

BLACKPEARL RESOURCES INC.

Management's Discussion and Analysis

The following is Management's Discussion and Analysis (MD&A) of the operating and financial results of BlackPearl Resources Inc. ("BlackPearl" or "the Company") for the three and nine months ended September 30, 2016. These results are being compared with the three and nine months ended September 30, 2015. The MD&A should be read in conjunction with the Company's unaudited consolidated financial statements for the three and nine months ended September 30, 2016, together with the accompanying notes and with the Company's annual MD&A for the year ended December 31, 2015.

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

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

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

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

Non-GAAP Financial Measures

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

The following table reconciles non-GAAP measurement "Funds flow from operations" to "Cash flow from operating activities", the nearest GAAP measure. "Funds flow from operations" excludes decommissioning costs incurred and changes in non-cash working capital related to operations, while the GAAP measurement, "Cash flow from operating activities" includes these items.

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

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

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

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

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

The effective date of this MD&A is November 3, 2016.

OVERVIEW

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

BlackPearl’s current core properties are:

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

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

2016 SIGNIFICANT EVENTS

- Crude oil prices were lower in the first nine months of 2016, with WTI oil prices averaging US\$41.33 per bbl during the first nine months of 2016 compared to US\$51.00 per bbl during the same period in 2015.
- During the first nine months of 2016, oil and gas production averaged 9,942 boe/d; a 25% increase compared to the same period in 2015. The increase was mainly attributable to the first phase of the Onion Lake thermal project which has been on production for just over a year. During the third quarter of 2016, production from this project averaged 6,472 bbls/d, with a steam to oil ratio of 2.45.
- During the third quarter of 2016, the Company received regulatory and environmental approval from the Alberta Energy Regulator and Alberta government for its 80,000 bbls/d Blackrod SAGD commercial development application.

- Due to low oil prices, the Company limited capital spending in the first nine months of 2016 and used the majority of its cash flow from operating activities to reduce debt. Capital expenditures during the first nine months of the year were \$4.8 million, with approximately \$2.3 million spent at the Onion Lake thermal project related to facility improvements and planning costs for the second phase of the project, \$0.6 million spent at Blackrod primarily related to continued capitalization of net revenues from operating the Blackrod pilot and \$1.9 million spent in other areas. No new drilling activity occurred during the first nine months of 2016.
- Oil and gas sales during the first nine months of 2016 were \$74 million and funds flow from operations (a non-GAAP measure) were \$29 million. For the three months ended September 30, 2016, the Company recognized net income of \$0.6 million. For the nine months ended September 30, 2016, the Company incurred a net loss of \$17.7 million.
- The decline in crude oil prices was partially offset by realized gains on crude oil hedging contracts. For the nine months ended September 30, 2016, the Company realized gains of \$10.2 million from these contracts.
- As a result of the Company's current cost reduction initiative, operating and transportation costs averaged \$14.24/bbl in the third quarter, a 32% decrease from Q3 2015.
- During the first nine months of 2016, 8,333 common shares were issued pursuant to the exercise of stock options. The Company did not undertake any equity issuances during the first nine months of 2016.
- At September 30, 2016, BlackPearl had working capital of \$3.4 million and \$67 million in bank debt, leaving \$50.5 million available to be drawn under the Company's existing credit facilities. The Company's bank debt is \$21 million lower than at the beginning of the year.

SELECTED QUARTERLY INFORMATION

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

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

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

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

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

BUSINESS ENVIRONMENT

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

Commodity Prices

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

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

Crude oil prices were relatively flat during the third quarter of 2016 compared to the second quarter; however, prices remain lower than the comparable period in 2015. WTI oil prices averaged US\$44.94 per bbl in the third quarter of 2016 compared to US\$45.59 per bbl in the second quarter of 2016 and US\$46.43 per bbl in the third quarter of 2015. For the first nine months of 2016 WTI oil prices averaged US\$41.33 per bbl, down from US\$51.00 per bbl in the same period in 2015. The improvement in third quarter crude oil pricing has been attributed to higher global

demand for oil, lower production volumes, particularly in the US and the recent decision by the Organization of Petroleum Exporting Countries (OPEC) to limit production levels to between 32.5 and 33 million bbls/d of oil. OPEC has indicated that details related to the production limit are expected to be finalized at its next meeting in November.

