BLACKPEARL RESOURCES INC.
700, 444 – 7th Avenue SW, Calgary, AB T2P 0X8
Ph. (403) 215-8313 Fax (403) 265-8324
www.blackpearlresources.ca

NEWS RELEASE **May 4, 2016**

BLACKPEARL ANNOUNCES FIRST 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 months ended March 31, 2016.

Highlights include:

- Production averaged 9,166 barrels of oil equivalent (boe) per day, an 11% increase compared to Q1 2015 volumes. The increase is attributable to the production ramp-up on the Onion Lake thermal project.
- Operating costs and transportation costs averaged $15.03/bbl, a 36% decrease from Q1 2015.
- During a period of exceptionally low oil prices we reduced our bank debt by $2 million to $86 million at March 31, 2016.
- Revenues for the quarter were $13 million and funds flow from operations was $3.3 million.
- The first phase of the Onion Lake thermal EOR project is currently producing 5,300 barrels of oil per day – on target to reach its design capacity of 6,000 barrels per day by mid-year.
- The Blackrod SAGD pilot continues to provide very positive results – the pilot has averaged over 550 barrels of oil per day at a steam oil ratio of 2.75 over the last 12 months.

John Festival, President of BlackPearl commented “The first quarter was a very challenging period for the oil and gas sector. During the first quarter we saw oil prices drop to levels we had not seen in over 12 years. Our objective during the period was to limit spending, cut costs, maintain financial liquidity and focus on our best projects. Production from our Onion Lake thermal project steadily increased during the quarter. This long life, low cost project is very beneficial in the current low price environment. Our Blackrod and Onion Lake assets provide us with an excellent suite of thermal assets with many years of development potential. Expansion of the Onion Lake thermal project is the next large project we expect to tackle as oil prices recover”.

Operations Review

In the current low oil price environment our objective has been to reduce exploration and development activities, limit capital spending and focus on our most cost effective projects. We did not undertake any new drilling activity during the first quarter of 2016. Capital expenditures in the first quarter were $2 million.

At Onion Lake, we are continuing to achieve a steady production ramp-up from the first phase of our thermal EOR project. We initiated steam injection in June of last year and achieved first oil in September. During the first quarter of 2016 oil production from the project averaged over 4,200 bbl/d, with a steam oil ratio of 3.5. In April, the project produced approximately 5,300 bbl/d with a steam oil ratio of 2.9 and we are on target to reach our design capacity of 6,000 bbl/d by mid-year. We have commenced preliminary planning for the second 6,000 bbl/d phase on the project; however, we do not expect to incur any significant expenditures on this phase until oil prices improve. The thermal project in the Onion Lake area is our lowest cost production. During the first quarter of 2016 operating and transportation costs were $15.17/bbl on the thermal project, and we expect these costs to trend lower as our production volumes increase.

At Blackrod, we did not undertake any new activities in 2016; however, our existing SAGD pilot is continuing to perform exceptionally well. In March, oil production averaged over 600 bbls/d, with a steam oil ratio of 2.7. The pilot well's production rate has averaged in excess of 550 bbl/d of oil for 12 consecutive months and has cumulatively produced over 300,000 barrels of oil. We are planning to continue to operate the pilot as we are still acquiring valuable technical and operational data. In 2012, we filed an application for an 80,000 bbl/d commercial development of the Blackrod leases, including a full environmental impact study. We have been advised that our application has met all of the regulatory requirements and we are waiting on final approval. Having an approved development application with a successful pilot project would be very helpful in reviewing financing options for the project in the future.

At Mooney, during the first quarter of 2016 we elected to temporarily shut-in the majority of the first phase of the ASP flood until oil prices improve. Due to the polymer and other chemicals required for an ASP flood, Mooney is one of our higher cost areas and we feel it is prudent to defer on-going development of the area until we see a sustained increase in oil prices. 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 9,166 barrels of oil equivalent per day in the first quarter of 2016, an 11% increase compared with the first quarter of 2015. The increase reflects the successful ramp-up of production from our Onion Lake thermal EOR project. Production has decreased in our non-thermal areas as a result of limited new drilling activity, natural declines as well as the result of the Company's decision to temporarily shut-in oil production at Mooney and on our conventional Onion Lake properties. Approximately 900 bbl/d are currently shut-in at Mooney and 1,000 bbl/d at Onion Lake.We plan to put these wells back on production when oil prices recover to a level where they can contribute positive cash flow to our operations.

Average Daily Sales Volume

Production by area (boe/d)	**Q1 2016**	Q4 2015	Q1 2015
Onion Lake - thermal	**4,252**	3,010	-
Onion Lake - conventional	**2,232**	2,914	3,959
Mooney	**1,042**	1,902	2,797
John Lake	**861**	955	1,011
Blackrod	**584**	562	406
Other	**195**	178	96
	9,166	9,521	8,269

Financial Results

Oil and gas revenues were $13.0 million in the first quarter of 2016, a decrease of 41% from the first quarter of 2015. The decrease in revenues is attributable to a 47% decrease in our average sales price partially offset by an 11% increase in production volumes.

Our realized oil price (before the effects of risk management activities) in Q1 2016 was $16.77 per barrel compared to $32.05 per barrel in 2015. The decrease in our realized wellhead price reflects significantly lower WTI reference oil prices in Q1 2016 compared with Q1 2015 (US$33.45/bbl vs US$48.63/bbl), partially offset by a weaker Canadian dollar relative to the US dollar ($0.727 vs $0.806) and slightly tighter heavy oil differentials (US$14.32/bbl vs US$14.71).

During the first quarter we also realized a gain of $6.1 million from our oil hedging program, which was the equivalent of adding $7.84 per barrel to our wellhead price in the quarter. The following summarizes the hedging contracts we currently have outstanding:

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

Operating costs decreased significantly in the first quarter of 2016. In Q1 2016 operating and transportation costs were $11.7 million or $15.03/bbl compared with $16.7 million or $23.58/bbl in Q1 2015. The decrease in operating and transportation costs is attributable to our on-going efforts to reduce our cost structure including 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, which includes the Mooney ASP flood.

Reduced revenue, partially offset by lower royalties, transportation costs and operating costs resulted in a 75% decrease in funds flow from operations in Q1 2016 to $3.3 million compared to $12.9 million for the same period in 2015.

Bank debt at March 31, 2016 was $86 million. The total credit facilities available to the Company are currently $150 million. The lenders next review of these facilities will be completed by May 31, 2016.

