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NEWS RELEASE **August 9, 2016**

BLACKPEARL ANNOUNCES SECOND 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 six months ended June 30, 2016.

Highlights include:

- The Onion Lake thermal EOR project successfully reached its design capacity of 6,000 barrels of oil per day (bbl/d) during the second quarter and is currently producing over 6,400 bbl/d at a steam oil ratio of 2.5.
- Corporately, production averaged 9,698 barrels of oil equivalent (boe) per day in Q2 2016, a 20% increase compared to Q2 2015 volumes. The increase is attributable to the production ramp-up on the Onion Lake thermal project.
- Stronger Q2 crude oil prices contributed to a 117% increase in revenues and 251% increase in funds from operations compared to Q1 2016. Year to date we have generated revenues of $41 million and funds from operations of $15 million;
- We continued to use free cash flow to reduce debt levels; our bank debt dropped from $88 million at the beginning of the year to $80 million on June 30, 2016; and it has been further reduced to $75 million after the end of the quarter.
- At Blackrod, the pilot well pair has produced in excess of 550 bbl/d at a steam oil ratio of 2.8 for the last 12 months. The continuing positive results generated from our SAGD pilot further support the viability of our proposed 80,000 bbl/d commercial development.
- As a result of the Company’s on-going cost reduction initiative operating and transportation costs averaged $14.71/bbl, a 30% decrease from Q2 2015.

John Festival, President of BlackPearl commenting on Q2 activities indicated that “the highlight of the quarter was the impressive performance of our Onion Lake thermal operations. These results put our Onion Lake project in the top quartile of Canadian thermal projects. We have a high quality team that built and is now operating the project and the success of the first phase bolsters our confidence and commitment to expand the project that will double its size.”

Financial and Operating Highlights

	Three months ended June 30, 2016	Three months ended June 30, 2015	Six months ended June 30, 2016	Six months ended June 30, 2015
Daily sales volumes				
Oil (bbl/d)	9,004	6,937	8,723	7,207
Bitumen (bbl/d)	553	613	568	510
	9,557	7,550	9,291	7,717
Natural gas (mcf/d)	847	3,004	846	2,655
Combined (boe/d) (1)	9,698	8,051	9,432	8,159
Product pricing ($) (before the effects of hedging transactions)				
Crude oil - per bbl	34.44	47.52	25.89	39.53
Natural gas - per mcf	1.29	2.61	1.53	2.62
Combined - per boe (1)	34.03	45.37	25.63	38.15
Netback ($/boe) (1) (2)				
Oil and gas sales	34.03	45.37	25.63	38.15
Realized gain on risk management contracts	2.35	7.75	5.01	13.69
Royalties	4.58	6.58	3.20	6.19
Transportation	1.48	1.18	2.06	1.14
Operating costs	13.23	19.86	12.80	21.20
	17.09	25.50	12.58	23.31
($000's, except per share amounts)				
Revenue				
Oil and gas revenue – gross	28,318	30,712	41,339	52,827
Loss for the period	(8,945)	(10,079)	(18,267)	(21,023)
Per share, basic and diluted	(0.03)	(0.03)	(0.05)	(0.06)
Funds flow from operations(3)	11,497	14,968	14,775	27,908
Capital expenditures	945	15,992	3,022	58,973
Working capital deficiency (surplus), end of period	(4,497)	20,086	(4,497)	20,086
Long term debt	80,000	79,000	80,000	79,000
Net debt (4)	75,503	99,086	75,503	99,086
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 (the closest GAAP measure) 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.

(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

Our new Onion Lake thermal project is proving to be the low cost, low risk growth opportunity, that we anticipated when we sanctioned the development of the project in 2014.

We commenced construction of the project in March 2014. Construction was completed 15 months later and we initiated steam injection in June 2015. Production has steadily increased over the last year and, in June 2016, production reached name plate design capacity of 6,000 bbls/d. Equally important, the steam oil ratio averaged 2.7 in June, lower than our engineering design of 2.9. The ramp-up in production volumes is continuing, with July 2016 oil production averaging over 6,400 bbls/d. A planned turn-around of the central processing facilities for general maintenance and minor equipment modifications was completed in May.

Thermal projects in Saskatchewan, such as our Onion Lake project, provide some of the most attractive economics in industry in terms of capital efficiency and low operating costs. The first phase of our Onion Lake thermal project was built for under $35,000 per flowing barrel and operating costs are currently under $10/bbl. Because thermal production is our lowest cost production, growth from the Onion Lake project has the effect of bringing down our overall cost structure which is critical in a lower oil price environment. Additionally, these projects have stable production for 15 to 20 years, with relatively low annual sustaining capital of $4 to $6 per barrel.

We have begun the planning for phase two expansion of the Onion Lake thermal project. This phase will be similar to the first phase – designed for production of 6,000 bbl/d, with similar central processing facilities, and primarily using a modified SAGD process (horizontal producers, vertical injectors). Because the second phase will be a “look-a-like” to the first phase and the fact that phase one included construction of certain infrastructure to support phases one and two, total engineering, design and construction time is expected to be less, likely 12 to 15 months. We currently have regulatory approval for a 12,000 bbl/d development at Onion Lake. Detailed cost estimates have not been completed for phase two; however, our preliminary estimates are in the range of $175 to $185 million, which is 20% less than the costs to construct phase one. Timing to sanction phase two development is dependent on improved economic conditions (oil prices) and securing additional financing for the project. We are evaluating various funding opportunities for the phase two expansion.

We have also been looking for thermal growth opportunities at Onion Lake beyond phases one and two and our on-going technical review of our Onion Lake acreage has identified several opportunities that have the potential to add another phase of 6,000 bbl/d (phase three) of production. Further evaluation of these opportunities will continue over the next several months.

No new drilling occurred in Q2 2016 within our conventional development at Onion Lake; however we are planning a small drilling program during the second half of the year.

Blackrod

The performance of our SAGD pilot at Blackrod continues to demonstrate the positive technical traits required for a successful commercial development on our Blackrod lands. During the second quarter, the pilot produced an average of 553 bbl/d. The pilot has produced in excess of 550 bbl/d for 12 consecutive months, and has produced, cumulatively, over 390,000 barrels of oil.

Our Blackrod leases have over a billion barrels of oil in place. The success of our SAGD pilot bolsters our commitment to commercially develop these lands. Our 80,000 bbl/d commercial development application is waiting on Order-In-Council approval from the Alberta government. Our aim is to accelerate development of our Blackrod lands as market conditions improve.

Mooney

No new activities were initiated at Mooney during the first half of the year due to low oil prices. During the first quarter we temporarily shut-in the majority of the first phase of the ASP flood due to low oil prices. We plan to re-initiate the flood and ultimately expand it as oil prices recover. Temporarily shutting-in the ASP flood is not expected to affect the ultimate recovery of the reserves in the area.

Production

Oil and gas production averaged 9,698 barrels of oil equivalent per day in the second quarter of 2016, a 20% increase compared with the second 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 to selectively shut-in production at Onion Lake and Mooney due to low oil prices.

Average Daily Sales Volume

	Three months ended June 30,		Six months ended June 30,	
(boe/day)	2016	2015	2016	2015
Onion Lake - thermal	5,221	-	4,737	-
Onion Lake - conventional	2,138	3,624	2,185	3,790
Mooney	714	2,588	878	2,692
John Lake	870	1,022	865	1,016
Blackrod	553	613	568	510
Other	202	204	199	151
	9,698	8,051	9,432	8,159

Financial Results

Oil and gas revenues in Q2 2016 improved significantly from the first quarter due to higher crude oil prices and higher production volumes; however, revenues were lower than the comparable quarter in 2015. Oil and gas revenues were $28.3 million in the second quarter of 2016, an 8% decrease from the second quarter of 2015. The decrease in revenues is attributable to a 25% decrease in our average sales price partially offset by a 20% increase in production volumes.