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

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

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

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

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

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

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

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

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

(1) Natural gas production converted at 6:1 (for boe figures)

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

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

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

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

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

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

In 2011, BlackPearl commenced its SAGD pilot project at Blackrod. The pilot started with a single horizontal well pair and associated steam and water handling facilities. A second pilot well pair was drilled and put on production in 2013. The pilot is being undertaken to provide operating data to design the commercial development of the Blackrod lands. The original pilot SAGD well was shut-in in August 2015. All sales and expenses from the pilot are being recorded as an adjustment to the capitalized costs of the project until commercial production commences. During the third quarter of 2016, the pilot wells produced an average of 565 bbls/d of bitumen and the net revenues capitalized for the first nine months of 2016 were a loss of \$0.3 million (\$1.8 million loss in the first nine months of 2015).

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

Risk Management Activities

The Company periodically enters into risk management contracts in order to ensure a certain level of cash flow to fund planned capital projects and to maintain as much financial flexibility as possible. BlackPearl's strategy is to mainly focus on swaps, collars, calls and fixed price contracts to limit exposure to fluctuations in oil prices and revenues. The Company's risk management activities are conducted pursuant to the Company's Risk Management Policy approved by the Board of Directors and are not used for trading or speculative purposes. The policy permits us to hedge up to 60% of our forecast production for a period of up to 24 months.

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

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

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

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

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

Royalties

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

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

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

Transportation Costs

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

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

Production Costs

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

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

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

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

Operating Netback ⁽¹⁾

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

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

Operating netback is the cash margin we receive from each barrel of oil equivalent sold. Operating netback, before realized gains on risk management activities, increased in the third quarter of 2016 to \$15.33 per boe from \$6.49 per boe in the same period in 2015. The increase is primarily attributable to lower royalties and production costs.

General and Administrative Expenses (G&A)

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

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

Stock-Based Compensation

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

Stock-based compensation costs are non-cash charges which reflect the estimated value of stock options granted. The Company uses the fair value method of accounting for stock options granted to directors, officers, employees and consultants whereby the fair value of all stock options granted is recorded as a charge to operations over the

period from the grant date to the vesting date of the option. The fair value of common share options granted is estimated on the date of grant using the Black-Scholes option pricing model.

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

Finance Costs

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

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

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

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

Depletion and Depreciation

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

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

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

Income Taxes

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

RESULTS FROM OPERATIONS

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

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

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

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

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

LIQUIDITY AND CAPITAL RESOURCES

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

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

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

Pursuant to the terms of the credit agreement, the Company is required to maintain a working capital ratio of 1:1 at the end of each fiscal quarter. Working capital as defined in the lending agreement is current assets, as indicated on the Company's consolidated balance sheet, plus any undrawn amount on the credit facilities compared to current liabilities from the Company's consolidated balance sheet (excluding any current amounts due on credit facilities). In addition, amounts related to risk management contracts are excluded from the calculations of current assets and current liabilities. The Company had a working capital ratio of 5.0:1 at September 30, 2016 and was in compliance with this covenant at September 30, 2016.

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

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

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

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

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

CAPITAL EXPENDITURES

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

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

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The Company has a number of financial obligations in the ordinary course of business. The following table summarizes the contractual obligations and commitments of the Company outstanding as at September 30, 2016. These obligations are expected to be funded from cash flow from operating activities and the Company's credit facilities.

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

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

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

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

(4) The Company also has ongoing obligations related to the decommissioning of well sites and facilities which have reached the end of their economic lives. The undiscounted estimated obligations associated with the retirement of the Company's oil and gas properties were \$82.7 million as at September 30, 2016. Decommissioning programs are undertaken regularly in accordance with applicable legislative requirements.

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

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments as at September 30, 2016 include cash and cash equivalents, trade and other receivables, deposits within prepaid expenses and deposits, accounts payable and accrued liabilities, risk management assets and liabilities and long-term debt. The fair value of cash and cash equivalents, trade and other receivables, deposits and accounts payable and accrued liabilities approximate their carrying amount due to the short-term nature of the instruments. The fair value of the Company's long-term debt approximates its carrying value as the interest rates charged on this debt are comparable to current market rates. The fair values of the Company's risk management contracts are determined by discounting the difference between the contracted prices and published forward price curves as at the consolidated balance sheet date, using the remaining contracted oil volumes and a risk-free interest rate (based on published government rates).

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

OFF-BALANCE-SHEET ARRANGEMENTS

The Company had no off-balance-sheet arrangements during the period ended September 30, 2016 or 2015. We do utilize various operating leases in our normal course of business as disclosed under Contractual Obligations and Commitments.

RELATED-PARTY TRANSACTIONS

There was no related-party transactions during the period ended September 30, 2016 or 2015 except for key management compensation.

OUTSTANDING SHARE DATA AND STOCK OPTIONS

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

OUTSTANDING LONG-TERM DEBT DATA

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

PROPOSED TRANSACTIONS

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

SIGNIFICANT ACCOUNTING JUDGEMENTS AND ESTIMATES

The preparation of the interim consolidated financial statements requires management to make judgements and estimates that affect the reported amounts of assets, liabilities, sales, expenses and the disclosure of contingencies. Such judgements and estimates primarily relate to unsettled transactions and events as of the date of the interim consolidated financial statements. These judgements and estimates are subject to measurement uncertainty. Actual results could differ from and affect the results reported in the interim consolidated financial statements. Further information on the Company's critical accounting estimates can be found in the notes to the annual consolidated financial statements and annual MD&A for the year ended December 31, 2015. There have been no significant changes to the Company's critical accounting estimates as of September 30, 2016.

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

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

In May 2014, the IASB issued IFRS 15, "*Revenue from Contracts with Customers*" ("IFRS 15") to replace IAS 11, "*Construction Contracts*", IAS 18, "*Revenue*" and a number of revenue-related interpretations. IFRS 15 specifies how and when to recognize revenue as well as requiring entities to provide users of financial statements with more informative, relevant disclosures. IFRS 15 is effective for years beginning on or after January 1, 2018 with earlier adoption permitted. The standard may be applied retrospectively or using a modified retrospective approach. The Company is currently evaluating the impact of adopting IFRS 15 on the Company's consolidated financial statements.

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

In January 2016, the IASB issued IFRS 16, "*Leases*" ("IFRS 16") to replace IAS 17, "*Leases*." Under IFRS 16, a single recognition and measurement model will apply for lessees which will require recognition of assets and

liabilities for most leases. IFRS 16 is effective for years beginning on or after January 1, 2019 with earlier adoption permitted. The Company is currently evaluating the impact of adopting IFRS 16 on the Company's consolidated financial statements.

RISK FACTORS

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

- (a) As a result of the prolonged downturn in the oil and gas industry the number of orphan wells (wells owned by insolvent parties) has increased. The cost of abandoning orphan wells has largely been funded by industry. Accordingly, the increase in the number of orphaned wells could result in an increase in fees or assessments to other oil and gas producers, such as BlackPearl, to fund the abandonment and reclamation of these orphaned wells.
- (b) In response to recent court decisions, the Alberta Energy Regulator has implemented new regulations regarding the ability to transfer leases, licenses, permits, wells and facilities between parties. The AER has increased the minimum abandonment liability rating of the buyer before they will accept a transfer of oil and gas assets. These new regulations may make it more difficult and costly for producers, such as BlackPearl, to transfer or sell assets to other parties in the future.

CONTROL CERTIFICATION

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

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

OUTLOOK

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

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

Our plans for the remainder of 2016 are relatively unchanged from our Q2 2016 guidance update. We are still planning to limit capital spending and use most of our cash flow to reduce debt levels. Capital spending in 2016 is

expected to be between \$7 million and \$10 million, down from our Q2 guidance of \$10 million to \$15 million. Capital spending includes preliminary planning for the second phase of the Onion Lake thermal project, continuing to operate the Blackrod SAGD pilot through the year, a small drilling program on our conventional lands and maintenance capital in all our core areas.

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

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

FORWARD-LOOKING STATEMENTS

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

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

- The expected production limits to be set by OPEC at its next meeting in November as discussed in the Commodity Prices section;
- The estimated change in annualized funds flow from operations for 2016 due to changes in key variables as discussed in the Commodity Prices section;
- With the recent improvement in crude oil prices, the Company plans to put some of the shut-in wells back on production at Mooney and Onion Lake as discussed in the Oil and Gas Production, Oil and Gas Pricing and Oil and Gas sales section;
- Exploring financing options to accelerate development of the Blackrod SAGD project as discussed in the Oil and Gas Production, Oil and Gas Pricing and Oil and Gas sales section;
- Expected stock-based compensation expense for the remainder of 2016, 2017 and 2018 as discussed in the Stock-based Compensation section;
- The expected interest rate charged on our debt outstanding for the remainder of 2016 as discussed in the Finance Costs section;
- Potential future asset impairments as discussed in the Depletion and Depreciation section;
- Expected cash taxes to be paid for the remainder of 2016 in the Income Taxes section;
- Exploring financing options and estimated costs to expand our Onion Lake thermal project as discussed in the Liquidity and Capital Resources section;
- Expectation that if oil prices improve, the Company would be in a position to resume our capital programs as discussed in the Liquidity and Capital Resources section;
- The Company's expectation that it will not be paying dividends in the near term as discussed in the Liquidity and Capital resources section;
- The Company's expectation that the revolving and operating lines of credit will be extended at the next review as discussed in the Contractual Obligations and Commitments section; and
- All of the statements under the Outlook section and the table presented since they are estimates of future conditions and results.

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

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

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