Financial and Operating Highlights

	Three months ended March 31	
	2016	2015
Daily sales volumes[(1)]		
Oil (bbl/d)	8,422	7,479
Bitumen (bbl/d)	584	406
Combined	9,026	7,885
Natural gas (mcf/d)	845	2,303
Combined (boe/d)	9,166	8,269
Product pricing ($)		
Crude oil - per bbl	16.77	32.05
Natural gas - per mcf	1.77	2.63
Combined - per boe	16.67	31.25
Operating netback ($/boe)		
Sales	16.67	31.25
Realized gains on risk management contracts	7.84	19.37
	24.51	50.62
Royalties	1.72	5.82
Transportation costs	2.68	1.10

Operating costs	12.35	22.48
Netback [3]	7.76	21.22
($000's, except per share and boe amounts)		
Revenue		
Oil and gas revenue – gross	13,021	22,115
Loss for the period	(9,322)	(10,944)
Per share, basic and diluted	(0.03)	(0.03)
Funds flow from operations[2]	3,278	12,940
Capital expenditures	2,077	42,981
Working capital defiency (surplus), end of period	(9,155)	11,137
Long term debt	86,000	78,000
Net debt [4]	76,845	89,137
Shares outstanding, end of period	335,638,226	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)Funds flow from operations is a non-GAAP measure that represents cash flow from operating activities before decommissioning costs incurred and changes in non-cash working capital related to operations. Funds flow from operations does not have a standardized meaning prescribed by Canadian GAAP and therefore may not be comparable to similar measures used by other companies.

(3)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

(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

Outlook

For the remainder of the year we will continue to maintain our strong balance sheet by limiting our capital spending and using a portion of our funds flow to reduce debt levels until we see a sustained price recovery. We are planning to spend $10 to $15 million on capital projects, unchanged from our February 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 and maintenance capital in all our core areas. Expansion of the Mooney ASP flood has been deferred until oil prices improve. The Company continues to have the flexibility to expand or defer our capital program as economic conditions change.

The capital program is expected to be funded from our anticipated funds flow from operations which is expected to be between $20 and $25 million, up from our February guidance of $5 to $10 million. The increase in funds flow is a result of an increase in our forecast oil prices for the remainder of the year. For budget purposes, we are using US$40/bbl WTI prices, a heavy oil differential of US$14/bbl and Cdn$1=US$0.77 foreign exchange rate for the remainder of the year. A portion of anticipated funds flow is also expected to be used to reduce our debt levels. Yearend debt levels are expected to between $75 and $80 million, a decrease from our February guidance of $90 to $95 million.

We anticipate oil and gas production to average between 9,000 and 10,000 boe/d in 2016, unchanged from our February guidance. We will continue to monitor crude oil prices and make prudent changes to our capital spending programs and operations as we believe are required.

The 2016 first quarter report to shareholders, including the financial statements, management's discussion and analysis and notes to the financial statements are available on the Company's website (www.blackpearlresources.ca) or SEDAR (www.sedar.com).

Non-GAAP Measures

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 the target date for the Onion Lake thermal EOR project to reach its design capacity of 6,000 bbl/d, timing for expansion of the Onion Lake thermal EOR project, the expectation that operating costs will trend lower as production volumes increase at the Onion Lake thermal 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 Outlook 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.

For further information, please contact:

John Festival - President and Chief Executive Officer
Tel.: (403) 215-8313

Don Cook – Chief Financial Officer
Tel: (403) 215-8313

Robert Eriksson – Investor Relations Sweden
Tel.: +46 701-112615

The information in this release is subject to the disclosure requirements of BlackPearl Resources Inc. under the Swedish Securities Market Act and/or the Swedish Financial Instruments Trading Act. This information was publicly communicated on May 4, 2016 at 3:30 p.m. Mountain Time.

BLACKPEARL RESOURCES INC.

Management's Discussion and Analysis

The following is Management's Discussion and Analysis (MD&A) of the operating and financial results of BlackPearl Resources Inc. ("BlackPearl" or "the Company") for the three months ended March 31, 2016. These results are being compared with the three months ended March 31, 2015. The MD&A should be read in conjunction with the Company's unaudited consolidated financial statements for the three months ended March 31, 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.

($000s)	**Q1 2016**	Q4 2015	Q1 2015
Cash flow from operating activities(1)	**3,787**	12,179	23,849
Add (deduct):			
Decommissioning costs incurred	**147**	152	245
Changes in non-cash working capital related to operations	**(656)**	(1,433)	(11,154)
Funds flow from operations(2)	**3,278**	10,898	12,940

(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 May 4, 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 using the SAGD recovery process. The Company is currently operating a pilot project on this property.

These core properties provide the Company with a combination of short-term cash flow generation 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 significantly lower in the first quarter of 2016. In Q1 2016, WTI oil prices averaged US$33.45 per bbl compared to US$48.63 per bbl in the first quarter of 2015.

- Capital expenditures during the first quarter were $2.1 million, with approximately $1.2 million spent at the Onion Lake thermal EOR project related to facility improvements and maintenance and planning costs for the second phase of the project, $0.7 million spent at Blackrod primarily related to continued capitalization of net revenues from operating the Blackrod pilot and $0.2 million spent in other areas.

- Oil and gas sales during the first quarter were $13 million and funds flow from operations (non-GAAP measure) were $3.3 million. For the quarter ended March 31, 2016, the Company incurred a net loss of $9.3 million.

- The decline in crude oil prices was partially offset by realized gains on crude oil hedging contracts. For the quarter ended March 31, 2016, the Company realized gains of $6.1 million from these contracts.

- The Company did not undertake any equity issuances and no common shares were issued pursuant to the exercise of stock options during the first quarter.

- At March 31, 2016, BlackPearl had working capital of $9.2 million and $86 million in long-term debt, leaving $64 million available to drawn under the Company's existing credit facilities.

- During the second quarter of 2015, construction was completed and initial steam injection occurred at the first phase of the Onion Lake thermal EOR project. Effective October 1, 2015, the Company commenced commercial production at the project. The first phase of the project was designed for oil production of approximately 6,000 bbls/d and we expect to reach this production rate in mid-2016. In April 2016, production from the first phase of the Onion Lake thermal EOR project was approximately 5,300 bbls/d.