Our realized oil price (before the effects of risk management activities) in Q2 2016 was $34.44 per barrel compared to $47.52 per barrel in 2015. The decrease in our realized wellhead price reflects lower WTI reference oil prices in Q2 2016 compared with Q2 2015 (US$45.59/bbl vs US$57.94/bbl) and wider heavy oil differentials (US$13.30/bbl vs US$11.62/bbl), partially offset by a weaker Canadian dollar relative to the US dollar ($0.776 vs $0.813).

Our oil hedging program has helped mitigate some of the negative impact of the low oil price environment in 2016. During the first half of 2016 we realized a gain of $8.1 million from our oil hedging program, which was the equivalent of adding $5.01 per barrel to our wellhead price. The following summarizes the hedging contracts we currently have outstanding:

Subject of Contract	Volume	Term	Reference	Strike Price	Type
2016					
Oil	1,000 bbls/d	July 1, 2016 to December 31, 2016	CDN$ WCS	CDN$ 51.15/bbl	Swap
Oil	2,000 bbls/d	July 1, 2016 to December 31, 2016	CDN$ WCS	USD$ 47.60/bbl	Swap
Oil	2,000 bbls/d	July 1, 2016 to December 31, 2016	US$ WTI	USD$ 65.00/bbl	Sold Call
2017					
Oil	1,000 bbls/d	January 1, 2017 to December 31, 2017	CDN$ WCS	CDN$ 50.00/bbl	Swap
Oil	1,000 bbls/d	January 1, 2017 to December 31, 2017	CDN$ WCS	CDN$ 49.50/bbl	Swap
Oil	1,000 bbls/d	January 1, 2017 to December 31, 2017	US$ WTI	USD$ 60.00/bbl	Sold Call

Operating costs continued to trend lower during the second quarter of 2016. In Q2 2016 operating and transportation costs were $12.2 million or $14.71/bbl compared with $14.2 million or $21.04/bbl in Q2 2015. The decrease in operating and transportation costs is attributable to our on-going efforts to reduce our cost structure which includes generating a higher proportion of our production volumes from the Onion Lake thermal project which has lower average operating costs, as well as temporarily shutting-in some of our higher cost production at Onion Lake and the majority of the Mooney ASP flood.

Stronger crude oil prices and higher production volumes in Q2 2016 had a positive impact on our funds flow from operations during the quarter. In Q2 2016 our funds flow from operations was $11.5 million, significantly higher than the $3.3 million generated during the first quarter of the year.

During this low oil price environment our focus has been to use our operating cash flow to reduce our debt levels. Long term debt as at June 30, 2016 was $80 million, $8 million lower than at the beginning of the year. The Company recently completed its annual review and semi-annual borrowing base redetermination with the syndicate of lending institutions in its credit facility. Under the terms of the amended credit agreement with the lenders, the total credit facilities available to the Company was amended to $117.5 million, consisting of a $107.5 million syndicated revolving line of credit and a non-syndicated operating line of credit of $10 million.

The 2016 second 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 for the remainder of 2016 are relatively unchanged from our Q1 2016 guidance update. We are still planning to limit capital spending and use most of our cash flow to reduce debt levels until oil prices recover. Capital spending in 2016 is expected to be between $10 million and $15 million, unchanged from our Q1 guidance. Capital spending includes preliminary planning for the second phase of the Onion Lake thermal EOR 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.

Funds flow from operations for 2016 is expected to be between $35 and $40 million, an increase from our Q1 guidance of $20 to $25 million. Year-end 2016 debt levels are anticipated to be between $60 and $65 million, down from our Q1 guidance of $75 to $80 million. The increase in expected funds flow from operations and lower year-end debt levels is primarily due to higher average wellhead prices than what was used in previous guidance. For budget purposes we are using an average US$44.00/bbl WTI price, a heavy oil differential of

US$14.30/bbl and Cdn$1 = US$0.76 foreign exchange rate for the second half of the year. We anticipate oil and gas production to average between 9,000 and 10,000 boe/d in 2016, unchanged from our Q1 2016 guidance update.

Non-GAAP Measures

Throughout this news release, the Company uses terms “funds flow from operations”, “netback” and “net debt”. 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. “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. “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. 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 expected annual sustaining capital for the Onion Lake EOR project, the expectation that temporarily shutting-in the Mooney ASP flood will not impact the ultimate recovery of reserves, timing as to when we would bring back on production the Onion Lake and Mooney shut-in wells 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 Financial Instruments Trading Act. This information was publicly communicated on August 9, 2016 at 3:00 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 six months ended June 30, 2016. These results are being compared with the three and six months ended June 30, 2015. The MD&A should be read in conjunction with the Company's unaudited consolidated financial statements for the three and six months ended June 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	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", "funds flow from operations per share - basic", "funds flow from operations per share – diluted", "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. Funds flow from operations per share – basic & diluted is calculated as cash flow from operating activities before decommissioning costs incurred and changes in non-cash working capital related to operations divided by the weighted average number of common shares outstanding for the period.

	2016		2015	Six months ended June 30	
($000s)	**Q2**	Q1	Q2	**2016**	2015
Cash flow from operating activities[(1)]	**7,184**	3,787	12,100	**10,971**	35,949
Add (deduct):					
Decommissioning costs incurred	**369**	147	17	**516**	262
Changes in non-cash working capital related to operations	**3,944**	(656)	2,851	**3,288**	(8,303)
Funds flow from operations[(2)]	**11,497**	3,278	14,968	**14,775**	27,908

(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 August 9, 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 EOR 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 half of 2016, with WTI oil prices averaging US$39.52 per bbl during the first six months of 2016 compared to US$53.29 per bbl during the same period in 2015.

- During the second quarter of 2016, the first phase of the Onion Lake thermal EOR project reached its productive design capacity and production is continuing to ramp-up. Oil production during the month of June averaged 6,055 bbls/d, with a steam ratio of 2.7. In July 2016, production from this project was over 6,400 bbls/d.

- As a result of the Company’s current cost reduction initiative, operating and transportation costs averaged $14.71/bbl in the second quarter, a 30% decrease from Q2 2015.

- Due to low oil prices, the Company limited capital spending in the first half of 2016 and used the majority of our cash flow from operating activities to reduce debt. Capital expenditures during the first half of the year were $3.0 million, with approximately $1.7 million spent at the Onion Lake thermal EOR project related to facility improvements and planning costs for the second phase of the project, $0.8 million spent at Blackrod primarily related to continued capitalization of net revenues from operating the Blackrod pilot and $0.5 million spent in other areas.

- Oil and gas sales during the first half of 2016 were $41 million and funds flow from operations (a non-GAAP measure) were $14.8 million. For the six months ended June 30, 2016, the Company incurred a net loss of $18.3 million.

- The decline in crude oil prices was partially offset by realized gains on crude oil hedging contracts. For the six months ended June 30, 2016, the Company realized gains of $8.1 million from these contracts.

- During the first half 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 half of 2016.

- At June 30, 2016, the Company's long-term debt was $80 million; $8 million lower than at the beginning of the year. At the completion of the most recent semi-annual review of the Company's credit facilities with its syndicated group of lenders, the Company's maximum borrowing amount was reduced from $150 million to $117.5 million. At June 30, 2016, BlackPearl had working capital of $4.5 million and $80 million in long-term debt, leaving $37.5 million available to be drawn under the Company's existing credit facilities.

