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NEWS RELEASE **August 9, 2017**

BLACKPEARL ANNOUNCES SECOND QUARTER 2017 FINANCIAL AND OPERATING RESULTS

CALGARY, ALBERTA – BlackPearl Resources Inc. ("BlackPearl" or the "Company") (TSX: PXX) (NASDAQ Stockholm: PXXS) is pleased to announce its financial and operating results for the three and six months ended June 30, 2017.

Highlights include:

- We continued with construction of the 6,000 barrel per day (bbl/d) Phase 2 expansion of our successful Onion Lake thermal project. Facility modules started being delivered to site and we have commenced drilling injector and producer wells. Our target completion date for the expansion is mid-2018, unchanged from our original target completion date.

- We completed the funding for the Onion Lake expansion project with the successful closing of a $75 million term debt financing in June. In addition, we maintained our strong financial position as we exited the quarter with a renewed undrawn $120 million bank credit facility and had positive working capital of $43 million.

- Production for the quarter averaged 10,386 bbls/d, 7% higher than Q2 2016. The increase is primarily attributable to production from the Onion Lake thermal project and the partial re-initiation of the ASP flood at Mooney.

- Net income for the first half of 2017 was $16.1 million compared to a loss of $18.3 million in the first half of 2016. Adjusted funds flow nearly doubled in the first half of 2017 to $27 million compared to the first half of 2016.

John Festival, President of BlackPearl commenting on Q2 activities indicated that "our focus in the near term is the expansion of our very successful low cost, long life thermal project at Onion Lake. We completed the financing for the project during Q2 and we are part way through construction which will see nameplate capacity double to 12,000 bbls/d. We remain on time and on budget for a mid-2018 start-up and first oil in late 2018. The on-going operating performance from the first phase of the project supports our view that Saskatchewan thermal projects are in the top decile of North American oil projects."

Financial and Operating Highlights

	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Daily sales volumes				
Oil (bbl/d)	9,843	9,004	9,973	8,723
Bitumen (bbl/d) (1)	437	553	489	568
	10,280	9,557	10,462	9,291
Natural gas (mcf/d)	633	847	635	846
Combined (boe/d) (2)	10,386	9,698	10,568	9,432
Product pricing ($) (before the effects of hedging transactions)				
Crude oil - per bbl	41.93	34.44	41.33	25.89
Natural gas - per mcf	2.58	1.29	2.54	1.53
Combined - per boe	41.65	34.03	41.06	25.63
Netback ($/boe)				
Oil and gas sales	41.65	34.03	41.06	25.63
Realized gain on risk management contracts	(0.04)	2.35	0.17	5.01
Royalties	5.87	4.58	5.89	3.20
Transportation	2.62	1.48	2.64	2.06
Operating costs	14.97	13.23	14.98	12.80
Netback (5)	18.15	17.09	17.72	12.58
($000's, except per share amounts)				
Revenue				
Oil and gas revenue – gross	37,702	28,318	74,906	41,339
Net income (loss) for the period	8,318	(8,945)	16,132	(18,267)
Per share, basic and diluted	0.02	(0.03)	0.05	(0.05)
Adjusted funds flow(3)	14,179	11,497	27,103	14,775
Cash flow from operating activities (4)	15,080	7,184	29,866	10,971
Capital expenditures	53,434	945	66,790	3,022
Working capital deficiency (surplus), end of period	(43,680)	(4,497)	(43,680)	(4,497)
Long term debt	72,320	80,000	72,320	80,000
Net debt (6)	28,640	75,503	28,640	75,503
Shares outstanding, end of period	336,250,902	335,646,559	336,250,902	335,646,559

(1) Includes 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) 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.

(3) Adjusted funds flow is a non-GAAP measure that represents cash flow from operating activities before changes in non-cash working capital related to operations and decommissioning costs. Adjusted funds flow does not have a standardized meaning prescribed by Canadian GAAP and therefore may not be comparable to similar measures used by other companies. See non-GAAP measures.

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

(5) 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. See non-GAAP measures.

(6) 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. See non-GAAP measures.

Property Review

Onion Lake

Construction of the second 6,000 barrel per day phase of the Onion Lake thermal project continued throughout the quarter. The modules for the central processing facilities and well pads are being constructed in a fabrication shop near Calgary and we began moving these modules to site in July. Site preparation was completed during the quarter and field construction will ramp-up throughout the summer and fall.

In early July, we commenced drilling the steam injector and oil production wells. In total, we are planning to drill 23 injector/observation wells and 14 horizontal producer wells. Drilling is expected to be completed by the end of the year.

Our estimated capital cost of the second phase of the Onion Lake thermal project remains unchanged at $185 million, 20% lower than phase one costs, and first steam is scheduled to commence in mid-2018. Peak production rates are expected to be reached twelve months after commencement of steam injection, which is similar to what we achieved for phase one. Once the phase two expansion is completed, our Onion Lake thermal project will have a design capacity of 12,000 bbls/d. In addition, we are planning for further thermal expansion opportunities on our Onion Lake lands.

We are continuing to realize excellent operating performance from the first phase of the Onion Lake thermal project. Production averaged 5,816 bbls/d for the quarter, with a steam oil ratio of 2.5 and operating costs of $10.60 per barrel (energy costs - $4.16; non-energy - $6.44). Production, as well as operating costs, in the second quarter was impacted by a planned facility turnaround and inspection which began in late June. The turnaround was planned to coincide with drilling some of the phase two wells to reduce the amount of facility downtime. Phase one production is expected to return to full rates in August or early September.

We have also commenced a five well (2.5 net) primary drilling program in July at Onion Lake. These wells are being drilled outside of the current thermal development area.

Blackrod

Although there were no new activities undertaken in the second quarter, we continue to be pleased with the results achieved for the Blackrod SAGD pilot. After 27 months of maintaining production in excess of 500 bbls/d, we started to see natural declines in production during the second quarter, which is line with our expectations for the pilot. The pilot has cumulatively produced nearly 600,000 barrels of oil. Q2 2017 production was also impacted by a facility turnaround in June. Blackrod's commercial operation will have the ability to further improve on oil production rates and SOR's through applying our learnings from the pilot well and industry proven co-injection with gas or solvents. Pilot well learnings to increase production and improve SOR's include the benefits of having bound wells that get pressure support from offsetting wells, longer horizontal well lengths and improved completion techniques using inflow control devices. We are planning to continue to operate the pilot as it produces positive cash flow and to fully understand the well characteristics through a full life cycle.

Mooney

During the second quarter, we continued to see a positive response from the re-initiation of the ASP (Alkali, Surfactant, Polymer) flood at Mooney. Production from the Mooney field averaged 1,103 bbls/d in Q2 2017, a 17% increase from Q1 2017 and a 41% increase from Q4 2016 when the ASP flood was restarted. We will continue to defer expansion of the ASP flood to our phase two and three lands until we see a sustained improvement in crude oil prices.

Production

Oil and gas production averaged 10,386 barrels of oil equivalent per day (boe/day) in the second quarter of 2017, a 7% increase compared with the second quarter of 2016. The increase in oil production reflects the successful ramp-up of production from our Onion Lake thermal project as well as increased production at Mooney as a result of the re-initiation of the ASP flood on the phase one lands earlier this year.

Average Daily Sales Volume

	Three months ended June 30,		Six months ended June 30,	
(boe/day)	2017	2016	2017	2016
Onion Lake - thermal	5,816	5,221	5,998	4,737
Onion Lake - conventional	2,087	2,138	2,117	2,185
Mooney	1,103	714	1,023	878
John Lake	801	870	804	865
Blackrod	437	553	489	568
Other	142	202	137	199
	10,386	9,698	10,568	9,432

Financial Results

Oil and natural gas sales increased 33% in the second quarter of 2017 to $37.7 million from $28.3 million in the same period in 2016. The increase in oil and gas sales is attributable to a 22% increase in average sale price received and a 7% increase in production volumes (on a boe basis) in the second quarter of 2017 compared to the same period in 2016.

Our realized oil price (before the effects of risk management activities) in Q2 2017 was $41.93 per barrel compared to $34.44 per barrel for the same period in 2016. The increase in our realized wellhead price reflects higher WTI reference oil prices in Q2 2017 compared with Q2 2016 (US$48.29/bbl vs US$45.59/bbl) and tighter heavy oil differentials (US$11.14/bbl vs US$13.30/bbl), in addition to a weaker Canadian dollar relative to the US dollar ($0.743 vs $0.776).

Operating costs in Q2 2017 were similar to the first quarter of 2017 at $14.97 per barrel but were higher than the comparable period in 2016. The increase from the prior year reflects the re-start of the ASP flood at Mooney as well as the turnaround costs related to the facility maintenance on the Onion Lake thermal facility during the quarter.

Stronger crude oil prices and higher production volumes in Q2 2017 had a positive impact on our adjusted funds flow during the quarter. In Q2 2017 our adjusted funds flow was $14.2 million, significantly higher than the $11.5 million generated for the same period in 2016.

First half 2017 capital expenditures were $67 million with the majority of spending on the Onion Lake thermal expansion project.

On June 30, 2017 we issued $75 million aggregate principal amount of senior secured second lien notes (”Notes”) to Prudential Capital Group. The Notes were issued at par, bear interest at 8.00% per year and mature on June 30, 2020. Proceeds from the issuance of the Notes were initially used to repay amounts outstanding under our existing credit facilities and will also be used to fund the construction of the expansion of our Onion Lake thermal project and for general corporate purposes.

In conjunction with the issuance of the Notes, the Company also amended its existing credit facilities with its banking syndicate. The amendments include an increase in the borrowing base amount from $117.5 million to $120 million. The next borrowing base review is scheduled to occur by November 30, 2017. At June 30, 2017, we had not drawn any amounts under these facilities.

The 2017 second quarter report to shareholders, including the financial statements, management’s discussion and analysis and notes to the financial statements are available on the Company’s website (www.blackpearlresources.ca) or SEDAR (www.sedar.com).

Guidance

We have not changed our plans for the remainder of 2017, with the focus being the expansion of the Onion Lake thermal project with a target completion date of mid-2018. We are planning to spend between $195 and $200 million on capital projects, up from our previous guidance of $185 and $190 million. The increase in capital spending is the result of adjusting the timing of expenditures on the Onion Lake thermal expansion.

The capital program is expected to be funded from a combination of our anticipated adjusted funds flow, proceeds from the recent issuance of the $75 million senior secured second lien notes and our undrawn senior credit facilities. Adjusted funds flow is expected to be between $52 and $57 million, down slightly from our previous guidance of $55 to $60 million. The decrease in adjusted funds flow is primarily attributable to lower forecast oil prices than what we used in previous guidance updates. For the remainder of the year we have used a WTI oil price of US$48.75, a heavy oil differential of US$11.00 and a US$ to Cdn$ exchange rate of $0.80. We have also entered into a number of hedging transactions that fix the WCS oil price on 4,500 bbl/d for the last six months of the year at a price of approximately $52.40 per barrel. Year-end 2017 debt levels are anticipated to be between $140 and $145 million, up from our previous guidance of $130 and $135 million. The increase in year-end debt levels reflects an increase in capital spending and slightly lower forecasted adjusted funds flow for the remainder of the year.

We anticipate oil and gas production to average between 10,000 and 11,000 boe/d in 2017, unchanged from our previous guidance. Production from the Onion Lake thermal facility was temporarily impacted by a facility turnaround which began in late June. Phase one production is expected to return to full rates in August or early September; however, as a result of the turnaround, corporate production for Q3 2017 is expected to be between 9,000 and 9,500 boe/d.

Non-GAAP Measures

Throughout this release, the Company uses terms “adjusted funds flow”, “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.

Adjusted funds flow is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring a company’s ability to finance its capital programs, decommissioning costs, debt repayments and other financial obligations. Adjusted funds flow is defined as cash flow from operating activities before decommissioning costs incurred and changes in non-cash working capital related to operations. Adjusted funds flow is not intended to represent cash flow from operating activities or other measures of financial performance in accordance with GAAP. The Company previously referred to “adjusted funds flow” as “funds flow from operations”.

The following table reconciles non-GAAP measure adjusted funds flow to cash flow from operating activities, the nearest GAAP measure:

	Three months ended June 30,		Six months ended June 30,	
($000s)	2017	2016	2017	2016
Cash flow from operating activities	15,080	7,184	29,866	10,971
Changes in non-cash working capital related to operations	(984)	3,944	(2,888)	3,288
Decommissioning costs	83	369	125	516
Adjusted funds flow	14,179	11,497	27,103	14,775

Operating netback is calculated as oil and gas revenues less royalties, production costs and transportation costs on a dollar basis and divided by total production for the period on a barrel of oil equivalent basis. Operating netback is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring operating performance against prior periods on a comparable basis. Our operating netback calculation is consistent with the definition found in the Canadian Oil and Gas Evaluation (COGE) Handbook.

