

## 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 year ended December 31, 2017. These results are being compared with the year ended December 31, 2016. The MD&A should be read in conjunction with the Company's audited consolidated financial statements for the year ended December 31, 2017, together with the accompanying notes.

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		

### 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.

(\$000s)	Three months ended December 31		Year ended December 31	
	2017	2016	2017	2016
Cash flow from operating activities <sup>(1)</sup>	17,474	15,079	58,115	42,491
Decommissioning costs incurred	225	26	790	580
Changes in non-cash working capital related to operations	1,203	693	512	1,704
Adjusted funds flow <sup>(2)</sup>	18,902	15,798	59,417	44,775

(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)	December 31, 2017	December 31, 2016
Long-term debt <sup>(1)</sup>	92,944	–
Add (deduct) working capital:		
Cash and cash equivalents	(8,214)	(5,368)
Trade and other receivables	(14,821)	(13,391)
Inventory	(217)	(46)
Prepaid expenses and deposits	(810)	(705)
Fair value of risk management assets	(2,541)	–
Accounts payable and accrued liabilities	37,541	17,950
Current portion of decommissioning liabilities	1,176	644
Fair value of risk management liabilities	11,798	5,507
Net debt <sup>(2)</sup>	116,856	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 shareholders and other users as the measures provide increased transparency and the ability to better analyze the performance against prior periods on a comparable basis.

This MD&A makes reference to the term “EBITDA”, a non-GAAP measure defined under the Company’s lending agreement as 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. It is used to calculate a debt to EBITDA ratio which determines applicable margins applied to interest rates for any advances made and the Company is limited to a maximum

debt to EBITDA ratio under the lending agreement. Management does not use this measure to assess performance or liquidity of the Company as it does with the other non-GAAP measures above.

Additional information relating to the Company, including its Annual Information Form, is available on SEDAR at [www.sedar.com](http://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 February 21, 2018.

## OVERVIEW

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

BlackPearl's current core properties are:

- Onion Lake, Saskatchewan – a conventional heavy oil property as well as a multi-phase thermal project with the first phase constructed and put on production in 2015. The second phase is currently under construction; and expected to be completed during the first quarter of 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 of 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

- The Company's primary focus in 2017 was the construction of the second 6,000 bbls/d phase of the Onion Lake thermal project. Construction of the second phase began in the first quarter of 2017 and total estimated costs for the project are between \$180 and \$185 million. Currently, construction of the second phase of the Onion Lake thermal project is ahead of schedule and on budget. Commissioning of the facilities has begun and steam injection began in February 2018. First oil is expected before the end of the second quarter of 2018 and we anticipate reaching peak production approximately 12 months after initial steam injection, a similar timeline to that achieved for phase one.
- Crude oil prices were higher in 2017, with WTI oil prices averaging US\$50.95 per bbl compared to US\$43.32 per bbl during 2016. WCS oil prices averaged Cdn\$50.52 per bbl in 2017 compared to Cdn\$38.89 per bbl during 2016.
- During 2017, oil and gas production averaged 10,199 boe/d; an increase compared to 2016. The increase was mainly attributable to the first phase of the Onion Lake thermal project and the restart of the ASP flood at Mooney, partially offset by natural declines in our primary production. Production from Onion Lake accounted for 76% of total production in 2017.
- Capital expenditures in 2017 were \$169.9 million, with approximately \$157.9 million spent at the Onion Lake thermal project related to construction of the second phase of the project, \$4.4 million spent at John Lake which included the drilling of two horizontal heavy oil wells, \$2.0 million at Mooney related to bringing shut-in production back online, \$1.2

million at Onion Lake primary related to drilling five gross (2.5 net) conventional heavy oil wells and \$4.4 million spent in other areas. The Company also completed dispositions of non-producing properties for proceeds totaling \$3.4 million during the year.

- Oil and gas sales during 2017 were \$151.3 million, cash flow from operating activities were \$58.1 million and adjusted funds flow (a non-GAAP measure) was \$59.4 million. For the year ended December 31, 2017, the Company recognized net income of \$17.2 million.
- During 2017, 318,340 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 other equity issuances during 2017.
- On June 30, 2017, the Company issued \$75 million aggregate principal amount of senior secured second lien notes to Prudential Capital Group. Proceeds of the issue were used to partially fund the construction of the second phase of our Onion Lake thermal project.
- During the fourth quarter of 2017 the Company's lending syndicate completed their semi-annual review of our credit facilities and agreed to maintain the borrowing amount available to the Company at \$120 million. At December 31, 2017, BlackPearl had a working capital deficiency of \$23.9 million, \$75 million senior secured notes outstanding and had drawn \$20 million under its existing senior credit facilities; leaving \$100 million available to be drawn.
- BlackPearl's proved plus probable oil and gas reserves were 162 million boe, before royalties, as at December 31, 2017. This amount was determined by BlackPearl's independent reserve evaluators, Sproule Associates Limited ("Sproule"). The estimated pre-tax net present value of the future net cash flows of the proved plus probable reserves, discounted at 10% per annum was \$2 billion.
- Sproule also attributed, on a risked basis, contingent resources (best estimate) of 640 million boe, before royalties, to the Company's working interest in its three core properties (see cautionary statement on contingent resources on page 36).

## ANNUAL FINANCIAL INFORMATION

<i>(\$000s, except where noted)</i>	2017	2016	2015
Production (boe/d) <sup>(1)</sup>	10,199	10,077	8,330
Oil and gas sales	151,286	109,066	96,271
Realized gain on risk management contracts	364	10,793	37,227
Unrealized loss on risk management contracts	(4,982)	(15,283)	(11,303)
Net income (loss)	17,159	(19,928)	(46,793)
Per share – basic and diluted (\$)	0.05	(0.06)	(0.14)
Cash flow from operating activities	58,115	42,491	62,344
Adjusted funds flow <sup>(2)</sup>	59,417	44,775	48,962
Long-term debt	92,944	–	88,000
Capital expenditures	169,917	10,925	68,508
Total assets at year end	883,296	732,404	808,344
Common shares outstanding (000s)	336,267	335,949	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. Technical feasibility and commercial viability is established when significant proved reserves are recognized and regulatory approval has been obtained.

(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.

## SELECTED QUARTERLY INFORMATION

(\$000s, except where noted)	2017				2016			
	Dec 31	Sep 30	Jun 30	Mar 31	Dec 31	Sep 30	Jun 30	Mar 31
Production (boe/d) <sup>(1)</sup>	10,600	9,072	10,386	10,753	10,479	10,951	9,698	9,166
Oil and gas sales	43,486	32,894	37,702	37,204	35,360	32,367	28,318	13,021
Oil sales (\$/bbl)	47.07	42.05	41.93	40.75	38.83	34.15	34.44	16.77
Gas sales (\$/mcf)	1.45	1.31	2.58	2.50	2.90	2.10	1.29	1.77
Oil and gas sales (\$/boe)	46.71	41.71	41.65	40.48	38.61	33.87	34.03	16.67
Production & transportation costs	14,493	14,815	15,926	16,233	13,550	13,603	12,246	11,736
Production costs (\$/boe)	13.43	16.46	14.97	15.00	12.11	12.13	13.23	12.35
Transportation costs (\$/boe)	2.14	2.33	2.62	2.67	2.69	2.11	1.48	2.68
Gain (loss) on risk management contracts								
Realized	(1,392)	1,448	(34)	342	578	2,137	1,958	6,120
Unrealized	(8,184)	(8,091)	5,724	5,569	(5,676)	(538)	(8,597)	(472)
Net income (loss)	6,472	(5,445)	8,318	7,814	(2,217)	556	(8,945)	(9,322)
Per share, basic and diluted (\$)	0.02	(0.02)	0.02	0.02	(0.01)	0.00	(0.03)	(0.03)
Capital expenditures	44,535	58,592	53,434	13,356	6,150	1,753	945	2,077
Cash flow from operating activities	17,474	10,775	15,080	14,786	15,079	16,441	7,184	3,787
Adjusted funds flow <sup>(2)</sup>	18,902	13,412	14,179	12,924	15,798	14,202	11,497	3,278
Long-term debt (end of period)	92,944	72,738	72,320	–	–	67,000	80,000	86,000
Total assets (end of period)	883,296	845,946	822,325	737,735	732,404	773,206	782,591	795,336
Shares outstanding (000s)	336,267	336,267	336,251	336,196	335,949	335,647	335,647	335,638
Weighted average shares outstanding								
Basic	336,267	336,266	336,226	336,157	335,733	335,646	335,641	335,638
Diluted	338,568	338,744	339,019	340,700	340,686	337,959	335,641	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 from operations is a non-GAAP measure. Adjusted 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. 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 Q3 2017 decreased as a result of a planned three week turnaround and inspection at the Onion Lake thermal facility.