SELECTED QUARTERLY INFORMATION

	2016		**2015**				2014	
($000s, except where noted)	**Jun 30**	**Mar 31**	**Dec 31**	**Sep 30**	Jun 30	Mar 31	Dec 31	Sep 30
Production (boe/d) [1]	**9,698**	**9,166**	**9,521**	**7,478**	8,051	8,269	9,639	9,248
Oil and gas sales	**28,318**	**13,021**	**22,630**	**20,814**	30,712	22,115	47,798	58,818
Oil sales ($/bbl)	**34.44**	**16.77**	**27.65**	**35.02**	47.52	32.05	59.34	75.89
Gas sales ($/mcf)	**1.29**	**1.77**	**2.91**	**2.88**	2.61	2.63	3.39	3.97
Oil and gas sales ($/boe)	**34.03**	**16.67**	**27.45**	**34.05**	45.37	31.25	57.00	72.90
Production & transportation costs	**12,246**	**11,736**	**15,666**	**12,843**	14,245	16,686	22,306	22,686
Production costs ($/boe)	**13.23**	**12.35**	**17.77**	**20.04**	19.86	22.48	25.12	26.05
Transportation costs ($/boe)	**1.48**	**2.68**	**1.23**	**0.97**	1.18	1.10	1.48	2.06
Gain (loss) on risk management contracts								
Realized	**1,958**	**6,120**	**10,334**	**7,940**	5,245	13,708	5,846	(468)
Unrealized	**(8,597)**	**(472)**	**1,778**	**11,826**	(13,533)	(11,374)	20,697	4,961
Net income (loss)	**(8,945)**	**(9,322)**	**(31,172)**	**5,402**	(10,079)	(10,944)	16,254	7,013
Per share, basic and diluted ($)	**(0.03)**	**(0.03)**	**(0.09)**	**0.01**	(0.03)	(0.03)	0.05	0.02
Capital expenditures	**945**	**2,077**	**1,665**	**7,870**	15,992	42,981	57,700	80,262
Funds flow from operations [2]	**11,497**	**3,278**	**10,898**	**10,156**	14,968	12,940	19,716	23,809
Per share, basic and diluted ($)	**0.03**	**0.01**	**0.04**	**0.03**	0.04	0.04	0.06	0.07
Long-term debt	**80,000**	**86,000**	**88,000**	**97,000**	94,000	78,000	29,000	-

	2016		2015				2014	
($000s, except where noted)	**Jun 30**	**Mar 31**	**Dec 31**	**Sep 30**	Jun 30	Mar 31	Dec 31	Sep 30
Total assets (end of period)	**782,591**	**795,336**	**808,344**	**861,107**	864,926	866,018	837,773	785,538
Shares outstanding (000s)	**335,647**	**335,638**	**335,638**	**335,638**	335,638	335,638	335,638	335,638
Weighted average shares outstanding								
Basic	**335,641**	**335,638**	**335,638**	**335,638**	335,638	335,638	335,638	335,638
Diluted	**335,641**	**335,638**	**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 EOR 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	Q2	Q1	Q4	Q3	Q2	Q1
Average Crude Oil Prices								
West Texas Intermediate (WTI) (US$/bbl)	39.52	53.29	45.59	33.45	42.18	46.43	57.94	48.63
Western Canadian Select (WCS) (Cdn$/bbl)	33.96	49.53	41.61	26.31	36.86	43.27	56.95	42.11
Differential – WCS/WTI (US$/bbl)	14.02	13.19	13.30	14.32	14.57	13.39	11.62	14.71
Differential - WCS/WTI (%)	35.5%	24.8%	29.2%	42.8%	34.5%	28.8%	20.1%	30.2%
Average Natural Gas Prices								
AECO gas (Cdn$/GJ)	1.53	2.56	1.33	1.74	2.34	2.75	2.52	2.61
Average Foreign Exchange (US$ per Cdn$1)	0.751	0.810	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 improved during the second quarter of 2016 compared to the first quarter; however, prices remain significantly lower than the comparable periods in 2015. WTI oil prices averaged US$45.59 per bbl in the second quarter of 2016 compared to US$33.45 per bbl in the first quarter of 2016 and US$57.94 per bbl in the second quarter of 2015. For the first six months of 2016 WTI oil prices averaged US$39.52 per bbl which is down from US$53.29 per bbl in the same period in 2015. The improvement in second quarter crude oil pricing has been attributed to higher global demand for oil and lower production volumes, particularly in the US.

The heavy oil differential (WTI oil prices compared to WCS oil prices) improved in the second quarter of 2016. Heavy oil differentials averaged US$13.30 per bbl in the second quarter of 2016 compared to US$14.32 per bbl in the first quarter of 2016. Seasonal demand, disruptions caused by forest fires and improved refining and transportation capacity all contributed to the tighter heavy oil differentials.

Natural gas prices decreased in the first half of 2016 averaging $1.53/GJ compared to $2.56/GJ in the same period in 2015. The decrease in natural gas prices during the first half of 2016 is attributable 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 EOR project. The cost of natural gas is the most significant component of the cost of production in these areas and therefore lower natural gas prices in the first half of 2016 reduced 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 half 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$0.75 during the first half of 2016 compared to Cdn$1 = US$0.81 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	1,430
Realized crude oil price (Cdn$/bbl)	1.00	1,651
US $ to Canadian $ exchange rate	0.01	323

(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	Six months ended June 30	
	Q2	Q1	Q2	**2016**	2015
Daily production/sales volumes					
Oil (bbls/d)	**9,004**	8,442	6,937	**8,723**	7,207
Bitumen – Blackrod (bbls/d) (2)	**553**	584	613	**568**	510
Combined (bbls/d)	**9,557**	9,026	7,550	**9,291**	7,717
Natural gas (Mcf/d)	**847**	845	3,004	**846**	2,655
Total production (boe/d) (1)	**9,698**	9,166	8,051	**9,432**	8,159
Product pricing (excluding risk management activities) (2)					
Oil ($/bbl)	**34.44**	16.77	47.52	**25.89**	39.53
Natural gas ($/Mcf)	**1.29**	1.77	2.61	**1.53**	2.62
Combined ($/boe) (1)	**34.03**	16.67	45.37	**25.63**	38.15
Sales ($000s) (2)					
Oil and gas sales – gross	**28,318**	13,021	30,712	**41,339**	52,827
Royalties	**(3,813)**	(1,345)	(4,455)	**(5,158)**	(8,574)
Oil and gas revenues – net	**24,505**	11,676	26,257	**36,181**	44,253

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

Oil and natural gas sales decreased 8% in the second quarter of 2016 to $28.3 million from $30.7 million in the same period in 2015. The decrease in oil and gas sales is attributable to a 25% decrease in our average sales price received in the second quarter of 2016 compared to the same period in 2015, partially offset by a 20% increase in production volumes (on a boe basis).

Lower WTI crude oil prices and wider heavy oil differentials, partially offset by a weaker Canadian dollar relative to the US dollar, contributed to a decrease in our realized crude oil sales price in the second quarter of 2016. Our average oil wellhead sales price in the second quarter of 2016, prior to the impact of risk management activities, was $34.44 per bbl compared with $47.52 per bbl in the same period in 2015. Quarter over quarter our realized wellhead sales price improved in the second quarter of 2016. Our second quarter 2016 average oil wellhead sales price of $34.44 per bbl was 105% higher than the first quarter of 2016. The increase is attributed to higher crude oil prices and tighter heavy oil differentials during the second quarter of 2016.

Production growth in the first half of 2016 compared to the same period in 2015 came from the first phase of our Onion Lake thermal EOR project. During the second quarter of 2016, the Onion Lake thermal EOR project reached its productive design capacity and production is continuing to ramp-up. Oil production from the thermal project averaged 5,221 bbls/d during Q2 2016. In July 2016, production from this project was over 6,400 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. During the second quarter we selectively brought back 11 shut-in wells at Onion Lake and others will be brought back on production if oil prices improve to US$45 – US$50 per bbl on a sustained basis. Production from our non-thermal areas will likely continue to decrease as a result of natural declines and our intention to limit capital investment until oil prices improve.

On a boe basis, 98% of the Company's oil and natural gas production in the second quarter of 2016 was heavy oil or bitumen. The Onion Lake area accounted for 76% of total production in the second quarter of 2016.