Net debt is calculated as long-term debt plus working capital for the period ended. Working capital consists of cash and cash equivalents, trade and other receivables, inventory, prepaid expenses and deposits, fair value of risk management assets less accounts payable and accrued liabilities, current portion of decommissioning liabilities, and fair value of risk management liabilities. Management utilizes net debt as a key measure to assess the liquidity of the Company.

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, this release contains forward-looking statements pertaining to the estimated capital costs of $185 million to construct the phase 2 expansion of the Onion Lake thermal project and the estimated mid-2018 completion date and estimated timing to reach peak production rates, timing to return to full production rates from phase one of the Onion Lake thermal project after facility maintenance is complete and all the information under *Guidance*.

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

By their nature, forward-looking statements involve numerous known and unknown risks and uncertainties that contribute to the possibility that actual results will differ from those anticipated in the forward-looking statements. Further information regarding these risk factors may be found under “Risk Factors” in the Annual Information Form, which can be accessed on SEDAR at www.sedar.com.

Undue reliance should not be placed on these forward-looking statements. There can be no assurance that the plans, intentions or expectations upon which forward-looking statements are based will be realized. Actual results will differ, and the differences may be material and adverse to the Company and its shareholders. Furthermore, the forward-looking statements contained in this release are made as of the date hereof, and the Company does not undertake any obligation, except as required by applicable securities legislation, to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

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This is information that BlackPearl Resources Inc. is obliged to make public pursuant to the EU Market Abuse Regulation and the Swedish Securities Markets Act. The information was submitted for publication at 3:00 p.m. Mountain Time on August 9, 2017.

BLACKPEARL RESOURCES INC.

Management's Discussion and Analysis

The following is Management's Discussion and Analysis (MD&A) of the operating and financial results of BlackPearl Resources Inc. ("BlackPearl" or "the Company") for the three and six months ended June 30, 2017. These results are being compared with the three and six months ended June 30, 2016. The MD&A should be read in conjunction with the Company's unaudited consolidated financial statements for the three and six months ended June 30, 2017, together with the accompanying notes and with the Company's annual MD&A for the year ended December 31, 2016.

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

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

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

Oil and Natural Gas Liquids		Natural Gas	
bbl	barrel	Mcf	thousand cubic feet
bbls/d	barrels per day	MMcf	million cubic feet
Mbbls/d	thousand barrels per day	Mcf/d	thousand cubic feet per day
MMbbls	million barrels	Bcf	billion cubic feet
NGLs	natural gas liquids	MMBtu	million british thermal units
boe	barrel of oil equivalent	GJ	gigajoule
boe/d	barrel of oil equivalent per day		
WTI	West Texas Intermediate (a light oil reference price)		
WCS	Western Canadian Select (a heavy oil reference price)		
SAGD	Steam Assisted Gravity Drainage (a thermal recovery process)		
ASP	Alkali, Surfactant, Polymer		
EOR	Enhanced Oil Recovery		
EBITDA (adjusted)	Comprehensive income (loss) before income tax, financing charges, non-cash items, unrealized gain or losses on risk management contracts and income/loss attributed to assets acquired or disposed as defined in the Company's lending agreement.		

Non-GAAP Financial Measures

Throughout this MD&A, the Company uses terms "adjusted funds flow", "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.

Adjusted funds flow is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring a company's ability to finance its capital programs, decommissioning costs, debt repayments and other financial obligations. Adjusted funds flow is defined as cash flow from operating activities before decommissioning costs incurred and changes in non-cash working capital related to operations. Adjusted funds flow is not intended to represent cash flow from operating activities or other measures of financial performance in accordance with GAAP. The Company previously referred to "adjusted funds flow" as "funds flow from operations".

The following table reconciles non-GAAP measure adjusted funds flow to cash flow from operating activities, the nearest GAAP measure.

				Six months ended	
	2017		2016		June 30
($000s)	**Q2**	Q1	Q2	**2017**	2016
Cash flow from operating activities [1]	**15,080**	14,786	7,184	**29,866**	10,971
Decommissioning costs incurred	**83**	42	369	**125**	516
Changes in non-cash working capital related to operations	**(984)**	(1,904)	3,944	**(2,888)**	3,288
Adjusted funds flow [2]	**14,179**	12,924	11,497	**27,103**	14,775

(1) Cash flow from operating activities is a GAAP measure and has a standardized meaning prescribed by Canadian GAAP.
(2) Adjusted funds flow is a non-GAAP measure. Adjusted funds flow 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 calculated as oil and gas revenues less royalties, production costs and transportation costs on a dollar basis and divided by total production for the period on a boe basis. Operating netback is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring operating performance against prior periods on a comparable basis. Our operating netback calculation is consistent with the definition found in the Canadian Oil and Gas Evaluation (COGE) Handbook.

Net debt is calculated as long-term debt less working capital for the period ended. Working capital consists of cash and cash equivalents, trade and other receivables, inventory, prepaid expenses and deposits, current portion of fair value of risk management assets less accounts payable and accrued liabilities, current portion of decommissioning liabilities and current portion of fair value of risk management liabilities. Management utilizes net debt as a key measure to assess the liquidity of the Company. The following table reconciles non-GAAP measure net debt to long-term debt, the nearest GAAP measure.

($000s)	**June 30, 2017**	December 31, 2016
Long-term debt [1]	**72,320**	-
Add (deduct) working capital:		
Cash and cash equivalents	**(43,441)**	(5,368)
Trade and other receivables	**(14,284)**	(13,391)
Inventory	**(65)**	(46)
Prepaid expenses and deposits	**(1,822)**	(705)
Fair value of risk management assets	**(6,636)**	-
Accounts payable and accrued liabilities	**21,835**	17,950
Current portion of decommissioning liabilities	**733**	644
Fair value of risk management liabilities	**-**	5,507
Net debt [2]	**28,640**	4,591

(1) Long-term debt is a GAAP measure and has a standardized meaning prescribed by Canadian GAAP.
(2) 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.

Management believes the presentation of the non-GAAP measures above provide useful information to investors and shareholders as the measures provide increased transparency and the ability to better analyze the performance against prior periods on a comparable basis.

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

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

The effective date of this MD&A is August 9, 2017.

OVERVIEW

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

BlackPearl's current core properties are:

- Onion Lake, Saskatchewan – a conventional heavy oil property as well as a multi-phase thermal project. The first phase of the thermal project was put on production in 2015 and the second phase is currently under construction and is expected to be completed in mid-2018;
- Mooney, Alberta – a conventional heavy oil property currently developed using both horizontal drilling and ASP flooding; and
- Blackrod, Alberta – a bitumen property, in the exploration and evaluation phase, located in the Athabasca oil sands region in which the Company is currently operating a pilot project using the SAGD recovery process.

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

2017 SIGNIFICANT EVENTS

- On June 30, 2017, the Company issued $75 million aggregate principal amount of senior secured second lien notes to Prudential Capital Group. The senior secured notes were issued at par and bear interest at 8.00% per year, payable quarterly in arrears, and mature on June 30, 2020. In conjunction with the issuance of the senior secured notes, the Company also amended its existing senior credit facilities with its lending syndicate. The amendments include an increase in the borrowing base amount from $117.5 million to $120 million. Proceeds from the issue of the senior secured notes and our existing senior credit facilities will be used to fund the construction of the second phase of our Onion Lake thermal project and for general corporate purposes.

- During the first quarter of 2017, the Company commenced construction of the second 6,000 bbls/d phase of the Onion Lake thermal project. Total estimated capital costs for the project are approximately $185 million and the project is expected to be completed in mid-2018 with peak production rates by mid-year 2019. As of June 30, 2017, approximately 80% of the module fabrications for the second phase plant facilities were complete and we commenced drilling the steam injector and producer wells.

- In the first half of 2017, WTI oil prices averaged US$50.10 per bbl compared to US$39.52 per bbl in the first half of 2016.

- During the second quarter of 2017, oil and gas production averaged 10,386 boe/d; a 7% increase compared to the same period in 2016. The increase was mainly attributable to the first phase of the Onion Lake thermal project and the re-start of the ASP flood at Mooney. During the first half of 2017, oil and gas production averaged 10,568 boe/d.

- Capital expenditures during the first half were $66.8 million, with approximately $59.5 million spent at the Onion Lake thermal project related to construction of the second phase of the project, $3.7 million spent at John Lake related to the drilling of two horizontal heavy oil wells, $1.7 million at Mooney related to bringing shut-in production back online and $1.9 million spent in other areas. The Company also completed dispositions of non-producing properties for proceeds totaling $3.4 million during the first half of the year.

- Oil and gas sales during the first half of 2017 increased 81% to $75 million, cash flow from operating activities were $30 million and adjusted funds flow (a non-GAAP measure) were $27 million. For the six months ended June 30, 2017, the Company recognized net income of $16 million.

- During the first half of 2017, 302,007 common shares were issued pursuant to the exercise of stock options which generated net proceeds of $0.3 million for the Company. The Company did not undertake any equity issuances during the first half of 2017.

SELECTED QUARTERLY INFORMATION

	2017		2016				2015	
($000s, except where noted)	**Jun 30**	**Mar 31**	**Dec 31**	**Sep 30**	Jun 30	Mar 31	Dec 31	Sep 30
Production (boe/d) (1)	**10,386**	**10,753**	**10,479**	**10,951**	9,698	9,166	9,521	7,478
Oil and gas sales	**37,702**	**37,204**	**35,360**	**32,367**	28,318	13,021	22,630	20,814
Oil sales ($/bbl)	**41.93**	**40.75**	**38.83**	**34.15**	34.44	16.77	27.65	35.02
Gas sales ($/mcf)	**2.58**	**2.50**	**2.90**	**2.10**	1.29	1.77	2.91	2.88
Oil and gas sales ($/boe)	**41.65**	**40.48**	**38.61**	**33.87**	34.03	16.67	27.45	34.05
Production & transportation costs	**15,926**	**16,233**	**13,550**	**13,603**	12,246	11,736	15,666	12,843
Production costs ($/boe)	**14.97**	**15.00**	**12.11**	**12.13**	13.23	12.35	17.77	20.04
Transportation costs ($/boe)	**2.62**	**2.67**	**2.69**	**2.11**	1.48	2.68	1.23	0.97
Gain (loss) on risk management contracts								
Realized	**(34)**	**342**	**578**	**2,137**	1,958	6,120	10,334	7,940
Unrealized	**5,724**	**5,569**	**(5,676)**	**(538)**	(8,597)	(472)	1,778	11,826
Net income (loss)	**8,318**	**7,814**	**(2,217)**	**556**	(8,945)	(9,322)	(31,172)	5,402
Per share, basic and diluted ($)	**0.02**	**0.02**	**(0.01)**	**0.00**	(0.03)	(0.03)	(0.09)	0.01
Capital expenditures	**53,434**	**13,356**	**6,150**	**1,753**	945	2,077	1,665	7,870
Adjusted funds flow (2)	**14,179**	**12,924**	**15,798**	**14,202**	11,497	3,278	10,898	10,156
Cash flow from operating activities	**15,080**	**14,786**	**15,079**	**16,441**	7,184	3,787	12,179	14,216
Long-term debt	**72,320**	**-**	**-**	**67,000**	80,000	86,000	88,000	97,000
Total assets (end of period)	**822,325**	**737,735**	**732,404**	**773,206**	782,591	795,336	808,344	861,107
Shares outstanding (000s)	**336,251**	**336,196**	**335,949**	**335,647**	335,647	335,638	335,638	335,638
Weighted average shares outstanding								
Basic	**336,226**	**336,157**	**335,733**	**335,646**	335,641	335,638	335,638	335,638
Diluted	**339,019**	**340,700**	**340,686**	**337,959**	335,641	335,638	335,638	335,638

(1) Includes test production from the Blackrod SAGD pilot. All sales and expenses from the Blackrod SAGD pilot are being recorded as an adjustment to the capitalized costs of the project until the technical feasibility and commercial viability of the project is established.

(2) Adjusted funds flow is a non-GAAP measure. Adjusted funds flow 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. See non-GAAP financial measures.

Fluctuations in quarterly oil and gas sales and net income (loss) over the last eight quarters are primarily attributable to the volatility in crude oil prices and changes in sales volumes from new drilling activity, partially offset by natural declines in production. Production volumes in Q4 2015 increased as a result of the start-up of commercial production from the first phase of the Onion Lake thermal project. The net loss incurred in Q4 2015 is mainly attributable to an impairment charge of $33 million taken on our Mooney cash generating unit ("CGU").