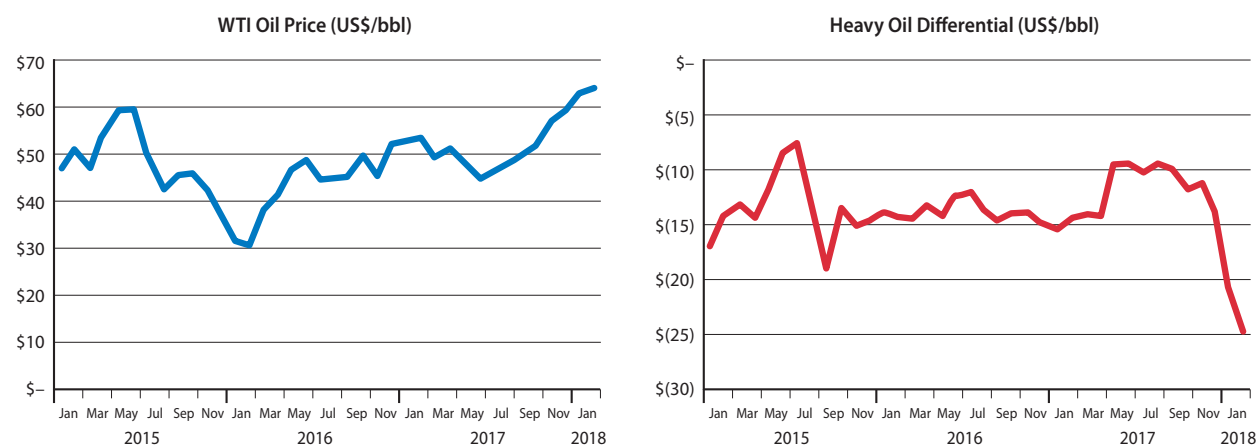
## BUSINESS ENVIRONMENT

Fluctuations in commodity prices have a significant impact 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

	Year ended December 31		2017				2016			
	2017	2016	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Average Crude Oil Prices										
West Texas Intermediate (WTI) (US\$/bbl)	50.95	43.32	55.40	48.21	48.29	51.91	49.29	44.94	45.59	33.45
Western Canadian Select (WCS) (Cdn\$/bbl)	50.52	38.89	54.86	47.88	49.96	49.36	46.62	41.02	41.61	26.31
Differential – WCS/WTI (US\$/bbl)	12.03	13.90	12.26	9.96	11.14	14.61	14.34	13.51	13.30	14.32
Differential – WCS/WTI (%)	23.6%	32.1%	22.1%	20.7%	23.1%	28.1%	29.1%	30.1%	29.2%	42.8%
Average Natural Gas Prices										
AECO gas (Cdn\$/GJ)	2.04	2.05	1.61	1.38	2.64	2.55	2.93	2.20	1.33	1.74
Average Foreign Exchange (US\$ per Cdn\$1)										
	0.770	0.757	0.786	0.799	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 were higher in 2017 compared to 2016. WTI oil prices averaged US\$50.95 per bbl in 2017, 18% higher than the average of US\$43.32 per bbl in 2016. The increase in oil prices has been attributed to supply and demand rebalancing in the crude oil markets as a result of increased global demand for oil and oil production curtailments by the Organization of Petroleum Exporting Countries (OPEC) and certain non-OPEC countries of approximately 1.8 million bbls/d. This has resulted in a reduction in global crude oil inventories.

During the fourth quarter of 2017, oil prices continued to improve as WTI averaged US\$55.40 per bbl compared to US\$48.21 per bbl in the third quarter of 2017 and US\$49.29 per bbl in the fourth quarter of 2016. The increase in fourth quarter crude

oil pricing has been attributed to continued supply/demand rebalancing, geopolitical tensions in the Middle East, deteriorating macroeconomic picture in Venezuela and the decision by the OPEC and certain non-OPEC countries to extend their oil production cuts for a further nine months commencing on March 1, 2018.

The heavy oil differential (WTI oil prices compared to WCS oil prices) improved in 2017 averaging US\$12.03 per bbl compared to US\$13.90 per bbl in 2016. The lower differential in 2017 has been attributed to temporarily shut-in heavy oil production in Canada due to planned and unplanned maintenance during the year, decreased US imports of heavier grades of oil from OPEC countries due to their decision to reduce oil output and lower Mexican and Venezuela heavy oil production, all resulting in greater demand for Canadian heavy oil.

In the fourth quarter of 2017, the heavy oil differential widened compared to the third quarter of 2017 primarily as a result of a leak on the Keystone Pipeline System in mid-November. The pipeline was temporarily shut-down resulting in higher inventories in Western Canada as other pipelines were running at or near capacity before the shut-down. The heavy oil differential continued to widen during the first quarter of 2018 as the pipeline is being operated at reduced pressure and volumes. Producers have had to either shut-in production or utilize higher cost rail transport during the pipeline curtailment.

Transportation constraints have become an important issue in Canada. With increased oil production expected in Canada from new and expanded oil sands projects, building additional pipeline capacity is important to ensure Canadian producers have market access and receive world prices for their oil. During the fourth quarter of 2016, the federal government approved the expansion of the existing Trans Mountain Express Pipeline and the Enbridge Line 3 replacement project. The proposed expansion of the existing Trans Mountain Express Pipeline would expand capacity to carry up to 890,000 bbls/d of oil to ports in Vancouver, from the current capacity of approximately 300,000 bbls/d and the Line 3 replacement project would expand capacity to carry up to 760,000 bbls/d of oil to Wisconsin, from the current pressure restricted capacity of approximately 390,000 bbls/d. However, both the pipeline projects have faced multiple delays in 2017 from court challenges by First Nations, environmental groups, provincial and state governments and local municipalities. Various court and regulatory decisions on these issues are expected in 2018. The Keystone XL pipeline project was approved by the US government on March 24, 2017. The Keystone XL pipeline would transport approximately 830,000 bbls/d of oil production to the US Gulf Coast. Construction of the project is expected to commence after remaining local and state permits are issued. The proposed Energy East pipeline was terminated during the fourth quarter of 2017 which was intended to transport increased oil production to Eastern Canada.

Until additional export pipeline capacity is built, incremental oil production is expected to be transported to sales markets by rail. Alberta has approximately 600,000 bbls/d of rail loading capacity. Shipping by rail is typically more expensive than shipping oil on pipelines and these higher transport costs will likely result in wider heavy oil differentials until additional pipeline capacity comes available.

Natural gas prices in 2017 were comparable to 2016; however, in the second half of 2017 natural gas prices in Canada decreased significantly due to an oversupply of natural gas in North America, as well as infrastructure maintenance work and pipeline constraints. 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 at our Onion Lake thermal project and our Blackrod pilot operations. During the fourth quarter of 2017, natural gas prices increased averaging \$1.61/GJ compared to \$1.38/GJ in the third quarter of 2017 due to cold weather during the period resulting in higher demand for heating but were significantly lower compared to \$2.93/GJ in the fourth quarter of 2016.

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 during 2017 compared to the same period in 2016. The exchange rate between the Canadian dollar and the US dollar averaged Cdn\$1 = US\$0.77 during 2017 compared to Cdn\$1 = US\$0.76 during 2016. More recently, the Canadian dollar has strengthened relative to the US dollar (in the range of \$0.79 - \$0.81 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 adjusted funds flow for 2017 <sup>(1) (2)</sup>:

Key variable	Change (\$)	\$000s
West Texas Intermediate (WTI) (US\$/bbl)	1.00	1,166
Realized crude oil price (Cdn\$/bbl)	1.00	1,382
US \$ to Canadian \$ exchange rate	0.01	772

(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

	Three months ended December 31		Year ended December 31	
	2017	2016	2017	2016
Daily production/sales volumes				
Oil (bbls/d)	10,026	9,853	9,611	9,391
Bitumen – Blackrod (bbls/d) <sup>(2)</sup>	481	523	490	556
Combined (bbls/d)	10,507	10,376	10,101	9,947
Natural gas (Mcf/d)	561	620	587	781
Total production (boe/d) <sup>(1)</sup>	10,600	10,479	10,199	10,077
Product pricing (excluding risk management activities) <sup>(2) (3)</sup>				
Oil (\$/bbl)	47.07	38.83	43.00	31.57
Natural gas (\$/Mcf)	1.45	2.90	2.01	1.95
Combined (\$/boe) <sup>(1)</sup>	46.71	38.61	42.69	31.30
Sales (\$000s) <sup>(2)</sup>				
Oil and gas sales – gross	43,486	35,360	151,286	109,066
Royalties	(5,899)	(4,516)	(21,128)	(13,785)
Oil and gas revenues – net <sup>(3)</sup>	37,587	30,844	130,158	95,281

(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 39% in 2017 to \$151.3 million from \$109.1 million in 2016. The increase in oil and gas sales is mainly attributable to a 36% increase in our average realized price. Higher WTI crude oil prices and narrower heavy oil differentials contributed to the increase in our realized crude oil sales prices in 2017. Our average oil wellhead sales price, prior to the impact of risk management activities, in 2017 was \$43.00 per bbl compared with \$31.57 per bbl in 2016.

Oil and natural gas sales increased 23% in the fourth quarter of 2017 to \$43.5 million from \$35.4 million in the same period in 2016. The increase in oil and gas sales is attributable to a 21% increase in average sales price received in the fourth quarter of 2017.

With the improvement in crude oil prices, during 2017 we selectively brought back on production certain shut-in wells at Onion Lake and re-initiated a portion of the ASP flood and restarted some primary wells at Mooney. Production from the re-initiated ASP flood at Mooney contributed to a 37% increase in oil production in 2017 from the Mooney field compared to 2016.

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

Production by area (boe/d)	Three months ended December 31		Year ended December 31	
	2017	2016	2017	2016
Onion Lake – thermal	6,204	6,119	5,686	5,520
Onion Lake – conventional	1,917	2,011	2,022	2,135
Mooney	1,178	785	1,096	801
John Lake	699	837	770	863
Blackrod	481	523	490	556
Other	121	204	135	202
<b>Total production</b>	<b>10,600</b>	10,479	<b>10,199</b>	10,077

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 first phase of 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 2017, the pilot well produced an average of 490 bbls/d of bitumen and the net revenues capitalized in 2017 were \$0.5 million (\$0.1 million in 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 loss of \$4.6 million on its risk management contracts during 2017, consisting of a \$0.4 million realized gain on the contracts and an unrealized loss of \$5.0 million. The realized gain on risk management contracts was the equivalent of adding \$0.10 per bbl to our wellhead price during 2017.

(\$000s, except per boe)	Three months ended December 31		Year ended December 31	
	2017	2016	2017	2016
Realized gain (loss) on risk management contracts	(1,392)	578	364	10,793
Per boe (\$)	(1.50)	0.63	0.10	3.10
Unrealized loss on risk management contracts	(8,184)	(5,676)	(4,982)	(15,283)

The table below summarizes the Company's outstanding commodity contracts as at December 31, 2017.