SELECTED QUARTERLY INFORMATION

	2016		**2015**				2014	
($000s, except where noted)	**Mar 31**	**Dec 31**	**Sep 30**	**Jun 30**	Mar 31	Dec 31	Sep 30	Jun 30
Production (boe/d) [1]	**9,166**	**9,521**	**7,478**	**8,051**	8,269	9,639	9,248	8,897
Oil and gas sales	**13,021**	**22,630**	**20,814**	**30,712**	22,115	47,798	58,818	62,174
Oil sales ($/bbl)	**16.77**	**27.65**	**35.02**	**47.52**	32.05	59.34	75.89	81.82
Gas sales ($/mcf)	**1.77**	**2.91**	**2.88**	**2.61**	2.63	3.39	3.97	4.61
Oil and gas sales ($/boe)	**16.67**	**27.45**	**34.05**	**45.37**	31.25	57.00	72.90	79.53
Production & transportation costs	**11,736**	**15,666**	**12,843**	**14,245**	16,686	22,306	22,686	21,979
Production costs ($/boe)	**12.35**	**17.77**	**20.04**	**19.86**	22.48	25.12	26.05	25.96
Transportation costs ($/boe)	**2.68**	**1.23**	**0.97**	**1.18**	1.10	1.48	2.06	2.16
Realized gain (loss) on risk management contracts	**6,120**	**10,334**	**7,940**	**5,245**	13,708	5,846	(468)	(2,842)
Unrealized gain (loss) on risk management contracts	**(472)**	**1,778**	**11,826**	**(13,533)**	(11,374)	20,697	4,961	271
Net income (loss)	**(9,322)**	**(31,172)**	**5,402**	**(10,079)**	(10,944)	16,254	7,013	4,684
Per share, basic and diluted ($)	**(0.03)**	**(0.09)**	**0.01**	**(0.03)**	(0.03)	0.05	0.02	0.01
Capital expenditures	**2,077**	**1,665**	**7,870**	**15,992**	42,981	57,700	80,262	48,044
Funds flow from operations [2]	**3,278**	**10,898**	**10,156**	**14,968**	12,940	19,716	23,809	23,161
Per share, basic and diluted ($)	**0.01**	**0.04**	**0.03**	**0.04**	0.04	0.06	0.07	0.07
Long-term debt	**86,000**	**88,000**	**97,000**	**94,000**	78,000	29,000	-	-
Total assets (end of period)	**795,336**	**808,344**	**861,107**	**864,926**	866,018	837,773	785,538	765,233
Shares outstanding (000s)	**335,638**	**335,638**	**335,638**	**335,638**	335,638	335,638	335,638	335,638

	2016	2015				2014		
	Mar 31	**Dec 31**	**Sep 30**	**Jun 30**	Mar 31	Dec 31	Sep 30	Jun 30
Weighted average shares outstanding (000s)								
Basic	**335,638**	**335,638**	**335,638**	**335,638**	335,638	335,638	335,638	334,817
Diluted	**335,638**	**335,638**	**335,638**	**335,638**	335,638	335,638	335,638	335,244

(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

	2016	2015				2014		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Average Crude Oil Prices								
West Texas Intermediate (WTI) (US$/bbl)	33.45	42.18	46.43	57.94	48.63	73.15	97.17	102.99
Western Canadian Select (WCS) (Cdn$/bbl)	26.31	36.86	43.27	56.95	42.11	66.73	83.80	90.42
Differential – WCS/WTI (US$/bbl)	14.32	14.57	13.39	11.62	14.71	14.39	20.24	20.08
Differential - WCS/WTI (%)	42.8%	34.5%	28.8%	20.1%	30.2%	19.7%	20.8%	19.5%
Average Natural Gas Prices								
AECO gas (Cdn$/GJ)	1.74	2.34	2.75	2.52	2.61	3.41	3.81	4.71
Average Foreign Exchange (US$ per Cdn$1)	0.727	0.749	0.764	0.813	0.806	0.881	0.918	0.917

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.

The drop in oil prices continued in 2016 with WTI oil prices averaged US$33.45 per bbl in the first quarter of 2016 compared to US$42.18 per bbl in the fourth quarter of 2015. The decrease in oil prices has been attributed to a continuing global demand-supply imbalance for oil. In an effort to stabilize the crude oil markets several OPEC and non-OPEC countries proposed limits on crude oil production; however, at a meeting held on April 17, 2016 these countries failed to reach an agreement on limiting oil production. Oil prices improved in April 2016 with WTI oil prices averaging US$41.12 per bbl and as of May 4, 2016, WTI oil prices were approximately US$43.50 per bbl.

The heavy oil differential (WTI oil prices compared to WCS oil prices) was comparable between the first quarter of 2016 and the fourth quarter of 2015 as well as the first quarter of 2015. In the first quarter of 2016 the differential averaged US$14.32 per bbl compared to US$14.57 per bbl in the fourth quarter of 2015 and US$14.71 per bbl in the first quarter of 2015. However, the differential as a percentage of the WTI price increased to 43% in the first quarter of 2016 compared to 30% in the same period in 2015.

Natural gas prices decreased in the first quarter of 2016 averaging $1.74/GJ compared to $2.34/GJ in the fourth quarter of 2015. The decrease in natural gas prices during the first quarter 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 quarter 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 US benchmark prices. The Canadian dollar weakened against the US dollar in the first quarter 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$0.73 during the first quarter of 2016 compared to Cdn$1 = US$0.75 in the fourth quarter of 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	1,848
Realized crude oil price (Cdn$/bbl)	1.00	2,275
US $ to Canadian $ exchange rate	0.01	418

(1) This analysis assumes annualized estimated average production of 9,600 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

	Q1 2016	Q4 2015	Q1 2015
Daily production/sales volumes			
Oil (bbls/d)	**8,442**	8,785	7,479
Bitumen – Blackrod (bbls/d) [(2)]	**584**	562	406
Combined (bbls/d)	**9,026**	9,347	7,885
Natural gas (Mcf/d)	**845**	1,047	2,303
Total production (boe/d) [(1)]	**9,166**	9,521	8,269
Product pricing (excluding risk management activities) [(2)]			
Oil ($/bbl)	**16.77**	27.65	32.05
Natural gas ($/Mcf)	**1.77**	2.91	2.63
Combined ($/boe) [(1)]	**16.67**	27.45	31.25
Sales ($000s) [(2)]			
Oil and gas sales – gross	**13,021**	22,630	22,115
Royalties	**(1,345)**	(3,613)	(4,119)
Oil and gas revenues – net	**11,676**	19,017	17,996

(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 41% in the first quarter of 2016 to $13.0 million from $22.1 million in the same period in 2015. The decrease in oil and gas sales is attributable to a 47% decrease in the average sales price received in the first quarter of 2016 compared to the same period in 2015, partially offset by a 11% increase in production (on a boe basis).

Significantly lower WTI crude oil prices 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 first quarter of 2016. Our average oil wellhead sales price in the first quarter of 2016, prior to the impact of risk management activities, was $16.77 per bbl compared with $32.05 per bbl in the same period in 2015.

Production growth in the first quarter of 2016 compared to the same period in 2015 came from the first phase of our Onion Lake thermal EOR project. Production from the thermal project continues to ramp-up and is currently producing over 5,000 bbls/d of oil. We anticipate production from this project to reach its 6,000 barrel per day design capacity in mid-2016.

Production in our non-thermal areas has declined from previous quarters. This is primarily attributable 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 1,000 bbls of oil per day currently shut-in. 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. We expect oil prices would have to improve to US$45 to US$50 per barrel before we would consider putting some of the shut-in wells back on production. 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 first quarter of 2016 was heavy oil or bitumen. The Onion Lake area accounted for 71% of total production in the first quarter of 2016.

Production by area (boe/d)	**Q1 2016**	Q4 2015	Q1 2015
Onion Lake - thermal	**4,252**	3,010	-
Onion Lake - conventional	**2,232**	2,914	3,959
Mooney	**1,042**	1,902	2,797
John Lake	**861**	955	1,011
Blackrod	**584**	562	406
Other	**195**	178	96
Total production	**9,166**	9,521	8,269

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 March 31, 2016, BlackPearl had not received regulatory approval for the 80,000 bbl/d commercial Blackrod project. During the first quarter of 2016, the pilot wells produced an average of 584 bbls/d of bitumen and the net revenues capitalized were a loss of $0.7 million ($1.2 million loss in the first quarter 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 mainly focuses on swaps and fixed price contracts to limit exposure to fluctuations in oil prices and revenues. The Company's risk management trading activities are conducted pursuant to the Company's Risk Management Policy approved by the Board of Directors and are not used for trading or speculative purposes. The policy permits us to hedge up to 60% of our forecast production for a period of up to 24 months.

Gains and losses on risk management contracts include both realized gains and losses representing the portion of contracts that have been settled during the year and unrealized gains and losses that represent the non-cash change in the fair values of our outstanding risk management contracts. The Company had a net gain of $5.6 million on its risk management contracts during the first quarter of 2016, consisting of a $6.1 million realized gain on the contracts and an unrealized loss of $0.5 million. The realized gain on risk management contracts was the equivalent of adding $7.84 per bbl to our wellhead price during the first quarter of 2016.

($000s, except per boe)	**Q1 2016**	Q4 2015	Q1 2015
Realized gain on risk management contracts	**6,120**	10,334	13,708
Per boe ($)	**7.84**	12.54	19.37
Unrealized gain (loss) on risk management contracts	**(472)**	1,778	(11,374)

The table below summarizes the Company's outstanding commodity contracts as at March 31, 2016:

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

At March 31, 2016, these contracts had a fair value of approximately $8.9 million. A 10% decrease to the oil price used to calculate the fair value of these contracts would result in an approximately $4 million increase in fair value.

Royalties

	Q1 2016	Q4 2015	Q1 2015
Royalties ($000s)	**1,345**	3,613	4,119
Per boe ($)	**1.72**	4.38	5.82
As a percentage of oil and gas sales	**10%**	16%	19%

BlackPearl makes royalty payments to the owners of the mineral rights on the lands we have leased. Most of the payments are to provincial governments or, in the case of our Onion Lake area production, to the Onion Lake Cree Nation.

Royalties were $1.3 million in the first quarter of 2016, down from $4.1 million in the same period in 2015. Reduced royalties in the first quarter of 2016 reflects lower wellhead prices and lower revenues.

Royalties as a percentage of oil and gas sales decreased to 10% in the first quarter of 2016 from 19% of oil and gas sales in the same period in 2015. Royalty rates are generally price sensitive and the lower oil prices realized in Q1 2016 resulted in lower royalties as a percentage of oil and gas sales. In addition, lower royalty rates in Q1 2016 are attributable to an increase in production from the Onion Lake thermal EOR project. Production from this project was 46% of our total production in Q1 2016 (0% in Q1 2015). During the pre-payout period the royalties from this project will be approximately 10%, which is lower than our average royalty rate for our other producing areas.

Transportation Costs

	Q1 2016	Q4 2015	Q1 2015
Conventional Production			
Transportation costs ($000s)	**318**	379	781
Per boe ($)	**0.81**	0.69	1.10
Thermal Production			
Transportation costs ($000s)	**1,775**	639	-
Per boe ($)	**4.59**	2.31	-
Total Production			
Transportation costs ($000s)	**2,093**	1,018	781
Per boe ($)	**2.68**	1.23	1.10

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 first quarter of 2016 to $2.1 million from $0.7 million in the same period of 2015. The increase in transportation costs is attributable to increased production from the first phase of the Onion Lake thermal EOR project. During the first quarter of 2016 the majority of the oil from this project was shipped as clean marketable barrels rather than emulsion. This resulted in higher clean oil transportation costs but it decreased production expenses.

Production Costs

	Q1 2016	Q4 2015	Q1 2015
Conventional Production			
Production costs ($000s)	**5,550**	8,522	15,905
Per boe ($)	**14.09**	15.57	22.48
Thermal Production			
Production costs ($000s)	**4,093**	6,126	-
Per boe ($)	**10.58**	22.12	-
Total Production			
Production costs ($000s)	**9,643**	14,648	15,905
Per boe ($)	**12.35**	17.77	22.48

Total production costs decreased 39% in the first quarter of 2016 to $9.6 million from $15.9 million in the same period in 2015. On a per boe basis, total production costs decreased 45% in the first quarter of 2016 to $12.35 per boe from $22.48 per boe in the same period in 2015.

The decrease in conventional production costs in the first quarter of 2016 is attributable, in part, to decreased 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. In addition, during the first quarter of 2016 the Company 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 decrease in thermal production costs in the first quarter of 2016 compared to the fourth quarter of 2015 is attributable to lower natural gas prices which is one of the largest production costs at the Onion Lake thermal EOR project. As well, we shipped more production as clean oil transportation rather than emulsion from the Onion Lake thermal EOR project in the first quarter of 2016 compared to the fourth quarter of 2015, resulting in higher clean oil transportation costs and a decrease in production costs.

Operating Netback [(1)]

($/boe)	**Q1 2016**	Q4 2015	Q1 2015
Oil and gas sales	**16.67**	27.45	31.25
Royalties	**1.72**	4.38	5.82
Transportation costs	**2.68**	1.23	1.10
Production costs	**12.35**	17.77	22.48
Operating netback before realized risk management contracts	**(0.08)**	4.07	1.85
Realized gain on risk management contracts	**7.84**	12.54	19.37
Operating netback after realized risk management contracts	**7.76**	16.61	21.22

(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 first quarter of 2016 to a loss of $0.08 per boe from $1.85 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)

($000s, except per boe)	**Q1 2016**	Q4 2015	Q1 2015
Gross G&A expense	**2,129**	2,088	2,499
Operator recoveries	**(230)**	(268)	(360)
Net G&A expense	**1,899**	1,820	2,139
Per boe ($)	**2.43**	2.21	3.02

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 quarter of 2016 compared to the same period in 2015 reflects lower third party consultants' costs as well as lower staff compensation costs in 2016. In an effort to lower our overall cost structure during this extremely low oil price environment, during the first quarter, the Company implemented salary reductions and reduced work schedules for its staff. Lower operator recoveries in the first quarter of 2016 compared to same period in 2015 is attributable to lower capital spending in 2016. Net G&A costs are comparable between the first quarter of 2016 and the fourth quarter of 2015.

Stock-Based Compensation

($000s, except per boe)	**Q1 2016**	Q4 2015	Q1 2015
Gross stock-based compensation	**1,178**	1,759	1,628
Recoveries from forfeitures	**(48)**	(3)	(45)
Net stock-based compensation before capitalization	**1,130**	1,756	1,583
Capitalized stock-based compensation	**-**	-	(53)
Net stock-based compensation	**1,130**	1,756	1,530
Per boe ($)	**1.45**	2.13	2.16

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 quarter 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 quarter of 2016, 75,000 options were granted and 118,334 options were forfeited. Based on stock options outstanding as at March 31, 2016, the Company has an unamortized stock option compensation expense of approximately $3.2 million, of which $2.2 million is expected to be expensed in the remainder of 2016, $0.9 million in 2017 and $0.1 million in 2018.

Finance Costs

($000s)	**Q1 2016**	Q4 2015	Q1 2015
Gross interest & financing charges	**835**	930	583
Capitalized interest & financing charges	**-**	-	(520)
Net interest & financing charges	**835**	930	63
Accretion of decommissioning liabilities	**366**	370	417
Total finance costs	**1,201**	1,300	480

The increase in gross interest and financing charges in the first quarter of 2016 compared to the same period in 2015 are a result of higher average debt levels in 2016. The average interest rate on advances under the Company's credit facilities was 3.4% in the first quarter of 2016. 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 increase to 3.75 - 4% for the remainder of 2016 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 quarter of 2016 we did not capitalize any interest charges. In Q1 2015 we capitalized $0.5 million of interest costs related to debt incurred during the construction of the Onion Lake EOR project.

Depletion and Depreciation

	Q1 2016	Q4 2015	Q1 2015
Depletion and depreciation ($000s)	**10,632**	12,872	13,765
Per boe ($)	**13.61**	15.62	19.45

The Company's properties are depleted on a unit of production basis based on estimated proven plus probable reserves. Depletion and depreciation expense decreased 23% in the first quarter of 2016 to $10.6 million from $13.8 million in the same period in 2015. On a boe basis, depletion and depreciation expense decreased to $13.61 per boe in the first quarter of 2016 compared to $19.45 per boe in the same period in 2015. The decrease in depletion and depletion on a boe basis is primarily attributable to an increase in relative production from the Onion Lake thermal EOR project in the first quarter 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 three months ended March 31, 2016. 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

	Q1 2016	Q4 2015	Q1 2015
Deferred income recovery ($000s)	**-**	(4,063)	(3,265)

BlackPearl did not pay cash income taxes in the first quarter 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

	Q1 2016	Q4 2015	Q1 2015
Net loss ($000s)	**(9,322)**	(31,172)	(10,944)
Per share, basic ($)	**(0.03)**	(0.09)	(0.03)
Per share, diluted ($)	**(0.03)**	(0.09)	(0.03)

For the quarter ended March 31, 2016, the Company incurred a net loss of $9.3 million compared to a net loss of $10.9 million in the same period in 2015. The reduction in the net loss in 2016 is primarily a result of lower production, royalty and depletion costs and increased gains on risk management contracts partially offset by lower wellhead prices.

	Q1 2016	Q4 2015	Q1 2015
Funds flow from operations (1) ($000s)	**3,278**	10,898	12,940
Per share, basic ($)	**0.01**	0.04	0.04
Per share, diluted ($)	**0.01**	0.04	0.04

(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 75% to $3.3 million during the first quarter of 2016 compared to $12.9 million in the same period in 2015. The decrease in funds flow in 2016 is primarily a result of significantly lower wellhead sales prices, partially offset by the realized gain on risk management contracts and lower royalties and production costs.

LIQUIDITY AND CAPITAL RESOURCES

($000s)	**March 31, 2016**	December 31, 2015
Working capital surplus	**(9,155)**	(11,063)
Revolving line of credit due beyond one year	**86,000**	88,000
Net debt (1)	**76,845**	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 March 31, 2016, the Company had $86 million drawn under its existing credit facilities and issued letters of credit in the amount of $20,000; leaving $64 million available to be drawn under these credit facilities. The facilities are secured by a floating and fixed charge debenture on the assets of the Company. The amount available under these facilities ("Borrowing Base") is re-determined at least twice a year and is 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 May 31, 2016. The facilities are also subject to annual reviews by the lenders and the next scheduled review is to be completed by May 31, 2016. In the event the lenders elected not to renew the credit facilities during the annual review, any amounts outstanding on the revolving and operating lines of credit would be due and payable in full by May 27, 2017.

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 6.7:1 at March 31, 2016 and was in compliance with this covenant at March 31, 2016.

($000s, except working capital ratio)	**March 31, 2016**	December 31, 2015
Current assets per consolidated financial statements	**20,349**	25,537
Add: amount available to be drawn on credit facilities	**64,000**	62,000
Less: current risk management assets	**(9,544)**	(10,548)
Current assets for working capital ratio	**74,805**	76,989
Current liabilities per consolidated financial statements	**11,194**	14,474
Less: current risk management liabilities	**-**	-
Current liabilities for working capital ratio	**11,194**	14,474
Working capital ratio	**6.7**	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 March 31, 2016, there were 335,638,226 common shares issued and outstanding. In the first quarter of 2016 the Company did not issue any common shares.

The Company did not pay dividends on its common shares in the first quarter 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 significantly in the first 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 first quarter of 2016 capital spending was $2.1 million, a decrease from $43.0 million during the same period in 2015. The main components of the capital spending program during the first quarter of 2016 was facility improvements and maintenance at the Onion Lake thermal EOR project and planning for the second phase of the project and the continued capitalization of net revenues from operating the Blackrod pilot. No new drilling activity occurred during the first quarter of 2016.

($000s)	**Q1 2016**	Q4 2015	Q1 2015
Land	**117**	203	146
Seismic	**(5)**	5	651
Drilling and completion	**1,464**	1,059	3,964
Equipment and facilities	**494**	358	38,145
Other	**7**	40	75
Total	**2,077**	1,665	42,981
Property acquisitions	**-**	-	-
Total capital expenditures	**2,077**	1,665	42,981
Property dispositions	**-**	-	-
Net capital expenditures	**2,077**	1,665	42,981

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 March 31, 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)	1,097	270	220	84	-	-
Electrical service agreement (2)	644	1,000	585	119	119	1,987
Transportation service agreement (3)	101	135	135	135	33	-
Decommissioning liabilities (4)	492	394	455	333	8,619	72,895
Long-term debt (5)	2,451	87,362	-	-	-	-
	4,785	89,161	1,395	671	8,771	74,882

(1) *The Company's most significant operating lease is for office space. As at March 31, 2016 the Company had six months remaining on its office lease. The Company's office lease was executed jointly with another party. Under the terms of the lease, BlackPearl and the other party are joint and severally liable for the obligations pursuant to the lease. Accordingly, if the other party is unable to fulfill their share of the lease obligation, BlackPearl would be required to pay a maximum additional amount of $1.6 million (including an estimate for operating costs) over the next 6 months. At March 31, 2016, no amounts were owed (2015 – no amounts owing).*

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

(3) *The Company entered into certain 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 $83.2 million as at March 31, 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 2017 assuming these facilities are not extended during the scheduled credit facility review in May 2016. At this time management expects the facility will be extended. Amounts include principal and interest. Interest is based on rates existing at March 31, 2016.*

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments as at March 31, 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 months ended March 31, 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 March 31, 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 March 31, 2016 or 2015 except for key management compensation.

OUTSTANDING SHARE DATA AND STOCK OPTIONS

As at May 4, 2016, the Company had 335,638,226 common shares outstanding and 29,312,500 stock options outstanding under its stock-based compensation program.

OUTSTANDING LONG-TERM DEBT DATA

As at May 4, 2016, the Company had $86,000,000 drawn under its existing credit facilities and had issued letters of credit in the amount of $20,000; leaving $63,980,000 available to be drawn under these credit facilities.

PROPOSED TRANSACTIONS

As of May 4, 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 March 31, 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. There have been no significant changes in these risks and uncertainties during the first three months of 2016.

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 three months ended March 31, 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
Production (boe/d)			
Annual average	10,000 – 10,500	9,000 – 10,000	9,000 – 10,000
Funds flow from operations [(1)] ($millions)	35 – 40	5 – 10	20 – 25
Capital expenditures ($millions)	15 – 20	10 – 15	10 – 15
Year-end debt ($millions)	70 – 75	90 - 95	75 – 80
Pricing Assumptions (annual average)			
Crude oil - WTI	US $50.00	US $35.00	US $38.36
Light/heavy differential	US$ 15.00	US$ 14.00	US$ 14.06
Foreign Exchange (Cdn$ to US$)	0.75	0.71	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.

For the remainder of the year we will continue to maintain a strong balance sheet by limiting our capital spending and using a portion of our funds flow to reduce debt levels until we see signs of a sustained price recovery. We are planning to spend $10 to $15 million on capital projects, unchanged from our February 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 and maintenance capital in all our core areas. Expansion of the Mooney ASP flood has been deferred until oil prices improve. The Company continues to have the flexibility to expand or defer our capital program as economic conditions change.

The capital program is expected to be funded from our anticipated funds flow from operations which is expected to be between $20 and $25 million, up from our February guidance of $5 to $10 million. The increase in our estimated funds flow from operations is a result of an increase in our estimate of crude oil prices for the remainder of the year. For budget purposes we are using US$40/bbl WTI price, a heavy oil differential of US$14/bbl and Cdn$1 = US$0.77 foreign exchange rate for the remainder of the year. A portion of anticipated funds flow is also expected to be used to reduce our debt levels. Year-end debt levels are expected to between $75 and $80 million, a decrease from our February guidance of $90 to $95 million.

We anticipate oil and gas production to average between 9,000 and 10,000 boe/d in 2016, unchanged from our February guidance. Exit production levels for 2016 are expected to be within that same range. We will continue to monitor crude oil prices and make changes to our capital spending programs and operations as we believe are required. This may include shutting-in more of our higher operating cost wells until oil prices improve.

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”, “planning”, “planned”, “could”, “continue”, “continues”, “continued”, “estimate”, “estimates”, “estimated”, “forecast”, “likely”, “expect”, “expects”, “expected”, “may”, “intention”, “intended”, “impact”, “new”, “will”, “scheduled”, “outlook”, “in the event” 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:

- Anticipated timing of reaching design oil production capacity of 6,000 bbl/d at the Onion Lake thermal EOR project as discussed in the 2016 Significant Events section and in the Oil and Gas Production, Oil and Gas Pricing and Oil and Gas sales section;
- The estimated change in annualized funds flow from operations for 2016 due to changes in key variables as discussed in the Commodity Prices section;
- 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;
- Expected stock-based compensation expense for the remainder of 2016, 2017 and 2018 as discussed in the Stock-based Compensation section;
- Expected increase on the interest rate charged on our debt for the remainder of 2016 as a result of carrying a higher debt to EBITDA ratio 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 May 4, 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	**March 31, 2016**	December 31, 2015
Assets			
Current assets			
Cash and cash equivalents	4	**$ 1,132**	$ 2,300
Trade and other receivables	5	**8,669**	10,801
Inventory		**157**	605
Prepaid expenses and deposits		**847**	1,283
Fair value of risk management assets	13	**9,544**	10,548
		20,349	25,537
Exploration and evaluation assets	6	**170,307**	169,493
Property, plant and equipment	7	**604,680**	613,314
		$ 795,336	$ 808,344
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	8	**$ 10,702**	$ 13,939
Current portion of decommissioning liabilities	9	**492**	535
		11,194	14,474
Fair value of risk management liabilities	13	**691**	1,223
Decommissioning liabilities	9	**67,388**	66,392
Long-term debt	10	**86,000**	88,000
		165,273	170,089
Shareholders' equity			
Share capital	11	**970,134**	970,134
Contributed surplus		**40,930**	39,800
Deficit		**(381,001)**	(371,679)
		630,063	638,255
		$ 795,336	$ 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 March 31, 2016**	Three months ended March 31, 2015
Revenue			
Oil and gas sales		**$ 13,021**	$ 22,115
Royalties		**(1,345)**	(4,119)
Net oil and gas revenue		**11,676**	17,996
Gain on risk management contracts	13	**5,648**	2,334
		17,324	20,330
Expenses			
Production		**9,643**	15,905
Transportation		**2,093**	781
General and administrative		**1,899**	2,139
Depletion and depreciation	7	**10,632**	13,765
Finance costs	14	**1,201**	480
Stock-based compensation	11	**1,130**	1,530
Foreign currency exchange loss (gain)		**48**	(55)
		26,646	34,545
Other income			
Interest income		**-**	6
Loss before income taxes		**(9,322)**	(14,209)
Income taxes			
Deferred income recovery		**-**	(3,265)
Net and comprehensive loss for the period		**$ (9,322)**	$ (10,944)
Loss per share			
Basic	11	**$ (0.03)**	$ (0.03)
Diluted	11	**$ (0.03)**	$ (0.03)

See accompanying notes to consolidated financial statements

BLACKPEARL RESOURCES INC.

Consolidated Statements of Changes in Equity

(unaudited)
(Cdn$ in thousands)

	Three months ended March 31, 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	-	-	(9,322)	(9,322)
Stock-based compensation	-	1,130	-	1,130
Balance - March 31, 2016	**$ 970,134**	**$ 40,930**	**$ (381,001)**	**$ 630,063**

	Three months ended March 31, 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	-	-	(10,944)	(10,944)
Stock-based compensation	-	1,583	-	1,583
Balance - March 31, 2015	$ 970,134	$ 35,371	$ (335,830)	$ 669,675

See accompanying notes to consolidated financial statements

BLACKPEARL RESOURCES INC.

Consolidated Statements of Cash Flows

(unaudited) **(Cdn$ in thousands)**	Note	**Three months ended** **March 31, 2016**	Three months ended March 31, 2015
Operating activities			
Net and comprehensive loss for the period		**$ (9,322)**	$ (10,944)
Items not involving cash:			
Depletion and depreciation	7	**10,632**	13,765
Accretion of decommissioning liabilities	14	**366**	417
Stock-based compensation	11	**1,130**	1,530
Foreign exchange loss		**-**	63
Deferred income recovery		**-**	(3,265)
Unrealized loss on risk management contracts	13	**472**	11,374
Decommissioning costs incurred	9	**(147)**	(245)
Changes in non-cash working capital	14	**656**	11,154
Cash flow from operating activities		**3,787**	23,849
Financing activities			
Proceeds on issue of long-term debt		**-**	49,000
Repayment of long-term debt		**(2,000)**	-
Cash flow from (used) in financing activities		**(2,000)**	49,000
Investing activities			
Capital expenditures - exploration and evaluation assets	6	**(792)**	(2,134)
Capital expenditures - property, plant and equipment	7	**(1,285)**	(40,794)
Changes in non-cash working capital	14	**(926)**	(27,279)
Cash flow used in investing activities		**(3,003)**	(70,207)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**48**	(118)
Increase (decrease) in cash and cash equivalents		**(1,168)**	2,524
Cash and cash equivalents, beginning of period		**2,300**	2,918
Cash and cash equivalents, end of period		**$ 1,132**	$ 5,442

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 months ended March 31, 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 May 4, 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

		March 31, 2016		December 31, 2015
Cash at financial institutions	**$**	**1,132**	$	2,300

Cash at financial institutions earns interest at floating rates based on daily deposit rates. As of March 31, 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

		March 31, 2016		December 31, 2015
Trade accounts receivable	**$**	**6,449**	$	6,264
Receivables from joint operation partners		**379**		304
Allowance for doubtful accounts		**(285)**		(285)
Net accounts receivable		**6,543**		6,283
Receivable from risk management contracts		**1,653**		4,228
Other receivables		**473**		290
Total trade and other receivables	**$**	**8,669**	$	10,801

Aging of trade and other receivables are as follows:

At March 31, 2016		Current		31 to 60 days		61 to 90 days		Over 90 days		Total
Trade accounts receivable	$	6,449	$	-	$	-	$	-	$	6,449
Receivables from joint operation partners		40		39		1		299		379
Allowance for doubtful accounts		-		-		-		(285)		(285)
Receivable from risk management contracts		1,653		-		-		-		1,653
Other receivables		473		-		-		-		473
Total trade and other receivables	$	8,615	$	39	$	1	$	14	$	8,669

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	792
Change in decommissioning provision	22
At March 31, 2016	$ 170,307

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 three 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 three months ended March 31, 2016 the Company capitalized net operating revenues totalling a loss of $0.7 million ($1.2 million loss in the first quarter 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 three months ended March 31, 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	1,285	-	1,285
Change in decommissioning provision	713	-	713
At March 31, 2016	$ 1,242,643	$ 3,507	$ 1,246,150
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	10,594	38	10,632
At March 31, 2016	$ 638,949	$ 2,521	$ 641,470
Net book value			
December 31, 2015	$ 612,290	$ 1,024	$ 613,314
March 31, 2016	$ 603,694	$ 986	$ 604,680

During the three months ended March 31, 2016, the Company did not capitalize any borrowing costs related to development activities (2015 - $0.5 million). The Company did not capitalize any general and administrative costs related to development activities during the three months ended March 31, 2016 (2015 - $Nil).

The Company performed review tests at March 31, 2016 for any indication of impairment. There were no impairment losses or reversals of property, plant and equipment during the three months ended March 31, 2016 (2015 - $Nil).

8. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	March 31, 2016	December 31, 2015
Trade payables and accrued liabilities	**$ 10,169**	$ 13,371
Payables to joint operation partners	**368**	218
Other payables	**165**	350
Total accounts payable and accrued liabilities	**$ 10,702**	$ 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 $83.2 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:

		Three months ended March 31, 2016		Year ended December 31, 2015
Decommissioning liability, beginning of year	$	**66,927**	$	60,683
New liabilities recognized		**-**		15,067
Decommissioning costs incurred		**(147)**		(531)
Change in estimated costs of decommissioning		**-**		(7,670)
Change in inflation rate		**-**		(4,883)
Change in discount rate		**734**		2,615
Accretion expense		**366**		1,646
Decommissioning liability, end of year		**67,880**		66,927
Less current portion of decommissioning liability		**(492)**		(535)
Non-current portion of decommissioning liability	$	**67,388**	$	66,392

10. LONG-TERM DEBT

At March 31, 2016 the Company had credit facilities of $150 million, consisting of a $140 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 March 31, 2016, the Company had drawn $86 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 $64 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. The next scheduled Borrowing Base redetermination is to occur by May 31, 2016. 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 facilities are also subject to annual reviews by the lenders and the next scheduled review is to be completed by May 31, 2016. In the event the lenders elected not to renew the credit facilities during the annual review, any amounts outstanding on the facilities would be due and payable in full by May 27, 2017.

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 6.7:1 at March 31, 2016 (December 31, 2015 – 5.3:1) and was in compliance with this covenant at March 31, 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 and March 31, 2016	335,638,226	$ 970,134

(c) Stock Options Outstanding

The Company has a stock option plan (the "Plan") available to directors, officers, employees and certain consultants of the Company. 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
Forfeited	(118,334)	2.10
Outstanding at March 31, 2016	29,611,835	2.04

Options outstanding and exercisable as at March 31, 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	11,366,834	0.84	4.22	3,751,245	0.83	4.22
1.51 – 3.00	14,299,001	2.31	2.93	10,254,210	2.32	2.86
3.01 – 4.50	1,786,500	3.70	1.25	1,786,500	3.70	1.25
4.51 – 6.00	1,844,500	4.92	0.63	1,844,500	4.92	0.63
6.01 – 7.66	315,000	6.91	0.19	315,000	6.91	0.19
	29,611,835	2.04	3.15	17,951,455	2.50	2.71

The fair value of common share options granted is estimated on the date of grant using the Black-Scholes option pricing model. During the three months ended March 31, 2016, 75,000 options were granted (2015 – 7,165,000). The fair value of these options was estimated using the following weighted average assumptions:

Assumptions	**Three months ended March 31, 2016**	Three months ended March 31, 2015
Risk free interest rate (%)	**0.6**	0.7
Dividend yield (%)	**0.0**	0.0
Expected life (years)	**3.7**	3.6
Expected volatility (%)	**54.6**	53.6
Forfeiture rate (%)	**11.7**	13.6
Weighted average fair value of options	**$ 0.32**	$ 0.36

(d) Stock-based Compensation

		Three months ended March 31, 2016		Three months ended March 31, 2015
Gross stock-based compensation	**$**	**1,178**	$	1,628
Recoveries from forfeitures		**(48)**		(45)
Net stock-based compensations before capitalization		**1,130**		1,583
Stock-based compensation capitalized to property, plant and equipment		**-**		(53)
Net stock-based compensation	**$**	**1,130**	$	1,530

(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 March 31, 2016		Three months ended March 31, 2015
Net and comprehensive loss	**$**	**(9,322)**	$	(10,944)
Weighted average number of common shares - basic		**335,638**		335,638
Dilutive effect:				
Outstanding options		**-**		-
Weighted average number of common shares - diluted		**335,638**		335,638
Basic loss per share	**$**	**(0.03)**	$	(0.03)
Diluted loss per share	**$**	**(0.03)**	$	(0.03)

For the three months ended March 31, 2016, the Company used a weighted average market closing price of $0.61 (2015 - $0.94) per share to calculate the dilutive effect of stock options. For the three months ended March 31, 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]	$ 1,097	$ 270	$ 220	$ 84	$ -	$ -
Electrical service agreement [2]	644	1,000	585	119	119	1,987
Transportation service agreement [3]	101	135	135	135	33	-
Decommissioning liabilities [4]	492	394	455	333	8,619	72,895
Long-term debt [5]	2,451	87,362	-	-	-	-
Total	$ 4,785	$ 89,161	$ 1,395	$ 671	$ 8,771	$ 74,882

(1) The Company's most significant operating lease is for office space. As at March 31, 2016 the Company had six months remaining on its office lease. The Company's office lease was executed jointly with another party. Under the terms of the lease, BlackPearl and the other party are joint and severally liable for the obligations pursuant to the lease. Accordingly, if the other party is unable to fulfill their share of the lease obligation, BlackPearl would be required to pay a maximum additional amount of $1.6 million (including an estimate for operating costs) over the next 6 months. At March 31, 2016, no amounts were owed (2015 – no amounts owing).

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

(3) The Company entered into certain 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 $83.2 million as at March 31, 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 2017 assuming these facilities are not extended during the scheduled credit facility review in May 2016. At this time management expects the facility will be extended. Amounts include principal and interest. Interest is based on rates existing at March 31, 2016.

13. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments as at March 31, 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.

		March 31, 2016		December 31, 2015	
	Measurement Level	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Financial Assets					
Loans and receivables:					
Cash and cash equivalents	1	$ 1,132	$ 1,132	$ 2,300	$ 2,300
Trade and other receivables	2	$ 8,669	$ 8,669	$ 10,801	$ 10,801
Deposits	2	$ 409	$ 409	$ 409	$ 409
Financial assets at fair value through profit or loss:					
Risk management assets	2	$ 9,544	$ 9,544	$ 10,548	$ 10,548
Financial liabilities					
Financial liabilities at amortized cost:					
Accounts payable and accrued liabilities	2	$ 10,702	$ 10,702	$ 13,939	$ 13,939
Long-term debt	2	$ 86,000	$ 86,000	$ 88,000	$ 88,000
Financial liabilities at fair value through profit or loss:					
Risk management liabilities	2	$ 691	$ 691	$ 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 March 31, 2016, the Company held $1.1 million in cash at various major financial institutions throughout Canada and the USA; however, one Canadian financial institution held over 70% 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 March 31, 2016, 74% 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 quarter of 2016, the Company had three 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 70% of the Company’s total oil and gas sales in the first quarter of 2016.

Risk management assets consist of commodity contracts used to manage the Company’s exposure to fluctuations in commodity prices. At March 31, 2016, the Company had a $1.7 million receivable related to its risk management contracts, which represents over 19% of total accounts receivables. 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 March 31, 2016, the Company had $64 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	10,702	-	-
Risk management liabilities	-	-	691
Long-term debt [(1)]	1,672	1,672	86,469

(1) Includes principal and interest. Interest is based on rates existing at March 31, 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 March 31, 2016, if interest rates had been 1 percent higher with all other variables held constant, after tax net loss for the period would have been approximately $216,000 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 March 31, 2016, the Company has not entered into any fixed rate contracts to mitigate its currency risks.

As at March 31, 2016, the Company held US $0.6 million cash and cash equivalents, US $21,000 trade and other receivables and US $32,000 accounts payable and accrued liabilities.

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 March 31, 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 during 2016 were as follows:

		Three months ended March 31, 2016		Three months ended March 31, 2015
Realized gain on risk management contracts	**$**	**6,120**	$	13,708
Unrealized loss on risk management contracts		**(472)**		(11,374)
Gain on risk management contracts	**$**	**5,648**	$	2,334

The table below summarizes the Company's outstanding commodity contracts as at March 31, 2016:

Subject of Contract	Volume	Term	Reference	Strike Price	Option Traded	Fair value
2016						
Oil	1,000 bbls/d	April 1, 2016 to December 31, 2016	CDN$ WCS	CDN$ 51.15/bbl	Swap	$ 3,903
Oil	2,000 bbls/d	April 1, 2016 to December 31, 2016	CDN$ WCS	CDN$ 47.60/bbl	Swap	6,029
Oil	2,000 bbls/d	April 1, 2016 to December 31, 2016	USD$ WTI	USD$ 65.00/bbl	Sold Call	(157)
2017						
Oil	1,000 bbls/d	January 1, 2017 to December 31, 2017	USD$ WTI	USD$ 60.00/bbl	Sold Call	(922)
Total						$ 8,853
Current portion of fair value of contracts						$ 9,544
Non-current portion of fair value of contracts						$ (691)

As at March 31, 2016, a 10% decrease to the oil price used to calculate the fair value for the risk management contracts would result in a $4.0 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 March 31, 2016		Three months ended March 31, 2015
Cash interest paid	**$**	**835**	$	583

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

		Three months ended March 31, 2016		Three months ended March 31, 2015
Gross interest and financing charges	**$**	**835**	$	583
Capitalized interest and financing charges		**-**		(520)
Net interest and financing charges		**835**		63
Accretion of decommissioning liabilities		**366**		417
Finance costs	**$**	**1,201**	$	480

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

		Three months ended March 31, 2016		Three months ended March 31, 2015
Changes in non-cash working capital:				
Trade and other receivables	**$**	**2,132**	$	3,425
Inventory		**448**		100
Prepaid expenses and deposits		**436**		37
Accounts payable and accrued liabilities		**(3,286)**		(19,687)
Changes in non-cash working capital	**$**	**(270)**	$	(16,125)
Relating to:				
Operating activities	**$**	**656**	$	11,154
Investing activities		**(926)**		(27,279)
Changes in non-cash working capital	**$**	**(270)**	$	(16,125)