BUSINESS ENVIRONMENT

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

Commodity Prices

	YTD		2017		2016			
	2017	2016	Q2	Q1	Q4	Q3	Q2	Q1
Average Crude Oil Prices								
West Texas Intermediate (WTI) (US$/bbl)	50.10	39.52	48.29	51.91	49.29	44.94	45.59	33.45
Western Canadian Select (WCS) (Cdn$/bbl)	49.66	33.96	49.96	49.36	46.62	41.02	41.61	26.31
Differential – WCS/WTI (US$/bbl)	12.86	14.02	11.14	14.61	14.34	13.51	13.30	14.32
Differential - WCS/WTI (%)	25.7%	35.5%	23.1%	28.1%	29.1%	30.1%	29.2%	42.8%
Average Natural Gas Prices								
AECO gas (Cdn$/GJ)	2.60	1.53	2.64	2.55	2.93	2.20	1.33	1.74
Average Foreign Exchange (US$ per Cdn$1)	0.750	0.751	0.743	0.756	0.750	0.766	0.776	0.727

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

Crude oil prices decreased during the second quarter of 2017 compared to the first quarter; however, prices remain higher than the comparable periods in 2016. WTI oil prices averaged US$48.29 per bbl in the second quarter of 2017 compared to US$51.91 per bbl in the first quarter of 2017 and US$45.59 per bbl in the second quarter of 2016. The decline in second quarter WTI oil prices has been attributed to higher production, particularly in the US and continuing high inventory levels. For the first six months of 2017 WTI oil prices averaged US$50.10 per bbl which is up from US$39.52 per bbl in the same period in 2016.

The heavy oil differential (WTI oil prices compared to WCS oil prices) improved in the second quarter of 2017. Heavy oil differentials averaged US$11.14 per bbl in the second quarter of 2017 compared to US$14.61 per bbl in the first quarter of 2017. Heavy oil differentials narrowed in the second quarter of 2017 as a result of temporarily shut-in heavy oil production in Canada and decreased US imports of heavier grades of oil from OPEC countries due to their decision to reduce oil output, resulting in greater demand for Canadian heavy oil.

Natural gas prices increased in the first half of 2017 averaging $2.60/GJ compared to $1.53/GJ in the same period in 2016. BlackPearl produces very little natural gas and therefore prices do not have a significant impact on our current revenues. However, we do consume relatively large amounts of gas in our Blackrod pilot operations and at our Onion Lake thermal project, therefore, fluctuations in natural gas prices can have a significant effect on our costs in these areas.

Changes in the value of the Canadian dollar relative to the US dollar impacts our revenues and cash flows as our oil sales price is determined by reference to US benchmark prices. The Canadian dollar was fairly consistent against the US dollar in the first half of 2017 compared to the same period in 2016. The exchange rate between the Canadian dollar and the US dollar averaged Cdn$1 = US$0.75 during the first half of 2017 and 2016. More recently, the Canadian dollar has strengthened relative to the US dollar which will negatively impact our future revenues and cash flows.

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 adjusted funds flow for 2017 (1) (2):

Key variable	Change ($)	$000s
West Texas Intermediate (WTI) (US$/bbl)	1.00	851
Realized crude oil price (Cdn$/bbl)	1.00	1,489
US $ to Canadian $ exchange rate	0.01	423

(1) This analysis assumes current royalty rates and operating costs, no changes in working capital and includes the impact of realized risk management contracts.

(2) Adjusted funds flow is a non-GAAP measure. Adjusted funds flow 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. See non-GAAP financial measures.

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

	2017		2016	Six months ended June 30	
	Q2	Q1	Q2	**2017**	2016
Daily production/sales volumes					
Oil (bbls/d)	**9,843**	10,105	9,004	**9,973**	8,723
Bitumen – Blackrod (bbls/d) (2)	**437**	542	553	**489**	568
Combined (bbls/d)	**10,280**	10,647	9,557	**10,462**	9,291
Natural gas (Mcf/d)	**633**	638	847	**635**	846
Total production (boe/d) (1)	**10,386**	10,753	9,698	**10,568**	9,432
Product pricing (excluding risk management activities) (2)					
Oil ($/bbl)	**41.93**	40.75	34.44	**41.33**	25.89
Natural gas ($/Mcf)	**2.58**	2.50	1.29	**2.54**	1.53
Combined ($/boe) (1)	**41.65**	40.48	34.03	**41.06**	25.63
Sales ($000s) (2)					
Oil and gas sales – gross	**37,702**	37,204	28,318	**74,906**	41,339
Royalties	**(5,317)**	(5,422)	(3,813)	**(10,739)**	(5,158)
Oil and gas revenues – net (3)	**32,385**	31,782	24,505	**64,167**	36,181

(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.

(3) Excludes deferred consideration amount recognized during the period.

Oil and natural gas sales increased 33% in the second quarter of 2017 to $37.7 million from $28.3 million in the same period in 2016. The increase in oil and gas sales is attributable to a 22% increase in our average realized sale price and a 7% increase in production volumes (on a boe basis) in the second quarter of 2017 compared to the same period in 2016.

Higher WTI crude oil prices and narrower heavy oil differentials contributed to an increase in our realized crude oil sales prices in the second quarter of 2017 compared to the same period in 2016. Our average oil wellhead sales price in the second quarter of 2017, prior to the impact of risk management activities, was $41.93 per bbl compared with $34.44 per bbl in the same period in 2016.

Production growth in the first half of 2017 compared to the same period in 2016 is mainly attributable to the first phase of our Onion Lake thermal project. During the first half of 2017, production from this project averaged 5,998 bbls/d compared with 4,737 bbls/d during the same period in 2016. Production from the Onion Lake thermal facility was temporarily impacted in Q2 2017 by a planned facility turnaround and inspection which began in late June. The three week turnaround was planned to coincide with drilling some of the phase two wells to reduce the amount of facility downtime. Phase one production is expected to return to full rates in August or early September.

With the improvement in crude oil prices, during the first half of 2017 we selectively brought back on production certain shut-in wells at Onion Lake and re-initiated a portion of the ASP flood at Mooney. Production from the re-initiated ASP flood at Mooney contributed to a 54% increase in oil production in Q2 2017 from the Mooney field compared to Q2 2016. We still have approximately 500 bbls of oil per day currently shut-in at Onion Lake. The Company continues to evaluate the shut-in production at Onion Lake to determine if any would become economic at current oil prices based on our internal payout metrics. We expect oil prices would have to improve to US$55 to US$60 per bbl before we would consider putting some of these shut-in wells back on production.

On a boe basis, 99% of the Company's oil and natural gas production in the second quarter of 2017 was heavy oil or bitumen. The Onion Lake area accounted for 76% of total production in the second quarter of 2017.

	2017		2016	Six months ended June 30	
Production by area (boe/d)	**Q2**	Q1	Q2	**2017**	2016
Onion Lake - thermal	**5,816**	6,182	5,221	**5,998**	4,737
Onion Lake - conventional	**2,087**	2,147	2,138	**2,117**	2,185
Mooney	**1,103**	942	714	**1,023**	878
John Lake	**801**	808	870	**804**	865
Blackrod	**437**	542	553	**489**	568
Other	**142**	132	202	**137**	199
Total production	**10,386**	10,753	9,698	**10,568**	9,432

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 SAGD pilot well was shut-in in August 2015. All sales and expenses from the pilot are being recorded as an adjustment to the capitalized costs of the project until commercial production commences. During the first half of 2017, the pilot well produced an average of 489 bbls/d of bitumen and the net revenues capitalized in the first half of 2017 were $0.2 million ($0.6 million loss in the first half of 2016).

Risk Management Activities

The Company periodically enters into risk management contracts in order to ensure a certain level of cash flow to fund planned capital projects and to maintain as much financial flexibility as possible. BlackPearl's strategy is to mainly focus on swaps, collars, calls and fixed price contracts to limit exposure to fluctuations in oil prices and revenues. The Company's risk management activities are conducted pursuant to the Company's Risk Management Policy approved by the Board of Directors and are not used for trading or speculative purposes. The policy permits the Company 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 $5.7 million on its risk management contracts during the second quarter of 2017, consisting of a $34,000 realized loss on the contracts and an unrealized gain of $5.7 million.

	2017		2016	Six months ended June 30	
($000s, except per boe)	**Q2**	Q1	Q2	**2017**	2016
Realized gain (loss) on risk management contracts	**(34)**	342	1,958	**308**	8,078
Per boe ($)	**(0.04)**	0.37	2.35	**0.17**	5.01
Unrealized gain (loss) on risk management contracts	**5,724**	5,569	(8,597)	**11,293**	(9,069)

The table below summarizes the Company's outstanding commodity contracts as at June 30, 2017:

Subject of Contract	Volume	Term	Reference	Strike Price	Type
2017					
Oil	500 bbls/d	July 1 to December 31	CDN$ WCS	CDN$ 54.30/bbl	Swap
Oil	500 bbls/d	July 1 to December 31	CDN$ WCS	CDN$ 53.10/bbl	Swap
Oil	500 bbls/d	July 1 to December 31	CDN$ WCS	CDN$ 53.00/bbl	Swap
Oil	500 bbls/d	July 1 to December 31	CDN$ WCS	CDN$ 52.75/bbl	Swap
Oil	500 bbls/d	July 1 to December 31	US$ WCS	US$ 40.15/bbl	Swap
Oil	1,000 bbls/d	July 1 to December 31	CDN$ WCS	CDN$ 50.00/bbl	Swap
Oil	1,000 bbls/d	July 1 to December 31	CDN$ WCS	CDN$ 49.50/bbl	Swap
Oil	1,000 bbls/d	July 1 to December 31	US$ WTI	US$ 60.00/bbl	Sold Call
2018					
Oil	2,000 bbls/d	January 1 to June 30	CDN$ WCS	CDN$ 49.55/bbl	Swap
Oil	1,000 bbls/d	January 1 to June 30	US$ WTI	US$ 45.00/bbl to 57.75/bbl	Collar
Oil	1,500 bbls/d	January 1 to June 30	US$ WTI	US$ 40.00/bbl to 50.00/bbl	Collar
Oil	2,200 bbls/d	July 1 to December 31	US$ WTI	US$ 40.00/bbl to 51.00/bbl	Collar
Oil	500 bbls/d	January 1 to December 31	US$ WTI	US$ 70.00/bbl	Sold Call

At June 30, 2017, these contracts had a net fair value of $5.3 million in a derivative asset position. A 10% decrease to the oil price used to calculate the fair value of these contracts would result in an approximate $9.5 million increase in fair value. A 10% increase to the oil price used to calculate the fair value of these contracts would result in an approximate $11.8 million decrease in fair value.

Royalties

	2017		2016	Six months ended June 30	
	Q2	Q1	Q2	**2017**	2016
Royalties ($000s)	**5,317**	5,422	3,813	**10,739**	5,158
Per boe ($)	**5.87**	5.90	4.58	**5.89**	3.20
As a percentage of oil and gas sales	**14%**	15%	13%	**14%**	12%

BlackPearl makes royalty payments to the owners of the mineral rights on the lands we have leased as well as overriding royalties paid to third parties as a result of contractual arrangements. Most of the payments are to provincial governments or, in the case of our Onion Lake area production, the majority of the royalties are paid to Indian Oil and Gas Canada on behalf of the Onion Lake Cree Nation. Royalty rates are generally dependent on commodity prices, oil quality and well productivity. Enhanced oil recovery projects (such as our Onion Lake thermal project) typically pay lower royalties until the project recovers its capital costs and then royalty rates increase.

Royalties were $5.3 million in the second quarter of 2017, an increase from $3.8 million in the same period in 2016. The increase in royalties is primarily attributable to higher revenues in 2017. Royalties as a percentage of oil and gas sales increased to 14% in the second quarter of 2017 from 13% in the same period in 2016. Higher oil prices realized in the second quarter of 2017 resulted in higher royalties as a percentage of oil and gas sales. The increase in royalty rates in 2017 is also attributable to the sale, in late 2016, of a 1.75% royalty on substantially all of our current and future Onion Lake production.

Transportation Costs

	2017		2016	Six months ended June 30	
	Q2	Q1	Q2	**2017**	2016
Conventional Production					
Transportation costs ($000s)	**605**	407	127	**1,012**	445
Per boe ($)	**1.61**	1.12	0.36	**1.37**	0.59
Thermal Production					
Transportation costs ($000s)	**1,769**	2,043	1,106	**3,812**	2,881
Per boe ($)	**3.34**	3.67	2.33	**3.51**	3.34
Total Production					
Transportation costs ($000s)	**2,374**	2,450	1,233	**4,824**	3,326
Per boe ($)	**2.62**	2.67	1.48	**2.64**	2.06

Transportation costs are incurred to move marketable crude oil and natural gas to their selling points. Costs to ship oil emulsion to a treating facility before it is sold are included in production expenses rather than transportation costs. Transportation costs increased in the second quarter of 2017 to $2.4 million from $1.2 million in the same period of 2016. The increase in transportation costs is primarily attributable to increased production from the first phase of the Onion Lake thermal project which ships mostly clean marketable crude oil. Transportation costs in Q2 2017 were similar to Q1 2017 costs.