Year of Contract	Volume	Term	Reference	Strike Price	Type
<b>Oil</b>					
2018	2,000 bbls/d	January 1 to March 31	CDN\$ WCS/WTI Differential	CDN\$ 16.25/bbl	Swap
2018	2,000 bbls/d	January 1 to June 30	CDN\$ WCS	CDN\$ 49.55/bbl	Swap
2018	1,000 bbls/d	January 1 to June 30	US\$ WTI	US\$ 45.00/bbl to 57.75/bbl	Collar
2018	1,500 bbls/d	January 1 to June 30	US\$ WTI	US\$ 40.00/bbl to 50.00/bbl	Collar
2018	500 bbls/d	July 1 to September 30	US\$ WTI	US\$ 40.00/bbl to 58.00/bbl	Collar
2018	500 bbls/d	July 1 to September 30	US\$ WTI	US\$ 45.00/bbl to 54.00/bbl	Collar
2018	1,000 bbls/d	July 1 to September 30	US\$ WTI	US\$ 40.00/bbl to 60.00/bbl	Collar
2018	1,000 bbls/d	July 1 to September 30	US\$ WTI	US\$ 45.00/bbl to 57.00/bbl	Collar
2018	2,200 bbls/d	July 1 to December 31	US\$ WTI	US\$ 40.00/bbl to 51.00/bbl	Collar
2018	2,000 bbls/d	October 1 to December 31	US\$ WTI	US\$ 45.00/bbl to 61.50/bbl	Collar
2018	2,000 bbls/d	October 1 to December 31	US\$ WTI	US\$ 45.00/bbl to 62.50/bbl	Collar
2018	500 bbls/d	January 1 to December 31	US\$ WTI	US\$ 70.00/bbl	Sold Call
2019	500 bbls/d	January 1 to March 31	US\$ WTI	US\$ 40.00/bbl to 60.00/bbl	Collar
2019	500 bbls/d	January 1 to March 31	US\$ WTI	US\$ 43.25/bbl to 57.00/bbl	Collar
2019	1,600 bbls/d	January 1 to March 31	US\$ WTI	US\$ 40.00/bbl to 58.25/bbl	Collar
2019	1,500 bbls/d	April 1 to June 30	US\$ WTI	US\$ 45.00/bbl to 59.05/bbl	Collar
2019	1,200 bbls/d	April 1 to June 30	US\$ WTI	US\$ 45.00/bbl to 59.75/bbl	Collar
<b>Gas <sup>(1)</sup></b>					
2018	2,000 GJ/d	January 1 to December 31	CDN\$ AECO	CDN\$ 1.92/GJ	Swap
2018	2,000 GJ/d	January 1 to December 31	CDN\$ AECO	CDN\$ 2.00/GJ	Swap
2019	4,000 GJ/d	January 1 to December 31	CDN\$ AECO	CDN\$ 1.65/GJ	Swap

(1) The Company is the buyer of these financial swaps. The Company enters into these financial swaps to mitigate price volatility on natural gas purchases for its thermal operations.

At December 31, 2017, these contracts had a net fair value of \$10.9 million liability. A 10% decrease to the oil price used to calculate the fair value of these contracts would result in an approximate \$13.6 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 \$14.8 million decrease in fair value.

The table below summarizes commodity contracts the Company entered into subsequent to December 31, 2017.

Year of Contract	Volume	Term	Reference	Strike Price	Type
<b>Gas <sup>(1)</sup></b>					
2019	2,000 GJ/d	January 1 to December 31	CDN\$ AECO	CDN\$ 1.50/GJ	Swap

## Royalties

	Three months ended December 31		Year ended December 31	
	2017	2016	2017	2016
Royalties (\$000s)	5,899	4,516	21,128	13,785
Per boe (\$)	6.34	4.93	5.96	3.96
As a percentage of oil and gas sales	14%	13%	14%	13%

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 \$21.1 million in 2017, an increase from \$13.8 million 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 2017 from 13% in 2016. The increase in royalty rates in 2017 is 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

	Three months ended December 31		Year ended December 31	
	2017	2016	2017	2016
Conventional Production				
Transportation costs (\$000s)	523	318	2,105	969
Per boe (\$)	1.45	0.93	1.43	0.66
Thermal Production				
Transportation costs (\$000s)	1,472	2,144	6,551	6,832
Per boe (\$)	2.58	3.81	3.16	3.38
Total Production				
Transportation costs (\$000s)	1,995	2,462	8,656	7,801
Per boe (\$)	2.14	2.69	2.44	2.24

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 2017 to \$8.6 million from \$7.8 million in 2016. This increase is attributable to increased production from our Mooney area which ships mostly clean marketable crude oil. During the fourth quarter of 2017, transportation costs decreased due to a chemical trial at the Onion Lake thermal project which required the oil to be shipped to a treating facility and therefore the costs were classified as production expenses rather than transportation costs. Thermal transportation costs are expected to return to normal amounts on a per boe (\$) basis in 2018.

## Production Costs

	Three months ended December 31		Year ended December 31	
	2017	2016	2017	2016
<b>Conventional Production</b>				
Production costs (\$000s)	<b>7,834</b>	6,387	<b>32,314</b>	24,696
Per boe (\$)	<b>21.75</b>	18.59	<b>22.00</b>	16.87
<b>Thermal Production</b>				
Production costs (\$000s)	<b>4,664</b>	4,701	<b>20,497</b>	18,638
Per boe (\$)	<b>8.17</b>	8.35	<b>9.88</b>	9.22
Energy costs	<b>2.30</b>	3.74	<b>3.56</b>	3.47
Non-energy costs	<b>5.87</b>	4.61	<b>6.32</b>	5.75
<b>Total Production</b>				
Production costs (\$000s)	<b>12,498</b>	11,088	<b>52,811</b>	43,334
Per boe (\$)	<b>13.43</b>	12.11	<b>14.90</b>	12.44

The most significant components of our production costs are labor, energy (including natural gas for thermal operations), maintenance and workover costs, chemicals (including polymer) and property taxes. Total production costs increased 22% in 2017 to \$52.8 million from \$43.3 million in 2016. On a per boe basis, total production costs increased 20% in 2017 to \$14.90 per boe from \$12.44 per boe in 2016.

Conventional production costs increased in 2017 compared to the same period in 2016. The re-initialization of a portion of the ASP flood and restarting some primary wells at Mooney resulted in an increase in workover expenses and chemical and injection costs during the year. The increase in thermal production costs is mainly related to increased production in 2017 as well as a planned three week turnaround and inspection at the Onion Lake thermal facility.

The majority of our operations are located in the province of Saskatchewan. The province of Saskatchewan has not implemented a tax/cost on carbon emissions; however, in December 2017 the Saskatchewan government announced a climate change strategy to reduce emissions which will come into effect on January 1, 2019. The federal government has indicated that effective January 1, 2019 it will impose a carbon tax in provinces that do not implement its own carbon tax. Until draft legislation is published we are not able to determine the impact on our Saskatchewan operations; however, it is likely to increase the costs to operate our properties.

**Operating Netback**<sup>(1) (2) (3)</sup>

	Year ended December 31			
	2017	2017	2016	2016
	\$000s	\$/boe	\$000s	\$/boe
Oil and gas sales	151,286	42.69	109,066	31.30
Royalties	21,128	5.96	13,785	3.96
Transportation costs	8,656	2.44	7,801	2.24
Production costs	52,811	14.90	43,334	12.44
Operating netback before realized risk management contracts	68,691	19.39	44,146	12.66
Realized gain on risk management contracts	364	0.10	10,793	3.10
<b>Operating netback after realized risk management contracts</b>	<b>69,055</b>	<b>19.49</b>	54,939	15.76

	Three months ended December 31			
	2017	2017	2016	2016
	\$000s	\$/boe	\$000s	\$/boe
Oil and gas sales	43,486	46.71	35,360	38.61
Royalties	5,899	6.34	4,516	4.93
Transportation costs	1,995	2.14	2,462	2.69
Production costs	12,498	13.43	11,088	12.11
Operating netback before realized risk management contracts	23,094	24.80	17,294	18.88
Realized gain (loss) gain on risk management contracts	(1,392)	(1.50)	578	0.63
<b>Operating netback after realized risk management contracts</b>	<b>21,702</b>	<b>23.30</b>	17,872	19.51

(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, and Onion Lake thermal as disclosed in the Oil and Gas, Oil and Gas Pricing and Oil and Gas Sales section of this MD&A. (Q4 2017 – 10,119 boe/d; Q4 2016 – 9,956; Year ended December 31, 2017 – 9,709; Year ended December 31, 2016 – 9,521)

(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 53% in 2017 to \$19.39 per boe from \$12.66 per boe 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)**

	Three months ended December 31		Year ended December 31	
	2017	2016	2017	2016
<i>(\$000s, except per boe)</i>				
Gross G&A expense	2,628	1,774	9,639	7,704
Operator recoveries	(414)	(191)	(1,281)	(808)
Net G&A expense	2,214	1,583	8,358	6,896
Per boe (\$)	2.38	1.73	2.36	1.98

General and administrative expenses consist primarily of salaries and wages of employees, office rent, computer services, legal, accounting and consulting fees. The increase in gross G&A expenses in 2017 compared to 2016 reflects primarily higher staff compensation costs during the year. As oil prices stabilized during 2017, previous salary reductions were rescinded and performance incentive payments to staff were made during the year. Higher operator recoveries in 2017 compared to 2016 is attributable to higher capital spending in 2017.

## Stock-Based Compensation

(\$000s, except per boe)	Three months ended December 31		Year ended December 31	
	2017	2016	2017	2016
Gross stock-based compensation	622	700	2,357	3,356
Recoveries from forfeitures	(1)	(6)	(27)	(54)
Net stock-based compensation	621	694	2,330	3,302
Per boe (\$)	0.67	0.76	0.66	0.95

Stock-based compensation costs are non-cash charges that 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 2017 compared to 2016 is primarily attributable to a decrease in the weighted average number of options outstanding in 2017. In 2017, 318,340 options were exercised, 1,937,000 options were granted, 339,999 options were forfeited and 1,644,500 options expired. Also, 1,760,000 RSUs were granted and 50,000 RSUs were forfeited during the year. Based on stock options and RSUs outstanding as at December 31, 2017, the Company has an unamortized stock based compensation expense of approximately \$2.0 million, of which \$1.2 million is expected to be expensed in 2018, \$0.7 million in 2019 and \$0.1 million in 2020.