				Six months ended	
	2016		2015		June 30
Production by area (boe/d)	**Q2**	Q1	Q2	**2016**	2015
Onion Lake - thermal	**5,221**	4,252	-	**4,737**	-
Onion Lake - conventional	**2,138**	2,232	3,624	**2,185**	3,790
Mooney	**714**	1,042	2,588	**878**	2,692
John Lake	**870**	861	1,022	**865**	1,016
Blackrod	**553**	584	613	**568**	510
Other	**202**	195	204	**199**	151
Total production	**9,698**	9,166	8,051	**9,432**	8,159

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. As of June 30, 2016, BlackPearl had not received regulatory approval for the 80,000 bbl/d commercial Blackrod project. During the second quarter of 2016, the pilot wells produced an average of 553 bbls/d of bitumen and the net revenues capitalized for the first half of 2016 were a loss of $0.6 million ($1.4 million loss in the first half of 2015).

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 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 loss of $6.6 million on its risk management contracts during the second quarter of 2016, consisting of a $2.0 million realized gain on the contracts and an unrealized loss of $8.6 million. The realized gain on risk management contracts was the equivalent of adding $2.35 per bbl to our wellhead price during the second quarter of 2016.

	2016		2015	Six months ended	June 30
($000s, except per boe)	**Q2**	Q1	Q2	**2016**	2015
Realized gain on risk management contracts	**1,958**	6,120	5,245	**8,078**	18,953
Per boe ($)	**2.35**	7.84	7.75	**5.01**	13.69
Unrealized loss on risk management contracts	**(8,597)**	(472)	(13,533)	**(9,069)**	(24,907)

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

Subject of Contract	Volume	Term	Reference	Strike Price	Type
2016					
Oil	1,000 bbls/d	July 1, 2016 to December 31, 2016	CDN$ WCS	CDN$ 51.15/bbl	Swap
Oil	2,000 bbls/d	July 1, 2016 to December 31, 2016	CDN$ WCS	CDN$ 47.60/bbl	Swap
Oil	2,000 bbls/d	July 1, 2016 to December 31, 2016	US$ WTI	US$ 65.00/bbl	Sold Call
2017					
Oil	1,000 bbls/d	January 1, 2017 to December 31, 2017	CDN$ WCS	CDN$ 50.00/bbl	Swap
Oil	1,000 bbls/d	January 1, 2017 to December 31, 2017	CDN$ WCS	CDN$ 49.50/bbl	Swap
Oil	1,000 bbls/d	January 1, 2017 to December 31, 2017	US$ WTI	US$ 60.00/bbl	Sold Call

At June 30, 2016, these contracts had a fair value of approximately $0.3 million. A 10% decrease to the oil price used to calculate the fair value of these contracts would result in an approximate $8 million increase in fair value.

Royalties

	2016		2015	Six months ended	June 30
	Q2	Q1	Q2	**2016**	2015
Royalties ($000s)	**3,813**	1,345	4,455	**5,158**	8,574
Per boe ($)	**4.58**	1.72	6.58	**3.20**	6.19
As a percentage of oil and gas sales	**13%**	10%	15%	**12%**	16%

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 $3.8 million in the second quarter of 2016, down from $4.5 million in the same period in 2015. Reduced royalties in the second quarter of 2016 reflects lower wellhead prices. Royalties as a percentage of oil and gas sales decreased to 13% in the second quarter of 2016 from 15% of oil and gas sales in the same period in 2015.

Lower royalty rates in Q2 2016 are attributable to an increase in production from the Onion Lake thermal EOR project. Production from this project was 54% of our total production in Q2 2016 (0% in Q2 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.

The increase in royalties as a percentage of revenue and royalty per boe in the second quarter of 2016 compared to the first quarter of 2016 is attributed to higher wellhead prices in the second quarter of 2016, which impact royalty rates in our non-thermal producing areas. In addition, during the second quarter of 2016 we amended the royalty calculations for certain previous periods. Without these amendments the average royalty rate in the second quarter of 2016 would have been approximately 11%.

In July the Alberta government announced a new EOR royalty program which will come into effect on January 1, 2017. Under the new program, new or expanded EOR projects will pay a flat 5% royalty for up to 90 months and after this period the project will pay normal royalty rates. The new program will affect EOR projects, such as our Mooney ASP flood. The existing phase one of the flood will remain under the old incentive program until December 31, 2026. Any expansion of the flood to phase 2 or phase 3 lands at Mooney will be governed by the new incentive program. Our initial assessment of the new program is that it should not have a material impact on a net present value basis of our Mooney assets.

Transportation Costs

				Six months ended	
	2016		2015		June 30
	Q2	Q1	Q2	**2016**	2015
Conventional Production					
Transportation costs ($000s)	**127**	318	800	**445**	1,581
Per boe ($)	**0.36**	0.81	1.18	**0.59**	1.14
Thermal Production					
Transportation costs ($000s)	**1,106**	1,775	-	**2,881**	-
Per boe ($)	**2.33**	4.59	-	**3.34**	-
Total Production					
Transportation costs ($000s)	**1,233**	2,093	800	**3,326**	1,581
Per boe ($)	**1.48**	2.68	1.18	**2.06**	1.14

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 second quarter of 2016 to $1.2 million from $0.8 million in the same period of 2015. This increase is attributable to increased production from our Onion Lake thermal EOR project. The decrease in transportation costs during the second quarter of 2016 compared to the first quarter of 2016 is attributable to shipping less clean marketable barrels and more emulsion during the second quarter of 2016 which increased production expenses.

Production Costs

	2016		2015	Six months ended June 30	
	Q2	Q1	Q2	**2016**	2015
Conventional Production					
Production costs ($000s)	**6,400**	5,550	13,445	**11,950**	29,350
Per boe ($)	**17.92**	14.09	19.86	**15.91**	21.20
Thermal Production					
Production costs ($000s)	**4,613**	4,093	-	**8,706**	-
Per boe ($)	**9.71**	10.58	-	**10.10**	-
Total Production					
Production costs ($000s)	**11,013**	9,643	13,445	**20,656**	29,350
Per boe ($)	**13.23**	12.35	19.86	**12.80**	21.20

Total production costs decreased 18% in the second quarter of 2016 to $11.0 million from $13.4 million in the same period in 2015. The decrease in our total production costs was made up of a significant drop in costs related to our conventional production offset by production costs from our new thermal project at Onion Lake. On a per boe basis, total production costs decreased 33% in the second quarter of 2016 to $13.23 per boe from $19.86 per boe in the same period in 2015.

The decrease in conventional production costs in the second quarter of 2016 is attributable, in part, to a 44% decrease in conventional production volumes. In addition, due to the current low oil price environment 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 second quarter of 2016 compared to the first quarter of 2016 is primarily attributable to increased production volumes, partially offset by lower gas consumption costs as a result of lower natural gas prices in the second quarter. On a boe basis however, thermal production costs decreased in the second quarter due to a 23% increase in production volumes during the second quarter.

Operating Netback [(1)]

	2016		2015	Six months ended June 30	
($/boe)	**Q2**	Q1	Q2	**2016**	2015
Oil and gas sales	**34.03**	16.67	45.37	**25.63**	38.15
Royalties	**4.58**	1.72	6.58	**3.20**	6.19
Transportation costs	**1.48**	2.68	1.18	**2.06**	1.14
Production costs	**13.23**	12.35	19.86	**12.80**	21.20
Operating netback before realized risk management contracts	**14.74**	(0.08)	17.75	**7.57**	9.62
Realized gain on risk management contracts	**2.35**	7.84	7.75	**5.01**	13.69
Operating netback after realized risk management contracts	**17.09**	7.76	25.50	**12.58**	23.31

(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, decreased in the second quarter of 2016 to $14.74 per boe from $17.75 per boe in the same period in 2015. The decrease is primarily attributable to the decrease in realized crude oil prices, partially offset by lower royalties and production costs.

General and Administrative Expenses (G&A)

	2016		2015	Six months ended June 30	
($000s, except per boe)	**Q2**	Q1	Q2	**2016**	2015
Gross G&A expense	**2,009**	2,129	2,279	**4,138**	4,778
Operator recoveries	**(209)**	(230)	(262)	**(439)**	(622)
Net G&A expense	**1,800**	1,899	2,017	**3,699**	4,156
Per boe ($)	**2.16**	2.43	2.98	**2.29**	3.00

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 half 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 prices. Lower operator recoveries in the first half of 2016 compared to same period in 2015 is attributable to lower capital spending in 2016.

Stock-Based Compensation

	2016		2015	Six months ended June 30	
($000s, except per boe)	**Q2**	Q1	Q2	**2016**	2015
Gross stock-based compensation	**711**	1,178	1,328	**1,889**	2,956
Recoveries from forfeitures	**-**	(48)	(3)	**(48)**	(48)
Net stock-based compensation before capitalization	**711**	1,130	1,325	**1,841**	2,908
Capitalized stock-based compensation	**-**	-	(46)	**-**	(99)
Net stock-based compensation	**711**	1,130	1,279	**1,841**	2,809
Per boe ($)	**0.85**	1.45	1.89	**1.14**	2.03

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 half 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 half of 2016, 8,333 options were exercised, 75,000 options were granted, 342,669 options were forfeited and 125,000 options expired. Based on stock options outstanding as at June 30, 2016, the Company has an unamortized stock option compensation expense of approximately $2.5 million, of which $1.5 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	Six months ended June 30	
($000s)	**Q2**	Q1	Q2	**2016**	2015
Gross interest & financing charges	**918**	835	1,062	**1,753**	1,645
Capitalized interest & financing charges	**-**	-	(760)	**-**	(1,280)
Net interest & financing charges	**918**	835	302	**1,753**	365
Accretion of decommissioning liabilities	**361**	366	428	**727**	845
Total finance costs	**1,279**	1,201	730	**2,480**	1,210

The decrease in gross interest and financing charges in the second quarter of 2016 compared to the same period in 2015 is primarily attributed to credit agreement amendment fees. In 2015 these fees were incurred during the second quarter whereas in 2016 the amendments to the credit agreement did not occur until July and therefore the fees will be incurred during the third quarter.

During the first six months of 2016 we incurred slightly higher interest rates charged on amounts borrowed. The average interest rate on advances under the Company's credit facilities was 3.6% in the first half of 2016 compared to 3.1% in the first half 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 3.75 - 4% for the remainder of 2016 (assuming no other changes in market conditions) as a result of carrying a higher debt to EBITDA ratio during a period of lower oil prices. We have not entered into any financial instruments to fix the interest rate on our debt.

During the first half of 2016 we did not capitalize any interest charges. In the first half of 2015 we capitalized $1.3 million of interest costs related to debt incurred during the construction of the Onion Lake EOR project.

Depletion and Depreciation

	2016		2015	Six months ended June 30	
	Q2	Q1	Q2	**2016**	2015
Depletion and depreciation ($000s)	**10,773**	10,632	12,953	**21,405**	26,718
Per boe ($)	**12.95**	13.61	19.14	**13.27**	19.30

The Company's properties are depleted on a unit of production basis based on estimated proven plus probable reserves. Depletion and depreciation expense decreased 17% in the second quarter of 2016 to $10.8 million from $13.0 million in the same period in 2015. On a boe basis, depletion and depreciation expense decreased to $12.95 per boe in the second quarter of 2016 compared to $19.14 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 EOR project in the first half of 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 six months ended June 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 half 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	Six months ended June 30	
	Q2	Q1	Q2	**2016**	2015
Net loss ($000s)	**(8,945)**	(9,322)	(10,079)	**(18,267)**	(21,023)
Per share, basic ($)	**(0.03)**	(0.03)	(0.03)	**(0.05)**	(0.06)
Per share, diluted ($)	**(0.03)**	(0.03)	(0.03)	**(0.05)**	(0.06)

For the quarter ended June 30, 2016, the Company incurred a net loss of $8.9 million compared to a net loss of $10.1 million in the same period in 2015. The reduction in the net loss in 2016 is primarily a result of lower royalties, production and transportation costs and depletion changes, partially offset by lower revenues due to lower average wellhead prices.

	2016		2015	Six months ended June 30	
	Q2	Q1	Q2	**2016**	2015
Funds flow from operations [(1)] ($000s)	**11,497**	3,278	14,968	**14,775**	27,908
Per share, basic ($)	**0.03**	0.01	0.04	**0.04**	0.08
Per share, diluted ($)	**0.03**	0.01	0.04	**0.04**	0.08

(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 decreased 23% to $11.5 million during the second quarter of 2016 compared to $15.0 million in the same period in 2015. The decrease in funds flow in 2016 is primarily a result of lower wellhead sales prices, partially offset by lower royalties and production and transportation costs.

LIQUIDITY AND CAPITAL RESOURCES

($000s)	**June 30, 2016**	December 31, 2015
Working capital surplus	**(4,497)**	(11,063)
Revolving line of credit due beyond one year	**80,000**	88,000
Net debt [(1)]	**75,503**	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 the completion of the most recent semi-annual review of the Company's credit facilities with its syndicated group of lenders, the Company's maximum borrowing amount was reduced from $150 million to $117.5 million. At June 30, 2016, the Company had $80 million drawn under these credit facilities and issued letters of credit in the amount of $20,000; leaving $37.5 million available to be drawn. 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 4.3:1 at June 30, 2016 and was in compliance with this covenant at June 30, 2016.

($000s, except working capital ratio)	**June 30, 2016**	December 31, 2015
Current assets per consolidated financial statements	**16,814**	25,537
Add: amount available to be drawn on credit facilities	**37,500**	62,000
Less: current risk management assets	**(760)**	(10,548)
Current assets for working capital ratio	**53,554**	76,989
Current liabilities per consolidated financial statements	**12,317**	14,474
Less: current risk management liabilities	**-**	-
Current liabilities for working capital ratio	**12,317**	14,474
Working capital ratio	**4.3**	5.3

The current low oil price environment 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 June 30, 2016, there were 335,646,559 common shares issued and outstanding. In the first half 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 half 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 second 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 second quarter of 2016 capital spending was $0.9 million, a decrease from $16.0 million during the same period in 2015. The main components of the capital spending program during the second quarter of 2016 was facility improvements at the Onion Lake thermal EOR project and planning for the second phase of the project. No new drilling activity occurred during the first half of 2016.

	2016		2015	Six months ended June 30	
($000s)	**Q2**	Q1	Q2	**2016**	2015
Land	**325**	117	194	**442**	340
Seismic	**-**	(5)	(132)	**(5)**	519
Drilling and completion	**70**	1,464	1,824	**1,534**	5,788
Equipment and facilities	**550**	494	14,067	**1,044**	52,212
Other	**-**	7	39	**7**	114
Total	**945**	2,077	15,992	**3,022**	58,973
Property acquisitions	**-**	-	-	**-**	-
Total capital expenditures	**945**	2,077	15,992	**3,022**	58,973
Property dispositions	**-**	-	-	**-**	-
Net capital expenditures	**945**	2,077	15,992	**3,022**	58,973

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 June 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)	584	792	743	628	544	544
Electrical service agreement (2)	474	1,000	585	119	119	1,987
Transportation service agreement (3)	68	135	135	135	33	-
Decommissioning liabilities (4)	358	394	456	334	8,225	72,984
Long-term debt (5)	-	-	80,000	-	-	-
Interest payments on long-term debt (5)	1,560	3,120	1,300	-	-	-
	3,044	5,441	83,219	1,216	8,921	75,515

(1) *The Company's most significant operating leases are for office space. As at June 30, 2016 the Company had three months remaining on its current office lease. The Company's current office lease was executed jointly with another party. Under the terms of the lease, BlackPearl and the other party are joint and severally liable for the obligations pursuant to the lease. Accordingly, if the other party is unable to fulfill their share of the lease obligation, BlackPearl would be required to pay a maximum additional amount of $0.8 million (including an estimate for operating costs) over the next 3 months. At June 30, 2016, no amounts were owed (2015 – no amounts owing). The Company entered into a new office lease that will commence on January 1, 2017 and run for five years.*

(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 $82.8 million as at June 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 June 30, 2016.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments as at June 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 six months ended June 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 June 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 June 30, 2016 or 2015 except for key management compensation.

