		**-**	45	**-**	95
Deferred income tax (recovery)		**-**	2,443	**-**	(3,955)
Unrealized loss (gain) on risk management contracts	13	**538**	(11,826)	**9,607**	13,081
Decommissioning costs incurred	9	**(38)**	(117)	**(554)**	(379)
Changes in non-cash working capital	14	**2,277**	4,177	**(1,011)**	12,480
Cash flow from operating activities		**16,441**	14,216	**27,412**	50,165
Financing activities					
Proceeds on issue of common shares, net of costs		**-**	-	**6**	-
Proceeds on issue of long-term debt		**-**	3,000	**-**	68,000
Repayment of long-term debt		**(13,000)**	-	**(21,000)**	-
Cash flow from (used in) financing activities		**(13,000)**	3,000	**(20,994)**	68,000
Investing activities					
Capital expenditures - exploration and evaluation assets	6	**(9)**	(415)	**(936)**	(2,962)
Capital expenditures - property, plant and equipment	7	**(1,744)**	(7,408)	**(3,839)**	(63,735)
Changes in non-cash working capital	14	**960**	(10,573)	**(455)**	(49,633)
Cash flow used in investing activities		**(793)**	(18,396)	**(5,230)**	(116,330)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**(12)**	(82)	**40**	(190)
Increase (decrease) in cash and cash equivalents		**2,636**	(1,262)	**1,228**	1,645
Cash and cash equivalents, beginning of period		**892**	5,825	**2,300**	2,918
Cash and cash equivalents, end of period		**$ 3,528**	$ 4,563	**$ 3,528**	$ 4,563

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)
(audited)

1. GENERAL INFORMATION

BlackPearl Resources Inc. (together with its subsidiaries collectively referred to as 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's common shares are listed and traded on the TSX Exchange under the trading symbol "PXX". The Company's Swedish Depository Receipts trade on the NASDAQ Stockholm exchange under the symbol "PXXS". BlackPearl is incorporated under the Canada Business Corporations Act and is located in Canada. The address of its registered office is 900, 215 – 9th Avenue SW, Calgary, Alberta, T2P 1K3.

2. BASIS OF PREPARATION

These condensed unaudited interim consolidated financial statements for the three and nine months ended September 30, 2016 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, 2015. 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 3, 2016, 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, 2016 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, 2015 which have been prepared in accordance with IFRS as issued by the IASB.

3. SIGNIFICANT ACCOUNTING POLICIES

Accounting standards issued but not yet applied
The standards and interpretations that are issued but not yet effective up to the date of issuance of the Company's financial statements are listed below.

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, 2018 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 Instruments: 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.

In January 2016, the IASB issued IFRS 16, "*Leases*" ("IFRS 16") to replace IAS 17, "*Leases.*" Under IFRS 16, a single recognition and measurement model will apply for lessees which will require recognition of assets and liabilities for most leases. IFRS 16 is effective for years beginning on or after January 1, 2019 with earlier adoption permitted. The Company is currently evaluating the impact of adopting IFRS 16 on the Company's consolidated financial statements.

4. CASH AND CASH EQUIVALENTS

		September 30, 2016		December 31, 2015
Cash at financial institutions	**$**	**3,528**	$	2,300

Cash at financial institutions earns interest at floating rates based on daily deposit rates. As of September 30, 2016, US $0.5 million (December 31, 2015 – US $0.9 million) is included in cash at financial institutions. The Company only deposits cash with major financial institutions of high quality credit ratings.

5. TRADE AND OTHER RECEIVABLES

		September 30, 2016		December 31, 2015
Trade accounts receivable	**$**	**10,759**	$	6,264
Receivables from joint operation partners		**323**		304
Allowance for doubtful accounts		**(285)**		(285)
Net accounts receivable		**10,797**		6,283
Receivable from risk management contracts		**779**		4,228
Other receivables		**94**		290
Total trade and other receivables	**$**	**11,670**	$	10,801

Aging of trade and other receivables are as follows:

At September 30, 2016		Current		31 to 60 days		61 to 90 days		Over 90 days		Total
Trade accounts receivable	$	10,759	$	-	$	-	$	-	$	10,759
Receivables from joint operation partners		3		-		-		320		323
Allowance for doubtful accounts		-		-		-		(285)		(285)
Receivable from risk management contracts		779		-		-		-		779
Other receivables		94		-		-		-		94
Total trade and other receivables	$	11,635	$	-	$	-	$	35	$	11,670

At December 31, 2015		Current		31 to 60 days		61 to 90 days		Over 90 days		Total
Trade accounts receivable	$	6,264	$	-	$	-	$	-	$	6,264
Receivables from joint operation partners		3		6		2		293		304
Allowance for doubtful accounts		-		-		-		(285)		(285)
Receivable from risk management contracts		4,228		-		-		-		4,228
Other receivables		290		-		-		-		290
Total trade and other receivables	$	10,785	$	6	$	2	$	8	$	10,801

6. EXPLORATION AND EVALUATION ASSETS

At January 1, 2015	$ 166,344
Expenditures	3,477
Change in decommissioning provision	(328)
At December 31, 2015	169,493
Expenditures	936
Change in decommissioning provision	62
At September 30, 2016	$ 170,491

The Company's exploration and evaluation assets consist predominately of costs pertaining to the Blackrod SAGD pilot 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 2016, no assets were considered to be impaired.

The transfer of exploration and evaluation assets to property, plant and equipment occurs when commercial viability and technical feasibility is established. Technical feasibility and commercial viability is established when significant proved reserves are recognized and regulatory approval has been obtained. During the nine months ended September 30, 2016, the Company received regulatory approval for Blackrod SAGD commercial development; however, significant proved reserves have yet to be recognized to date. During the nine months ended September 30, 2016, the Company capitalized net operating revenues totalling a loss of $0.3 million ($1.8 million loss in the first nine months of 2015) related to the Blackrod SAGD pilot project. The Company did not capitalize any general and administrative costs related to exploration activities during the nine months ended September 30, 2016 (2015 - $Nil).

7. PROPERTY, PLANT AND EQUIPMENT

	Oil and natural gas properties	Corporate	Total
Cost			
At January 1, 2015	$ 1,170,170	$ 3,496	$ 1,173,666
Expenditures	64,874	11	64,885
Capitalized stock-based compensation	146	-	146
Change in decommissioning provision	5,455	-	5,455
At December 31, 2015	1,240,645	3,507	1,244,152
Expenditures	3,780	59	3,839
Change in decommissioning provision	2,039	-	2,039
At September 30, 2016	$ 1,246,464	$ 3,566	$ 1,250,030
Accumulated depletion and depreciation			
At January 1, 2015	$ 543,574	$ 2,314	$ 545,888
Depletion and depreciation	51,781	169	51,950
Impairment	33,000	-	33,000
At December 31, 2015	628,355	2,483	630,838
Depletion and depreciation	33,278	111	33,389
At September 30, 2016	$ 661,633	$ 2,594	$ 664,227
Net book value			
December 31, 2015	$ 612,290	$ 1,024	$ 613,314
September 30, 2016	$ 584,831	$ 972	$ 585,803

During the nine months ended September 30, 2016, the Company did not capitalize any borrowing costs related to development activities (2015 - $2.1 million). The Company did not capitalize any general and administrative costs related to development activities during the nine months ended September 30, 2016 (2015 - $Nil).

The Company performed a review of impairment indicators at September 30, 2016 for any indication of impairment. There were no impairment losses or reversals of property, plant and equipment during the nine months ended September 30, 2016 (2015 - $Nil).

8. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	September 30, 2016	December 31, 2015
Trade payables and accrued liabilities	**$ 12,275**	$ 13,371
Payables to joint operation partners	**193**	218
Other payables	**415**	350
Total accounts payable and accrued liabilities	**$ 12,883**	$ 13,939

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

9. 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, processing and thermal facilities. The total undiscounted amount of the estimated cash flows required to settle the liability is approximately $82.7 million (December 31, 2015 - $83.3 million). The estimated net present value of the decommissioning liability was calculated using an inflation factor of 1.5% (December 31, 2015 – 1.5%) and discounted using a risk-free rate of 2.0% (December 31, 2015 – 2.2%). 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, 2016		Year ended December 31, 2015
Decommissioning liability, beginning of the period	**$**	**66,927**	$	60,683
New liabilities recognized		**-**		15,067
Decommissioning costs incurred		**(554)**		(531)
Change in estimated costs of decommissioning		**-**		(7,670)
Change in inflation rate		**-**		(4,883)
Change in discount rate		**2,099**		2,615
Accretion expense		**1,084**		1,646
Decommissioning liability, end of the period		**69,556**		66,927
Less current portion of decommissioning liability		**(645)**		(535)
Non-current portion of decommissioning liability	**$**	**68,911**	$	66,392

10. LONG-TERM DEBT

At September 30, 2016, the Company had credit facilities of $117.5 million, consisting of a $107.5 million syndicated revolving line of credit (December 31, 2015 - $140 million) and a non-syndicated operating line of credit of $10 million (December 31, 2015 - $10 million). At September 30, 2016, the Company had drawn $67 million (December 31, 2015 - $88 million) under these credit facilities as well as letters of credit issued in the amount of $20,000 (December 31, 2015 - $20,000); leaving $50.5 million (December 31, 2015 - $62 million) available to be drawn under these facilities. 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, the lending institution's forecast commodity prices, the current economic environment and other factors as determined by the syndicate of lending institutions. If the total advances made under the credit facilities are greater than the re-determined Borrowing Base, the Company has 60 days to repay the difference. The next scheduled Borrowing Base redetermination is to occur by November 30, 2016. The facilities are also subject to annual reviews by the lenders and the next scheduled review is to be completed by May 27, 2017. If the lenders elected not to renew the credit facilities during the annual review, any amounts outstanding would convert to a term loan that would be due and payable in full by May 26, 2018.

Pursuant to the terms of the credit 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 applicable margins range between 2.00% and 3.50%. The lending agreement defines debt as any advances outstanding on the credit facilities plus any outstanding letters of credit/guarantee. The lending agreement defines EBITDA as comprehensive income (loss) before income tax, financing charges, non-cash items deducted in determining comprehensive income (loss), unrealized gains or losses on risk management contracts and any income/losses attributable to assets acquired or disposed of when determining net comprehensive income (loss) for the period as indicated on the Company's consolidated statement of comprehensive income (loss). The Company also incurs a standby fee for undrawn amounts.

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 compared to current liabilities from the Company's consolidated balance sheet. In addition, amounts related to risk management contracts are excluded from the calculation of current assets and current liabilities. The Company had a working capital ratio of 5.0:1 at September 30, 2016 (December 31, 2015 – 5.3:1) and was in compliance with this covenant at September 30, 2016.

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 December 31, 2015	335,638,226	$ 970,134
Shares issued on exercise of stock options	8,333	6
Transferred from contributed surplus on exercise of stock options	-	2
Balance as at September 30, 2016	335,646,559	$ 970,142

(c) Stock Options Outstanding

The Company has a stock option plan (the "Plan") available to directors, officers, employees and certain consultants of the Company. 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. 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, 2015	20,916,335	3.00
Granted	11,458,500	0.84
Forfeited	(666,666)	2.71
Expired	(2,053,000)	4.89
Outstanding at December 31, 2015	29,655,169	2.04
Granted	125,000	0.88
Exercised	(8,333)	0.71
Forfeited	(342,669)	3.34
Expired	(275,000)	6.88
Outstanding at September 30, 2016	29,154,167	1.98

Options outstanding and exercisable as at September 30, 2016 are summarized below:

	Options Outstanding			**Options Exercisable**		
Range of Exercise Prices ($)	**Number of Options Outstanding**	**Weighted-Average Exercise Price ($)**	**Weighted-Average Remaining Life (Years)**	**Number of Options Exercisable**	**Weighted-Average Exercise Price ($)**	**Weighted-Average Remaining Life (Years)**
0.71 – 1.50	11,395,167	0.84	3.73	3,746,245	0.84	3.72
1.51 – 3.00	14,254,000	2.31	2.43	10,265,876	2.32	2.36
3.01 – 4.50	1,705,500	3.71	0.74	1,705,500	3.71	0.74
4.51 – 4.97	1,799,500	4.92	0.13	1,799,500	4.92	0.13
	29,154,167	1.98	2.70	17,517,121	2.41	2.26

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, 2016, 125,000 options were granted (2015 – 7,195,000) and during the three months ended September 30, 2016, 50,000 options were granted (2015 – no options granted). 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	**2016**	2015	**2016**	2015
Risk free interest rate (%)	**0.5**	-	**0.6**	0.7
Dividend yield (%)	**0.0**	-	**0.0**	0.0
Expected life (years)	**3.8**	-	**3.7**	3.6
Expected volatility (%)	**55.8**	-	**55.1**	53.5
Forfeiture rate (%)	**10.8**	-	**11.3**	13.6
Weighted average fair value of options	**$ 0.43**	-	**$ 0.36**	$ 0.36

(d) Stock-based Compensation

	Three months ended September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Gross stock-based compensation	**$ 767**	$ 1,358	**$ 2,656**	$ 4,314
Recoveries from forfeitures	**-**	(10)	**(48)**	(58)
Net stock-based compensations before capitalization	**767**	1,348	**2,608**	4,256
Stock-based compensation capitalized to property, plant and equipment	**-**	(47)	**-**	(146)
Net stock-based compensation	**$ 767**	$ 1,301	**$ 2,608**	$ 4,110

(e) Income (loss) per Share

Basic income (loss) per share amounts are calculated by dividing net and comprehensive income (loss) 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 (loss) per share:

	Three months ended September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Net and comprehensive income (loss)	**$ 556**	$ 5,402	**$ (17,711)**	$ (15,621)
Weighted average number of common shares - basic	**335,646**	335,638	**335,642**	335,638
Dilutive effect:				
Outstanding options	**2,313**	-	**-**	-
Weighted average number of common shares - diluted	**337,959**	335,638	**335,642**	335,638
Basic income (loss) per share	**$ 0.00**	$ 0.01	**$ (0.05)**	$ (0.05)
Diluted income (loss) per share	**$ 0.00**	$ 0.01	**$ (0.05)**	$ (0.05)

For the nine months ended September 30, 2016, the Company used a weighted average market closing price of $0.94 (2015 - $0.97) per share to calculate the dilutive effect of stock options. For the nine months ended September 30, 2016, all outstanding options were anti-dilutive (2015 – all outstanding options were anti-dilutive) and were not included in the calculation of diluted income (loss) per share.

12. COMMITMENTS AND CONTINGENCIES

	2016	2017	2018	2019	2020	Thereafter
Operating leases (1)	$ 114	$ 960	$ 885	$ 687	$ 556	$ 545
Electrical service agreement (2)	264	1,000	585	119	119	1,987
Transportation service agreement (3)	34	135	135	135	33	-
Decommissioning liabilities (4)	349	394	456	334	8,225	72,984
Long-term debt (5)	-	-	67,000	-	-	-
Interest payments on long-term debt (5)	620	2,479	1,033	-	-	-
Total	$ 1,381	$ 4,968	$ 70,094	$ 1,275	$ 8,933	$ 75,516

(1) The Company's most significant operating lease is for office space.

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

(3) The Company entered into certain long-term agreements to transport natural gas to one of its facilities.

(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 $82.7 million as at September 30, 2016. Decommissioning programs are undertaken regularly in accordance with applicable legislative requirements.

(5) Based on the existing terms of the Company's revolving and operating lines of credit, the first possible mandatory repayment date (assuming no changes in the Borrowing Base amount - see note 10) may come in 2018 assuming these facilities are not extended during the scheduled credit facility review in May 2017. Estimated future interest payments are based on rates existing at September 30, 2016.

13. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments as at September 30, 2016 include cash and cash equivalents, trade and other receivables, deposits within prepaid expenses and deposits, accounts payable and accrued liabilities, risk management assets and liabilities and long-term debt.

(a) Fair value of financial instruments

The following table summarizes the carrying value and fair value of the Company's financial assets and liabilities.

		September 30, 2016		December 31, 2015	
	Measurement Level	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Financial Assets					
Loans and receivables:					
Cash and cash equivalents	1	**$ 3,528**	**$ 3,528**	$ 2,300	$ 2,300
Trade and other receivables	2	**$ 11,670**	**$ 11,670**	$ 10,801	$ 10,801
Deposits	2	**$ 96**	**$ 96**	$ 409	$ 409
Financial assets at fair value through profit or loss:					
Risk management assets	2	**$ 326**	**$ 326**	$ 10,548	$ 10,548
Financial liabilities					
Financial liabilities at amortized cost:					
Accounts payable and accrued liabilities	2	**$ 12,883**	**$ 12,883**	$ 13,939	$ 13,939
Long-term debt	2	**$ 67,000**	**$ 67,000**	$ 88,000	$ 88,000
Financial liabilities at fair value through profit or loss:					
Risk management liabilities	2	**$ 609**	**$ 609**	$ 1,223	$ 1,223

The fair values of financial instruments have been determined by various valuation methods as defined below:

- Level 1: fair value is based on quoted prices (unadjusted) in active markets for identical assets or liabilities;
- Level 2: fair value is based on inputs other than quoted prices included within level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices); and
- Level 3: fair value is based on inputs for the asset or liability that are not based on observable market data (unobservable inputs).

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 fair value of the Company's long-term debt approximates its carrying value as the interest rates charged on this debt are comparable to current market rates. The fair values of the Company's risk management contracts are determined by discounting the difference between the contracted prices and published forward price curves as at the balance sheet date, using the remaining contracted oil volumes and a risk-free interest rate (based on published government rates).

(b) Risks associated with financial instruments

The following summarizes the risks associated with the Company's financial instruments:

(i) Credit Risk

Credit risk is the risk that a third party fails to meet its contractual obligations that could result in the Company incurring a loss.

As at September 30, 2016, the Company held $3.5 million in cash at various major financial institutions throughout Canada and the USA; however, one Canadian financial institution held over 90% of our cash and short-term deposits. The financial institution is a Canadian provincial crown corporation with a high investment grade rating and therefore we believe the credit risk is limited.

At September 30, 2016, 92% of receivables were from oil and gas marketers related to the sale of our oil and gas production. Receivables from oil and gas marketers are generally collected on the 25th day of the month following production. The Company attempts to mitigate the credit risk associated with these marketers by assessing their financial strength and entering into relationships with larger purchasers with established credit history. During 2016, the Company did not experience any collection issues with its marketers.

In the first nine months of 2016, the Company had four customers which individually accounted for more than 10 percent of its total oil and gas sales. Oil and gas sales to these collective customers represented approximately 86% of the Company's total oil and gas sales in the first nine months of 2016.

Risk management assets consist of commodity contracts used to manage the Company's exposure to fluctuations in commodity prices. At September 30, 2016, the Company had a $0.8 million receivable related to its risk management contracts. The Company manages the credit risk exposure related to risk management contracts by selecting investment grade counterparties and by not entering into contracts for trading or speculative purposes. During 2016, the Company did not experience any collection issues with its risk management contracts.

The Company typically does not obtain or post collateral or security from its oil and natural gas marketers or financial institution counterparties. The carrying amounts of accounts receivable represent the maximum credit exposure. The Company is not the operator of certain oil and natural gas properties in which it has an ownership interest. The Company is dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators. In addition, the Company's activities may be impacted by the ability, expertise, judgment and financial capability of the operators.

(ii) Liquidity risk

Liquidity risk is the risk the Company is unable to meet its financial obligations as they come due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. The Company has an on-going cash flow planning and forecasting model to help determine the funds required to meet its operational needs at all times. In addition, the Company manages its liquidity risk by ensuring that it has access to multiple sources of capital including cash and cash equivalents, cash from operating activities, undrawn credit facilities and opportunities to issue additional equity. As at September 30, 2016, the Company had $50.5 million available on its credit facilities. Management believes that these sources will be adequate to settle the Company's financial liabilities and commitments.

The maturity dates for the Company's undiscounted cash outflows related to financial liabilities are as follows:

	<6 Months	**6 months - 1 Year**	**1 - 2 Years**
Accounts payable and accrued liabilities	12,883	-	-
Risk management liabilities	-	-	609
Long-term debt	-	-	67,000
Interest payments on long-term debt [(1)]	1,240	1,240	1,652

(1) Estimated future interest payments are based on rates existing at September 30, 2016.

(iii) Interest Rate Risk

Interest rate risk refers to the risk that a financial instrument, or cash flows associated with the instrument, will fluctuate due to changes in market interest rates. The Company is exposed to interest rate risk related to interest expense on its credit facilities due to the floating interest rate charged on advances. For the nine months ended September 30, 2016, if interest rates had been one percent higher with all other variables held constant, after tax net loss for the period would have been approximately $614,000 higher. The Company has not entered into any fixed rate contracts to mitigate its interest rate risk.

(iv) Foreign currency exchange risk

The Company is exposed to risks arising from fluctuations in foreign currency exchange rates and the volatility of those rates. This exposure primarily relates to: (i) revenues received for the sale of its crude oil production are primarily priced relative to US dollars; (ii) certain expenditure commitments, deposits, accounts receivable, and accounts payable are denominated in US dollars; and to a lesser extent (iii) its operations in the United States. A significant change in the currency exchange rates between the US and Canadian dollar could have a material impact on the Company's revenues and net earnings. As at September 30, 2016, the Company has not entered into any fixed rate contracts to mitigate its currency risks.

As at September 30, 2016, the Company held US $0.5 million in cash and cash equivalents. If exchange rates to convert from US dollars to Canadian dollars had been $0.10 lower with all other variables held constant, after tax net loss for the year would have been approximately $54,000 higher as a result of the re-valuation of the Company's US dollar denominated financial assets and liabilities as at September 30, 2016. An equal opposite impact would have occurred to net loss had exchange rates been $0.10 higher.

(v) Commodity price risk

Commodity price risk is the risk that future cash flows will fluctuate as a result of changes in the price of oil and natural gas. Commodity prices are impacted by world economic events that affect supply and demand, which are generally beyond the Company's control. Changes in crude oil prices may significantly affect the Company's results of operations, cash generated from operating activities, capital spending and the Company's ability to meet its obligations. The majority of the Company's production is sold under short-term contracts; consequently BlackPearl is at risk to near term price movements. The Company manages this risk by constantly monitoring commodity prices and factoring them into operational decisions, such as contracting or expanding its capital expenditures program. Natural gas currently represents less than 2% of the Company's total production and, as a result, any fluctuation in natural gas prices would have a nominal effect on current revenues.

From time to time, 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 (loss).

Risk management amounts recognized were as follows:

	Three months ended September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Realized gain on risk management contracts	**$ 2,137**	$ 7,940	**$ 10,215**	$ 26,893
Unrealized gain (loss) on risk management contracts	**(538)**	11,826	**(9,607)**	(13,081)
Gain on risk management contracts	**$ 1,599**	$ 19,766	**$ 608**	$ 13,812

The table below summarizes the Company's outstanding commodity contracts as at September 30, 2016:

Subject of Contract	Volume	Term	Reference	Strike Price	Type	Fair value
2016						
Oil	1,000 bbls/d	October 1 to December 31	CDN$ WCS	CDN$ 51.15/bbl	Swap	$ 472
Oil	2,000 bbls/d	October 1 to December 31	CDN$ WCS	CDN$ 47.60/bbl	Swap	340
Oil	2,000 bbls/d	October 1 to December 31	US$ WTI	US$ 65.00/bbl	Sold Call	(13)
2017						
Oil	1,000 bbls/d	January 1 to December 31	CDN$ WCS	CDN$ 50.00/bbl	Swap	714
Oil	1,000 bbls/d	January 1 to December 31	CDN$ WCS	CDN$ 49.50/bbl	Swap	463
Oil	500 bbls/d	January 1 to June 30	CDN$ WCS	CDN$ 40.00/bbl to 52.50/bbl	Collar	(98)
Oil	500 bbls/d	January 1 to June 30	CDN$ WCS	CDN$ 40.00/bbl to 47.00/bbl	Collar	(310)
Oil	1,000 bbls/d	January 1 to December 31	US$ WTI	US$ 60.00/bbl	Sold Call	(1,263)
2018						
Oil	500 bbls/d	January 1 to December 31	US$ WTI	US$ 70.00/bbl	Sold Call	(588)
Total						$ (283)

Current portion of fair value of contracts	$ 326
Non-current portion of fair value of contracts	$ (609)

As at September 30, 2016, a 10% decrease to the oil price used to calculate the fair value for the risk management contracts would result in an approximate $6.6 million increase in fair value of these contracts and decrease in the after tax net loss for the period.

14. SUPPLEMENTARY INFORMATION

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

	Three months ended September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Cash interest paid	**$ 986**	$ 923	**$ 2,739**	$ 2,568

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

	Three months ended September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Gross interest and financing charges	**$ 986**	$ 923	**$ 2,739**	$ 2,568
Capitalized interest and financing charges	**-**	(786)	**-**	(2,066)
Net interest and financing charges	**986**	137	**2,739**	502
Accretion of decommissioning liabilities	**357**	431	**1,084**	1,276
Finance costs	**$ 1,343**	$ 568	**$ 3,823**	$ 1,778

(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	
	2016	2015	**2016**	2015
Changes in non-cash working capital				
Trade and other receivables	**$ 1,437**	$ 5,956	**$ (869)**	$ 8,854
Inventory	**10**	(8)	**517**	299
Prepaid expenses and deposits	**657**	288	**(17)**	(1,147)
Accounts payable and accrued liabilities	**1,133**	(12,632)	**(1,097)**	(45,159)
Changes in non-cash working capital	**$ 3,237**	$ (6,396)	**$ (1,466)**	$ (37,153)
Relating to:				
Operating activities	**$ 2,277**	$ 4,177	**$ (1,011)**	$ 12,480
Investing activities	**960**	(10,573)	**(455)**	(49,633)