## Finance Costs

(\$000s)	Three months ended December 31		Year ended December 31	
	2017	2016	2017	2016
Gross interest & financing charges	1,672	523	4,188	3,262
Capitalized interest & financing charges	(1,080)	–	(2,986)	–
Net interest & financing charges	592	523	1,202	3,262
Accretion of decommissioning liabilities	452	377	1,663	1,461
Amortization of debt issuance costs	205	–	411	–
Total finance costs	1,249	900	3,276	4,723

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 increase in gross interest and financing charges in 2017 compared to 2016 is primarily attributed to the Company's issuance on June 30, 2017, of \$75 million of senior secured second lien notes that bear interest at 8% per year.

During 2017, we capitalized \$3.0 million in interest charges related to debt incurred during the construction of the second phase of the Onion Lake thermal project. During 2016, we did not capitalize any interest charges.

In addition to the \$75 million second lien notes, we also have senior credit facilities provided by a syndicate of lenders. These credit facilities are floating rate debt, so the interest rate charged is based on general market conditions. Additionally, the interest rate charged on these credit facilities is determined, in part, by our debt to EBITDA ratio (as defined in our credit agreement). The average interest rate on advances under the Company's senior credit facilities was 3.4% in 2017 and 2016.

The interest rate charged on our senior credit facilities debt is expected to be 3.5 – 4.0% through out 2018 (assuming no other changes in market conditions). We have not entered into any financial instruments to fix the interest rate on our floating rate debt.

### Depletion and Depreciation

	Three months ended December 31		Year ended December 31	
	2017	2016	2017	2016
Depletion and depreciation (\$000s)	10,751	11,237	42,026	44,626
Per boe (\$)	11.55	12.27	11.86	12.81

The Company's properties are depleted on a unit of production basis based on estimated proven plus probable reserves. Depletion and depreciation expense decreased 6% in 2017 to \$42.0 million from \$44.6 million in 2016. On a boe basis, depletion and depreciation expense decreased to \$11.86 per boe in 2017 compared to \$12.81 per boe in 2016. The decrease in depletion and depreciation on a boe basis is primarily attributable to increased reserves recognized at Onion Lake in 2017 as well as a reduction in the carrying value of the Onion Lake assets as a result of the sale of a royalty interest at the end of 2016.

### Impairment

Cash-generating units ("CGUs") are petroleum and natural gas properties, exploration and evaluation assets and other corporate assets that are aggregated based on their ability to generate largely independent cash inflows and are used for impairment testing. At December 31, 2017, the Company had five CGU's, one for each of our core areas and two CGU's for some of our minor properties. As indicators periodically dictate, the net book values of these CGU's are tested for impairment. At December 31, 2017, the Company determined that there were impairment indicators at the Blackrod CGU. The primary impairment indicator was the reclassification of Blackrod probable undeveloped reserves to contingent resources due to the uncertainty in the timing of development of the Blackrod project at December 31, 2017.

At December 31, 2017, the Company performed impairment calculations on the Blackrod CGU to assess whether the respective carrying value was recoverable. The recoverable amount used in assessing impairment was calculated at the fair value less costs of disposal using an after tax discounted cash flow model with a discount rate of 13% for the Blackrod CGU. At December 31, 2017, the recoverable amount at the Blackrod CGU was greater than the carrying value and no impairment was recorded. 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. In the contingent resource report prepared by Sproule, development of the first 20,000 barrel per day phase at the Blackrod project is anticipated to begin in 2022 with capital costs expected to be approximately \$800 million and first commercial production to occur in 2024 based on Sproule's price forecasts at December 31, 2017.

The estimated recoverable amount of the Blackrod CGU is sensitive to the discount rate and forward price estimates. Changes to these assumptions, assuming all other variables remained constant, would have the following earnings impact. A one percent increase in the assumed discount rate would not result in an impairment loss at the Blackrod CGU. A ten percent decrease in the forward commodity price estimates would result in an impairment loss of \$28.8 million at the Blackrod CGU.

### Gain on Disposition of Properties

In 2017, the Company sold various non-core, non-producing properties for total proceeds of \$3.4 million, which resulted in a gain on disposition of \$1.1 million.

## Income Taxes

BlackPearl did not pay cash income taxes in 2017 and does not expect to pay income taxes in 2018 as we have sufficient tax pools to shelter expected income.

The Company has the following estimated tax pools as at:

<i>(\$000s, except for left-hand column)</i>	Rate %	December 31, 2017	December 31, 2016
Canadian exploration expenses	100	32,311	26,105
Canadian development expenses	30	46,350	36,212
Canadian oil and gas property expenses	10	6,746	–
Undepreciated capital costs	10–30	310,316	247,606
Non-capital losses (expiry dates 2027 to 2036)	100	360,588	335,235
Share issuance costs	5 years	672	1,345
Debt issuance costs	5 years	1,974	–
<b>Total estimated tax pools</b>		<b>758,957</b>	<b>646,503</b>

The Company has recorded a deferred income tax recovery of \$7.5 million in 2017 as a result of management's expectation that it is probable we will utilize certain previously unrecognized tax pools against future taxable income.

## RESULTS FROM OPERATIONS

	Three months ended December 31		Year ended December 31	
	2017	2016	2017	2016
Net income (loss) (\$000s)	6,472	(2,217)	17,159	(19,928)
Per share, basic (\$)	0.02	(0.01)	0.05	(0.06)
Per share, diluted (\$)	0.02	(0.01)	0.05	(0.06)

For the year ended December 31, 2017, the Company recognized a net income of \$17.2 million compared to a net loss of \$19.9 million in 2016. The increase in net income in 2017 is primarily a result of increased revenue from higher realized well-head prices and a tax recovery due to recognition of a deferred income tax asset partially offset by higher royalties and production costs.

	Three months ended December 31		Year ended December 31	
	2017	2016	2017	2016
<i>(\$000s)</i>				
Cash flow from operating activities	17,474	15,079	58,115	42,491
Adjusted funds flow <sup>(1)</sup>	18,902	15,798	59,417	44,775

(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 33% to \$59.4 million during 2017 compared to \$44.8 million in 2016. The increase in adjusted funds flow in 2017 is primarily a result of increased revenue from 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. Cash flow from operating activities is lower than adjusted funds flow due to decommissioning costs incurred of \$0.8 million and changes in non-cash working capital of \$0.5 million for the year ended December 31, 2017.

## LIQUIDITY AND CAPITAL RESOURCES

The Company will generally utilize cash flow from operating activities and available credit facilities to fund its capital spending programs and repay debt. In addition, from time to time the Company will seek additional capital in the form of debt, equity or the disposition of properties.

<i>(\$000s)</i>	<b>December 31, 2017</b>	December 31, 2016
Working capital deficiency	<b>23,912</b>	4,591
Long-term debt	<b>92,944</b>	–
Net debt <sup>(1)</sup>	<b>116,856</b>	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.

At year-end, the Company had a working capital deficiency of \$23.9 million. The deficiency is expected to be eliminated using our existing available credit facilities and cash flow from operating activities. At December 31, 2017, the Company had senior credit facilities of \$120 million, consisting of a \$110 million syndicated revolving line of credit and a non-syndicated operating line of credit of \$10 million. At December 31, 2017, \$20 million was drawn on these credit facilities and the Company had issued letters of credit in the amount of \$20,000; leaving \$100 million available to be drawn under these credit facilities. The facilities are secured by a floating and fixed charge debenture on the assets of the Company. The amount available under these facilities ("Borrowing Base") is re-determined at least twice a year and is primarily based on the Company's oil and gas reserves, the lending institution's forecast commodity prices, the current economic environment and other factors as determined by the syndicate of lending institutions. If the total advances made under the credit facilities are greater than the re-determined Borrowing Base, the Company has 60 days to repay any shortfall. The next scheduled Borrowing Base redetermination is to occur by May 31, 2018. 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.

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 3.2:1 at December 31, 2017 (December 31, 2016 – 7.2:1).

<i>(\$000s, except working capital ratio)</i>	<b>Year ended December 31, 2017</b>	Year ended December 31, 2016
Current assets per consolidated financial statements	<b>26,603</b>	19,510
Add: amount available to be drawn on credit facilities	<b>100,000</b>	117,500
Less: current risk management assets	<b>(2,541)</b>	–
Current assets for working capital ratio	<b>124,062</b>	137,010
Current liabilities per consolidated financial statements	<b>51,064</b>	24,505
Less: current risk management liabilities	<b>(11,798)</b>	(5,507)
Current liabilities for working capital ratio	<b>39,266</b>	18,998
Working capital ratio	<b>3.2</b>	7.2

In June 2017, the Company issued \$75 million of 8% senior secured second lien notes. The terms of the senior secured second lien notes included certain additional 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 any amounts drawn on the senior credit facilities plus any letters of credit outstanding. 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 1.5:1 and a senior credit facilities debt to EBITDA ratio of 0.3:1 at December 31, 2017.

In addition, the Company is required to pass an asset coverage ratio test twice a year. The Company is required to maintain a ratio of at least 1.5:1. The asset coverage ratio is defined as the discounted pre-tax net present value of the Company's total proved reserves at strip pricing discounted at 10% compared to total debt. The Company had an asset coverage ratio of 3.4:1 at December 31, 2017.

At December 31, 2017, the Company was in compliance with all debt covenants.

The Company's primary focus in 2017 was the construction of the second 6,000 bbls/d phase of the Onion Lake thermal project. Construction of the second phase began in the first quarter of 2017 and total estimated costs for the project are between \$180 and \$185 million. Proceeds from the issuance of the senior secured second lien notes, the Company's borrowing capacity on our existing senior credit facilities and cash flow from operating activities were used to fund the construction of the second phase of our Onion Lake thermal project.