Production Costs

	2017		2016	Six months ended June 30	
	Q2	Q1	Q2	**2017**	2016
Conventional Production					
Production costs ($000s)	**7,941**	8,858	6,400	**16,799**	11,950
Per boe ($)	**21.11**	24.43	17.92	**22.74**	15.91
Thermal Production					
Production costs ($000s)	**5,611**	4,925	4,613	**10,536**	8,706
Per boe ($)	**10.60**	8.85	9.71	**9.71**	10.10
Energy costs	**4.16**	4.27	2.47	**4.22**	3.53
Non-energy costs	**6.44**	4.58	7.23	**5.49**	6.57
Total Production					
Production costs ($000s)	**13,552**	13,783	11,013	**27,335**	20,656
Per boe ($)	**14.97**	15.00	13.23	**14.98**	12.80

The most significant components of our production costs are labor, utilities, maintenance and workover costs, chemicals (including polymer), property taxes and the cost of natural gas (thermal operations).

Total production costs increased 23% in the second quarter of 2017 to $13.6 million from $11.0 million in the same period in 2016. On a per boe basis, total production costs increased 13% in the second quarter of 2017 to $14.97 per boe from $13.23 per boe in the same period in 2016.

Conventional production costs increased in the second quarter of 2017 compared to the same period in 2016. The re-initialization of a portion of the ASP flood at Mooney resulted in an increase in chemical and injection costs during the second quarter of 2017. Conventional production costs decreased in the second quarter of 2017 compared to the first quarter of 2017. During the first quarter of 2017, we incurred increased workover costs on the wells we restarted at Mooney and Onion Lake, whereas during the second quarter of 2017, workover activities returned to more normal levels.

The increase in thermal production costs in the second quarter of 2017 compared to the same period in 2016 is primarily attributable to higher natural gas consumption costs as a result of higher natural gas prices in 2017. In addition, thermal production costs increased in the second quarter of 2017 compared to the first quarter of 2017 primarily due to costs related to a planned facility turnaround and inspection at Onion Lake that were incurred at the end of June.

Operating Netback (1) (2 (3)

Three months ended

	Q2 2017		Q1 2017		Q2 2016	
	$000s	**$/boe**	$000s	$/boe	$000s	$/boe
Oil and gas sales	**37,702**	**41.65**	37,204	40.48	28,318	34.03
Royalties	**5,317**	**5.87**	5,422	5.90	3,813	4.58
Transportation costs	**2,374**	**2.62**	2,450	2.67	1,233	1.48
Production costs	**13,552**	**14.97**	13,783	15.00	11,013	13.23
Operating netback before realized risk management contracts	**16,459**	**18.19**	15,549	16.91	12,259	14.74
Realized gain on risk management contracts	**(34)**	**(0.04)**	342	0.37	1,958	2.35
Operating netback after realized risk management contracts	**16,425**	**18.15**	15,891	17.28	14,217	17.09

Six months ended

	June 2017		June 2016	
	$000s	**$/boe**	$000s	$/boe
Oil and gas sales	**74,906**	**41.06**	41,339	25.63
Royalties	**10,739**	**5.89**	5,158	3.20
Transportation costs	**4,824**	**2.64**	3,326	2.06
Production costs	**27,335**	**14.98**	20,656	12.80
Operating netback before realized risk management contracts	**32,008**	**17.55**	12,199	7.57
Realized gain on risk management contracts	**308**	**0.17**	8,078	5.01
Operating netback after realized risk management contracts	**32,316**	**17.72**	20,277	12.58

(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. See non-GAAP financial measures.

(2) Production used when calculating operating netback is determined by the number of days in the period multiplied by average daily production less capitalized production at Blackrod as disclosed in the Oil and Gas, Oil and Gas Pricing and Oil and Gas Sales section of this MD&A. (Q2 2017 – 9,948 boe/d; Q1 2017 – 10,211 boe/d; Q2 2016 – 9,145 boe/d; Six months ended June 2017 – 10,079 boe/d; Six months ended June 2016 – 8,864 boe/d).

(3) Excludes deferred consideration amount recognized during the period.

Operating netback is the cash margin we receive from each barrel of oil equivalent sold. Operating netback, before realized gains on risk management activities, increased in the second quarter of 2017 to $18.19 per boe from $14.74 per boe in the same period in 2016. The increase is primarily attributable to the increase in realized crude oil prices, partially offset by higher royalties and production costs.

General and Administrative Expenses (G&A)

	2017		2016	Six months ended June 30	
($000s, except per boe)	**Q2**	Q1	Q2	**2017**	2016
Gross G&A expense	**2,033**	3,023	2,009	**5,056**	4,138
Operator recoveries	**(219)**	(236)	(209)	**(455)**	(439)
Net G&A expense	**1,814**	2,787	1,800	**4,601**	3,699
Per boe ($)	**2.00**	3.03	2.16	**2.52**	2.29

General and administrative expenses consist primarily of salaries and wages of employees, office rent, computer services, legal, accounting and consulting fees. Q2 2017 general and administrative costs were comparable to Q2 2016. The increase in gross G&A expenses in the first half of 2017 compared to the same period in 2016 reflects higher staff compensation costs in 2017. As oil prices stabilized during 2017, previous salary reductions were rescinded and performance incentive payments to staff were made during the first quarter of the year.

Stock-Based Compensation

	2017		2016	Six months ended	June 30
($000s, except per boe)	**Q2**	Q1	Q2	**2017**	2016
Gross stock-based compensation	**566**	570	711	**1,136**	1,889
Recoveries from forfeitures	**(21)**	(5)	-	**(26)**	(48)
Net stock-based compensation	**545**	565	711	**1,110**	1,841
Per boe ($)	**0.60**	0.62	0.85	**0.61**	1.14

Stock-based compensation costs are non-cash charges which reflect the estimated value of stock options and restricted share units (RSUs) 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 Company accounts for RSUs as equity based awards and the estimated fair value of the awards is determined at the time of grant.

The decrease in gross stock-based compensation in the first half of 2017 compared to the same period in 2016 is primarily attributable to a decrease in the weighted average number of options outstanding during 2017. In the first half of 2017, 302,007 options were exercised, 1,867,000 options were granted, 179,999 options were forfeited and 1,279,500 options expired. Based on stock options and RSUs outstanding as at June 30, 2017, the Company has an unamortized stock based compensation expense of approximately $3.8 million, of which $1.2 million is expected to be expensed in the remainder of 2017, $1.4 million in 2018, $1.0 million in 2019 and $0.2 million in 2020.

Finance Costs

	2017		2016	Six months ended	June 30
($000s)	**Q2**	Q1	Q2	**2017**	2016
Gross interest & financing charges	**632**	162	918	**794**	1,753
Capitalized interest and financing charges	**(272)**	-	-	**(272)**	-
Net interest and financing charges	**360**	162	918	**522**	1,753
Accretion of decommissioning liabilities	**390**	387	361	**777**	727
Total finance costs	**750**	549	1,279	**1,299**	2,480

Finance costs are made up of interest on our outstanding debt, standby fees on credit facilities available to us that are not currently being utilized, amortization of debt issuance costs, annual credit facilities renewal fees and accretion of decommissioning liabilities.

The decrease in gross interest and financing charges in the second quarter of 2017 compared to the same period in 2016 is primarily attributed to lower weighted average debt outstanding in the second quarter of 2017. The increase in interest and financing charges in the second quarter of 2017 compared to the first quarter of 2017 is the result of higher loan advances on our credit facilities during the second quarter.

During the first six months of 2017 we incurred slightly lower interest rates charged on amounts borrowed under our credit facilities. The average interest rate on advances under the Company's credit facilities was 3.4% in the first half of 2017 compared to 3.6% in the first half of 2016. This does not include standby fees charged on unutilized amounts of the credit facilities. Our credit facilities are floating rate debt, so the interest rate charged is based on general market conditions. Additionally, the interest rate charged on our credit facilities is determined, in part, by our debt to EBITDA ratio (as defined in our credit agreement). The interest rate charged on our credit facilities debt is expected to be 3.5 – 4.0% for the remainder of 2017 (assuming no other changes in market conditions) as a result of carrying a higher debt to EBITDA ratio. We have not entered into any financial instruments to fix the interest rate on our debt.

In addition, gross interest and financing charges will increase during the remainder of the year as a result of the Company's recent issuance of $75 million of senior secured second lien notes, which bear interest at 8.00% per year.

During the second quarter of 2017 we capitalized $0.3 million in interest charges related to debt incurred for the construction of the second phase of the Onion Lake thermal project. During 2016 we did not capitalize any interest charges.

Depletion and Depreciation

	2017		2016	Six months ended	June 30
	Q2	Q1	Q2	**2017**	2016
Depletion and depreciation ($000s)	**10,754**	10,953	10,773	**21,707**	21,405
Per boe ($)	**11.88**	11.92	12.95	**11.90**	13.27

The Company's properties are depleted on a unit of production basis based on estimated proven plus probable reserves. On a boe basis, depletion and depreciation expense decreased to $11.88 per boe in the second quarter of 2017 compared to $12.95 per boe in the same period in 2016. The decrease in depletion and depreciation on a boe basis is primarily attributable to a higher proportion of our production generated from the Onion Lake thermal project in the second quarter of 2017. The depletion rate on this project is below $10 per boe which is lower than the depletion rates for our other producing areas.

There were no impairment losses or reversals recorded for the six months ended June 30, 2017. However, declines in forecast commodity prices could reduce reserve values and result in the recognition of future asset impairments. Future impairments can also result from changes to reserve estimates, future development costs and capitalized costs.

Income Taxes

BlackPearl did not pay cash income taxes in the first six months of 2017 and does not expect to pay income taxes during the remainder of 2017 as we have sufficient tax pools to shelter expected income. In addition, due to a change in the amount of previously unrecognized deferred tax assets, no net deferred tax provision was recorded for the first six months of 2017.

RESULTS FROM OPERATIONS

	2017		2016	Six months ended	June 30
	Q2	Q1	Q2	**2017**	2016
Net income (loss) ($000s)	**8,318**	7,814	(8,945)	**16,132**	(18,267)
Per share, basic ($)	**0.02**	0.02	(0.03)	**0.05**	(0.05)
Per share, diluted ($)	**0.02**	0.02	(0.03)	**0.05**	(0.05)

For the quarter ended June 30, 2017, the Company recognized net income of $8.3 million compared to a net loss of $8.9 million in the same period in 2016. The increase in net income in 2017 is primarily a result of increased revenue from higher realized wellhead prices and an increase in unrealized gains on risk management contracts partially offset by higher royalties and production costs.

	2017		2016	Six months ended June 30	
($000s)	**Q2**	Q1	Q2	**2017**	2016
Cash flow from operating activities	**15,080**	14,786	7,184	**29,866**	10,971
Adjusted funds flow (1)	**14,179**	12,924	11,497	**27,103**	14,775

(1) Adjusted funds flow is a non-GAAP measure. Adjusted funds flow 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. See non-GAAP financial measures.

Adjusted funds flow increased 23% to $14.2 million during the second quarter of 2017 compared to $11.5 million in the same period in 2016. The increase in adjusted funds flow in 2017 is primarily a result of higher realized wellhead prices partially offset by higher royalties and production costs.

Cash flow from operating activities differs from adjusted funds flow principally due to the inclusion of decommissioning costs incurred and changes in non-cash working capital. For the three months ended June 30, 2017, cash flow from operating activities was higher than adjusted funds flow due to changes in non-cash working capital of $1.0 million.

LIQUIDITY AND CAPITAL RESOURCES

($000s)	**June 30, 2017**	December 31, 2016
Working capital deficiency (surplus)	**(43,680)**	4,591
Long-term debt	**72,320**	-
Net debt (1)	**28,640**	4,591

(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. See non-GAAP financial measures.

On June 30, 2017, the Company issued $75 million aggregate principal amount of senior secured second lien notes to Prudential Capital Group. The senior secured notes were issued at par and bear interest at 8.00% per year, payable quarterly in arrears, and mature on June 30, 2020. The proceeds from the senior secured notes will be used, in part, to fund the expansion of our Onion Lake thermal project in Saskatchewan. The senior secured notes are secured by substantially all of the assets of the Company on a second priority basis, subordinate only to the senior credit facilities. The Company may redeem the senior secured notes at any time at a price equal to par, plus a "make-whole" premium and any accrued interest. At June 30, 2017, the carrying value of the senior secured notes, net of deferred financing costs, was $72.3 million.

In conjunction with the issuance of the senior secured second lien notes, the Company also amended its existing credit facilities with its lending syndicate. The amendments include an increase in the borrowing base amount from $117.5 million to $120 million. The lenders previously agreed to extend the revolving period to May 27, 2018, which may be extended in the future at the discretion of the lenders. If the revolving period is not extended, any balance owing on the facilities would be required to be repaid by May 27, 2019. The pricing grid used to calculate the interest rates charged on the loans and stand-by fees remains unchanged. The next borrowing base review is scheduled to occur by November 30, 2017.