OUTSTANDING SHARE DATA AND STOCK OPTIONS

As at August 9, 2016, the Company had 335,646,559 common shares outstanding and 29,104,167 stock options outstanding under its stock-based compensation program.

OUTSTANDING LONG-TERM DEBT DATA

As at August 9, 2016, the Company had $75,000,000 drawn under its existing credit facilities and had issued letters of credit in the amount of $20,000; leaving $42,480,000 available to be drawn under these credit facilities.

PROPOSED TRANSACTIONS

As of August 9, 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 June 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 9 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 six months ended June 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
Production (boe/d)				
Annual average	10,000 – 10,500	9,000 – 10,000	9,000 – 10,000	9,000 – 10,000
Funds flow from operations (1) ($millions)	35 – 40	5 – 10	20 – 25	35 – 40
Capital expenditures ($millions)	15 – 20	10 – 15	10 – 15	10 – 15
Year-end debt ($millions)	70 – 75	90 - 95	75 – 80	60 – 65
Pricing Assumptions (annual average)				
Crude oil - WTI	US $50.00	US $35.00	US $38.36	US $41.76
Light/heavy differential	US$ 15.00	US$ 14.00	US$ 14.06	US $14.04
Foreign Exchange (Cdn$ to US$)	0.75	0.71	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 Q1 2016 guidance update. We are still planning to limit capital spending and use most of our cash flow to reduce debt levels until oil prices recover. Capital spending in 2016 is expected to be between $10 million and $15 million, unchanged from our Q1 guidance. Capital spending includes preliminary planning for the second phase of the Onion Lake thermal EOR 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.

Funds flow from operations for 2016 is expected to be between $35 and $40 million, an increase from our Q1 guidance of $20 to $25 million. Year-end 2016 debt levels are anticipated to be between $60 and $65 million, down from our Q1 guidance of $75 to $80 million. The increase in expected funds flow from operations and lower year-end debt levels is primarily due to higher average wellhead prices than what was used in previous guidance. For budget purposes we are using an average US$44.00/bbl WTI price, a heavy oil differential of US$14.30/bbl and Cdn$1 = US$0.76 foreign exchange rate for the second half of the year. We anticipate oil and gas production to average between 9,000 and 10,000 boe/d in 2016, unchanged from our Q1 2016 guidance update.

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”, “plans”, “planning”, “planned”, “could”, “continue”, “continues”, “continued”, “estimate”, “estimates”, “estimated”, “forecast”, “likely”, “expect”, “expects”, “expected”, “may”, “intention”, “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 estimated change in annualized funds flow from operations for 2016 due to changes in key variables as discussed in the Commodity Prices section;
- The expected WTI oil prices the Company would require before we start to put some of the shut-in wells back on production as discussed in the Oil and Gas Production, Oil and Gas Pricing and Oil and Gas sales section;
- The expected continued decrease in production from our non-thermal areas as discussed in the Oil and Gas Production, Oil and Gas Pricing and Oil and Gas sales section;

- Our initial impact assessment of the new EOR royalty program introduced by the Alberta government in July as discussed in the Royalties 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;
- 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 August 9, 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.
   700, 444 – 7 Avenue S.W.
   Calgary, Alberta T2P 0X8
   Canada
   Telephone: +1.403.215.8313
   Fax: +1.403.265.8324
   Website: www.blackpearlresources.ca

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

   For further information, please contact:
   John Festival - President and Chief Executive Officer, +1.403.215.8313
   Don Cook – Chief Financial Officer, +1.403.215.8313

BLACKPEARL RESOURCES INC.

Consolidated Balance Sheets

(unaudited) (Cdn$ in thousands)	Note		**June 30, 2016**		December 31, 2015
Assets					
Current assets					
Cash and cash equivalents	4	**$**	**892**	$	2,300
Trade and other receivables	5		**13,107**		10,801
Inventory			**98**		605
Prepaid expenses and deposits			**1,957**		1,283
Fair value of risk management assets	13		**760**		10,548
			16,814		25,537
Exploration and evaluation assets	6		**170,461**		169,493
Property, plant and equipment	7		**595,316**		613,314
		$	**782,591**	$	808,344
Liabilities					
Current liabilities					
Accounts payable and accrued liabilities	8	**$**	**11,762**	$	13,939
Current portion of decommissioning liabilities	9		**555**		535
			12,317		14,474
Fair value of risk management liabilities	13		**504**		1,223
Decommissioning liabilities	9		**67,935**		66,392
Long-term debt	10		**80,000**		88,000
			160,756		170,089
Shareholders' equity					
Share capital	11		**970,142**		970,134
Contributed surplus			**41,639**		39,800
Deficit			**(389,946)**		(371,679)
			621,835		638,255
		$	**782,591**	$	808,344

Commitments and contingencies (note 12)

See accompanying notes to consolidated financial statements

BLACKPEARL RESOURCES INC.

Consolidated Statements of Comprehensive Loss

(unaudited) **(Cdn$ in thousands, except for per share amounts)**	Note	**Three months ended June 30, 2016**	Three months ended June 30, 2015	**Six months ended June 30, 2016**	Six months ended June 30, 2015
Revenue					
Oil and gas sales		**$ 28,318**	$ 30,712	**$ 41,339**	$ 52,827
Royalties		**(3,813)**	(4,455)	**(5,158)**	(8,574)
Net oil and gas revenue		**24,505**	26,257	**36,181**	44,253
Loss on risk management contracts	13	**(6,639)**	(8,288)	**(991)**	(5,954)
		17,866	17,969	**35,190**	38,299
Expenses					
Production		**11,013**	13,445	**20,656**	29,350
Transportation		**1,233**	800	**3,326**	1,581
General and administrative		**1,800**	2,017	**3,699**	4,156
Depletion and depreciation	7	**10,773**	12,953	**21,405**	26,718
Finance costs	14	**1,279**	730	**2,480**	1,210
Stock-based compensation	11	**711**	1,279	**1,841**	2,809
Foreign currency exchange loss (gain)		**4**	(3)	**52**	(58)
		26,813	31,221	**53,459**	65,766
Other income					
Interest income		**2**	40	**2**	46
Loss before income taxes		**(8,945)**	(13,212)	**(18,267)**	(27,421)
Income taxes					
Deferred income recovery		**-**	(3,133)	**-**	(6,398)
Net and comprehensive loss for the period		**$ (8,945)**	$ (10,079)	**$ (18,267)**	$ (21,023)
Loss per share					
Basic	11	**$ (0.03)**	$ (0.03)	**$ (0.05)**	$ (0.06)
Diluted	11	**$ (0.03)**	$ (0.03)	**$ (0.05)**	$ (0.06)

See accompanying notes to consolidated financial statements

BLACKPEARL RESOURCES INC.

Consolidated Statements of Changes in Equity

(unaudited)
(Cdn$ in thousands)

	Six months ended June 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	-	-	(18,267)	(18,267)
Stock-based compensation	-	1,841	-	1,841
Shares issued on exercise of stock options	6	-	-	6
Transfer to share capital on exercise of stock options	2	(2)	-	-
Balance - June 30, 2016	**$ 970,142**	**$ 41,639**	**$ (389,946)**	**$ 621,835**

	Six months ended June 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	-	-	(21,023)	(21,023)
Stock-based compensation	-	2,908	-	2,908
Balance - June 30, 2015	$ 970,134	$ 36,696	$ (345,909)	$ 660,921

See accompanying notes to consolidated financial statements

BLACKPEARL RESOURCES INC.

Consolidated Statements of Cash Flows

(unaudited) **(Cdn$ in thousands)**	Note	**Three months ended June 30, 2016**	Three months ended June 30, 2015	**Six months ended June 30, 2016**	Six months ended June 30, 2015
Operating activities					
Net and comprehensive loss for the period		**$ (8,945)**	$ (10,079)	**$ (18,267)**	$ (21,023)
Items not involving cash:					
Depletion and depreciation	7	**10,773**	12,953	**21,405**	26,718
Accretion of decommissioning liabilities	14	**361**	428	**727**	845
Stock-based compensation	11	**711**	1,279	**1,841**	2,809
Foreign exchange loss (gain)		**-**	(13)	**-**	50
Deferred income recovery		**-**	(3,133)	**-**	(6,398)
Unrealized loss on risk management contracts	13	**8,597**	13,533	**9,069**	24,907
Decommissioning costs incurred	9	**(369)**	(17)	**(516)**	(262)
Changes in non-cash working capital	14	**(3,944)**	(2,851)	**(3,288)**	8,303
Cash flow from operating activities		**7,184**	12,100	**10,971**	35,949
Financing activities					
Proceeds on issue of common shares, net of costs		**6**	-	**6**	-
Proceeds on issue of long-term debt		**-**	16,000	**-**	65,000
Repayment of long-term debt		**(6,000)**	-	**(8,000)**	-
Cash flow from (used in) financing activities		**(5,994)**	16,000	**(7,994)**	65,000
Investing activities					
Capital expenditures - exploration and evaluation assets	6	**(135)**	(413)	**(927)**	(2,547)
Capital expenditures - property, plant and equipment	7	**(810)**	(15,533)	**(2,095)**	(56,327)
Changes in non-cash working capital	14	**(489)**	(11,781)	**(1,415)**	(39,060)
Cash flow used in investing activities		**(1,434)**	(27,727)	**(4,437)**	(97,934)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**4**	10	**52**	(108)
Increase (decrease) in cash and cash equivalents		**(240)**	383	**(1,408)**	2,907
Cash and cash equivalents, beginning of period		**1,132**	5,442	**2,300**	2,918
Cash and cash equivalents, end of period		**$ 892**	$ 5,825	**$ 892**	$ 5,825

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 700, 444 – 7th Avenue SW, Calgary, Alberta, T2P 0X8.

2. BASIS OF PREPARATION

These condensed unaudited interim consolidated financial statements for the three and six months ended June 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 August 9, 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 9 on the Company's consolidated financial statements.

4. CASH AND CASH EQUIVALENTS

		June 30, 2016		December 31, 2015
Cash at financial institutions	**$**	**892**	$	2,300

Cash at financial institutions earns interest at floating rates based on daily deposit rates. As of June 30, 2016, US $0.6 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

		June 30, 2016		December 31, 2015
Trade accounts receivable	**$**	**12,713**	$	6,264
Receivables from joint operation partners		**462**		304
Allowance for doubtful accounts		**(285)**		(285)
Net accounts receivable		**12,890**		6,283
Receivable from risk management contracts		**159**		4,228
Other receivables		**58**		290
Total trade and other receivables	**$**	**13,107**	$	10,801

Aging of trade and other receivables are as follows:

At June 30, 2016		Current		31 to 60 days		61 to 90 days		Over 90 days		Total
Trade accounts receivable	$	12,713	$	-	$	-	$	-	$	12,713
Receivables from joint operation partners		99		3		16		344		462
Allowance for doubtful accounts		-		-		-		(285)		(285)
Receivable from risk management contracts		159		-		-		-		159
Other receivables		58		-		-		-		58
Total trade and other receivables	$	13,029	$	3	$	16	$	59	$	13,107

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	927
Change in decommissioning provision	41
At June 30, 2016	$ 170,461

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 six 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 six months ended June 30, 2016 the Company capitalized net operating revenues totalling a loss of $0.6 million ($1.4 million loss in the first six 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 six months ended June 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	2,095	-	2,095
Change in decommissioning provision	1,312	-	1,312
At June 30, 2016	$ 1,244,052	$ 3,507	$ 1,247,559
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	21,332	73	21,405
At June 30, 2016	$ 649,687	$ 2,556	$ 652,243
Net book value			
December 31, 2015	$ 612,290	$ 1,024	$ 613,314
June 30, 2016	$ 594,365	$ 951	$ 595,316

During the six months ended June 30, 2016, the Company did not capitalize any borrowing costs related to development activities (2015 - $1.3 million). The Company did not capitalize any general and administrative costs related to development activities during the six months ended June 30, 2016 (2015 - $Nil).

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

8. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	June 30, 2016	December 31, 2015
Trade payables and accrued liabilities	**$ 11,082**	$ 13,371
Payables to joint operation partners	**362**	218
Other payables	**318**	350
Total accounts payable and accrued liabilities	**$ 11,762**	$ 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 $82.8 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 2.1% (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:

		Six months ended June 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		(516)		(531)
Change in estimated costs of decommissioning		-		(7,670)
Change in inflation rate		-		(4,883)
Change in discount rate		1,352		2,615
Accretion expense		727		1,646
Decommissioning liability, end of the period		68,490		66,927
Less current portion of decommissioning liability		(555)		(535)
Non-current portion of decommissioning liability	$	67,935	$	66,392

10. LONG-TERM DEBT

At the completion of the most recent semi-annual review of the Company's credit facilities with its syndicated group of lenders, the Company's maximum borrowing amount was reduced from $150 million to $117.5 million. The Company's $117.5 million credit facilities consist 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 June 30, 2016, the Company had drawn $80 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 $37.5 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 loss before income tax, financing charges, non-cash items deducted in determining comprehensive loss, unrealized gains or losses on risk management contracts and any income/losses attributable to assets acquired or disposed of when determining net comprehensive loss for the period as indicated on the Company's consolidated statement of comprehensive 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 4.3:1 at June 30, 2016 (December 31, 2015 – 5.3:1) and was in compliance with this covenant at June 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 June 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	75,000	0.78
Exercised	(8,333)	0.71
Forfeited	(342,669)	3.34
Expired	(125,000)	7.44
Outstanding at June 30, 2016	29,254,167	2.00

Options outstanding and exercisable as at June 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	11,345,167	0.84	3.97	3,746,245	0.84	3.97
1.51 – 3.00	14,254,000	2.31	2.68	10,255,876	2.32	2.61
3.01 – 4.50	1,705,500	3.71	0.99	1,705,500	3.71	0.99
4.51 – 6.00	1,799,500	4.92	0.38	1,799,500	4.92	0.38
6.01 – 6.42	150,000	6.42	0.04	150,000	6.42	0.04
	29,254,167	2.00	2.93	17,657,121	2.44	2.49

The fair value of common share options granted is estimated on the date of grant using the Black-Scholes option pricing model. During the six months ended June 30, 2016, 75,000 options were granted (2015 – 7,195,000) and during the three months ended June 30, 2016, no options were granted (2015 – 30,000). The fair value of these options was estimated using the following weighted average assumptions:

	Three months ended June 30		Six months ended June 30	
Assumptions	**2016**	2015	**2016**	2015
Risk free interest rate (%)	**-**	0.8	**0.6**	0.7
Dividend yield (%)	**-**	0.0	**0.0**	0.0
Expected life (years)	**-**	3.7	**3.7**	3.6
Expected volatility (%)	**-**	50.6	**54.6**	53.5
Forfeiture rate (%)	**-**	13.2	**11.7**	13.6
Weighted average fair value of options	**-**	$ 0.43	**$ 0.32**	$ 0.36

(d) Stock-based Compensation

	Three months ended June 30		Six months ended June 30	
	2016	2015	**2016**	2015
Gross stock-based compensation	**$ 711**	$ 1,328	**$ 1,889**	$ 2,956
Recoveries from forfeitures	**-**	(3)	**(48)**	(48)
Net stock-based compensations before capitalization	**711**	1,325	**1,841**	2,908
Stock-based compensation capitalized to property, plant and equipment	**-**	(46)	**-**	(99)
Net stock-based compensation	**$ 711**	$ 1,279	**$ 1,841**	$ 2,809

(e) Loss per Share

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

	Three months ended June 30		Six months ended June 30	
	2016	2015	**2016**	2015
Net and comprehensive loss	**$ (8,945)**	$ (10,079)	**$ (18,267)**	$ (21,023)
Weighted average number of common shares - basic	**335,641**	335,638	**335,640**	335,638
Dilutive effect:				
Outstanding options	**-**	-	**-**	-
Weighted average number of common shares - diluted	**335,641**	335,638	**335,640**	335,638
Basic loss per share	**$ (0.03)**	$ (0.03)	**$ (0.05)**	$ (0.06)
Diluted loss per share	**$ (0.03)**	$ (0.03)	**$ (0.05)**	$ (0.06)

For the six months ended June 30, 2016, the Company used a weighted average market closing price of $0.83 (2015 - $0.99) per share to calculate the dilutive effect of stock options. For the six months ended June 30, 2016, all outstanding options were anti-dilutive (2015 – all outstanding options were anti-dilutive) and were not included in the calculation of diluted loss per share.

12. COMMITMENTS AND CONTINGENCIES

	2016	2017	2018	2019	2020	Thereafter
Operating leases (1)	$ 584	$ 792	$ 743	$ 628	$ 544	$ 544
Electrical service agreement (2)	474	1,000	585	119	119	1,987
Transportation service agreement (3)	68	135	135	135	33	-
Decommissioning liabilities (4)	358	394	456	334	8,225	72,984
Long-term debt (5)	-	-	80,000	-	-	-
Interest payments on long-term debt (5)	1,560	3,120	1,300	-	-	-
Total	$ 3,044	$ 5,441	$ 83,219	$ 1,216	$ 8,921	$ 75,515

(1) The Company's most significant operating leases are for office space. As at June 30, 2016 the Company had three months remaining on its current office lease. The Company's current office lease was executed jointly with another party. Under the terms of the lease, BlackPearl and the other party are joint and severally liable for the obligations pursuant to the lease. Accordingly, if the other party is unable to fulfill their share of the lease obligation, BlackPearl would be required to pay a maximum additional amount of $0.8 million (including an estimate for operating costs) over the next 3 months. At June 30, 2016, no amounts were owed (2015 – no amounts owing). The Company entered into a new office lease that will commence on January 1, 2017 and run for five years.

(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 $82.8 million as at June 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 June 30, 2016.

13. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments as at June 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.

		June 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	**$ 892**	**$ 892**	$ 2,300	$ 2,300
Trade and other receivables	2	**$ 13,107**	**$ 13,107**	$ 10,801	$ 10,801
Deposits	2	**$ 379**	**$ 379**	$ 409	$ 409
Financial assets at fair value through profit or loss:					
Risk management assets	2	**$ 760**	**$ 760**	$ 10,548	$ 10,548
Financial liabilities					
Financial liabilities at amortized cost:					
Accounts payable and accrued liabilities	2	**$ 11,762**	**$ 11,762**	$ 13,939	$ 13,939
Long-term debt	2	**$ 80,000**	**$ 80,000**	$ 88,000	$ 88,000
Financial liabilities at fair value through profit or loss:					
Risk management liabilities	2	**$ 504**	**$ 504**	$ 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 June 30, 2016, the Company held $0.9 million in cash at various major financial institutions throughout Canada and the USA; however, one Canadian financial institution held over 63% 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 June 30, 2016, 97% 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 half 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 85% of the Company's total oil and gas sales in the first half of 2016.

Risk management assets consist of commodity contracts used to manage the Company's exposure to fluctuations in commodity prices. At June 30, 2016, the Company had a $0.2 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 June 30, 2016, the Company had $37.5 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	11,762	-	-
Risk management liabilities	-	-	504
Long-term debt	-	-	80,000
Interest payments on long-term debt (1)	1,560	1,560	2,860

(1) Estimated future interest payments are based on rates existing at June 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 period ended June 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 $214,000 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 denominated in 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 June 30, 2016, the Company has not entered into any fixed rate contracts to mitigate its currency risks.

As at June 30, 2016, the Company held US $0.6 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 $55,000 higher as a result of the re-valuation of the Company's US dollar denominated financial assets and liabilities as at June 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 loss.

Risk management amounts recognized were as follows:

	Three months ended June 30		Six months ended June 30	
	2016	2015	**2016**	2015
Realized gain on risk management contracts	**$ 1,958**	$ 5,245	**$ 8,078**	$ 18,953
Unrealized loss on risk management contracts	**(8,597)**	(13,533)	**(9,069)**	(24,907)
Loss on risk management contracts	**$ (6,639)**	$ (8,288)	**$ (991)**	$ (5,954)

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

Subject of Contract	Volume	Term	Reference	Strike Price	Type	Fair value
2016						
Oil	1,000 bbls/d	July 1, 2016 to December 31, 2016	CDN$ WCS	CDN$ 51.15/bbl	Swap	$ 916
Oil	2,000 bbls/d	July 1, 2016 to December 31, 2016	CDN$ WCS	CDN$ 47.60/bbl	Swap	490
Oil	2,000 bbls/d	July 1, 2016 to December 31, 2016	US$ WTI	US$ 65.00/bbl	Sold Call	(141)
2017						
Oil	1,000 bbls/d	January 1, 2017 to December 31, 2017	CDN$ WCS	CDN$ 50.00/bbl	Swap	477
Oil	1,000 bbls/d	January 1, 2017 to December 31, 2017	CDN$ WCS	CDN$ 49.50/bbl	Swap	304
Oil	1,000 bbls/d	January 1, 2017 to December 31, 2017	US$ WTI	US$ 60.00/bbl	Sold Call	(1,790)
Total						$ 256

Current portion of fair value of contracts	$ 760
Non-current portion of fair value of contracts	$ (504)

As at June 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 $8.0 million increase in fair value and decrease in after tax net loss.

14. SUPPLEMENTARY INFORMATION

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

	Three months ended June 30		Six months ended June 30	
	2016	2015	**2016**	2015
Cash interest paid	**$ 918**	$ 1,062	**$ 1,753**	$ 1,645

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

	Three months ended June 30		Six months ended June 30	
	2016	2015	**2016**	2015
Gross interest and financing charges	**$ 918**	$ 1,062	**$ 1,753**	$ 1,645
Capitalized interest and financing charges	**-**	(760)	**-**	(1,280)
Net interest and financing charges	**918**	302	**1,753**	365
Accretion of decommissioning liabilities	**361**	428	**727**	845
Finance costs	**$ 1,279**	$ 730	**$ 2,480**	$ 1,210

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

	Three months ended June 30		Six months ended June 30	
	2016	2015	**2016**	2015
Changes in non-cash working capital				
Trade and other receivables	**$ (4,438)**	$ (527)	**$ (2,306)**	$ 2,898
Inventory	**59**	207	**507**	307
Prepaid expenses and deposits	**(1,110)**	(1,472)	**(674)**	(1,435)
Accounts payable and accrued liabilities	**1,056**	(12,840)	**(2,230)**	(32,527)
Changes in non-cash working capital	**$ (4,433)**	$ (14,632)	**$ (4,703)**	$ (30,757)
Relating to:				
Operating activities	**$ (3,944)**	$ (2,851)	**$ (3,288)**	$ 8,303
Investing activities	**(489)**	(11,781)	**(1,415)**	(39,060)
Changes in non-cash working capital	**$ (4,433)**	$ (14,632)	**$ (4,703)**	$ (30,757)