At December 31, 2017, there were 336,267,235 common shares issued and outstanding. During the year the Company issued 318,340 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 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 agreement restricts the payment of cash dividends to shareholders.

## CAPITAL EXPENDITURES

Capital spending increased in 2017 to \$169.9 million compared to \$10.9 million in 2016. The majority of the capital spending during the year related to the construction of the second phase of the Onion Lake thermal project.

(\$000s)	Three months ended December 31		Year ended December 31	
	2017	2016	2017	2016
Land	1,607	428	8,311	1,172
Seismic	7	9	81	4
Drilling and completion	5,701	560	34,153	3,282
Equipment and facilities	37,119	5,079	127,262	6,327
Other	101	74	110	140
Total	44,535	6,150	169,917	10,925
Property acquisitions	-	-	-	-
Total capital expenditures	44,535	6,150	169,917	10,925
Proceeds on disposition	-	(55,000)	(3,421)	(55,000)
Net capital expenditures	44,535	(48,850)	166,496	(44,075)

## 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 December 31, 2017. These obligations are expected to be funded from cash flow from operating activities and the Company's credit facilities.

(\$000s)	2018	2019	2020	2021	2022	Thereafter
Operating leases <sup>(1)</sup>	835	646	492	421	–	–
Electrical service agreement <sup>(2)</sup>	585	119	119	119	119	1,749
Transportation service agreement <sup>(3)</sup>	135	135	34	–	–	–
Decommissioning liabilities <sup>(4)</sup>	1,176	339	8,822	3,354	1,617	72,687
Capital commitments <sup>(5)</sup>	5,000	5,000	–	–	–	–
Senior credit facilities <sup>(6)</sup>	–	20,000	–	–	–	–
Senior secured second lien notes <sup>(7)</sup>	–	–	75,000	–	–	–
Interest payments on long-term debt <sup>(6,7)</sup>	6,680	6,283	3,000	–	–	–
	14,411	32,522	87,467	3,894	1,736	74,436

(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 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 \$88.0 million as at December 31, 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) Based on the existing terms of the Company's revolving and operating lines of credit, the first possible mandatory repayment date (assuming no changes in the Borrowing Base amount – see note 12 in the Company's consolidated financial statements) may come in 2019 assuming these facilities are not extended during the scheduled credit facility review in May 2018. At this time management expects the facility will be extended. Amounts include principal and interest. Interest is based on existing rate of 3.4% at December 31, 2017.

(7) 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 December 31, 2017 include cash and cash equivalents, trade and other receivables, deposits within prepaid expenses and deposits, accounts payable and accrued liabilities and 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).

### Foreign Currency 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, accounts receivable, and accounts payable are denominated in US dollars.

As at December 31, 2017, the Company held US \$2.9 million (2016 – US \$0.4 million) in cash and cash equivalents. The polymer we purchase for our ASP flood at Mooney is paid in US dollars. Fluctuations in exchange rates will have an impact in the Company's cost of polymer. In 2017, we spent approximately US\$1.8 million (2016 – US \$0.3 million) on polymer.

In 2017, a \$0.01 change in the average exchange rate between the US and Canadian dollar would have changed oil and gas sales by approximately \$1.5 million (2016 – \$1.4 million). In addition, if exchange rates to convert from US dollars to Canadian dollars had been \$0.10 lower with all other variables held constant, after tax net income for the year would have been approximately \$0.3 million lower as a result of the re-valuation of the Company's US dollar denominated financial assets and liabilities as at December 31, 2017 (after tax loss for 2016 – \$0.1 million higher). An equal opposite impact would have occurred to net loss had exchange rates been \$0.10 higher. The Company does not hedge its foreign currency risk.

### Credit Risk

Credit risk is the risk that a third party fails to meet its contractual obligations in a way that could result in the Company incurring a loss. The Company's credit risk is primarily related to its holdings of cash and cash equivalents and trade and other receivables.

As at December 31, 2017, the Company held \$8.2 million (2016 – \$5.4 million) in cash at various major financial institutions throughout Canada and the USA; however, one Canadian financial institution held over 68% (2016 – 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. Cash balances in excess of the Company's day to day requirements are invested in short-term deposits of less than 30 days.

At December 31, 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 2017 and 2016, the Company did not experience any collection issues with its marketers.

In 2017, the Company had four customers (2016 – four) which individually accounted for more than 10 percent of its total oil and gas sales. Cumulatively, these customers represented approximately 79% of the Company's total oil and gas sales in 2017 (2016 – 87%).

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 2017 and 2016, 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.

### Interest Rate Risk

Interest rate risk is the risk that future cash flows of a financial instrument will fluctuate due to changes in interest rates. The Company is exposed to interest rate risk primarily related to its cash and cash equivalents and its long-term debt. The Company has not entered into any fixed rate contracts to mitigate its interest rate risk.

The Company is exposed to interest rate risk related to interest expense on its senior credit facility due to the floating interest rate charged on advances. For the year ended December 31, 2017, if interest rates had been one percent higher with all other variables held constant, after tax net income for the year would have been approximately \$0.6 million lower (after tax net loss for 2016 – \$0.8 million higher).

The Company is also exposed to interest rate risk on its excess cash balances. As at December 31, 2017, if interest rates had been one percent higher, with all other variables held constant, after tax net income for the year would have been approximately \$0.2 million higher (after tax net loss for 2016 – \$0.1 million lower).

### 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 December 31, 2017, the Company had \$100 million available on its senior credit facilities. Management believes that these sources will be adequate to settle the Company's financial liabilities and commitments.

### 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 and shutting-in high operating costs wells as appropriate. 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 activities. As the Company's thermal projects continue to be commercially developed, natural gas will continue to become a more significant input cost to the Company.

In 2017, if our average oil wellhead sales price decreased \$1.00 with all other variables held constant, our after tax net income for the year would have been approximately \$1.2 million higher (2016 – \$1.1 million higher). An equal opposite impact would have occurred to net loss had average oil wellhead sales price been \$1.00 higher.

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

## OFF-BALANCE-SHEET ARRANGEMENTS

The Company had no off-balance-sheet arrangements during the year ended 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 related-party transactions during the year ended 2017 or 2016 except for key management compensation. Key management compensation has been disclosed in the Company's consolidated financial statements (Note 15).

## OUTSTANDING SHARE DATA AND STOCK OPTIONS

As at February 21, 2018, the Company had 336,275,568 common shares outstanding, 1,710,000 RSU and 26,552,163 stock options outstanding under its stock-based compensation program.

## OUTSTANDING LONG-TERM DEBT DATA

As at February 21, 2018, the Company had drawn \$30,550,000 under its existing senior credit facilities and had issued letters of credit in the amount of \$20,000; leaving \$89,430,000 available to be drawn under these senior credit facilities. The Company had \$75,000,000 outstanding on its senior secured second lien notes on February 21, 2018.

## PROPOSED TRANSACTIONS

As of February 21, 2018, the Company does not have any significant pending transactions.

## SIGNIFICANT ACCOUNTING JUDGEMENTS AND ESTIMATES

The timely preparation of the 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 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 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. A comprehensive discussion of the significant accounting policies adopted by BlackPearl can be found in notes 3 and 4 to the consolidated financial statements.

### (a) Significant accounting judgements

Areas where management exercised judgement in the process of applying accounting policies that have the most significant effect on the amounts recognized in the Company's consolidated financial statements include:

#### (i) Identification of CGUs

The Company's exploration and evaluation costs and property, plant and equipment costs are aggregated into CGUs. CGUs are defined as the lowest level of integrated assets for which there are separately identifiable cash flows that are largely independent of cash flows from other assets or groups of assets. The classification of assets into CGUs requires significant judgement and interpretation by management. Factors considered in the classification of CGUs include integration between assets, shared infrastructure, common sales points, similar geological structure, geographical proximity and the manner in which management monitors and makes decisions about operations. The recoverability of the Company's long-lived assets is assessed at the CGU level and as such; the determination of the CGU could have a significant impact on impairment losses.

#### (ii) Exploration and evaluation assets

The application of the Company's accounting policy for exploration and evaluation (E&E) assets requires judgement in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined. Factors such as proved and probable reserves, drilling results, future capital programs and future operating costs are considered. If it is determined that an E&E asset is not technically feasible and commercially viable or management decides not to continue E&E activity, the unrecoverable E&E costs are charged to exploration expense.

The decision to transfer exploration and evaluation assets to property, plant and equipment is when technical feasibility and commercial viability is established. Technical feasibility and commercial viability is established when significant proved reserves are recognized and regulatory approval has been obtained.

*(iii) 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 what the counterparty is entitled to and the associated risks and rewards attributable to them over the life of the property including the contractual terms 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.

**(b) Significant accounting estimates**

Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recognized in the period in which the estimates are revised. The following are the key accounting estimates at the end of the reporting period that if a change were to occur; it could result in a material adjustment to the carrying value of assets and liabilities within the next financial year.

*(i) Depletion and reserves*

Depletion is based on the proved plus probable reserve estimates as evaluated in accordance with the COGE Handbook. The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. Future development costs are estimated using assumptions as to the number of wells required to produce commercial reserves, the cost of such wells and associated production facilities and other capital costs. Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, subjective decisions, new geological or production information and changing environment may impact these estimates.

Changes in these variables could significantly impact the reserves estimates which would have significant impact on the impairment test and depletion expense of the Company's long-lived assets. The Company's oil and natural gas reserves are evaluated and reported to the Company by independent qualified reserve evaluators.

Certain costs related to exploration and evaluation assets have been excluded from costs subject to depletion. These costs relate primarily to the Blackrod property and will continue to be classified as E&E until the projects are technically feasible and commercially viable or their value is impaired. Technical feasibility and commercial viability is established when significant proved reserves are recognized and regulatory approval has been obtained. In 2016, the Company received regulatory approval for Blackrod SAGD commercial development; however, significant proved reserves have yet to be recognized to date. At December 31, 2017, \$175.0 million has been excluded from depletion and has been shown separately as exploration and evaluation assets on the Company's consolidated balance sheet.