At June 30, 2017, the Company had working capital of $43.7 million, no amounts drawn on its $120 million credit facilities and had issued letters of credit in the amount of $20,000; leaving $120 million available to be drawn under these credit facilities. The facilities are secured by a floating and fixed charge debenture on the assets of the Company. The amount available under these facilities ("Borrowing Base") is re-determined at least twice a year and is based on the Company's oil and gas reserves, the lending institution's forecast commodity prices, the current economic environment and other factors as determined by the syndicate of lending institutions. If the total advances made under the credit facilities are greater than the re-determined Borrowing Base, the Company has 60 days to repay the difference.

The Company is required to maintain a working capital ratio of 1:1 at the end of each fiscal quarter. Working capital is defined as current assets, as indicated on the Company's consolidated balance sheet, plus any undrawn amount on the senior 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 7.8:1 at June 30, 2017 (December 31, 2016 – 7.2:1).

($000s, except working capital ratio)	**June 30, 2017**	December 31, 2016
Current assets per consolidated financial statements	**66,248**	19,510
Add: amount available to be drawn on credit facilities	**120,000**	117,500
Less: current risk management assets	**(6,636)**	-
Current assets for working capital ratio	**179,612**	137,010
Current liabilities per consolidated financial statements	**22,933**	24,505
Less: current risk management liabilities	**-**	(5,507)
Current liabilities for working capital ratio	**22,933**	18,998
Working capital ratio	**7.8**	7.2

The terms of the senior secured notes we issued in June included certain other financial covenants the Company is required to comply with on an on-going basis. The Company is limited to a maximum total debt to EBITDA ratio of 4.5:1 at the end of each fiscal quarter. The Company is also limited to a maximum senior credit facilities debt to EBITDA ratio of 3.5:1 at the end of each fiscal quarter on or before December 31, 2018. After December 31, 2018, the Company is limited to maximum senior credit facilities debt to EBITDA ratio of 3:1. Total debt is defined as the Company's total debt outstanding excluding accounts payable and accrued liabilities, decommissioning liabilities, deferred consideration and liabilities under risk management contracts at the end of each fiscal quarter. Senior credit facilities debt is defined as total debt less the senior secured second lien notes at the end of each fiscal quarter. EBITDA is a non-GAAP measure and is defined as the Company's net income for the trailing 12 month period before financing charges, income taxes, all non-cash items including depletion and depreciation, accretion, future taxes, stock-based compensation, unrealized gains or losses on risk management contracts and write down or reversal of impairment of assets, income or losses attributable to extraordinary and non-recurring gains or losses and gains or losses from asset sales. The Company had a total debt to EBITDA ratio of 1.3:1 and a senior credit facilities debt to EBITDA ratio of 0.0:1 at June 30, 2017. In addition, the Company is required to pass an asset coverage test twice a year. The Company's net present value of proved reserves discounted at 10% must be at least 1.5 times of total debt. The first asset coverage test will occur on November 1, 2017.

At June 30, 2017, the Company was in compliance with all debt covenants.

During the first quarter of 2017, the Company commenced construction of the second 6,000 bbls/d phase of the Onion Lake thermal project with total estimated capital costs of approximately $185 million. The Company has entered into a fixed price agreement to fabricate the central processing facilities and pad facilities for this second phase. Proceeds from the recent issuance of the senior secured second lien notes, the Company's borrowing capacity on our existing senior credit facilities and expected cash flow from operating activities will be used to fund the construction of the second phase of our Onion Lake thermal project.

At June 30, 2017, there were 336,250,902 common shares issued and outstanding. In the first half of 2017 the Company issued 302,007 common shares for net proceeds of $0.3 million pursuant to the exercise of stock options.

The Company did not pay dividends on its common shares in the first half of 2017 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 facilities restricts the payment of cash dividends to shareholders.

CAPITAL EXPENDITURES

Capital spending during the second quarter of 2017 was $53.4 million, an increase from $1.0 million during the same period in 2016. The majority of the capital spending during the second quarter were related to the construction for the second phase of the Onion Lake thermal project.

	2017		2016	Six months ended June 30	
($000s)	**Q2**	Q1	Q2	**2017**	2016
Land	**3,157**	1,865	325	**5,022**	442
Seismic	**42**	-	-	**42**	(5)
Drilling and completion	**1,787**	3,781	70	**5,568**	1,534
Equipment and facilities	**48,446**	7,707	550	**56,153**	1,044
Other	**2**	3	-	**5**	7
Total	**53,434**	13,356	945	**66,790**	3,022
Property acquisitions	**-**	-	-	**-**	-
Total capital expenditures	**53,434**	13,356	945	**66,790**	3,022
Proceeds on disposition	**-**	(3,421)	-	**(3,421)**	-
Net capital expenditures	**53,434**	9,935	945	**63,369**	3,022

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The Company has a number of financial obligations in the ordinary course of business. The following table summarizes the contractual obligations and commitments of the Company outstanding as at June 30, 2017. These obligations are expected to be funded from cash flow from operating activities and the Company's credit facilities.

($000s)	2017	2018	2019	2020	2021	Thereafter
Operating leases (1)	493	912	703	560	545	-
Electrical service agreement (2)	474	585	119	119	119	1,868
Transportation service agreement (3)	68	135	135	33	-	-
Decommissioning liabilities (4)	519	428	347	8,992	1,651	62,802
Capital commitments (5)	18,340	5,000	5,000	-	-	-
Long-term debt (6)	-	-	-	75,000	-	-
Interest payments on long-term debt (6)	1,500	7,500	6,000	3,000	-	-
Total	21,394	14,560	12,304	87,704	2,315	64,670

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

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

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

(4) The Company also has ongoing obligations related to the decommissioning of well sites and facilities which have reached the end of their economic lives. The undiscounted estimated obligations associated with the retirement of the Company's oil and gas properties were $74.7 million as at June 30, 2017. Decommissioning programs are undertaken regularly in accordance with applicable legislative requirements.

(5) The Company entered into certain agreements pertaining to the construction of the second phase of the Onion Lake thermal project.

(6) The Company issued $75 million senior secured second lien notes bearing an interest rate of 8% payable quarterly in arrears and due on June 30, 2020.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments as at June 30, 2017 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 use level 2 valuation methods and 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).

See the Company's unaudited consolidated financial statements for the three and six months ended June 30, 2017 for details on the risks associated with these financial instruments including credit risk, liquidity risk, interest rate risk, foreign currency exchange risk and commodity price risk.

OFF-BALANCE-SHEET ARRANGEMENTS

The Company had no off-balance-sheet arrangements during the period ended June 30, 2017 or 2016. 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 significant related-party transactions during the period ended June 30, 2017 or 2016 except for key management compensation.

OUTSTANDING SHARE DATA, STOCK OPTIONS AND RESTRICTED SHARE UNITS

As at August 9, 2017, the Company had 336,267,235 common shares outstanding, 26,840,496 stock options outstanding and 1,710,000 restricted share units outstanding under its stock-based compensation program.

OUTSTANDING LONG-TERM DEBT DATA

As at August 9, 2017, the Company had not drawn any amounts under its existing senior credit facilities and had issued letters of credit in the amount of $20,000; leaving $119,980,000 available to be drawn under these credit facilities. The Company had $75,000,000 outstanding on its senior secured second lien notes on August 9, 2017.

PROPOSED TRANSACTIONS

As of August 9, 2017, the Company does not have any significant pending transactions.

SIGNIFICANT ACCOUNTING JUDGEMENTS AND ESTIMATES

The timely preparation of the interim consolidated financial statements in accordance with IFRS requires that management use judgement and make estimates and assumptions regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the interim consolidated financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the interim consolidated financial statements. The estimated fair value of financial assets and liabilities, by their very nature, are subject to measurement uncertainty. Accordingly, actual results may differ from estimated amounts as future confirming events occur. 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, 2016. There have been no significant changes to the Company's critical accounting estimates as of June 30, 2017. Additional disclosure has been provided on the sale of a royalty interest in note 10 of the Company's unaudited consolidated financial statements for the three and six months ended June 30, 2017.

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

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

RISK FACTORS

Please refer to the Company's annual MD&A and Annual Information Form for the year ended December 31, 2016 for a discussion of the risks and uncertainties associated with the Company's activities. Additional risk factors identified in 2017 include the following:

(a) As the result of the issuance of the senior secured second lien notes, the Company has certain additional financial covenants that are required to meet on a scheduled basis (see "Liquidity and Capital Resources"). In the event the Company breaches one of these covenants, the amounts payable on the notes as well as the senior credit facilities may become immediately due.

CONTROL CERTIFICATION

Management reported on its disclosure controls and procedures and the design of its internal controls over financial reporting ("ICFR") in the annual MD&A for the year ended December 31, 2016. There have been no changes to ICFR in the six months ended June 30, 2017 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

2017 Guidance	Initial Guidance	Q1 Update	Q2 Update
Production (boe/d)			
Annual average	10,000 – 11,000	10,000 – 11,000	10,000 – 11,000
Cash flow from operating activities (1) ($millions)	65 – 70	55 - 60	52 – 57
Adjusted funds flow (2) ($millions)	65 – 70	55 - 60	52 – 57
Capital expenditures ($millions)	200	185 - 190	195 – 200
Year-end debt ($millions)	135 - 140	130 - 135	140 – 145
Pricing Assumptions (annual average)			
Crude oil - WTI	US $54.50	US $52.75	US $49.50
Light/heavy differential	US $14.75	US $13.55	US $11.90
Foreign Exchange (Cdn$ to US$)	0.75	0.75	0.77

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

(2) Adjusted funds flow is a non-GAAP measure. Adjusted funds flow 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. See non-GAAP financial measures.

Our plan for the remainder of 2017 is relatively unchanged with the focus being the expansion of the Onion Lake thermal project with a target completion date of mid-2018. We are planning to spend between $195 and $200 million on capital projects, up from our previous guidance of $185 and $190 million. The increase in capital spending is the result of adjusting the timing of expenditures on the Onion Lake thermal expansion.

The capital program is expected to be funded from a combination of our anticipated adjusted funds flow, proceeds from the recent issuance of the $75 million senior secured second lien notes and our undrawn senior credit facilities. Adjusted funds flow is expected to be between $52 and $57 million, down from our previous guidance of $55 to $60 million. The decrease in adjusted funds flow is primarily attributable to lower forecast oil prices than what we used in previous guidance updates. For the remainder of the year we have assumed a WTI oil price of US$48.75, heavy oil differential of US$11.00 and a US$ to Cdn$ exchange rate of $0.80. Year-end 2017 debt levels are anticipated to be between $140 and $145 million, up from our previous guidance of $130 and $135 million. The increase in year-end debt levels reflects an increase in capital spending and lower forecasted adjusted funds flow for the remainder of the year.

We anticipate oil and gas production to average between 10,000 and 11,000 boe/d in 2017, unchanged from our previous guidance. Production from the Onion Lake thermal facility was temporarily impacted by a planned facility turnaround and inspection which began in late June. Production is expected to return to full rates in August or early September. As a result of the turnaround, corporate production for Q3 2017 is expected to be between 9,000 and 9,500 boe/d.

FORWARD-LOOKING STATEMENTS

This report contains certain forward-looking statements and forward-looking information (collectively referred to as "**forward-looking statements**") within the meaning of applicable Canadian securities laws. All statements other than statements of historical fact are forward-looking statements. Forward-looking information typically contains statements with words such as “anticipate”, “anticipated”, “approximately”, “believe”, “plan”, “planning”, “planned”, “project”, “projects”, “potential”, “could”, “estimate”, “estimates”, “estimated”, “forecast”, “forecasted”, “likely”, “expect”, “expected”, “may”, “target”, “impact”, “new”, “will”, “should”, “scheduled”, “outlook” or similar words suggesting future outcomes.

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

- Total estimated capital costs, expected completion date and peak production date for the second phase of the Onion Lake thermal project as discussed in the Overview and 2017 Significant Events section;
- Proceeds from the issue of the senior secured notes and our existing senior credit facilities will be used to fund the construction of the second phase of our Onion Lake thermal project and for general corporate purposes as discussed in the 2017 Significant Events section;
- Improved Canadian dollar relative to the US dollar which will negatively impact our future revenues and cash flows as discussed in the Commodity Prices section;
- The estimated change in annualized adjusted funds flow for 2017 due to changes in key variables as discussed in the Commodity Prices section;
- Expectation that Onion Lake thermal production will return to full rates in August or early September after a three week turnaround 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 2017, 2018, 2019 and 2020 as discussed in the Stock-based Compensation section;
- The expected interest rate charged on our senior credit facilities for the remainder of 2017 as discussed in the Finance Costs section;
- Expectation that gross interest and financing charges are expected to increase during the remainder of 2017 as a result of the Company’s recent issuance of senior secured second lien notes as discussed in the Finance Costs section;

- Potential future asset impairments or reversals of impairments as discussed in the Impairment section;
- Expected cash taxes to be paid during the remainder of 2017 as discussed in the Income Taxes 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; and
- All of the statements under the Outlook section and the table presented since they are estimates of future conditions and results.

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

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

Undue reliance should not be placed on these forward-looking statements. Readers are cautioned that the actual results achieved will vary from the information provided herein and the variations could be material. Readers are also cautioned that the foregoing list of assumptions, risks and factors is not exhaustive. Consequently, there is no assurance by the Company that actual results achieved will be the same in whole or in part as those set out in the forward-looking statements. Furthermore, the forward-looking statements contained in this document are made as of the date hereof, and the Company does not undertake any obligation, except as required by applicable securities legislation, to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

Other Supplementary Information

1. **List of directors and officers at August 9, 2017**
   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, 2017 is expected to be published on or before February 28, 2018.

3. **Other Information**
   Address (Corporate head office):
   BlackPearl Resources Inc.
   900, 215 – 9th Avenue S.W.
   Calgary, Alberta T2P 1K3
   Canada
   Telephone: +1.403.215.8313
   Fax: +1.403.265.5359
   Website: www.blackpearlresources.ca

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

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

BLACKPEARL RESOURCES INC.

Consolidated Balance Sheets

(unaudited) (Cdn$ in thousands)	Note	**June 30, 2017**	December 31, 2016
Assets			
Current assets			
Cash and cash equivalents	4	**$ 43,441**	$ 5,368
Trade and other receivables	5	**14,284**	13,391
Inventory		**65**	46
Prepaid expenses and deposits		**1,822**	705
Fair value of risk management assets	14	**6,636**	-
		66,248	19,510
Exploration and evaluation assets	6	**172,379**	170,737
Property, plant and equipment	7	**583,698**	542,157
		$ 822,325	$ 732,404
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	8	**$ 21,835**	$ 17,950
Current portion of decommissioning liabilities	9	**733**	644
Current portion of deferred consideration	10	**365**	404
Fair value of risk management liabilities	14	**-**	5,507
		22,933	24,505
Fair value of risk management liabilities	14	**1,302**	452
Decommissioning liabilities	9	**72,097**	71,122
Deferred consideration	10	**14,270**	14,425
Long-term debt	11	**72,320**	-
		182,922	110,504
Shareholders' equity			
Share capital	12	**970,878**	970,513
Contributed surplus		**44,000**	42,994
Deficit		**(375,475)**	(391,607)
		639,403	621,900
		$ 822,325	$ 732,404

Commitments and contingencies (note 13)

See accompanying notes to consolidated financial statements

BLACKPEARL RESOURCES INC.

Consolidated Statements of Comprehensive Income

(unaudited) **(Cdn$ in thousands, except for per share amounts)**	Note	**Three months ended June 30, 2017**	Three months ended June 30, 2016	**Six months ended June 30, 2017**	Six months ended June 30, 2016
Revenue					
Oil and gas sales		**$ 37,702**	$ 28,318	**$ 74,906**	$ 41,339
Deferred consideration	10	**95**	-	**194**	-
Royalties		**(5,317)**	(3,813)	**(10,739)**	(5,158)
Net oil and gas revenue		**32,480**	24,505	**64,361**	36,181
Gain (loss) on risk management contracts	14	**5,690**	(6,639)	**11,601**	(991)
		38,170	17,866	**75,962**	35,190
Expenses					
Production		**13,552**	11,013	**27,335**	20,656
Transportation		**2,374**	1,233	**4,824**	3,326
General and administrative		**1,814**	1,800	**4,601**	3,699
Depletion and depreciation	7	**10,754**	10,773	**21,707**	21,405
Finance costs	15	**750**	1,279	**1,299**	2,480
Stock-based compensation	12	**545**	711	**1,110**	1,841
Foreign currency exchange loss		**71**	4	**81**	52
		29,860	26,813	**60,957**	53,459
Other income					
Gain on disposition of properties		**-**	-	**1,110**	-
Interest income		**8**	2	**17**	2
		8	2	**1,127**	2
Net and comprehensive income (loss) for the period		**$ 8,318**	$ (8,945)	**$ 16,132**	$ (18,267)
Income (loss) per share					
Basic	12	**$ 0.02**	$ (0.03)	**$ 0.05**	$ (0.05)
Diluted	12	**$ 0.02**	$ (0.03)	**$ 0.05**	$ (0.05)

See accompanying notes to consolidated financial statements

BLACKPEARL RESOURCES INC.

Consolidated Statements of Changes in Equity

(unaudited)
(Cdn$ in thousands)

	Six months ended June 30, 2017			
	Share Capital	**Contributed Surplus**	**Deficit**	**Total Equity**
Balance - January 1, 2017	$ 970,513	$ 42,994	$ (391,607)	$ 621,900
Net and comprehensive income for the period	-	-	16,132	16,132
Stock-based compensation	-	1,110	-	1,110
Shares issued on exercise of stock options	261	-	-	261
Transfer to share capital on exercise of stock options	104	(104)	-	-
Balance - June 30, 2017	**$ 970,878**	**$ 44,000**	**$ (375,475)**	**$ 639,403**
			-	

	Six months ended June 30, 2016			
	Share Capital	**Contributed Surplus**	**Deficit**	**Total Equity**
Balance - January 1, 2016	$ 970,134	$ 39,800	$ (371,679)	$ 638,255
Net and comprehensive loss for the period	-	-	(18,267)	(18,267)
Stock-based compensation	-	1,841	-	1,841
Shares issued on exercise of stock options	6	-	-	6
Transfer to share capital on exercise of stock options	2	(2)	-	-
Balance - June 30, 2016	$ 970,142	$ 41,639	$ (389,946)	$ 621,835

See accompanying notes to consolidated financial statements

BLACKPEARL RESOURCES INC.

Consolidated Statements of Cash Flows

(unaudited) **(Cdn$ in thousands)**	Note	**Three months ended June 30, 2017**	Three months ended June 30, 2016	**Six months ended June 30, 2017**	Six months ended June 30, 2016
Operating activities					
Net and comprehensive income (loss) for the period		**$ 8,318**	$ (8,945)	**$ 16,132**	$ (18,267)
Items not involving cash:					
Depletion and depreciation	7	**10,754**	10,773	**21,707**	21,405
Accretion of decommissioning liabilities	15	**390**	361	**777**	727
Stock-based compensation	12	**545**	711	**1,110**	1,841
Foreign exchange loss		**(9)**	-	**(26)**	-
Deferred consideration	10	**(95)**	-	**(194)**	-
Unrealized loss (gain) on risk management contracts	14	**(5,724)**	8,597	**(11,293)**	9,069
Gain on disposition of properties		**-**	-	**(1,110)**	-
Decommissioning costs incurred	9	**(83)**	(369)	**(125)**	(516)
Changes in non-cash working capital	15	**984**	(3,944)	**2,888**	(3,288)
Cash flow from operating activities		**15,080**	7,184	**29,866**	10,971
Financing activities					
Proceeds on issue of common shares, net of costs	12	**46**	6	**261**	6
Proceeds on issue of senior secured second lien notes, net of debt issuance costs	11	**72,320**	-	**72,320**	-
Proceeds on issue of senior credit facilities		**40,000**	-	**40,000**	-
Repayment of senior credit facilities		**(40,000)**	(6,000)	**(40,000)**	(8,000)
Cash flow from (used in) financing activities		**72,366**	(5,994)	**72,581**	(7,994)
Investing activities					
Capital expenditures - exploration and evaluation assets	6	**(809)**	(135)	**(1,576)**	(927)
Capital expenditures - property, plant and equipment	7	**(52,625)**	(810)	**(65,214)**	(2,095)
Proceeds from disposition of properties		**-**	-	**3,421**	-
Changes in non-cash working capital	15	**(257)**	(489)	**(1,116)**	(1,415)
Cash flow used in investing activities		**(53,691)**	(1,434)	**(64,485)**	(4,437)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**83**	4	**111**	52
Increase (decrease) in cash and cash equivalents		**33,838**	(240)	**38,073**	(1,408)
Cash and cash equivalents, beginning of period		**9,603**	1,132	**5,368**	2,300
Cash and cash equivalents, end of period		**$ 43,441**	$ 892	**$ 43,441**	$ 892

See accompanying notes to consolidated financial statements

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

1. GENERAL INFORMATION

BlackPearl Resources Inc. (together with its subsidiaries collectively referred to as the "Company" or "BlackPearl") is engaged in the business of oil and gas exploration, development and production in North America. The Company's primary focus is on heavy oil and oil sands projects in Western Canada. The Company's common shares are listed and traded on the TSX Exchange under the trading symbol "PXX". The Company's Swedish Depository Receipts trade on the NASDAQ Stockholm Exchange under the symbol "PXXS". BlackPearl is incorporated under the Canada Business Corporations Act and is located in Canada. The address of its registered office is 900, 215 – 9th Avenue SW, Calgary, Alberta, T2P 1K3.

2. BASIS OF PREPARATION

These condensed unaudited interim consolidated financial statements for the three and six months ended June 30, 2017 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, 2016 except accounting policies noted below. Income taxes on earnings or loss in the interim periods are accrued using the income tax rate that would be applicable to the expected total annual earnings or loss.

The policies applied in these condensed interim consolidated financial statements are based on IFRS issued, outstanding and effective as of August 9, 2017, 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, 2017 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, 2016, which have been prepared in accordance with IFRS as issued by the IASB.

3. SIGNIFICANT ACCOUNTING POLICIES

Restricted Share Units ("RSUs")
Periodically, the Company will grant RSUs in exchange for the provision of services from certain employees, directors and officers. RSUs are accounted for as equity based awards and the estimated fair value of the awards is determined at the time of grant. Forfeitures are estimated at the grant date and are subsequently adjusted to reflect actual forfeitures. The fair value is recognized over the vesting period as stock-based compensation expense, with a corresponding increase to contributed surplus. RSUs granted to officers and directors cliff vest three years from the date of grant. RSUs granted to all other eligible plan participants vest over three years; one third on the first, second and third anniversary from the date of the grant.

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

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

4. CASH AND CASH EQUIVALENTS

		June 30, 2017		December 31, 2016
Cash at financial institutions	**$**	**43,441**	$	5,368

Cash at financial institutions earns interest at floating rates based on daily deposit rates. As of June 30, 2017, US $2.5 million (December 31, 2016 – US $0.4 million) is included in cash at financial institutions. The Company only deposits cash with major financial institutions of high quality credit ratings.

5. TRADE AND OTHER RECEIVABLES

		June 30, 2017		December 31, 2016
Trade accounts receivable	**$**	**13,709**	$	13,206
Receivables from joint operation partners		**432**		328
Allowance for doubtful accounts		**(285)**		(285)
Net accounts receivable		**13,856**		13,249
Receivable from risk management contracts		**334**		48
Other receivables		**94**		94
Total trade and other receivables	**$**	**14,284**	$	13,391

Aging of trade and other receivables are as follows:

At June 30, 2017		Current		31 to 60 days		61 to 90 days		Over 90 days		Total
Trade accounts receivable	$	13,709	$	-	$	-	$	-	$	13,709
Receivables from joint operation partners		46		37		27		322		432
Allowance for doubtful accounts		-		-		-		(285)		(285)
Receivable from risk management contracts		334		-		-		-		334
Other receivables		-		-		-		94		94
Total trade and other receivables	$	14,089	$	37	$	27	$	131	$	14,284

At December 31, 2016		Current		31 to 60 days		61 to 90 days		Over 90 days		Total
Trade accounts receivable	$	13,206	$	-	$	-	$	-	$	13,206
Receivables from joint operation partners		2		6		1		319		328
Allowance for doubtful accounts		-		-		-		(285)		(285)
Receivable from risk management contracts		48		-		-		-		48
Other receivables		-		-		-		94		94
Total trade and other receivables	$	13,256	$	6	$	1	$	128	$	13,391

6. EXPLORATION AND EVALUATION ASSETS

At January 1, 2016	$ 169,493
Expenditures	967
Change in decommissioning provision	277
At December 31, 2016	170,737
Expenditures	1,576
Change in decommissioning provision	66
At June 30, 2017	$ 172,379

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. The Company determined that none of our exploration and evaluation assets had any indicators of impairment at June 30, 2017 and no impairment losses were recorded during the six months ended June 30, 2017 (2016 - $Nil).

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. The Company has received regulatory approval for Blackrod SAGD commercial development; however, significant proved reserves have yet to be recognized to date.

During the six months ended June 30, 2017, the Company capitalized net operating revenues totalling a gain of $0.2 million ($0.6 million loss during the six months ended June 30, 2016) related to the Blackrod SAGD pilot project. The Company did not capitalize any general and administrative costs related to exploration activities during the six months ended June 30, 2017 (2016 - $Nil).

7. PROPERTY, PLANT AND EQUIPMENT

	Oil and natural gas properties	Corporate	Total
Cost			
At January 1, 2016	$ 1,240,645	$ 3,507	$ 1,244,152
Expenditures	9,825	133	9,958
Change in decommissioning provision	3,681	-	3,681
Dispositions	(40,170)	-	(40,170)
At December 31, 2016	1,213,981	3,640	1,217,621
Expenditures	65,209	5	65,214
Change in decommissioning provision	345	-	345
Dispositions	(2,311)	-	(2,311)
At June 30, 2017	$ 1,277,224	$ 3,645	$ 1,280,869
Accumulated depletion and depreciation			
At January 1, 2016	$ 628,355	$ 2,483	$ 630,838
Depletion and depreciation	44,476	150	44,626
At December 31, 2016	672,831	2,633	675,464
Depletion and depreciation	21,635	72	21,707
At June 30, 2017	$ 694,466	$ 2,705	$ 697,171
Net book value			
December 31, 2016	$ 541,150	$ 1,007	$ 542,157
June 30, 2017	$ 582,758	$ 940	$ 583,698

During the six months ended June 30, 2017, the Company capitalized borrowing costs of $0.3 million (2016 - $Nil) to development activities. The Company did not capitalize any general and administrative costs related to development activities during the six months ended June 30, 2017 (2016 - $Nil).

At June 30, 2017, the Company performed a review of each of our cash generating units ("CGUs") for any indicators of impairment. The Company has five CGU's, one for each of our core areas of Onion Lake, Mooney and Blackrod and two CGU's for some of our minor properties. The Company determined that none of our CGUs had any indicators of impairment at June 30, 2017 and no impairment losses or reversals of property, plant and equipment were recorded during the six months ended June 30, 2017 (2016 - $Nil).

8. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

		June 30, 2017		December 31, 2016
Trade payables and accrued liabilities	**$**	**20,567**	$	16,879
Payables to joint operation partners		**363**		275
Other payables		**905**		796
Total accounts payable and accrued liabilities	**$**	**21,835**	$	17,950

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 Company's liabilities is approximately $74.7 million (December 31, 2016 - $74.3 million). The estimated net present value of the decommissioning liability was calculated using an inflation factor of 2.0% (December 31, 2016 – 2.0%) and discounted using a risk-free rate of 2.0% to 2.3% (December 31, 2016 – 2.0% to 2.3%) based on expected settlement dates. Settlement of the liability, which may extend up to 40 years in the future, is expected to be funded from general corporate funds at the time of retirement.

Changes to the decommissioning liability were as follows:

		Six months ended June 30, 2017		Year ended December 31, 2016
Decommissioning liability, beginning of the period	**$**	**71,766**	$	66,927
New liabilities recognized		**412**		103
Decommissioning costs incurred		**(125)**		(580)
Change in estimated costs of decommissioning		**-**		(2,813)
Change in inflation rate		**-**		6,864
Change in discount rate		**-**		(196)
Accretion expense		**777**		1,461
Decommissioning liability, end of the period		**72,830**		71,766
Less current portion of decommissioning liability		**(733)**		(644)
Non-current portion of decommissioning liability	**$**	**72,097**	$	71,122

10. DEFERRED CONSIDERATION

Deferred consideration was recorded on the sale of a royalty interest in 2016 that will be recognized over the oil and gas reserve life of the Company's Onion Lake property. Changes to deferred consideration were as follows:

		Six months ended June 30, 2017		Year ended December 31, 2016
Deferred consideration, beginning of the period	**$**	**14,829**	$	-
Sale of a royalty interest at Onion Lake		**-**		14,829
Recognition of deferred consideration		**(194)**		-
Deferred consideration, end of the period		**14,635**		14,829
Less current portion of deferred consideration		**(365)**		(404)
Non-current portion of deferred consideration	**$**	**14,270**	$	14,425

Significant Accounting Judgements and Estimates – Sale of a Royalty Interest

When the Company sells a royalty interest linked to production at a specific property, judgment is required in assessing the appropriate accounting treatment of the transaction on the closing date and in future periods. We consider the specific terms of each arrangement to determine whether we have disposed of an interest in the reserves of the respective property. This assessment considers whether the counterparty is entitled to and the associated risks and rewards attributable to them over the life of the property including the contractual terms and implicit obligations related to production over the life of the property, the holder of the royalty having the option of either being paid in cash or in kind and the associated commitments, if any, to develop future expansions or projects at the property.

In the fourth quarter of 2016, the Company sold a royalty interest on its Onion Lake property for cash proceeds of $55 million whereby the Company will pay an approximate 1.75% royalty on production from substantially all of its Onion Lake lands. The Company applied judgment in concluding that the proceeds for the sale of the royalty interest on the Onion Lake properties comprised two components: (1) a payment for partial disposal of an interest in property, plant and equipment; and (2) an upfront payment received for future extraction services that will generate future royalties.

The Company used discounted future cash flows of future development and operating costs multiplied by the approximate 1.75% royalty rate to derive the upfront payment received for future extraction services of $14.8 million, which is being accounted for as deferred consideration and recognized as revenue over the reserve life at Onion Lake (as this is estimated to approximate the efforts we incur towards the extraction performance obligation). The calculation of the upfront payment received for future extraction services included estimated future development costs, estimated future operating costs and a discount rate applied to the future cash flows in determining the amount of deferred consideration based on management's judgment.

The remaining proceeds of $40.2 million were compared to the carrying value attributable to the partial disposal of property, plant and equipment, which resulted in no gain or loss recognized on the disposition. The Company applied judgment in determining the carrying value of property, plant and equipment to be disposed, which was derived based on the proportion of proved and probable reserve value given up on the Company's Onion Lake properties.

11. LONG-TERM DEBT

		Six months ended June 30, 2017		Year ended December 31, 2016
Senior credit facilities	**$**	**-**	$	-
$75 million 8% senior secured second lien notes		**75,000**		-
Less: unamortized debt issuance costs		**(2,680)**		-
Total long-term debt	**$**	**72,320**	$	-

(a) Senior Credit Facilities

At the completion of the most recent semi-annual review of the Company's senior credit facilities with its syndicated group of lenders, the Company's maximum borrowing amount was increased from $117.5 million to $120 million. The Company's $120 million senior credit facilities consist of a $110 million syndicated revolving line of credit (December 31, 2016 - $107.5 million) and a non-syndicated operating line of credit of $10 million (December 31, 2016 - $10 million). At June 30, 2017, the Company had not drawn any amounts (December 31, 2016 – no amounts drawn) under these senior credit facilities and had letters of credit issued in the amount of $20,000 (December 31, 2016 - $20,000); leaving $120 million (December 31, 2016 - $117.5 million) available to be drawn under these facilities. The facilities are secured by a floating and fixed charge debenture on the assets of the Company. The amount available under these facilities ("Borrowing Base") is re-determined at least twice a year and is primarily based on the Company's oil and gas reserves, the lending institution's forecast commodity prices, the current economic environment and other factors as determined by the syndicate of lending institutions. If the total advances made under the credit facilities are greater than the re-determined Borrowing Base, the Company has 60 days to repay any shortfall . The next scheduled Borrowing Base redetermination is to occur by November 30, 2017. The senior credit facilities have been provided on a revolving basis until May 27, 2018, at which time they may be extended at the lenders option. If the lenders elected not to renew the senior credit facilities, any amounts outstanding would convert to a term loan that would be due and payable in full by May 27, 2019.

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

(b) Senior Secured Second Lien Notes

On June 30, 2017, the Company issued $75 million senior secured second lien notes bearing an interest rate of 8%, payable quarterly in arrears, and due on June 30, 2020. The proceeds from the senior secured notes were made available in a single draw and amounts borrowed under the senior secured notes that are repaid or prepaid are not available for re-borrowing. The senior secured notes are secured by substantially all of the assets of the Company on a second priority basis, subordinate only to the senior credit facilities. The Company may redeem the senior secured second lien notes at any time at a price equal to par, plus a "make-whole" premium and any accrued interest. At June 30, 2017, the carrying value of the senior secured notes was $72.3 million, net of deferred financing costs.

(c) Covenants

The Company is subject to a number of financial covenants under the terms of the senior credit facilities and the senior secured second lien notes. The significant covenants under these debt instruments are summarized below.

(i) The Company is required to maintain a working capital ratio of 1:1 at the end of each fiscal quarter. Working capital is defined as current assets, as indicated on the Company's consolidated balance sheet, plus any undrawn amount on the senior 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 7.8:1 at June 30, 2017 (December 31, 2016 – 7.2:1).

(ii) The Company is limited to a maximum total debt to EBITDA ratio of 4.5:1 at the end of each fiscal quarter. The Company is also limited to a maximum senior credit facilities debt to EBITDA ratio of 3.5:1 at the end of each fiscal quarter on or before December 31, 2018. After December 31, 2018, the Company is limited to maximum senior credit facilities debt to EBITDA ratio of 3:1 Total debt is defined as the Company's total debt outstanding excluding accounts payable and accrued liabilities, decommissioning liabilities, deferred consideration and liabilities under risk management contracts at the end of each fiscal quarter. Senior credit facilities debt is defined as total debt less the senior secured second lien notes at the end of each fiscal quarter. EBITDA is defined as the Company's net income for the trailing 12 month period before financing charges, income taxes, all non-cash items including depletion and depreciation, accretion, future taxes, stock-based compensation, unrealized gains or losses on risk management contracts and write down or reversal of impairment of assets, income or losses attributable to extraordinary and non-recurring gains or losses and gains or losses from asset sales. The Company had a total debt to EBITDA ratio of 1.3:1 and a senior credit facilities debt to EBITDA ratio of 0.0:1 at June 30, 2017.

(iii) The Borrowing Base under the senior credit facilities cannot exceed $240 million.

(iv) The Company will not, as of any asset coverage test date, permit the asset coverage ratio to be less than 1.5:1. Asset coverage ratio is defined as the discounted net present value of the Company's total proved reserves discounted at 10% compared to total debt. The asset coverage test date is defined as May 1 and November 1 of each fiscal year and each date on which a material acquisition or disposition is consummated.

(v) The Company is required as at the end of each of its fiscal quarters, commencing with June 30, 2017, to have hedged at least 50% of our projected working interest production (net of royalties) for the forward looking 12 months and at least 20% of the next six months of projected production (months 13-18 forward) is required to be hedged.

At June 30, 2017, the Company was in compliance with all debt covenants.

12. SHARE CAPITAL

(a) Authorized

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

(b) Common Shares Issued

	Number of Shares	Attributed Value
Balance as at January 1, 2016	335,638,226	$ 970,134
Shares issued on exercise of stock options	310,669	271
Transferred from contributed surplus on exercise of stock options	-	108
Balance as at December 31, 2016	335,948,895	$ 970,513
Shares issued on exercise of stock options	302,007	261
Transferred from contributed surplus on exercise of stock options	-	104
Balance as at June 30, 2017	336,250,902	$ 970,878

(c) Restricted Share Units ("RSUs") Outstanding

In 2017, the Board and shareholders approved the adoption of a RSU plan. Under the terms of the RSU plan, the directors can issue up to 5,000,000 common shares from treasury to holders of RSUs.

RSUs are notional share instruments that track the value of the common shares. RSUs granted to officers and directors cliff vest three years from the date of grant. RSUs granted to all other eligible plan participants vest over three years; one third on the first, second and third anniversary from the date of the grant. RSUs may be settled in shares issued from treasury or cash, at the discretion of the Board. During the first half of 2017, 1,000,000 RSUs were granted to officers and directors and 760,000 RSUs were granted to other eligible plan participants. The following table summarizes RSUs outstanding:

	Number of RSUs
Outstanding at December 31, 2016	-
Granted	1,760,000
Forfeited	(50,000)
Outstanding at June 30, 2017	1,710,000

The Company accounts for RSUs as equity based awards and the estimated fair value of the awards is determined at the time of the grant. Forfeitures are estimated at the grant date and are subsequently adjusted to reflect actual forfeitures. During the six months ended June 30, 2017, 1,760,000 RSUs were granted (2016 – Nil) and the fair value of these RSUs was estimated using a forfeiture rate of 10.2% and a weighted average fair value of $1.56 per unit.

(d) Stock Options Outstanding

The Company has a stock option plan (the "Plan") available to directors, officers, employees and certain consultants of the Company. The number of common shares to be reserved and authorized for issuance pursuant to the Plan and all other security based compensation arrangements (such as the RSU 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, 2016	29,655,169	2.04
Granted	135,000	0.93
Exercised	(310,669)	0.87
Forfeited	(478,665)	3.04
Expired	(2,074,500)	5.18
Outstanding at December 31, 2016	26,926,335	1.79
Granted	1,867,000	1.50
Exercised	(302,007)	0.86
Forfeited	(179,999)	1.57
Expired	(1,279,500)	3.87
Outstanding at June 30, 2017	27,031,829	1.69

Options outstanding and exercisable as at June 30, 2017 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	10,905,829	0.84	3.02	6,934,713	0.84	2.97
1.51 – 3.00	15,761,000	2.23	2.02	14,110,667	2.31	1.71
3.01 – 3.87	365,000	3.22	0.35	365,000	3.22	0.35
	27,031,829	1.69	2.40	21,410,380	1.85	2.09

The fair value of common share options granted is estimated on the date of grant using the Black-Scholes option pricing model. During the six months ended June 30, 2017, 1,867,000 options were granted (2016 – 75,000) and during the three months ended June 30, 2017, 225,000 options were granted (2016 – Nil). The fair value of these options was estimated using the following weighted average assumptions:

	Three months ended June 30		Six months ended June 30	
Assumptions	**2017**	2016	**2017**	2016
Risk free interest rate (%)	**1.0**	-	**1.0**	0.6
Dividend yield (%)	**0.0**	-	**0.0**	0.0
Expected life (years)	**3.9**	-	**3.8**	3.7
Expected volatility (%)	**55.3**	-	**56.2**	54.6
Forfeiture rate (%)	**10.1**	-	**10.2**	11.7
Weighted average fair value of options	**$ 0.47**	-	**$ 0.65**	$ 0.32

(e) Stock-based Compensation

	Three months ended June 30		Six months ended June 30	
	2017	2016	**2017**	2016
Gross stock-based compensation related to options	**$ 297**	$ 711	**$ 785**	$ 1,889
Gross stock-based compensation related to RSUs	**269**	-	**351**	-
Total gross stock-based compensation	**566**	711	**1,136**	1,889
Recoveries from forfeitures related to options	**(18)**	-	**(23)**	(48)
Recoveries from forfeitures related to RSUs	**(3)**	-	**(3)**	-
Net stock-based compensation	**$ 545**	$ 711	**$ 1,110**	$ 1,841

(f) Income (loss) per Share

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

The following table shows the calculation of basic and diluted income (loss) per share:

	Three months ended June 30		Six months ended June 30	
	2017	2016	**2017**	2016
Net and comprehensive income (loss)	**$ 8,318**	$ (8,945)	**$ 16,132**	$ (18,267)
Weighted average number of common shares - basic	**336,226**	335,641	**336,192**	335,640
Dilutive effect:				
Outstanding options	**2,793**	-	**3,844**	-
Weighted average number of common shares - diluted	**339,019**	335,641	**340,036**	335,640
Basic income (loss) per share	**$ 0.02**	$ (0.03)	**$ 0.05**	$ (0.05)
Diluted income (loss) per share	**$ 0.02**	$ (0.03)	**$ 0.05**	$ (0.05)

For the six months ended June 30, 2017, the Company used a weighted average market closing price of $1.37 per share to calculate the dilutive effect of stock options. For the six months ended June 30, 2017, 16,633,102 options were antidilutive (2016 – all outstanding options were anti-dilutive) and were not included in the calculation of diluted income (loss) per share.

13. COMMITMENTS AND CONTINGENCIES

	2017	2018	2019	2020	2021	Thereafter
Operating leases (1)	$ 493	$ 912	$ 703	$ 560	$ 545	$ -
Electrical service agreement (2)	474	585	119	119	119	1,868
Transportation service agreement (3)	68	135	135	33	-	-
Decommissioning liabilities (4)	519	428	347	8,992	1,651	62,802
Capital commitments (5)	18,340	5,000	5,000	-	-	-
Long-term debt (6)	-	-	-	75,000	-	-
Interest payments on long-term debt (6)	1,500	7,500	6,000	3,000	-	-
Total	$ 21,394	$ 14,560	$ 12,304	$ 87,704	$ 2,315	$ 64,670

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

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

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

(4) The Company also has ongoing obligations related to the decommissioning of well sites and facilities which have reached the end of their economic lives. The undiscounted estimated obligations associated with the retirement of the Company's oil and gas properties were $74.7 million as at June 30, 2017. Decommissioning programs are undertaken regularly in accordance with applicable legislative requirements.

(5) The Company entered into certain agreements pertaining to the construction of the second phase of the Onion Lake thermal project.

(6) The Company issued $75 million senior secured second lien notes bearing an interest rate of 8% payable quarterly in arrears and due on June 30, 2020.

14. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments as at June 30, 2017 include cash and cash equivalents, trade and other receivables, deposits within prepaid expenses and deposits, accounts payable and accrued liabilities, risk management assets and liabilities and long-term debt.

(a) Fair value of financial instruments

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

	June 30, 2017		December 31, 2016	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Financial assets				
Loans and receivables:				
Cash and cash equivalents	$ 43,441	$ 43,441	$ 5,368	$ 5,368
Trade and other receivables	$ 14,284	$ 14,284	$ 13,391	$ 13,391
Deposits	$ 218	$ 218	$ 142	$ 142
Financial liabilities at fair value through profit or loss:				
Fair value of risk management assets	$ 6,636	$ 6,636	$ -	$ -
Financial liabilities				
Financial liabilities at amortized cost:				
Accounts payable and accrued liabilities	$ 21,835	$ 21,835	$ 17,950	$ 17,950
Long-term debt	$ 75,000	$ 75,000	$ -	$ -
Financial liabilities at fair value through profit or loss:				
Fair value of risk management liabilities	$ 1,302	$ 1,302	$ 5,959	$ 5,959

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 use level 2 valuation methods and 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).

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).

(b) Risks associated with financial instruments

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

(i) Credit Risk

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

As at June 30, 2017, the Company held $43.4 million in cash at various major financial institutions throughout Canada and the USA; however, one Canadian financial institution held over 94% of our cash and short-term deposits. The financial institution is a Canadian provincial crown corporation with a high investment grade rating and therefore we believe the credit risk is limited.

At June 30, 2017, 96% 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 the first half of 2017, the Company did not experience any collection issues with its marketers.

In the first half of 2017, the Company had four customers which individually accounted for more than 10 percent of its total oil and gas sales. Oil and gas sales to these collective customers represented approximately 87% of the Company's total oil and gas sales in the first half of 2017.

Risk management assets and liabilities consist of commodity contracts used to manage the Company's exposure to fluctuations in commodity prices. 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 the first half of 2017, the Company did not experience any collection issues with risk management contracts.

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

(ii) Liquidity risk

Liquidity risk is the risk the Company is unable to meet its financial obligations as they come due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. The Company has an on-going cash flow planning and forecasting model to help determine the funds required to meet its operational needs at all times. In addition, the Company manages its liquidity risk by ensuring that it has access to multiple sources of capital including cash and cash equivalents, cash from operating activities, undrawn credit facilities and opportunities to issue additional equity. As at June 30, 2017, the Company had $120 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:

	Total	**< 1year**	**1 – 5 Years**
Accounts payable and accrued liabilities	21,835	21,835	-
Risk management liabilities	1,302	-	1,302
Capital commitments	28,340	20,840	7,500
Long-term debt	75,000	-	75,000
Interest payments on long-term debt	18,000	4,500	13,500
Total	**144,477**	**47,175**	**97,302**

(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 senior credit facilities due to the floating interest rate charged on advances. For the period ended June 30, 2017, if interest rates had been one percent higher with all other variables held constant, after tax net income would have been approximately $57,000 lower. The remainder of the Company's financial assets and liabilities are not exposed to interest rate risk. The Company has not entered into any fixed rate contracts to mitigate its interest rate risk.

(iv) Foreign currency exchange risk

The Company is exposed to risks arising from fluctuations in foreign currency exchange rates and the volatility of those rates. This exposure primarily relates to: (i) revenues received for the sale of its crude oil production are primarily priced in US dollars while most of the Company's operating and capital expenditures are denominated in Canadian dollars and (ii) certain deposits and accounts payable are denominated in US dollars. As at June 30, 2017, the Company has not entered into any fixed rate contracts to mitigate its currency risks.

As at June 30, 2017, the Company held US $2.5 million in cash and cash equivalents and US $0.3 million in 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, income for the six months ended June 30, 2017 would have been approximately $0.2 million lower as a result of the re-valuation of the Company's US dollar denominated financial assets and liabilities as at June 30, 2017. An equal opposite impact would have occurred to income had exchange rates been $0.10 higher.

(v) Commodity price risk

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

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

Risk management amounts recognized were as follows:

	Three months ended June 30		Six months ended June 30	
	2017	2016	**2017**	2016
Realized gain (loss) on risk management contracts	**$ (34)**	$ 1,958	**$ 308**	**$** 8,078
Unrealized gain (loss) on risk management contracts	**5,724**	(8,597)	**11,293**	(9,069)
Gain (loss) on risk management contracts	**$ 5,690**	**$** (6,639)	**$ 11,601**	**$** (991)

The table below summarizes the Company's outstanding commodity contracts as at June 30, 2017:

Subject of Contract	Volume	Term	Reference	Strike Price	Type	Fair value
2017						
Oil	500 bbls/d	July 1 to December 31	CDN$ WCS	CDN$ 54.30/bbl	Swap	$ 796
Oil	500 bbls/d	July 1 to December 31	CDN$ WCS	CDN$ 53.10/bbl	Swap	686
Oil	500 bbls/d	July 1 to December 31	CDN$ WCS	CDN$ 53.00/bbl	Swap	674
Oil	500 bbls/d	July 1 to December 31	CDN$ WCS	CDN$ 52.75/bbl	Swap	653
Oil	500 bbls/d	July 1 to December 31	US$ WCS	US$ 40.15/bbl	Swap	566
Oil	1,000 bbls/d	July 1 to December 31	CDN$ WCS	CDN$ 50.00/bbl	Swap	802
Oil	1,000 bbls/d	July 1 to December 31	CDN$ WCS	CDN$ 49.50/bbl	Swap	677
Oil	1,000 bbls/d	July 1 to December 31	US$ WTI	US$ 60.00/bbl	Sold Call	(37)
2018						
Oil	2,000 bbls/d	January 1 to June 30	CDN$ WCS	CDN$ 49.55/bbl	Swap	2,094
Oil	1,000 bbls/d	January 1 to June 30	US$ WTI	US$ 45.00/bbl to 57.75/bbl	Collar	491
Oil	1,500 bbls/d	January 1 to June 30	US$ WTI	US$ 40.00/bbl to 50.00/bbl	Collar	(741)
Oil	2,200 bbls/d	July 1 to December 31	US$ WTI	US$ 40.00/bbl to 51.00/bbl	Collar	(1,234)
Oil	500 bbls/d	January 1 to December 31	US$ WTI	US$ 70.00/bbl	Sold Call	(93)
Total						$ 5,334

Current portion of fair value of contracts	$ 6,636
Non-current portion of fair value of contracts	$ (1,302)

As at June 30, 2017, a 10% decrease to the oil price used to calculate the fair value for the risk management contracts would result in an approximate $9.5 million increase in fair value of these contracts and increase in income for the period. A 10% increase to the oil price used to calculate the fair value for the risk management contracts would result in an approximate $11.8 million decrease in fair value of these contracts and decrease in income for the period.

15. SUPPLEMENTARY INFORMATION

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

	Three months ended June 30		Six months ended June 30	
	2017	2016	**2017**	2016
Cash interest paid	**$ 632**	**$** 918	**$ 794**	$ 1,753

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

	Three months ended June 30		Six months ended June 30	
	2017	2016	**2017**	2016
Gross interest and financing charges	**$ 632**	**$** 918	**$ 794**	$ 1,753
Capitalized interest and financing charges	**(272)**	-	**(272)**	-
Net interest and financing charges	**360**	918	**522**	1,753
Accretion of decommissioning liabilities	**390**	361	**777**	727
Finance costs	**$ 750**	**$** 1,279	**$ 1,299**	$ 2,480

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

	Three months ended June 30		Six months ended June 30	
	2017	2016	**2017**	2016
Changes in non-cash working capital				
Trade and other receivables	**$ (392)**	$ (4,438)	**$ (893)**	$ (2,306)
Inventory	**86**	59	**(19)**	507
Prepaid expenses and deposits	**(1,120)**	(1,110)	**(1,117)**	(674)
Accounts payable and accrued liabilities	**2,153**	1,056	**3,801**	(2,230)
Changes in non-cash working capital	**$ 727**	$ (4,433)	**$ 1,772**	$ (4,703)
Relating to:				
Operating activities	**$ 984**	$ (3,944)	**$ 2,888**	$ (3,288)
Investing activities	**$ (257)**	$ (489)	**$ (1,116)**	$ (1,415)