*(ii) Impairment*

The carrying value of the Company's long-lived assets is assessed for impairment at least annually and reviewed at each reporting date for indicators that the carrying value of an asset or CGU may be impaired. The recoverable amount of individual assets and CGUs is the greater of their fair value less costs of disposal and its value in use. These calculations require the use of estimates and assumptions and are subject to change as new information becomes available. Unless indicated otherwise, the recoverable amount used in assessing impairment charges is fair value less costs of disposal. The Company estimates fair value less costs of disposal using an after tax discounted cash flow model which has a number

of assumptions. The model uses expected cash flows from proved plus probable reserves and, in certain circumstances, risk adjusted contingent resources as estimated by the Company's third party reserve evaluators. Reserve estimates and expected future cash flows from production of reserves are subject to measurement uncertainty as discussed above and subject to variability to changes in forecasted commodity prices. The discount rate applied to the cash flows is also subject to management's judgment and will affect the recoverable amount calculated. Changes in estimates and assumptions used in determining the recoverable amount could affect the carrying value of the related assets.

Commodity price changes impact the expected future cash flows which may require a material adjustment to the carrying value of property, plant and equipment and E&E assets. The summary of the commodity price forecast and discount rates used to assess CGU impairment in 2017 is disclosed in Note 8 of the Company's consolidated financial statements.

In 2017 and 2016 we had five CGU's, one for each of our core areas and two CGU's for some of our minor properties. At December 31, 2017, the Company performed a review at each of our CGUs for any indication of impairment and determined that there were impairment indicators at the Blackrod CGU. The Company performed impairment calculations on the Blackrod CGU to assess whether the respective carrying value was recoverable. At December 31, 2017, the recoverable amount at the Blackrod CGU were greater than the carrying value and no impairment was recorded.

#### *(iii) Decommissioning costs*

Provisions are recognized for future decommissioning costs of the Company's E&E and oil and natural gas assets at the end of their economic lives. Decommissioning costs are uncertain and cost estimates can vary in response to many factors including change to relevant legal and regulatory requirements, the emergence of new restoration techniques, or experience at other production sites. The expected timing and amount of expenditure can also change in response to changes in reserves and or changes in laws and regulations or their interpretations. Assumptions have been made to estimate the future liability based on past experience and current factors which management believes are reasonable. However, the actual cost of decommissioning is uncertain and the difference between actual and estimated costs on the consolidated financial statements of future periods may be material. In addition, management determines the appropriate discount rates at the end of each reporting period to determine the present value of the estimated future cash outflows required to settle the decommissioning obligations and may change in response to numerous risk factors including the risk-free rate and future inflation rates. The inflation factor and discount rates used in determining decommissioning liabilities at December 31, 2017 is disclosed in Note 10 of the Company's consolidated financial statements.

#### *(iv) Deferred tax*

Judgment is required in the calculation of current and deferred taxes in applying tax laws and regulations, estimating the time of the reversal of temporary differences and estimating the ability to realize deferred tax assets. Assessing the recoverability of deferred tax assets requires the Company to make estimates related to the expectations of future cash flow from operations. To the extent that future cash flows and taxable income differ from estimates, the ability of the Company to realize the deferred tax assets and liabilities recorded at the balance sheet date could be impacted. Additionally, changes in tax laws could limit the ability of the Company to obtain tax deductions in the future. These estimates impact current and deferred tax assets and liabilities, and current and deferred tax expense (recovery).

#### *(v) Stock-based compensation*

The Company uses the Black-Scholes option pricing model to determine the fair value of stock options granted. The Black-Scholes option pricing model requires the Company to make certain assumptions including the expected life, share price volatility, expected forfeitures and anticipated dividends over the life of the options. Changes in these assumptions can materially affect the fair value estimate of the options which can impact stock-based compensation expense, stock-based compensation capitalized and contributed surplus.

(vi) *Risk management contracts*

The estimated fair value of the Company's risk management contracts by their very nature, are subject to measurement uncertainty. Estimates included in the determination of the fair value of risk management contracts include forward benchmark prices, discount rates and forward foreign exchange rates. Changes in estimates and assumptions used in determining the fair value could affect the carrying value of the related assets (liabilities).

## 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 consolidated 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 and the Company will adopt the new standard using the modified retrospective method. The Company has evaluated the impact of adopting IFRS 15 on the consolidated financial statements and it will not have a material impact. The Company will be required to provide enhanced disclosures relating to the disaggregation of revenues from contracts with customers, the Company's performance obligations and any significant judgements.

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. The Company has evaluated the impact of adopting IFRS 9 on the financial statements and will adopt the new standard using the modified retrospective method effective January 1, 2018. The new standard will result in a change of accounting policy for impairment of trade and other receivables using an expected credit loss model as compared to incurred loss model required by IAS 39. The Company will apply the simplified approach to providing for expected credit losses prescribed by IFRS 9, which requires the use of the lifetime expected loss provision for all trade receivables. In estimating the lifetime expected loss provision, the Company considered historical industry default rates as well as credit ratings of major customers. The effect of this change in accounting policy will not have a material impact on the Company's consolidated financial statements. Other financial instruments are not expected to have a material impact on the adoption of this standard.

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 identifying, gathering and analyzing contracts impacted by the adoption of the new standard, as well as evaluating the system requirements for implementation. The Company is continuing to evaluate the impact of adopting IFRS 16 on the Company's consolidated financial statements.

## RISK FACTORS

The Company is exposed to a number of risks and uncertainties inherent in exploring for, developing and producing crude oil and natural gas. Many of the risk factors and uncertainties are beyond the Company's control and it is impossible to ensure that any exploration drilling program or piloting program will ultimately result in commercial operations.

A full discussion of risk factors affecting the Company can be found in our Annual Information Form for the year ended December 31, 2017. The following explains how certain material principal and strategic risk factors impact our business:

### Financial risks

#### *Volatility of Oil and Natural Gas Prices*

The Company's revenues, cash flow, results of operations and financial condition are dependent upon, among other things, the price it receives from the sale of its crude oil and natural gas production. Historically, crude oil markets have been volatile and are likely to continue to be volatile in the future. These fluctuations in price are in response to factors including, but not limited to, supply and demand for crude oil and natural gas, market uncertainty, world economic conditions, government regulation, political instability, availability of refining capacity and transportation infrastructure, the ability to transport crude to markets, weather conditions and the prices and availability of alternative forms of energy, all of which are generally beyond the control of the Company and can result in a high degree of price volatility. Any decline in oil prices or continued periods of depressed oil prices could have a material adverse effect on BlackPearl's revenues, cash flow, financial condition and the value of the Company's oil and gas reserves.

The Company's financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. Of particular importance are the price differentials between the Company's heavy crude oil (in particular the heavy crude oil differential) and quoted market prices. The market price for heavy crude oil and bitumen is generally lower than market prices for light oil, due principally to the higher costs associated with refining a barrel of heavy crude oil and higher transportation costs (diluent is required to be purchased and blended with heavy crude oil to transport on most pipelines). Heavy crude oil differentials are also influenced by other factors such as capacity and interruptions, refining demand and the quality of the oil produced, all of which are beyond the Company's control. Over 99% of BlackPearl's production is from heavy crude oil and bitumen. It is difficult to predict future price differentials and any increase in heavy crude oil differentials could have an adverse effect on the Company's business, financial condition, results of operations and cash flows.

Fluctuations or depression in the price of commodities and price differentials may impact the value of the Company's assets, the Company's ability to maintain its business and to fund growth projects, including, but not limited to, the continued development of its oil sand property. Prolonged periods of commodity price volatility may also negatively impact the Company's ability to meet guidance targets.

Crude oil prices were higher in 2017 compared to 2016. WTI oil prices averaged US\$50.95 per bbl in 2017, 18% higher than the average of US\$43.32 per bbl in 2016. With the improvement in crude oil prices in 2017, we selectively brought back on production at certain shut-in wells that were previously uneconomic and proceeded to develop the second phase of the Onion Lake thermal project. However, even at these improved oil prices in 2017, the Company has deferred development of some its projects. An extended decline in the price of crude oil could result in the further delay or cancellation of future drilling programs or construction projects which could also negatively impact BlackPearl's business, financial condition, results of operations, cash flows and value of its oil and gas reserves.

The Company conducts an assessment of the carrying value of its assets in accordance with International Financial Reporting Standards, if indicators of impairment exist. For the year ended December 31, 2017, no impairment was recorded at any of the Company's oil and natural gas assets. If oil and natural gas prices were to decline and remain at low levels for an extended

period of time, the carrying value of the Company's assets may be subject to impairment. See the Company's audited consolidated financial statements for the year ended December 31, 2017 for additional financial information related to impairment.

### *Indebtedness*

BlackPearl currently has \$120.0 million in senior credit facilities. As at December 31, 2017, the Company had \$20.0 million drawn under these facilities. 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. At December 31, 2017, the carrying value of the senior secured notes was \$72.9 million, net of unamortized debt issuance costs.

The Company is subject to a number of financial covenants under the terms of its senior credit facilities and senior secured notes. In the event the Company does not satisfy these covenants, it may be notified that it is in default and could be restricted from borrowing additional amounts under its senior credit facilities or it may be required to repay all or a portion of the amounts owing under its senior credit facilities or senior secured notes .

In addition, the maximum amount we are permitted to borrow under our senior credit facilities is subject to periodic review by the lenders, typically semi-annually. BlackPearl's lenders generally review its oil and gas production and reserves, forecast oil and gas prices, general business environment and other factors to establish the amount we are entitled to borrow. In the event the lenders decide to reduce the amount of credit available under our senior credit facilities, the Company may be required to repay all or a portion of the amounts owing thereunder.

The Company's ability to make payments under its senior credit facilities or senior secured notes, to refinance its future indebtedness, and to fund planned capital expenditures will depend upon, among other things, the Company's ability to generate cash in the future which, in turn, is subject to general economic, financial, competitive, legislative, regulatory and other factors, many of which are beyond the Company's control. If BlackPearl is unable to make payments under its senior credit facilities or senior secured notes, the lenders could foreclose on the Company's assets and there is no assurance that the proceeds from the sale of the assets would be sufficient to repay the full amount owing to all creditors.

## **Operational risks**

### *Exploration, Development and Production Risks*

The long-term success of BlackPearl depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves from exploration, development or acquisition activities, BlackPearl's existing reserves and production will decline over time. Production decline rates will vary by the type of reservoir, age of the wells and other factors and are not necessarily indicative of future performance.

Future increases in BlackPearl's oil and gas reserves will depend not only on the Company's ability to explore and develop any properties it may have from time to time, but also on its ability to generate or raise sufficient capital to make the necessary investments to replace or expand its oil and gas reserves.

There is no assurance that expenditures made on future exploration, development or acquisition by BlackPearl will result in new discoveries of oil or natural gas in commercial quantities.

### *Uncertainty of Reserve and Contingent Resource Estimates*

There are numerous uncertainties inherent in estimating quantities of proved and probable reserves and quantities of contingent resources and future net revenues to be derived therefrom, including many factors beyond the control of the Company. The reserves, contingent resources and future net cash flow information set forth in the 2017 Annual Information Form represent estimates only. While the reserves, contingent resources and future net cash flow information from the Company's properties have been independently evaluated by Sproule in the Sproule Report, these evaluations include a number of assumptions, including, but not limited to, such factors as initial production rates, production decline rates, ultimate recovery

of reserves and contingent resources, timing and amount of capital expenditures, marketability of production, future prices of oil, bitumen and natural gas, operating costs, abandonment and reclamation costs, royalties and other government levies that may be imposed over the producing life of the reserves and resources. These assumptions were based on prices in use at the date the relevant evaluations were prepared, and many of these assumptions are subject to change and are beyond the control of the Company. Actual production and cash flow generated from this production will vary from these evaluations, and these variations could be material.

The present value of the Company's estimated future net revenue disclosed in the 2017 Annual Information Form or the Sproule Report should not be construed as the fair market value of the Company's reserves and contingent resources, as applicable.

BlackPearl has limited SAGD production history from its planned SAGD thermal project at Blackrod. Estimates with respect to reserves and contingent resources that may be developed and produced in the future are often based upon volumetric calculations, and upon analogy to similar types of reserves and contingent resources, rather than those based on actual production history. Subsequent evaluation of the same reserves and contingent resources based upon production history will result in variations, which may be material, in the estimated reserves or contingent resources.

In addition, the reserves and contingent resource estimates have been determined based upon assumed commodity prices and operating costs. Market price fluctuations of heavy crude oil, bitumen and natural gas prices and an increase in actual operating costs experienced on a project may render the recovery of the reserves or contingent resources uneconomic.

A portion of BlackPearl's reserves and contingent resources are non-producing or undeveloped. The reserves and contingent resources may not ultimately be developed or produced, either because it may not be commercially viable to do so or for other reasons. In addition, not all of the Company's undeveloped reserves and contingent resources may be ultimately produced within the time period BlackPearl has planned, at the costs the Company has budgeted, or at all.

The estimates of reserves, contingent resources and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves, contingent resources and future net revenue for all properties due to the effects of aggregation.

## Regulatory and Environmental risks

### *Government Regulations*

The Company's operations are subject to various levels of government regulation and law. These regulations and laws include, among other things, matters related to land tenure, drilling, production practices, environmental protection, royalties, carbon tax, marketing and pricing, reporting requirements under ESTMA and various taxes and levies. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and gas industry could have a material adverse impact on the Company's business, financial condition, results of operations and cash flows.

In general, the operations of BlackPearl require licenses and permits from various governmental authorities. The construction and operation of the thermal projects at Blackrod and Onion Lake will require various environmental and other regulatory approvals. During 2016, the Company received regulatory and environment approval for the first phase of the Blackrod SAGD development project; however, additional approvals will be required at various stages of developing this project. Any future phases of the Onion Lake thermal project will also require additional regulatory approvals at various stages of development.

There is no assurance that the applicable government authorities will issue the additional approvals required or that a third party will not object to the development of these projects. In addition, once permits are issued there is no assurance that the approvals will be renewed, or that they will not be repealed, or that they will not contain terms and conditions which make the Company's projects and operations uneconomic or cause the Company to significantly alter its projects and operations.

In response to recent court decisions, the AER 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.

Changes in government laws and regulations may be enacted which could impose higher standards which may increase the cost of our operations and have a material adverse effect on our business, financial condition, results of operations and cash flows. No assurance can be given that future government laws and regulations will not adversely impact the Company's ability to develop or operate its projects. A breach of government laws or regulations could occur and any such event may be material and could have material adverse effect on the financial condition, results of operations, cash flows and reputation of the Company.

#### *Environmental Regulations*

Our oil and gas operations are subject to significant environmental local, provincial and federal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells and facility sites be constructed, operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities.

Compliance with environmental legislation can require significant expenditures and failure to comply with these laws and regulations may result in the assessment of fines and penalties, orders to remediate property contamination and the issuance of injunctions that could limit or prohibit our operations, all of which could have a material adverse effect on the Company. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require BlackPearl to incur costs to remedy such discharge. It is likely the trend to stricter environmental regulation will continue.

Changes in environmental laws and regulations may be enacted which could impose higher environmental standards which may increase the cost of our operations and have a material adverse effect on our business, financial condition, results of operations and cash flows. No assurance can be given that future environmental laws and regulations will not adversely impact the Company's ability to develop or operate its projects. A breach of environmental laws or regulations could occur and any such event could have a material adverse effect on the financial condition, results of operations, cash flows and reputation of the Company.

#### *Climate Change Regulations*

GHG emission regulations in Canada and the US are evolving, but as these regulations are established they are likely to have a significant impact on organizations involved in the oil sands regions, including BlackPearl. It is difficult to assess the overall impact these regulations will have on BlackPearl at this time but it could result in increased costs to comply, delays in having projects approved and potentially a reduction in demand for oil from these regions, all of which could have a material negative impact on our business.

The direct and indirect costs of the various GHG regulations, existing and proposed, may adversely affect our business, operations and financial results. Equipment that meets future emission standards may not be available on an economic basis and other compliance methods to reduce our emissions or emissions intensity to future required levels may significantly increase operating costs or reduce the output of the projects. Offset, performance or fund credits may not be available for acquisition or may not be available on an economic basis. Any failure to meet emission reduction compliance obligations may materially and adversely affect BlackPearl's business and result in fines, penalties and the suspension of operations.

There is also a risk that one or more levels of government could impose additional emissions or emissions intensity reduction requirements or taxes on emissions created by BlackPearl or by consumers of BlackPearl's products. The imposition of such

measures might negatively affect BlackPearl's costs and prices for BlackPearl's products and have an adverse effect on earnings and results of operations.

Future federal legislation, including potential international requirements enacted under Canadian law, as well as provincial emissions reduction requirements, may require the reduction of GHG or other industrial air emissions, or emissions intensity, from BlackPearl's operations and facilities. Mandatory emissions reduction requirements may result in increased operating costs and capital expenditures for oil and natural gas producers. The Company is unable to predict the impact of emissions reduction legislation on the Company and it is possible that such legislation may have a material adverse effect on its business, financial condition, results of operations and cash flows.

Various foreign jurisdictions have proposed restrictions or penalties on the importation of emission-intensive fuel sources, which may impact the importation of bitumen from oil sands regions. These restrictions could limit the markets in which BlackPearl and other bitumen producers can sell their oil, which could result in lower sales prices for our heavy crude oil and bitumen. In addition, the Canadian federal government has indicated that it may restrict the export of bitumen to countries with less stringent GHG emissions standards than Canada. If implemented, these restrictions could reduce the markets we are able to sell our bitumen products to, which may result in lower sales prices.

On January 1, 2017, the Alberta government enacted new climate change regulations which includes an economy-wide carbon tax that applies across all sectors, in addition to the existing levy on large industrial emitters, and a cap on oil sand emissions with a limit of 100 megatonnes of emissions from the industry in any year by 2030. Currently the Alberta carbon tax has a minimal effect on the Company's earnings and cash flow as the majority of our production comes from Saskatchewan and conventional production in Alberta is exempt from the carbon tax until 2023. The only production the Company has that is currently subject to the Alberta carbon tax is from the Blackrod property. During the year-ended December 31, 2017, the Company paid \$0.4 million in Alberta carbon tax at this property and this amount will increase in 2018 as the carbon tax rate increases.

Alberta's new climate change regulations could have a material adverse impact on the Company's earnings and cash flow in the future and could make future capital investments or the Company's operations uneconomic. The new regulations may also have an impact on the costs of the Company's exploration and development activities in Alberta as a result of the imposition of the economy-wide carbon tax. There is no assurance that the new regulations will not affect the development of the Blackrod SAGD project.

On December 9, 2016, the federal government and all the provinces, except Saskatchewan and Manitoba, signed the Pan-Canadian Framework to meet the federal government's 2030 target of a 30% reduction in GHG emissions below 2005 levels. The Pan-Canadian Framework requires all provinces and territories to adopt a carbon pricing "backstop" specified by the federal government or otherwise implement an equivalent carbon pricing scheme by the fall of 2018. For those provinces, including Alberta, that have already established a carbon tax or a cap-and-trade regime, or both, the federal price on carbon will likely have little additional impact in the short term. However, none of the provinces have yet announced how they intend to comply with the long-term carbon pricing requirements proposed by the federal government. New regulations could have a material adverse impact on the Company's earnings and cash flow in the future and could make future capital investments or the Company's operations uneconomic. There is no assurance that new regulations will not affect the development of the Blackrod SAGD project or any future phases of the Onion Lake thermal project.

On December 4, 2017, the Government of Saskatchewan introduced the province's climate change strategy, which is to be fully implemented by January 1, 2019. The strategy includes reporting requirements and emissions reduction targets for the upstream oil and gas industry and output-based performance standards for facilities emitting more than 25,000 tonnes of carbon dioxide equivalent per year. The strategy is currently out for comment and consultation and, to date, no legislation or amendments to legislation have been introduced in respect of the strategy. It is unclear if Saskatchewan's announced strategy

will comply with the Pan-Canadian Framework, particularly as it does not include a carbon pricing scheme. The proposed Saskatchewan climate change strategy could have a material adverse impact on the Company's earnings and cash flow in the future and could make future capital investments or the Company's operations uneconomic. There is no assurance that the strategy will not affect the development of any future phases of the Onion Lake thermal project.

Climate change laws and regulations that impose higher climate change standards may be enacted in the future, which may increase the cost of our operations and have a material adverse effect on our business, financial condition, results of operations and cash flows. No assurance can be given that future climate change laws and regulations will not adversely impact the Company's ability to develop or operate its projects. A breach of climate change laws or regulations could occur and any such event may be material and could have material adverse effect on the financial condition, results of operations, cash flows and reputation of the Company.

## Other Risks

### Information Systems

The Company has become increasingly dependent on information systems to conduct day-to-day operations, including certain of our exploration, development and production activities. We depend on information systems, among other things, to estimate quantities of oil and natural gas reserves, process and recorded financial and operating data, analyze seismic and drilling information, process electronic payment transfers and store banking information, monitor and control pipeline and plant equipment, process and store personally identifiable information of our employees, contractors and royalty owners and communicate with employees, stakeholders and business associates. The Company is subject to a variety of information system risks including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach and destruction or interruption of the Company's information systems by third parties or insiders that could result in the disruption of our business operations and/or financial loss.

Management is responsible for overseeing the Company's information systems and although we have security measures and controls in place that are designed to monitor and protect against these threats and mitigate these risks, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. A breach of security measures and/or a loss of information could occur and result in a loss of material and confidential information and reputation, breach of privacy laws and a disruption to its business activities. Any such event may be material and could have material adverse effect on the financial condition, results of operations, cash flows and reputation of the Company.

## CONTROL CERTIFICATION

### Disclosure Controls and Procedures

Disclosure controls and procedures ("DC&P") as defined in National Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*, means controls and other procedures of an issuer that are designed to provide reasonable assurance that information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by an issuer in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the issuer's management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure. The Chief Executive Officer and Chief Financial Officer of the Company evaluated the effectiveness of the design and operation of the Company's DC&P. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's DC&P were effective as at December 31, 2017.

### Internal Controls over Financial Reporting

Internal control over financial reporting ("ICFR"), as defined in National Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*, means a process designed by, or under the supervision of, an issuer's certifying officers, and effected by the issuer's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP and includes those policies and procedures that:

- (a) Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the issuer;
- (b) Are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with the issuer's GAAP, and that receipts and expenditures of the issuer are being made only in accordance with authorizations of management and directors of the issuer; and
- (c) Are designed to provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the issuer's assets that could have a material effect on the annual financial statements or interim financial reports.

The Chief Executive Officer and the Chief Financial Officer are responsible for establishing and maintaining ICFR for the Company. The control framework the Chief Executive Officer and the Chief Financial Officer used to design the Company's ICFR is the Internal Control – Integrated Framework (2013) published by The Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Under the supervision of the Chief Executive Officer and the Chief Financial Officer, the Company conducted an evaluation of the effectiveness of the Company's ICFR in accordance with the COSO Framework as at December 31, 2017. Based on this evaluation, the officers concluded that as of December 31, 2017, the Company maintained effective ICFR.

It should be noted that while the Chief Executive Officer and the Chief Financial Officer believe that the Company's DC&P and ICFR provide a reasonable level of assurance that they are effective, they do not expect that the DC&P or ICFR will prevent all errors or fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

There were no changes in the Company's ICFR during the year ended December 31, 2017 that materially affected, or are reasonably likely to materially affect, the Company's ICFR.

## 2017 GUIDANCE AND 2018 OUTLOOK

	2017		2018	
	Initial Guidance	Actual	Initial Guidance	February Update
Production (boe/d)				
Annual average	10,000 – 11,000	10,199	11,000 – 12,000	11,000 – 12,000
Cash flow from operating activities (\$million) <sup>(1)</sup>	65 – 70	58	50 – 55	60 – 65
Adjusted funds flow (\$millions) <sup>(2)</sup>	65 – 70	59	50 – 55	60 – 65
Capital expenditures (\$millions)	200	170	60 – 65	80 – 85
Year-end debt (\$millions)	135 – 140	93	145 – 155	130 – 140
Pricing Assumptions (annual average)				
Crude oil – WTI	US \$54.50	US \$50.95	US \$52.00	US \$62.00
Light/heavy differential	US \$14.75	US \$12.03	US \$14.50	US \$21.50
Foreign Exchange (Cdn\$ to US\$)	0.75	0.77	0.80	0.80
AECO gas (Cdn\$/GJ)	3.00	2.04	2.50	1.65
Average wellhead price	\$45.75	\$43.00	\$39.00	\$43.00

(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.

### 2017 Guidance Compared to Actual

BlackPearl's average oil and gas production of 10,199 boe/day was within the initial guidance range we provided for the year. This is attributable to the positive performance from the Onion Lake thermal project which averaged 5,686 bbls/d during the year.

Cash flow from operating activities and adjusted funds flow were slightly below the guidance range primarily as a result of lower crude oil prices. Our actual wellhead price for 2017 was \$43.00 per bbl compared to \$45.75 per bbl assumed in our guidance.

Capital expenditures of \$170 million in 2017 were below our guidance of \$200 million. Lower capital expenditures in 2017 was primarily due to certain expenditures related to the second phase of the Onion Lake thermal project that were originally planned for 2017 being incurred in the first quarter of 2018. The lower capital spending also contributed to lower year-end debt levels than originally estimated.

### 2018 February Update

Our initial guidance for 2018 was released in November 2017 and as a result of recent volatility in crude oil prices, we have updated our 2018 guidance. We are now assuming a WTI oil price of US \$62.00 per bbl and a heavy oil differential of US \$21.50 per bbl for planning and budget purposes. Capital spending in 2018 is now expected to be between \$80 and \$85 million, an increase from our original estimate of between \$60 and \$65 million. The change reflects costs related to Onion Lake thermal expansion that were originally forecast to be spent in 2017 were not incurred until early in 2018. The focus of our 2018 capital spending continues to be the second phase of the Onion Lake thermal project. Currently, commissioning of the facilities and steam injection at the first well pad has begun. For the remainder of 2018, our capital plans remain unchanged with drilling on some of our conventional heavy oil projects, commence drilling a sustaining well pad for the Onion Lake thermal project and undertaking additional delineation drilling on our Blackrod lands.

A significant portion of these capital costs will continue to be funded with our anticipated adjusted funds flow, which is now budgeted to be between \$60 and \$65 million, an increase from our initial guidance of between \$50 million and \$55 million as the result of improved crude oil prices. As result of the increase in expected adjusted funds flow, our year-end 2018 debt levels decreased from our initial guidance of between \$145 and \$155 million to our current budget of between \$130 and \$140 million.

The average oil and gas production for 2018 remains unchanged and is expected to average between 11,000 and 12,000 boe/d. Exit production levels for 2018 of 14,000 boe/d also remain unchanged.

### Sensitivities for 2018 February Update

The significant factors that would affect forecast adjusted funds flows and net income include commodity prices, heavy oil differentials, exchange rates and production volumes.

<i>(\$millions)</i>	Adjusted Funds Flow <sup>(1)</sup>	Net Income
Price change		
CDN\$5 per bbl change in our realized oil price	17.9	13.1
CDN\$1 per bbl change in production costs	4.1	3.0
Exchange rate		
\$0.02 change in US/CDN rate	4.4	3.2
Production rate		
500 bbl/d change	5.1	5.1

(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.

## 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”, “planning”, “planned”, “could”, “continue”, “continued”, “estimate”, “estimates”, “estimated”, “forecast”, “forecasted”, “likely”, “expect”, “expects”, “expected”, “may”, “impact”, “impacted”, “new”, “will”, “schedule”, “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, completion, first oil and peak production dates for the second phase of the Onion Lake thermal project as discussed in the Overview and 2017 Significant Events section;
- The volumes and estimated value of the Company’s proved and probable reserves as discussed in the 2017 Significant Events section;
- The volumes of the Company’s contingent resources as discussed in the 2017 Significant Events section;
- The expectation of increased oil production in Canada and the need to secure additional pipeline capacity to tidewater and until additional export pipeline capacity is built, incremental oil production is expected to be transported to markets by rail as discussed in the Commodity Prices section;

- The expectation that thermal transportation costs are expected to return to normal rates in 2018 as discussed in the Transportation Costs section;
- A potential future carbon tax in Saskatchewan as the Company awaits legislation as discussed in the Production Costs section;
- Expected stock-based compensation expense for the remainder of 2018, 2019 and 2020 as discussed in the Stock-based Compensation section;
- The expectation that interest capitalized in 2018 will decrease as discussed in the Finance Costs section;
- The expected interest rate charged on our senior credit facilities for 2018 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 during 2018 as discussed in the Income Taxes section;
- Expectation that the Company will utilize certain previously unrecognized tax pools against future taxable income as discussed in the Income Taxes section;
- The Company's expectation that it will not pay 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;
- A number of statements under the Risk Factors section since they relate to future conditions and results; 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.

### CAUTIONARY STATEMENT ON CONTINGENT RESOURCES

This document makes reference to contingent resources. Contingent resources are defined in the COGE Handbook as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets and the uncertainty of timing of producing and development of the entire field. See our Annual Information Form for the year ended December 31, 2017 for detailed descriptions of the contingences for each our core areas.

There is no certainty that it will be commercially viable to produce any of the contingent resources. Best estimate (P50) is a classification of estimated resources described in the COGE Handbook as being considered to be the best estimate of the quantity that will be actually recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate.