BLACKPEARL RESOURCES INC.

700, 444 – 7th Avenue SW, Calgary, AB T2P 0X8
Tel: 403-215-8313 Fax: 403-265-8324
www.blackpearlresources.ca

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BLACKPEARL ANNOUNCES FOURTH QUARTER AND FULL YEAR 2015 FINANCIAL AND OPERATING RESULTS AND YEAR-END RESERVES AND RESOURCES

CALGARY, ALBERTA – BlackPearl Resources Inc. ("we", "our", "us", "BlackPearl" or the "Company") (TSX: PXX) (NASDAQ OMX Stockholm: PXXS) is pleased to announce its financial and operating results for the three and twelve months ended December 31, 2015 as well as the results of its 2015 year-end oil and gas reserves and resources evaluations.

Highlights and accomplishments included:

- Q4 2015 oil and gas production was 9,521 boe/day, a 27% increase from the third quarter. The increase reflects the successful production start-up of our Onion Lake thermal project. For the full year, production averaged 8,330 boe/day in 2015.

- We achieved positive results from our cost reduction strategy in 2015. Operating costs, on a boe basis, were 21% lower in 2015 compared to 2014.

- Q4 2015 revenue was $23 million and funds flow from operations (a non-GAAP measure) was $11 million, down from Q4 2014 as a result of lower oil prices. For the year, oil and gas revenue was $96 million and funds flow from operations was $49 million.

- Capital expenditures in 2015 were $69 million, a decrease from $235 million in 2014.Capital expenditures were reduced in 2015 due to completion of the Onion Lake thermal facilities in the first half of the year and our desire to maintain financial flexibility in this challenging oil price environment.

- At Onion Lake, we completed construction of phase one of the Onion Lake thermal project in the spring and we commenced commercial production at the beginning of the fourth quarter this year. The project is currently producing approximately 4,500 barrels of oil per day and we are continuing to optimize the project and expect to reach design production capacity of 6,000 barrels of oil per day by mid-2016. The project was completed on time and on budget, with capital costs of approximately $225 million.

- At Blackrod, we continue to achieve positive results from the SAGD pilot. In Q4, the second well pair produced an average of 562 bbls/day and for the full year the well produced 500 bbls/day with an average steam oil ratio of 2.75. Cumulatively, the well has produced in excess of 280,000 barrels of oil. These successful results strengthens our confidence that we have the technical information to move towards commercial development. The regulatory review for our 80,000 bbls/day commercial development application, which was filed in 2012, is on-going.

- At Mooney, no new activities were initiated in 2015 as our primary focus was to achieve operating cost savings in the field. Field operating costs decreased over 40% in 2015 compared to 2014.

- Sproule Unconventional Limited ("Sproule"), our independent reserves evaluator, assigned proved plus probable reserves of 294 million barrels of oil equivalent to our properties in their 2015 year-end evaluation. Proved developed producing reserves increased 127% as a result of the reclassification of the reserves assigned to the first phase of the Onion Lake thermal project from undeveloped to producing.

- Risked contingent resources (best estimate) for our three core properties totaled 494 million barrels of oil equivalent.

John Festival, President of BlackPearl, commenting on activities indicated that "although 2015 was a challenging year for the oil and gas sector we still made significant progress in the development of our properties. This included successfully building, commissioning and commencing production of our first commercial thermal project at Onion Lake. Additionally, in 2015, we continued to receive positive results from our SAGD pilot at Blackrod; results that will set us up for commercial development of this large resource when economic conditions permit. We are managing in this low price environment by reducing our costs and limiting capital expenditures to maintain a strong financial position."

Financial and Operating Highlights

	Three months ended December 31,		Twelve months ended December 31,	
	2015	2014	2015	2014
Daily sales volumes				
Oil (bbls/d)	8,785	8,567	7,434	8,492
Bitumen (bbls/d) (1)	562	523	541	380
Combined (bbls/d)	9,347	9,090	7,975	8,872
Natural gas (mcf/d)	1,047	3,294	2,130	2,492
Combined (boe/d) (2)	9,521	9,639	8,330	9,287
Product pricing ($)				
Crude oil - per bbl	27.65	59.34	35.00	72.47
Natural gas - per mcf	2.91	3.39	2.72	4.12
Combined - per boe (2)	27.45	57.00	34.14	70.24
Realized gains on risk management contracts – per boe	12.54	6.97	13.20	0.58
($000s, except where noted)				
Oil and natural gas revenue – gross	22,630	47,798	96,271	228,345
Net income (loss) for the period	(31,172)	16,254	(46,793)	26,825
Per share, basic ($)	(0.09)	0.05	(0.14)	0.08
Per share, diluted ($)	(0.09)	0.05	(0.14)	0.08
Funds flow from operations (3)	10,898	19,716	48,962	89,723
Capital expenditures	1,665	57,700	68,508	235,366
Working capital deficiency (surplus), end of period	(11,063)	18,237	(11,063)	18,237
Long term debt	88,000	29,000	88,000	29,000
Net Debt (4)	76,937	47,237	76,937	47,237
Shares outstanding, end of period (000s)	335,638	335,638	335,638	335,638

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

(2) Boe is based on a conversion ratio of 6 mcf of natural gas to 1 bbl 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 equivalency conversion method primarily applicable at the burner tip and is not intended to represent a value equivalency at the wellhead.

(3) Funds flow from operations is a non-GAAP measure (as defined herein) that represents cash flow from operating activities before decommissioning costs incurred and changes in non-cash working capital related to operations. Funds flow from operations does not have

standardized meanings prescribed by Canadian generally accepted accounting principles ("GAAP") and therefore may not be comparable to similar measures used by other companies. Management uses this non-GAAP measurement for its own performance measures and to provide its shareholders and investors with a measurement of the Company's efficiency and its ability to fund a portion of its growth expenditures.

(4) *Net debt is a non-GAAP measure*

FOURTH QUARTER 2015 ACTIVITIES

Activities in the fourth quarter of 2015 continued to be impacted by lower oil prices. Oil and gas revenues were $22.6 million in the fourth quarter of 2015, 53% lower compared to the same quarter of 2014. The decrease in revenues is primarily attributable to a decrease in our average realized crude oil sales price in Q4 2015. WTI oil prices averaged US$42.18 per barrel in Q4 2015 compared to US$73.15 per barrel in Q4 2014. Lower WTI oil prices combined with comparable heavy oil differentials and a weaker Canadian dollar relative to the US dollar resulted in our wellhead price averaging $27.65 per barrel in the fourth quarter of 2015 compared with $59.34 per barrel in the fourth quarter of 2014.

BlackPearl sold an average of 9,521 boe/day during the fourth quarter of 2015 compared with 9,639 boe/day during the fourth quarter of 2014. Production in the fourth quarter of 2015 increased significantly from the first three quarters of the year (7,930 boe/day) as a result of first commercial production from our Onion Lake thermal project. During the fourth quarter the thermal project produced 3,010 barrels of oil per day.

Production costs were $14.6 million or $17.77 per boe in the fourth quarter of 2015 compared to $21.1million or $25.12 per boe in the fourth quarter of 2014. The decrease in production costs in 2015 is primarily due to on-going field optimization efforts in a low price environment, which included reduced well maintenance work, shutting in some of our high cost production, not re-starting wells that required servicing and lower chemical costs related to our ASP flood at Mooney. General and administrative expenses were $1.8 million in the fourth quarter of 2015 compared to $1.9 million in the fourth quarter of 2014.

Funds flow from operations in the fourth quarter of 2015 was $10.9 million compared to $19.7 million in the fourth quarter of 2014. The decrease reflects lower revenues in Q4 2015. Net loss in the fourth quarter of 2015 was $31.2 million compared to net income of $16.3 million in the fourth quarter of 2014. The net loss in Q4 2015 included a non-cash impairment write-down of $33.0 million related to our Mooney area assets. The write-down is attributable to the current low oil price environment. The net loss in Q4 2015 also includes realized gains on risk management contracts (oil price hedging contracts) of $10.3 million.

Capital expenditures were limited in the fourth quarter of 2015 due to low oil prices. Capital spending was $1.7 million during the quarter compared with $57.7 million in Q4 2014.

Production

BlackPearl's Q4 2015 oil and gas sales volumes were 9,521 boe per day, a 27% increase over production during the third quarter. The increase in fourth quarter production is attributable to initial production from the star-up of our Onion Lake thermal project.

	Three months ended December 31,		Twelve months ended December 31,	
Production by Area (boe/d)	2015	2014	2015	2014
Onion Lake - conventional	2,914	4,651	3,312	4,263
Onion Lake – thermal	3,010	-	951	-
Mooney	1,902	3,236	2,367	3,469
John Lake	955	1,109	989	1,067
Blackrod SAGD Pilot	562	523	541	380
Other	178	120	170	108
Total production	9,521	9,639	8,330	9,287

Operating Netback

	Three months ended December 31,		Twelve months ended December 31,	
($/boe)	2015	2014	2015	2014
Oil and natural gas revenue	27.45	57.00	34.14	70.24
Realized gains on risk management contracts	12.54	6.97	13.20	0.58
	39.99	63.97	47.34	70.82
Royalties	4.35	11.51	5.70	13.49
Transportation costs	1.23	1.48	1.13	1.89
Production costs	17.77	25.12	19.94	25.24
Operating netback(1)	16.64	25.86	20.57	30.20

(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.

Hedging Position

Periodically we will enter into risk management contracts in order to ensure a certain level of cash flow to fund planned capital projects. The table below summarizes the Company's current risk management contracts:

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

(1) WCS refers to Western Canadian Select, a heavy oil reference price in Alberta
(2)WTI refers to West Texas Intermediate, a light oil reference price in Cushing Oklahoma

2016 Outlook - February Update

Our initial guidance for 2016 was released in December 2015 and as a result of the continued decrease in crude oil prices, we have updated our 2016 guidance. Our focus for the year will continue to be maintaining a strong balance sheet by limiting our capital spending until we see signs of a sustained price recovery. In 2016, we are planning to spend $10 to $15 million on capital projects down from our initial guidance which was to spend between $15 and $20 million. Budgeted capital spending includes preliminary planning for the second 6,000 bbl/d phase at the Onion Lake thermal EOR project, continuing to operate the Blackrod SAGD pilot throughout the year and maintenance capital in all our core areas. Expansion of the Mooney ASP flood has been deferred until oil prices improve. The Company continues to have the flexibility to expand or defer our capital program as economic conditions change.

The capital program is expected to be funded from our anticipated funds flow from operations and supplemented, if necessary, with our existing credit facilities. Funds flow from operations was initially budgeted to be between $35 and $40 million, but as a result of lower crude oil prices, we have updated our funds flow from operations to be between $5 and $10 million. This decrease in funds flow from operations resulted in our updated year end debt levels to be between $90 and $95 million, an increase from our initial guidance of $70 to $75 million. The updated guidance is based on a WTI oil price of US$35/bbl, a heavy oil differential of US$14/bbl and a Cdn/US dollar exchange rate of 0.71.

Our initial guidance for 2016 production was to average between 10,000 and 10,500 bbls/d. Due to the continued decrease in crude oil prices, the Company has decided to temporarily shut-in approximately 75% of the production from the first phase of the Mooney ASP flood (approximately 1,000 bbls/day) and defer the expansion of the Mooney ASP flood until oil prices improve. As a result, we have updated our 2016 production guidance to average between

9,000 and10,000 bbls/d. We will continue to monitor crude oil prices and make changes to our capital spending programs and operations as we believe are required. This may include shutting-in some of our higher operating cost wells until oil prices improve.

Oil and Gas Reserves

The following tables summarize certain information contained in the independent reserves report prepared by Sproule Unconventional Limited ("Sproule") as of December 31, 2015. The report was prepared in accordance with definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Additional reserve information as required under NI 51-101 has been included in the Company's Annual Information Form which has been filed on SEDAR. It should not be assumed that the net present value of reserves estimated by Sproule represents the fair market value of these reserves.

Summary of Oil and Gas Reserves

(Company interest, before royalties)	Heavy Crude Oil	Bitumen	Natural Gas	2015 Total	2014 Total
	(Mbbl)	(Mbbl)	(MMcf)	(MBoe)	(MBoe)
Proved developed producing	19,859	0	291	19,907	8,766
Proved developed non-producing	2,652	0	126	2,673	2,114
Proved undeveloped	40,935	429	71	41,376	55,275
Total proved	63,446	429	487	63,956	66,165
Probable	50,612	179,338	363	230,010	230,456
Total proved plus probable	114,058	179,767	850	293,966	296,621

Notes:
(1) BOE's may be misleading, particularly if used in isolation. In accordance with NI 51-101, a BOE conversion ratio of 6 Mcf: 1 barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
(2) Columns may not add due to rounding.

Net Present Value of Reserves

($000s)	0%	5%	10%	15%	20%
Before Tax					
Proved					
Developed producing	563,561	468,219	393,887	336,878	292,798
Developed non-producing	62,301	47,527	36,832	28,956	23,061
Undeveloped	1,341,432	687,208	388,170	238,426	156,510
Total proved	1,967,294	1,202,954	818,889	604,260	472,369
Probable	6,449,560	2,843,921	1,396,392	736,310	403,222
Total proved plus probable	8,416,854	4,046,875	2,215,281	1,340,569	875,591
After Tax					
Proved					
Developed producing	563,561	468,219	393,887	336,878	292,798
Developed non-producing	62,301	47,527	36,832	28,956	23,061
Undeveloped	992,882	511,591	291,152	180,650	119,979
Total proved	1,618,744	1,027,336	721,871	546,484	435,838
Probable	4,676,236	2,030,874	969,327	488,295	248,237
Total proved plus probable	6,294,980	3,058,210	1,691,198	1,034,779	684,075

Notes:
(1) Based on Sproule's December 31, 2015 forecast prices.
(2) Columns may not add due to rounding.

Estimated Future Development Capital

The following table summarizes the future development capital ("FDC") Sproule estimates is required to bring the proved, and proved plus probable reserves on production.

($ Millions)	Total Proved	Total Proved + Probable
2016	7.5	5.0
2017	31.6	118.6
2018	30.0	139.2
2019	28.2	95.8
2020	26.0	336.4
Remainder	268.8	1,660.6
Total FDC undiscounted	392.1	2,355.6
Total FDC discounted at 10%	180.5	1,018.2

Reconciliation of Changes in Reserves

The following table summarizes the changes in Sproule's evaluation of the Company's share of oil and natural gas reserves (before royalties) from December 31, 2014 to December 31, 2015.

	Heavy Crude Oil (Mbbl)	Bitumen (Mbbl)	Natural Gas (MMcf)	BOE (MBOE)
Proved				
Balance, Dec 31, 2014	64,358	1,739	407	66,165
Extensions	44	0	0	44
Technical revisions	2,182	0	975	2,344
Economic factors	(425)	(1,112)	(109)	(1,555)
Production	(2,712)	(198)	(786)	(3,041)
Balance, Dec 31, 2015	63,446	429	487	63,956
Probable				
Balance, Dec 31, 2014	50,947	179,456	319	230,456
Extensions	99	0	0	99
Technical revisions	(608)	0	83	(594)
Economic factors	174	(119)	(39)	49
Production	0	0	0	0
Balance, Dec 31, 2015	50,612	179,338	363	230,010
Proved plus Probable				
Balance, Dec 31, 2014	115,305	181,195	726	296,621
Extensions	143	0	0	143
Technical revisions	1,574	0	1,058	1,750
Economic factors	(251)	(1,231)	(148)	(1,507)
Production	(2,712)	(198)	(786)	(3,041)
Balance, Dec 31, 2015	114,058	179,767	850	293,966

Note:
(1) Columns may not add due to rounding

The pricing assumptions used in the Sproule evaluation are summarized below.

Pricing Assumptions

Year	WTI Cushing 40° API	Canadian Light Sweet Crude 40° API	Western Canadian Select 20.5° API	Alberta AECO-C Spot	Inflation rate	Exchange rate
	(US$/bbl)	(CDN$/bbl)	(CDN$/bbl)	(CDN$/MMBtu)	(%/yr)	(US$/Cdn$)
2016	45.00	55.20	45.26	2.25	0.0	0.75
2017	60.00	69.00	57.96	2.95	0.0	0.80
2018	70.00	78.43	65.88	3.42	1.5	0.83
2019	80.00	89.41	75.11	3.91	1.5	0.85
2020	81.20	91.71	77.03	4.20	1.5	0.85
2021	82.42	93.08	78.19	4.28	1.5	0.85
2022	83.65	94.48	79.36	4.35	1.5	0.85
2023	84.91	95.90	80.55	4.43	1.5	0.85
2024	86.18	97.34	81.76	4.51	1.5	0.85
2025	87.48	98.80	82.99	4.59	1.5	0.85
2026	88.79	100.28	84.23	4.67	1.5	0.85
Escalation rate of 1.5% thereafter						

Notes:
(1) The pricing assumptions were provided by Sproule.
(2) None of the Company's future production is subject to a fixed or contractually committed price.

Definitions:
(a) "Proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
(b) "Probable" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.
(c) "Developed" reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the reserves on production.
(d) "Developed Producing" reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
(e) "Developed Non-Producing" reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.
(f) "Undeveloped" reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.
(g) The Net Present Value (NPV) is based on Sproule forecast pricing and costs. The estimated NPV does not necessarily represent the fair market value of our reserves. There is no assurance that forecast prices and costs assumed in the Sproule evaluations will be attained, and variances could be material.

Contingent Resources

The following tables summarize certain information contained in the contingent resource evaluations prepared by Sproule as of December 31, 2015. The reports were independently prepared in accordance with definitions, standards and procedures contained in the COGE Handbook.

Amendments to NI 51-101 came into effect on July 1, 2015 and these amendments resulted in significant changes to the way contingent resources are disclosed compared to prior years. The most significant changes include:

- Changes to the product types, including the addition of new product types and providing new definitions for some existing product types;
- The classification of contingent resources into the following project maturity subclasses: Development pending, Development on hold, Development unclarified, and Development not viable;
- Disclosure of the chance of development risk for each project maturity subclass;
- The requirement to risk the contingent resource amounts based on the chance of development and disclose

the risked, best estimate contingent resources for each product type;

- For any contingent resources classified as "Development pending", the disclosure of the risked NPV of future net revenues, calculated using forecast prices and costs for each product type using discount rates of 0%, 5%, 10%, 15% and 20%;
- For any contingent resources reported in the subclass "Development on hold", the disclosure of and/or a comment on the economic viability of the contingent resources;
- The disclosure of the estimated total cost to achieve commercial production, the estimated date of first commercial production and the recovery technology to be used; and
- The disclosure and a discussion of the contingencies that need to be overcome in order to convert the contingent resources to reserves.

It should not be assumed that the estimates of recovery, production, and net revenue presented in the tables below represent the fair market value of the Company's contingent resources. There are certain contingencies which currently prevent the classification of these contingent resources as reserves. Information on these contingencies is provided in the footnotes to the tables below. There is no certainty that it will be commercially viable to produce any portion of the contingent resources. Please refer to our Annual Information Form for a more detailed discussion of our contingent resources.

An estimate of risked net present value of contingent resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of the Company proceeding with the required investment. It includes contingent resources that are considered too uncertain with respect to the chance of development to be classified as reserves. There is uncertainty that the risked net present value of future net revenue will be realized.

Summary of Best Estimate (P50) Contingent Resource Volumes – By Property [(1)(2)]

			Risked Volumes[(4)]				Unrisked Volumes			
			Heavy Crude Oil		Bitumen		Heavy Crude Oil		Bitumen	
Project	Maturity Subclass [(3)]	Chance of Development[(4)]	Gross[(5)]	Net	Gross[(5)]	Net	Gross[(5)]	Net	Gross[(5)]	Net
			(Mbbl)		(Mbbl)		(Mbbl)		(Mbbl)	
Blackrod [(6)]	Development/ pending	80%			452,908	358,722			566,135	448,402
Onion Lake [(7)]	Development/ pending	90%	29,889	23,362			33,210	25,958		
Mooney [(8)]	Development/ on hold	71%	11,162	8,875			15,721	12,500		

NPV of Best Estimate (P50) Contingent Resource Volumes – By Property

	Net Present Values of Future Net Revenue Before Income Taxes Discounted at (%/year)				
	0%	5%	10%	15%	20%
Project	($M)				
Risked Volumes [(4)]					
Blackrod	10,805,213	3,300,966	1,071,569	330,343	65,200
Onion Lake	1,087,542	460,899	218,983	114,131	63,520
Mooney	305,484	152,083	79,431	42,886	23,601
Unrisked Volumes					
Blackrod	13,506,517	4,126,208	1,339,461	412,929	81,500
Onion Lake	1,208,380	512,111	243,315	126,812	70,578
Mooney	430,259	214,201	111,874	60,402	33,241

Project	Net Present Values of Future Net Revenue After Income Taxes [10] Discounted at (%/year)				
	0%	5%	10%	15%	20%
	($M)				
Risked Volumes [4]					
Blackrod	7,815,272	2,304,132	685,097	161,012	-16,369
Onion Lake	789,321	330,535	153,761	77,504	40,976
Mooney	222,401	109,114	55,736	29,127	15,263
Unrisked Volumes					
Blackrod	9,769,090	2,880,165	856,371	201,265	-20,462
Onion Lake	877,023	367,261	170,845	86,115	45,529
Mooney	313,240	153,682	78,502	41,024	21,497

Notes:

(1) 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. It is also appropriate to classify as Contingent Resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage.

(2) There are three classifications of contingent resources: Low Estimate, Best Estimate and High Estimate. 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.

(3) Contingent resources are further classified based on project maturity. The project maturity subclasses include development pending, development on hold, development unclarified and development not viable. All of the Company's contingent resources are classified as either development pending or development on hold:

(a) Development pending is where resolution of the final conditions of development are being actively pursued, indicating there is a high chance of development.

(b) Development on hold is where there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator.

(4) Chance of Development is defined as the probability of a project being commercially viable. Sproule's estimate of unrisked contingent resources have been adjusted for risk based on the chance of development (risked amounts represent unrisked values multiplied by the Chance of Development).

(5) **"**Gross" means the Company's working interest share in the contingent resources of bitumen and heavy oil before deducting royalties. The Company has a 100% working interest at Blackrod and Mooney, and a 50 to 100% working interest at Onion Lake.

(6) The established recovery technology to be used in phases 3 and 4 of the Blackrod project is the SAGD process, the same process that is being used in the successful pilot that is currently being conducted within the Blackrod reservoir. The contingencies in the Sproule Report associated with the Company's Blackrod contingent resources are due to the following: (a) the requirement for more evaluation drilling, as required by the regulatory process, to define the reservoir characteristics to assist in the implementation and operation of the SAGD process; (b) the absence of submission of an application to expand the commercial SAGD development beyond the phase 2 project area; (c) the absence of corporate commitment related to the final investment decision and endorsement from the Board of Directors of the Company to move forward with commercial development; and (d) the uncertainty of timing of production and development of Phases 3 and 4 of the Blackrod project. For the Blackrod project contingent resources, the estimated timing of first commercial production is 2024 and the estimated capital to reach first commercial production is $1.3 billion (risked and escalated for inflation).

(7) The recovery of the Company's Onion Lake contingent resources will use a combination of production processes: the established modified SAGD process for phase 3 of the Onion Lake thermal EOR project, the same SAGD process that is already utilized commercially in phase 1 of the Onion Lake thermal EOR project; and the established cold heavy oil production with sand (CHOPS) process to extend the primary development area, the same CHOPS process that has already been extensively deployed throughout the field.

- For phase 3 of the Onion Lake thermal EOR project, the contingencies in the Sproule Report associated with the Company's Onion Lake contingent resources are due to the following: (a) the requirement for more evaluation drilling to define the reservoir characteristics; and (b) the absence of an application by the Company to expand the facility capacities and to extend the SAGD development area beyond phase 1, additionally, the current agreements with the Onion Lake Cree Nation (OLCN) are subject to policies and approvals by Indian Oil and Gas Canada (IOGC) and there is a potential for these agreements to be renegotiated due to changes imposed by IOGC. For the Onion Lake thermal EOR project contingent resources, the estimated timing of first commercial production is 2020, while the estimated capital to reach first commercial production is $61.0 million (risked and escalated for inflation).

- For the extension of the primary development area, the contingencies in the Sproule Report associated with the Company's Onion Lake contingent resources are due to the following: (a) the requirement for more evaluation drilling to confirm the geological continuity of the reservoir and reduce the distance from proven productivity; and (b) the potential for the current agreements with the Onion Lake Cree Nation (OLCN), which are subject to policies and approvals by Indian Oil and Gas Canada (IOGC), required to be renegotiated due to changes imposed by IOGC. First commercial production for the primary development area has already been achieved and, as a result, estimated capital to reach first commercial production is nil.

(8) The established recovery technology to be used for phases 3 and 4 of the Mooney project is the established ASP flood process, the same process that is already deployed commercially in phase 1 of the Mooney field. The contingencies in the Sproule Report associated with the Company's Mooney contingent resources are due to the following: (a) the requirement for more evaluation wells to confirm the reservoir characteristics needed for the ASP process; (b) the absence of regulatory approvals to expand the ASP development area beyond the phase 1 and phase 2 project areas; (c) the absence of a final investment decision from the Board of Directors of the Company to move forward with the ASP flood expansion to phases 3 and 4 of the Mooney project and (d) the uncertainty of timing of production and development of phases 3 and 4 of the Mooney project. First commercial production for the Mooney ASP flood has already been achieved and, as a result, estimated capital to reach first commercial production at the Mooney ASP flood is nil.

(9) The amounts included in these tables do not include the volume or net present value of the Company's proved plus probable reserves previously assigned by Sproule to these properties.

(10) The after-tax net present value of the Company's contingent resources reflects the tax burden on the properties on a stand-alone basis. It does not consider the business-entity-level tax situation, or tax planning. It does not provide an estimate of the value at the level of the business entity, which may be significantly different. The financial statements and the management's discussion & analysis of the Company should be consulted for information at the level of the business entity.

Other

The Company's financial statements, notes to the financial statements, management's discussion and analysis and Annual Information Form have been filed on SEDAR (www.sedar.com) and are available on the Company's website (www.blackpearlresources.ca). The Annual Information Form includes the Company's reserves and resource data for the period ended December 31, 2015 as evaluated by Sproule and other oil and natural gas information prepared in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities. BlackPearl's annual meeting of shareholders will be held on May 5, 2016 in Calgary Alberta.

Forward-Looking Statements

This release contains certain forward-looking statements and forward-looking information (collectively referred to as **"forward-looking statements"**) within the meaning of applicable Canadian securities laws. All statements other than statements of historic fact are forward-looking statements. Forward-looking statements are typically identified by such words as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "potential", "targeting", "intend", "could", "might", "should", "believe" or similar words suggesting future events or future performance.

In particular, this release contains forward-looking statements pertaining to the estimated volumes and net present values of BlackPearl's proved and probable reserves and contingent resources, the estimated 6,000 barrel per day productive capacity of the Onion Lake thermal project as well as the mid-2016 target date to reach that productive capacity and all the information under *2016 Outlook – February Update*.

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

By their nature, forward-looking statements involve numerous known and unknown risks and uncertainties that contribute to the possibility that actual results will differ from those anticipated in the forward looking statements. These risks include, but are not limited to, risks associated with fluctuations in market prices for crude oil, natural gas and diluent, general economic, market and business conditions, volatility of commodity inputs, substantial capital requirements, conditions including receipt of necessary regulatory and stock exchange approvals with respect to the issuance of common shares, 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, financial loss associated with derivative risk management contracts, potential cost overruns, variations in foreign exchange rates, variations in interest rates, diluent and water supply shortages, competition for capital, equipment, new leases, pipeline capacity and skilled personnel, uncertainties inherent in the SAGD bitumen and ASP recovery process, credit risks associated with counterparties, the failure of the Company or the holder of licences, leases and permits to meet requirements of such licences, 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. Readers are also cautioned that the foregoing list of factors is not exhaustive. Further information regarding these risk factors may be found under "Risk Factors" in the Annual Information Form.

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

Non-GAAP Measures

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

"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.

"Net debt" is a non-GAAP measure that represents long term debt less working capital.

For further information, please contact:

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

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

Robert Eriksson – Investor Relations Sweden
Tel.: +46 8 545 015 50

The information in this release is subject to the disclosure requirements of BlackPearl Resources Inc. under the Swedish Securities Market Act and/or the Swedish Financial Instruments Trading Act. This information was publicly communicated on February 25, 2016 at 3:00 p.m. Mountain Time.

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, 2015. These results are being compared with the year ended December 31, 2014. The MD&A should be read in conjunction with the Company's audited consolidated financial statements for the year ended December 31, 2015, 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		
EBITDA	Comprehensive income (loss) before income tax, financing charges, non-cash items, unrealized gain or losses on risk management contracts and income/loss attributed to assets acquired or disposed as defined in the Company's lending agreement.		

Non-GAAP Financial Measures

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

The following table reconciles non-GAAP measurement "Funds flow from operations" to "Cash flow from operating activities", the nearest GAAP measure. "Funds flow from operations" excludes decommissioning costs incurred and changes in non-cash working capital related to operations, while the GAAP measurement, "Cash flow from operating activities" includes these items. Funds flow from operations per share – basic & diluted is calculated as cash flow from operating activities before decommissioning costs incurred and changes in non-cash working capital related to operations divided by the weighted average number of common shares outstanding for the period.

	Three months ended December 31		Year Ended December 31	
($000s)	**2015**	2014	**2015**	2014
Cash flow from operating activities (1)	**12,179**	10,242	**62,344**	78,388
Add (deduct):				
Decommissioning costs incurred	**152**	263	**531**	963
Changes in non-cash working capital related to operations	**(1,433)**	9,211	**(13,913)**	10,372
Funds flow from operations (2)	**10,898**	19,716	**48,962**	89,723

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

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

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

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

The effective date of this MD&A is February 24, 2016.

OVERVIEW

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

BlackPearl's current core properties are:

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

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

2015 SIGNIFICANT EVENTS

- Crude oil prices were significantly lower in 2015, with WTI oil prices averaging US$48.80 per bbl compared to US$93.00 per bbl barrel during 2014.

- Capital expenditures during 2015 were $68.5 million, with approximately $62.4 million related to the construction of the first phase of the Onion Lake thermal EOR project and the capitalization of the pre-commercial first phase Onion Lake thermal EOR operations, $3.4 million spent at Blackrod primarily related to continued capitalization of net revenues from operating the Blackrod pilot and $2.7 million spent in other areas.

- Oil and gas sales during 2015 were $96.3 million and funds flow from operations (non-GAAP measure) was $49.0 million. For the year ended December 31, 2015, the Company incurred a net loss of $46.8 million which includes a $33.0 million impairment loss at our Mooney cash generating unit (CGU). This impairment loss is primarily attributable to the decline in crude oil prices.

- The decline in crude oil prices in 2015 were partially offset by realized gains on crude oil hedging contracts. For the year ended December 31, 2015, the Company realized gains of $37 million from these contracts.

- The Company did not undertake any equity issuances and no common shares were issued pursuant to the exercise of stock options during 2015.

- During the second quarter of 2015, construction was completed and initial steam injection occurred at the first phase of the Onion Lake thermal EOR project. The first phase of the project was designed for oil production of approximately 6,000 bbls/d. We expect to reach this production rate in the first half of 2016.

- Effective October 1, 2015, the Company commenced commercial production at the first phase of the Onion Lake thermal EOR project and related revenue and expenses were included in the financial and operating results as of that date. Currently production from the first phase of the Onion Lake thermal EOR project is approximately 4,500 bbls/d.

- During the fourth quarter of 2015 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 $150 million. The facilities currently consist of a $140 million syndicated revolving line of credit and a non-syndicated operating line of credit of $10 million. At December 31, 2015, BlackPearl had working capital of $11.1 million and $88 million in long-term debt, leaving $62 million available to be drawn under the Company's existing credit facilities.

- The new Alberta government announced potential changes to crown royalty rates applied to oil and gas production in the province and the introduction of a carbon tax related to their climate change strategy. These changes are currently not finalized but could expose the Company to new risks that could have a material impact. Further details on the risks associated with these changes in provincial regulations can be found in the "Risk Factors" section in the MD&A.

- BlackPearl proved plus probable oil and gas reserves were 294 million boe, before royalties, as at December 31, 2015. This amount was determined by BlackPearl's independent reserve evaluators, Sproule Unconventional 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 $2.2 billion ($6.60 per common share).

- Sproule also attributed, on a risked basis, contingent resources (best estimate) of 494 million boe, before royalties, to the Company's working interest in its three core properties (see cautionary statement on contingent resources on page 33). The estimated pre-tax net present value of the risk adjusted future net cash flows of contingent resources (best estimate), discounted at 10% per annum was $1.4 billion.

ANNUAL FINANCIAL INFORMATION

($000s, except where noted)	**2015**	2014	2013
Production (boe/d) [(1)]	**8,330**	9,287	9,730
Oil and gas sales	**96,271**	228,345	222,157
Realized gain on risk management contracts	**37,227**	1,870	–
Unrealized gain (loss) on risk management contracts	**(11,303)**	20,628	–
Net income (loss)	**(46,793)**	26,825	6,449
Per share – basic and diluted ($)	**(0.14)**	0.08	0.02
Funds flow from operations [(2)]	**48,962**	89,723	86,206
Per share – basic and diluted ($)	**0.15**	0.27	0.29
Long-term debt	**88,000**	29,000	–
Capital expenditures	**68,508**	235,366	93,491
Total assets at year end	**808,344**	837,773	652,216
Common shares outstanding (000s)	**335,638**	335,638	300,425

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

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

SELECTED QUARTERLY INFORMATION

	2015				2014			
($000s, except where noted)	**Dec 31**	**Sep 30**	**Jun 30**	**Mar 31**	Dec 31	Sep 30	Jun 30	Mar 31
Production (boe/d) [(1)]	**9,521**	**7,478**	**8,051**	**8,269**	9,639	9,248	8,897	9,363
Oil and gas sales	**22,630**	**20,814**	**30,712**	**22,115**	47,798	58,818	62,174	59,555
Oil sales ($/bbl)	**27.65**	**35.02**	**47.52**	**32.05**	59.34	75.89	81.82	73.23
Gas sales ($/mcf)	**2.91**	**2.88**	**2.61**	**2.63**	3.39	3.97	4.61	5.41
Oil and gas sales ($/boe)	**27.45**	**34.05**	**45.37**	**31.25**	57.00	72.90	79.53	72.30
Production costs	**14,648**	**12,248**	**13,445**	**15,905**	21,066	21,021	20,291	19,673
Production costs ($/boe)	**17.77**	**20.04**	**19.86**	**22.48**	25.12	26.05	25.96	23.88
Realized gain (loss) on risk management contracts	**10,334**	**7,940**	**5,245**	**13,708**	5,846	(468)	(2,842)	(666)
Unrealized gain (loss) on risk management contracts	**1,778**	**11,826**	**(13,533)**	**(11,374)**	20,697	4,961	271	(5,301)
Net income (loss)	**(31,172)**	**5,402**	**(10,079)**	**(10,944)**	16,254	7,013	4,684	(1,126)
Per share, basic and diluted ($)	**(0.09)**	**0.01**	**(0.03)**	**(0.03)**	0.05	0.02	0.01	0.00
Capital expenditures	**1,665**	**7,870**	**15,992**	**42,981**	57,700	80,262	48,044	49,360
Funds flow from operations [(2)]	**10,898**	**10,156**	**14,968**	**12,940**	19,716	23,809	23,161	23,037
Per share, basic and diluted ($)	**0.04**	**0.03**	**0.04**	**0.04**	0.06	0.07	0.07	0.08
Long-term debt	**88,000**	**97,000**	**94,000**	**78,000**	29,000	–	–	–
Total assets (end of period)	**808,344**	**861,107**	**864,926**	**866,018**	837,773	785,538	765,233	747,763
Shares outstanding (000s)	**335,638**	**335,638**	**335,638**	**335,638**	335,638	335,638	335,638	328,398
Weighted average shares outstanding (000s)								
Basic	**335,638**	**335,638**	**335,638**	**335,638**	335,638	335,638	334,817	304,841
Diluted	**335,638**	**335,638**	**335,638**	**335,638**	335,638	335,638	335,244	305,874

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

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

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

BUSINESS ENVIRONMENT

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

Commodity Prices

	Year Ended December 31		2015				2014			
	2015	2014	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Average Crude Oil Prices										
West Texas Intermediate (WTI) (US$/bbl)	48.80	93.00	42.18	46.43	57.94	48.63	73.15	97.17	102.99	98.68
Western Canadian Select (WCS) (Cdn$/bbl)	44.80	81.08	36.86	43.27	56.95	42.11	66.73	83.80	90.42	83.39
Differential – WCS/WTI (US$/bbl)	13.77	19.60	14.57	13.39	11.62	14.71	14.39	20.24	20.08	23.11
Differential – WCS/WTI (%)	28.2%	21.1%	34.5%	28.8%	20.1%	30.2%	19.7%	20.8%	19.5%	23.4%
Average Natural Gas Prices AECO gas (Cdn$/GJ)	2.55	4.27	2.34	2.75	2.52	2.61	3.41	3.81	4.71	4.91
Average Foreign Exchange (US$ per Cdn$1)	0.782	0.905	0.749	0.764	0.813	0.806	0.881	0.918	0.917	0.906

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 significantly lower in 2015 compared to 2014. WTI oil prices averaged US$48.80 per bbl in 2015, 48% lower than the average of US$93.00 per bbl in 2014. The decrease in oil prices has been attributed to a global over-supply of oil as a result of significantly higher US shale production and oil sands production in Canada, a slowing in the rate of increase in demand from China and other Asian economies, a strong US dollar and geopolitical events in various oil producing areas. During the fourth quarter of 2015 WTI oil prices averaged US$42.18 per bbl. The drop in oil prices has continued in 2016, with WTI oil prices averaging US$31.78 per bbl in January 2016 and, as of February 24, 2016, WTI oil prices were approximately US$32.00 per bbl.

As a result of the dramatic drop in oil prices, revenues for oil producers have also declined which has resulted in significantly lower capital spending in the oil sector and in some instances the oil price is lower than the cost of production and producers have elected to shut-in production.

For heavy oil producers, such as BlackPearl, the differential (WTI oil prices compared to WCS oil prices) improved in 2015, which partly offset the drop in WTI oil prices. In 2015, the differential averaged US$13.77 per bbl compared to US$19.60 per bbl in 2014. Increased refinery and transportation capacity has contributed to improved heavy oil differentials in 2015. The differential settled at US$13.90 and US$14.32 per bbl in January and February 2016 respectively.

While recent pipeline and rail terminal expansions have alleviated some of the short-term transportation issues, take-away capacity remains an issue for oil producers in Canada. With increased oil production expected in Canada from new and expanded oil sands projects, securing additional pipeline capacity to tidewater is important to ensure Canadian producers receive world prices for their oil. In 2015, the US president did not approve the Keystone XL pipeline, which was intended to ship up to 830,000 bbls/d of oil from Canada to the US Gulf Coast. There are additional pipeline proposals to transport increased oil production to the east and west coast of Canada for export; however, none of these pipeline proposals have received regulatory approval and are not expected to be built in the near term. Shipping crude oil by rail has alleviated some of the transportation issues and is expected to continue to play an important role until additional pipeline capacity is built.

Natural gas prices decreased in 2015 averaging $2.55/GJ compared to $4.27/GJ in 2014. BlackPearl produces very little natural gas and therefore prices do not have a significant impact on our current revenues. However, we do consume gas in our Blackrod pilot operations and at our Onion Lake thermal EOR project. The cost of natural gas is the most significant component of the cost of production in these areas and therefore lower natural gas prices in 2015 reduced the operating costs in these areas.

Changes in the value of the Canadian dollar relative to the US dollar impacts our revenues and cash flows as our oil sales price is determined by US benchmark prices. The Canadian dollar weakened against the US dollar in 2015 which partially mitigated the effect of lower crude oil prices on our revenues and cash flows. The exchange rate between the Canadian dollar and the US dollar averaged Cdn$1 = US$0.78 during 2015 compared to Cdn$1 = US$0.91 in 2014. The Canadian dollar continued to deteriorate against the US dollar in 2016 and the exchange rate between the Canadian dollar and the US dollar averaged Cdn$1 = US$0.70 in January.

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 funds flow from operations for 2015 (1):

Key variable	Change ($)	$000s
West Texas Intermediate (WTI) (US$/bbl)	1.00	1,026
Realized crude oil price (Cdn$/bbl)	1.00	1,425
US $ to Canadian $ exchange rate	0.01	640

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

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

	Three months ended December 31		Year Ended December 31	
	2015	2014	**2015**	2014
Daily production/sales volumes				
Oil (bbls/d)	**8,785**	8,567	**7,434**	8,492
Bitumen – Blackrod (bbls/d) (2)	**562**	523	**541**	380
Combined (bbls/d)	**9,347**	9,090	**7,975**	8,872
Natural gas (Mcf/d)	**1,047**	3,294	**2,130**	2,492
Total production (boe/d) (1)	**9,521**	9,639	**8,330**	9,287
Product pricing (excluding risk management activities) (2)				
Oil ($/bbl)	**27.65**	59.34	**35.00**	72.47
Natural gas ($/Mcf)	**2.91**	3.39	**2.72**	4.12
Combined ($/boe) (1)	**27.45**	57.00	**34.14**	70.24
Sales ($000s) (2) (3)				
Oil and gas sales – gross	**22,630**	47,798	**96,271**	228,345
Royalties	**(3,589)**	(9,655)	**(16,067)**	(43,870)
Oil and gas revenues – net	**19,041**	38,143	**80,204**	184,475

(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) Effective October 1, 2015, the first phase of the Onion Lake thermal EOR project commenced commercial production and all revenues and expenses associated with the project as of that date are reported in the operating results of the Company.

Oil and natural gas sales decreased 58% in 2015 to $96.3 million from $228.3 million in 2014. The decrease in oil and gas sales is attributable to a 52% decrease in average sales prices received in 2015 compared to 2014 and a 10% decrease in production (on a boe basis).

Significantly lower WTI crude oil prices partially offset by tighter heavy oil differentials and a weaker Canadian dollar relative to the US dollar contributed to a decrease in our realized crude oil sales price in 2015. Our average oil wellhead sales price, prior to the impact of risk management activities, in 2015 was $35.00 per bbl compared with $72.47 per bbl in 2014.

The decrease in oil and gas production during 2015 is primarily attributable to natural declines, selectively shutting-in uneconomic wells during this period of low oil prices and reduced capital re-investment in our conventional oil and gas program. In order to manage our financial flexibility we elected to reduce capital spending and no new drilling activity was undertaken in 2015.

On a boe basis, 95% of the Company's oil and natural gas production in 2015 was heavy oil or bitumen. The Onion Lake area accounted for 51% and the Mooney area accounted for 28% of total production in 2015.

	Three months ended December 31		Year Ended December 31	
Production by area *(boe/d)*	**2015**	2014	**2015**	2014
Onion Lake – conventional	**2,914**	4,651	**3,312**	4,263
Onion Lake – thermal	**3,010**	–	**951**	–
Mooney	**1,902**	3,236	**2,367**	3,469
John Lake	**955**	1,109	**989**	1,067
Blackrod	**562**	523	**541**	380
Other	**178**	120	**170**	108
Total production	**9,521**	9,639	**8,330**	9,287

Oil and natural gas sales decreased 53% in the fourth quarter of 2015 to $22.6 million from $47.8 million in the same period in 2014. The decrease in oil and gas sales is primarily attributable to a 53% decrease in average sales prices received in Q4 2015.

Production growth in Q4 2015 compared to the previous three quarters in 2015 came from the recently completed first phase of our Onion Lake thermal EOR project. Production from the thermal project continues to ramp-up and is currently producing approximately 4,500 bbls/d of oil. We anticipate production from this project to reach its 6,000 barrel per day design capacity in the first half of 2016. Production from our non-thermal areas will likely continue to decrease as a result of natural declines and our intention to limit capital re-investment until oil prices improve.

In 2011, BlackPearl commenced its SAGD pilot project at Blackrod. The pilot started with a single horizontal well pair and associated steam and water handling facilities. A second pilot well pair was drilled and put on production in 2013. The pilot is being undertaken to provide operating data to design the commercial development of the Blackrod lands. The original pilot SAGD well was shut-in in August 2015. All sales and expenses from the pilot are being recorded as an adjustment to the capitalized costs of the project until commercial production commences. As of December 31, 2015, BlackPearl had not received regulatory approval for the commercial Blackrod pilot project. During 2015, the pilot wells produced an average of 541 bbls/d of bitumen and the net revenues capitalized for 2015 were a loss of $2.1 million ($2.4 million loss in 2014).

Risk Management Activities

The Company periodically enters into risk management contracts in order to ensure a certain level of cash flow to fund planned capital projects and to maintain as much financial flexibility as possible. BlackPearl's strategy mainly focuses on swaps and fixed price contracts to limit exposure to fluctuations in oil prices and revenues. The Company's risk management trading activities are conducted pursuant to the Company's Risk Management Policy approved by the Board of Directors and are not used for trading or speculative purposes.

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 mark-to-market values of our outstanding risk management contracts. The Company had a net gain of $25.9 million on its risk management contracts during 2015, consisting of a $37.2 million realized gain on the contracts and an unrealized loss of $11.3 million. The realized gain on risk management contracts was the equivalent of adding $13.20 per bbl to our wellhead price during 2015.

	Three months ended December 31		Year Ended December 31	
($000s, except per boe)	**2015**	2014	**2015**	2014
Realized gain (loss) on risk management contracts	**10,334**	5,846	**37,227**	1,870
Per boe ($)	**12.54**	6.97	**13.20**	0.58
Unrealized gain (loss) on risk management contracts	**1,778**	20,697	**(11,303)**	20,628

The table below summarizes the Company's outstanding commodity contracts as at December 31, 2015:

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

At December 31, 2015, these contracts had a fair value of approximately $9.3 million. A 10% decrease to the oil price used to calculate the fair value of these contracts would result in an approximately $5.9 million increase in fair value.

Royalties

	Three months ended December 31		Year Ended December 31	
	2015	2014	**2015**	2014
Royalties ($000s)	**3,589**	9,655	**16,067**	43,870
Per boe ($)	**4.35**	11.51	**5.70**	13.49
As a percentage of oil and gas sales	**16%**	20%	**17%**	19%

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

Royalties were $16.1 million in 2015, down from $43.9 million in 2014. Royalties as a percentage of oil and gas decreased to 17% of oil and gas sales in 2015 from 19% of oil and gas sales in 2014 and in the fourth quarter of 2015 royalties were 16% of oil and gas sales compared to 20% of oil and gas sales in the same quarter in 2014. Lower wellhead prices in 2015 are the primary reason for the decrease in royalties in 2015 compared to 2014.

The decrease in royalties as a percentage of oil and gas sales is also attributable to the commencement of commercial production from the first phase of the Onion Lake thermal EOR project during the fourth quarter of 2015. During the pre-payout period, royalties paid on oil and gas sales from this project are expected to be approximately 10% which is lower than our corporate average for all of our other producing areas. Going forward, the Company's royalties as a percentage of oil and gas sales are expected to continue to drop to between 11% and 12% (assuming no change in wellhead prices) as production from the first phase of the Onion Lake thermal EOR project ramp-up.

In 2015 the new Alberta government established a Royalty Review Advisory Panel ("Panel") to review crown royalty rates applied to oil and gas production in the province. On January 29, 2016, the Alberta government announced the recommendations of the Panel. The details of the recommendations have not been finalized; however, the Panel recommended no changes to the oil sands royalty framework and the royalty framework for existing wells will continue for 10 years. Wells drilled after 2016 will initially have a flat 5% royalty until payout of capital costs and, after payout, royalty rates will be price sensitive. The recommendations will likely have no impact on our Blackrod and John Lake properties as they are located in the oil sands and the royalties on the existing Mooney project will continue until 2026. It is not clear what royalty rates will be charged on new enhanced oil recovery projects, such as the expansion of our Mooney ASP flood. Our Onion Lake conventional oil and gas assets and the thermal project are located in Saskatchewan and therefore are not impacted by the recommendations from the Panel.

Transportation Costs

	Three months ended December 31		Year Ended December 31	
	2015	2014	**2015**	2014
Transportation costs ($000s)	**1,018**	1,240	**3,194**	6,132
Per boe ($)	**1.23**	1.48	**1.13**	1.89

Transportation costs are incurred to move marketable crude oil and natural gas to their selling points. Changes in transportation costs, on a boe basis, are generally related to moving crude oil to different sales points to capture better marketing opportunities. Transportation costs decreased 48% in 2015 to $3.2 million from $6.1 million in 2014. The decrease in transportation costs is attributable, in part, to lower production volumes in 2015. The decrease in transportation costs is also the result of the downturn in activity levels in the energy sector where we have been able to negotiate a reduction in truck rates with transport companies in all our major producing areas and we have been shipping more of our Onion Lake volumes as emulsion rather than as clean marketable barrels. This results in lower clean oil transportation costs but it increases production expenses.

Production Costs

	Three months ended December 31		Year Ended December 31	
	2015	2014	**2015**	2014
Conventional Production				
Production costs ($000s)	**8,522**	21,066	**50,120**	82,051
Per boe ($)	**15.57**	25.12	**19.71**	25.24
Thermal Production				
Production costs ($000s)	**6,126**	–	**6,126**	–
Per boe ($)	**22.12**	–	**22.12**	–
Total Production				
Production costs ($000s)	**14,648**	21,066	**56,246**	82,051
Per boe ($)	**17.77**	25.12	**19.94**	25.24

Total production costs decreased 31% in 2015 to $56.2 million from $82.1 million in 2014. On a per boe basis, total production costs decreased 21% in 2015 to $19.94 per boe from $25.24 per boe in 2014. Total production costs decreased 30% in the fourth quarter of 2015 compared to the same period in 2014.

The decrease in conventional production expenses in 2015 is attributable, in part, to decreased production volumes. In addition, due to the current low oil price environment the Company has been focusing on reducing production costs. This included negotiating lower service rates with various suppliers and contractors, deferring well servicing work, shutting-in specific wells in the Onion Lake area that are not economic at current oil prices and lowering chemical injections at Mooney.

During the fourth quarter of 2015 the Company began commercial production from the first phase of the Onion Lake thermal EOR project. Production from the thermal project continues to ramp-up and is currently producing approximately 4,500 bbls/d of oil. During this ramp-up phase, we expect production costs per boe to range from $17 to $23 per boe depending on production levels. Production costs per boe are expected to drop to approximately $15 per boe when this project reaches design capacity of 6,000 bbls/d in the first half of 2016.

Operating Netback [(1)]

	Three months ended December 31		Year Ended December 31	
($/boe)	**2015**	2014	**2015**	2014
Oil and gas sales	**27.45**	57.00	**34.14**	70.24
Royalties	**4.35**	11.51	**5.70**	13.49
Transportation costs	**1.23**	1.48	**1.13**	1.89
Production costs	**17.77**	25.12	**19.94**	25.24
Operating netback before realized risk management contracts	**4.10**	18.89	**7.37**	29.62
Realized gain (loss) on risk management contracts	**12.54**	6.97	**13.20**	0.58
Operating netback after realized risk management contracts	**16.64**	25.86	**20.57**	30.20

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

Operating netback is the cash margin we receive from each barrel of oil equivalent sold. Operating netback, before realized gains on risk management activities, decreased 75% in 2015 to $7.37 per boe from $29.62 per boe in 2014. The decrease is primarily attributable to the decrease in realized crude oil prices, partially offset by lower royalties and production costs.

General and Administrative Expenses (G&A)

	Three months ended December 31		Year Ended December 31	
($000s, except per boe)	**2015**	2014	**2015**	2014
Gross G&A expense	**2,088**	2,417	**8,810**	10,587
Operator recoveries	**(268)**	(516)	**(1,134)**	(2,145)
Net G&A expense	**1,820**	1,901	**7,676**	8,442
Per boe ($)	**2.21**	2.27	**2.72**	2.60

General and administrative expenses consist primarily of salaries and wages of employees, office rent, computer services, legal, accounting and consulting fees. The decrease in gross G&A expenses in 2015 compared to 2014 is primarily attributable to lower third party consultants' costs as well as lower performance incentive payments to staff in 2015. Lower operator recoveries in 2015 compared to 2014 reflects lower capital spending in 2015. Net G&A costs are comparable in the fourth quarter of 2015 to 2014.

Stock-Based Compensation

	Three months ended December 31		Year Ended December 31	
($000s, except per boe)	**2015**	2014	**2015**	2014
Gross stock-based compensation	**1,759**	2,462	**6,073**	6,422
Recoveries from forfeitures	**(3)**	(35)	**(61)**	(273)
Net stock-based compensation before capitalization	**1,756**	2,427	**6,012**	6,149
Capitalized stock-based compensation	**–**	(87)	**(146)**	(258)
Net stock-based compensation	**1,756**	2,340	**5,866**	5,891
Per boe ($)	**2.13**	2.79	**2.08**	1.81

Stock-based compensation costs are non-cash charges which reflect the estimated value of stock options granted. The Company uses the fair value method of accounting for stock options granted to directors, officers, employees and consultants whereby the fair value of all stock options granted is recorded as a charge to operations over the period from the grant date to the vesting date of the option. The fair value of common share options granted is estimated on the date of grant using the Black-Scholes option pricing model.

The decrease in gross stock-based compensation in 2015 compared to 2014 is primarily attributable to a decrease in the weighted average market price of the Company's common shares during 2015. In 2015, 11,458,500 options were granted, 666,666 options were forfeited and 2,053,000 options expired. Based on stock options outstanding as at December 31, 2015, the Company has an unamortized stock option compensation expense of approximately $4.3 million, of which $3.3 million is expected to be expensed in 2016, $0.9 million in 2017 and $0.1 million in 2018.

During 2015, $146,000 of stock-based compensation costs were capitalized to property, plant and equipment related to options granted to contractors who worked exclusively on the development activities at the Onion Lake thermal EOR project. The Company ceased capitalizing stock-based compensation on the Onion Lake thermal EOR project as of October 1, 2015, when the project commenced commercial production.

Finance Costs

	Three months ended December 31		Year Ended December 31	
($000s)	**2015**	2014	**2015**	2014
Gross interest & financing charges	**930**	303	**3,498**	1,140
Capitalized interest & financing charges	**–**	(254)	**(2,066)**	(634)
Net interest & financing charges	**930**	49	**1,432**	506
Accretion of decommissioning liabilities	**370**	381	**1,646**	1,532
Total finance costs	**1,300**	430	**3,078**	2,038

The increase in gross interest and financing charges in 2015 compared to 2014 are a result of higher average debt levels in 2015, largely as a result of the increased capital spending on the construction of the first phase of the Onion Lake thermal EOR project. During 2015, $2.1 million of interest costs related to the construction of the Onion Lake thermal EOR project were capitalized. The Company ceased capitalizing interest costs on the Onion Lake thermal EOR project as of October 1, 2015, when the project commenced commercial production.

The average interest rate on advances under the Company's credit facilities was 3.8% in 2015. This does not include standby fees charged on unutilized amounts of the credit facilities. All our long-term debt is floating rate debt, so the interest rate charged is based on general market conditions. Additionally, the interest rate charged on our debt is determined, in part, by our debt to EBITDA ratio (as defined in our credit agreement). The interest rate charged on our debt outstanding is expected to increase in 2016 as a result of carrying a higher debt to EBITDA ratio. We have not entered into any financial instruments to fix the interest rate on our debt.

Depletion and Depreciation

	Three months ended December 31		Year Ended December 31	
	2015	2014	**2015**	2014
Depletion and depreciation ($000s)	**12,872**	15,143	**51,950**	66,794
Per boe ($)	**15.62**	18.06	**18.42**	20.55

The Company's properties are depleted on a unit of production basis based on estimated proven plus probable reserves. Depletion and depreciation expense decreased 22% in 2015 to $52.0 million from $66.8 million in 2014. The decrease in depletion is primarily a result of lower production volumes in 2015.

On a boe basis, depletion and depreciation expense decreased to $18.42 per boe in 2015 compared to $20.55 per boe in 2014 and in the fourth quarter of 2015 depletion and depreciation decreased to $15.62 per boe compared to $20.22 per boe in the third quarter of 2015. This decrease in depletion on a boe basis is primarily attributable to the Onion Lake thermal EOR project which the Company began depleting in the fourth quarter of 2015 when commercial production started. The depletion rate on this project is below $10 per boe as a result of the large proved plus probable oil and gas reserves recognized in our 2015 third party reserves evaluation.

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 flows and are used for impairment testing. At December 31, 2015, 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, and at a minimum on an annual basis, the net book values of these CGU's are tested for impairment. At December 31, 2015, the Company performed impairment calculations on our CGUs to assess whether their respective carrying values were recoverable. The discount rate used varied based on the nature of the assets held in each CGU to determine the fair value at the measurement date.

For the year ended December 31, 2015, primarily attributable to the current low oil price environment and the resulting decline in estimated future oil prices, it was determined that the recoverable amount for the Mooney CGU was less than its carrying value and as a result an impairment loss of $33 million was recognized. No impairment was recognized at any of the Company's other core CGUs or the Company's minor CGUs in 2015 due to Onion Lake and Blackrod having significant proved plus probable reserves and contingent resources and long reserve lives and the Company's minor CGUs consisting of primarily undeveloped land that has maintained its recoverable amount. The $33 million impairment loss can potentially be reversed in future periods if the estimated recoverable amount of the Mooney CGU increases (for example, if oil prices increases in the future).

A one percent increase in the assumed discount rate would result in an additional impairment of $10.3 million in 2015 while a ten percent decrease to the forward commodity price estimates would result in an additional impairment of $36.3 million in 2015 at the Mooney CGU. A one percent increase in the assumed discount rate or a ten percent decrease to the commodity price estimates would not result in an impairment at any of the Company's other core CGUs or the Company's minor CGUs in 2015.

If oil prices continue to decline and remain at lower levels for an extended period of time, the carrying value of the Company's assets may be subject to additional impairment. Future impairments can also result from changes to reserve estimates, future development costs and capitalized costs.

Interest Income

	Three months ended December 31		Year Ended December 31	
	2015	2014	**2015**	2014
Interest income *($000s)*	**3**	16	**53**	531

Interest income consists of interest earned on excess cash held by the Company. The decrease in interest income in 2015 was a result of lower average cash balances maintained by the Company during the year compared to 2014.

Income Taxes

	Three months ended December 31		Year Ended December 31	
($000s)	**2015**	2014	**2015**	2014
Current income tax	**23**	55	**123**	118
Deferred income tax (recovery)	**(4,063)**	6,281	**(8,018)**	9,232
Total income tax (recovery)	**(4,040)**	6,336	**(7,895)**	9,350

BlackPearl did not pay cash income taxes in 2015 and does not expect to pay income taxes in 2016 as we have sufficient tax pools to shelter expected income. The current income tax expense for 2015 is Saskatchewan capital tax.

The province of Alberta increased its corporate tax rate in 2015 from 10% to 12%. Canadian federal tax rates and Saskatchewan provincial tax rates were unchanged in 2015 at 15% and 12% respectively.

The Company has the following estimated tax pools as at:

($000s, except for left-hand column)	Rate %	**Dec 31, 2015**	Dec 31, 2014
Canadian exploration expenses	100	**26,274**	17,052
Canadian development expenses	30	**88,248**	130,374
Canadian oil and gas property expenses	10	**8,508**	9,205
Undepreciated capital costs	10-30	**328,586**	346,894
Non-capital losses (expiry dates 2026 to 2035)	100	**275,594**	215,785
Share issuance costs	5 years	**2,035**	2,706
Total estimated tax pools		**729,245**	722,016

RESULTS FROM OPERATIONS

	Three months ended December 31		Year Ended December 31	
	2015	2014	**2015**	2014
Net income (loss) ($000s)	**(31,172)**	16,254	**(46,793)**	26,825
Per share, basic ($)	**(0.09)**	0.05	**(0.14)**	0.08
Per share, diluted ($)	**(0.09)**	0.05	**(0.14)**	0.08

For the year ended December 31, 2015, the Company incurred a net loss of $46.8 million compared to net income of $26.8 million in 2014. For the quarter ended December 31, 2015, the Company incurred a net loss of $31.2 million compared to net income of $16.3 million in the same period in 2014. The decrease in net income in 2015 is primarily a result of lower wellhead prices and an impairment loss recognized at the Mooney CGU in 2015, partially offset by lower royalties and production costs and gains on risk management contracts.

	Three months ended December 31		Year Ended December 31	
	2015	2014	**2015**	2014
Funds flow from operations [1] ($000s)	**10,898**	19,716	**48,962**	89,723
Per share, basic ($)	**0.04**	0.06	**0.15**	0.27
Per share, diluted ($)	**0.04**	0.06	**0.15**	0.27

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

Funds flow from operations decreased 45% to $49.0 million during 2015 compared to $89.7 million in 2014. The decrease in funds flow in 2015 compared to 2014 is primarily a result of lower wellhead sales prices and lower production volumes in 2015, partially offset by the realized gain on risk management contracts and lower royalties and production costs.

LIQUIDITY AND CAPITAL RESOURCES

BlackPearl's primary sources of cash in 2015 were internally generated funds flow from operations and advances on the Company's credit facilities.

($000s)	**Year Ended December 31, 2015**	Year Ended December 31, 2014
Working capital deficiency (surplus)	**(11,063)**	18,237
Revolving line of credit due beyond one year	**88,000**	29,000
Net debt [1]	**76,937**	47,237

(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.

The increase in net debt as at December 31, 2015, is primarily attributable to increased capital expenditures related to the construction of the first phase of the Onion Lake thermal EOR project.

In November 2015, the Company completed its borrowing base redetermination with the syndicate of lending institutions in its credit facility. Under the terms of the amended credit agreement with the lenders, the total credit facilities available to the Company remains at $150 million, consisting of $140 million syndicated revolving line of credit and a non-syndicated operating line of credit of $10 million. The previous $15 million supplemental loan facility was eliminated and the advances under the supplemental facility were transferred to the revolving line of credit.

At December 31, 2015, the Company had $88 million drawn under its existing credit facilities and issued letters of credit in the amount of $20,000; leaving $62 million available to be drawn under these credit facilities. The facilities are secured by a floating and fixed charge debenture on the assets of the Company. The amount available under these facilities ("Borrowing Base") is re-determined at least twice a year and is primarily based on the Company's oil and gas reserves, the lending institution's forecast commodity prices, the current economic environment and other factors as determined by the syndicate of lending institutions. If the total advances made under the credit facilities are greater than the re-determined Borrowing Base, the Company has 60 days to repay the difference. The next scheduled Borrowing Base redetermination is to occur by May 31, 2016. The facilities are also subject to annual reviews by the lenders and the next scheduled review is to be completed by May 31, 2016. In the event the lenders elected not to renew the credit facilities during the annual review, any amounts outstanding on the revolving and operating lines of credit would be due and payable in full by May 27, 2017.

Pursuant to the terms of the credit agreement, the Company is required to maintain a working capital ratio of 1:1 at the end of each fiscal quarter. Working capital as defined in the lending agreement is current assets, as indicated on the Company's consolidated balance sheet, plus any undrawn amount on the credit facilities compared to current liabilities from the Company's consolidated balance sheet (excluding any current amounts due on credit facilities). In addition, amounts related to risk management contracts are excluded from the calculations of current assets and current liabilities. The Company had a working capital ratio of 5.3 at December 31, 2015 and was in compliance with this covenant at December 31, 2015 and throughout 2015.

($000s, except working capital ratio)	**Year Ended December 31, 2015**	Year Ended December 31, 2014
Current assets per consolidated financial statements	**25,537**	43,651
Add: amount available to be drawn on credit facilities	**62,000**	121,000
Less: current risk management assets	**(10,548)**	(20,628)
Current assets for working capital ratio	**76,989**	144,023
Current liabilities per consolidated financial statements	**14,474**	61,888
Less: current risk management liabilities	**-**	-
Current liabilities for working capital ratio	**14,474**	61,888
Working capital ratio	**5.3**	2.3

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

During 2015, construction was completed and initial steam injection occurred at the first phase of the Onion Lake thermal EOR project. The first phase of the project was designed for oil production of approximately 6,000 bbls/d. The second phase of the Onion Lake thermal EOR project is also designed for production of 6,000 bbls/d of oil and capital costs are expected to be approximately $200 million.

The Company is planning to build the Blackrod SAGD project in phases as well, with the first phase likely to be designed for 20,000 bbls/d. We have not completed detailed cost estimates for this phase but our internal estimates suggest initial capital costs will be approximately $800 million. Regulatory approval of the first phase of the Blackrod SAGD project is expected in 2016.

Neither of the Blackrod SAGD and Onion Lake thermal EOR projects are expected to be internally approved for development until we see indications of a sustained oil price recovery. We will consider joint venture opportunities to accelerate development of the Blackrod SAGD project.

At December 31, 2015, there were 335,638,226 common shares issued and outstanding. In 2015 the Company did not issue any common shares.

The Company did not pay dividends on its common shares in 2015 and it does not anticipate paying dividends in the near term. Dividends are at the discretion of the Company's board of directors. In addition, the terms and conditions of the Company's existing credit agreement restricts the payment of cash dividends to shareholders.

CAPITAL EXPENDITURES

Capital spending decreased significantly in 2015 compared to 2014 as we adjusted our activity levels to reflect a lower oil price environment that reduced our revenues and cash flows. In 2015 our primary focus was on completing the first phase of the Onion Lake thermal EOR project. During 2015 total capital spending was $68.5 million, with over 90% related to the Onion Lake thermal EOR project. The 2015 capital spending consisted of $62.4 million related to the construction of the first phase of the Onion Lake thermal EOR project and capitalization of the pre-commercial first phase Onion Lake thermal EOR operations, $3.4 million spent at Blackrod primarily related to continued capitalization of net revenues from operating the Blackrod pilot and $2.7 million spent in other areas. No new drilling activity occurred during 2015.

During the fourth quarter of 2015 capital spending was $1.7 million, a decrease from $57.7 million during the same period in 2014. The main components of the capital spending program during the fourth quarter were maintenance capital spending and the continued capitalization of net revenues from operating the Blackrod pilot.

	Three months ended December 31		Year Ended December 31	
($000s)	**2015**	2014	**2015**	2014
Land	**203**	315	**988**	1,023
Seismic	**5**	71	**598**	(46)
Drilling and completion	**1,059**	15,774	**8,187**	67,266
Equipment and facilities	**358**	41,431	**58,574**	165,363
Other	**40**	109	**161**	133
Total	**1,665**	57,700	**68,508**	233,739
Property acquisitions	**–**	–	**–**	1,627
Total capital expenditures	**1,665**	57,700	**68,508**	235,366
Property dispositions	**–**	–	**–**	–
Net capital expenditures	**1,665**	57,700	**68,508**	235,366

During 2015 the Company's estimated future undiscounted decommissioning costs increased to $83.3 million compared to $66.9 million in 2014. The increase is primarily related to the first phase of the Onion Lake thermal EOR project which completed construction during the second quarter of 2015.

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, 2015. These obligations are expected to be funded from cash flow from operating activities and the Company's credit facilities.

($000s)	2016	2017	2018	2019	2020	Thereafter
Operating leases (1)	1,610	270	220	84	–	–
Electrical service agreement (2)	520	119	119	119	119	1,987
Transportation service agreement (3)	135	135	135	135	33	–
Decommissioning liabilities (4)	535	394	455	333	8,619	72,999
Long-term debt (5)	3,344	89,393	–	–	–	–
	6,144	90,311	929	671	8,771	74,986

(1) The Company's most significant operating lease is for office space. As at December 31, 2015 the Company had nine months remaining on its office lease. The Company's office lease was executed jointly with another party. Under the terms of the lease, BlackPearl and the other party are joint and severally liable for the obligations pursuant to the lease. Accordingly, if the other party is unable to fulfill their share of the lease obligation, BlackPearl would be required to pay a maximum additional amount of $2.4 million (including an estimate for operating costs) over the next 9 months. At December 31, 2015, no amounts were owed (2014 – no amounts owing).

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

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

(4) The Company also has ongoing obligations related to the decommissioning of well sites and facilities which have reached the end of their economic lives. The undiscounted estimated obligations associated with the retirement of the Company's oil and gas properties were $83.3 million as at December 31, 2015. Decommissioning programs are undertaken regularly in accordance with applicable legislative requirements.

(5) Based on the existing terms of the Company's revolving and operating lines of credit, the first possible mandatory repayment date (assuming no changes in the Borrowing Base) may come in 2017 assuming these facilities are not extended during the scheduled credit facility review in May 2016. At this time management expects the facility will be extended. Amounts include principal and interest. Interest is based on rates existing at December 31, 2015.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments as at December 31, 2015 include cash and cash equivalents, trade and other receivables, deposits within prepaid expenses and deposits, accounts payable and accrued liabilities, risk management assets and liabilities and long-term debt. The fair value of cash and cash equivalents, trade and other receivables, deposits and accounts payable and accrued liabilities approximate their carrying amount due to the short-term nature of the instruments. The fair value of the Company's long-term debt approximates its carrying value as the interest rates charged on this debt are comparable to current market rates. The fair values of the Company's risk management contracts are determined by discounting the difference between the contracted prices and published forward price curves as at the consolidated balance sheet date, using the remaining contracted oil volumes and a risk-free interest rate (based on published government rates).

Foreign Currency Risk

Foreign currency risk is the risk that a variation in exchange rates between the Canadian dollar and the US dollar will affect the Company's operating and financial results. As at December 31, 2015, the Company held US $0.9 million cash and cash equivalents, US $21,000 trade and other receivables and US $254,000 accounts payable and accrued liabilities.

The polymer for our ASP flood at Mooney is supplied by a US company and we are required to pay in US dollars. Fluctuations in exchange rates will have an impact in the Company's cost of polymer. In 2015, we spent approximately US$3.4 million on polymer.

In 2015, a $0.01 change in the average exchange rate between the US and Canadian dollar would have changed oil and gas sales by approximately $1.9 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 loss for the year would have been approximately $62,000 higher as a result of the re-valuation of the Company's US dollar denominated financial assets and liabilities as at December 31, 2015. 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, 2015, the Company held $2.3 million in cash at various major financial institutions throughout Canada and the USA; however, one Canadian financial institution held over 82% 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, 2015, 57% 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 2015, the Company did not experience any collection issues with its marketers.

In 2015, the Company had four customers which individually accounted for more than 10 percent of its total oil and gas sales. Cumulatively, these customers represented approximately 80% of the Company's total oil and gas sales in 2015.

Risk management assets consist of commodity contracts used to manage the Company's exposure to fluctuations in commodity prices. At December 31, 2015, the Company had a $4.2 million receivable related to the risk management contracts, which represents over 39% of total accounts receivables. The Company manages the credit risk exposure related to risk management contracts by selecting investment grade counterparties and by not entering into contracts for trading or speculative purposes. During 2015, the Company did not experience any collection issues with its risk management contracts.

The Company typically does not obtain collateral or security from its joint venture partners or oil and natural gas marketers. 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 Corporation'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 in relation to interest expense on its revolving credit facility due to the floating interest rate charged on advances. For the year ended December 31, 2015, if interest rates had been one percent higher, with all other variables held constant, after tax net loss for the year would have been approximately $207,000 higher.

The Company is exposed to interest rate risk on its excess cash balances. As at December 31, 2015, if interest rates had been one percent higher, with all other variables held constant, after tax net loss for the year would have been approximately $55,000 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, 2015, the Company had $62 million available on its 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 5% of the Company's total production and, as a result, any fluctuation in natural gas prices would have a nominal effect on current activities. When the Company's thermal projects are commercially developed, natural gas will become a major input cost to the Company.

In 2015, if our average oil wellhead sales price decreased $1.00 with all other variables held constant including risk management contracts, after tax net loss for the year would have been approximately $2.2 million higher. An equal opposite impact would have occurred to net loss had average oil wellhead sales price been $1.00 higher.

From time to time, 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 income (loss).

OFF-BALANCE-SHEET ARRANGEMENTS

The Company had no off-balance-sheet arrangements during the year ended 2015 or 2014. 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 2015 or 2014 except for key management compensation. Key management compensation has been disclosed in the Company's financial statements (note 14).

OUTSTANDING SHARE DATA AND STOCK OPTIONS

As at February 24, 2016, the Company had 335,638,226 common shares outstanding and 29,628,502 stock options outstanding under its stock-based compensation program.

OUTSTANDING LONG-TERM DEBT DATA

As at February 24, 2016, the Company had $86,000,000 drawn under its existing credit facilities and had issued letters of credit in the amount of $20,000; leaving $63,980,000 available to be drawn under these credit facilities.

PROPOSED TRANSACTIONS

As of February 24, 2016, 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 exercise 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.

(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 Canadian Oil and Gas Evaluation Handbook (COGEH). 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. At December 31, 2015, $169.5 million has been excluded from depletion and has been shown separately on the Company's 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 used to assess CGU impairment in 2015 is disclosed in Note 8 of the consolidated financial statements.

In 2015 and 2014 we had five CGU's, one for each of our core areas and two CGU's for some of our minor properties. The Company performed impairment test calculations at December 31, 2015 to assess whether the carrying value of the property, plant and equipment and E&E assets were recoverable. For the year ended December 31, 2015, primarily attributable to the current low oil price environment and the resulting decline in future oil prices, an impairment loss of $33 million at the Mooney CGU was recognized. No impairment was recognized at any of the Company's other core CGUs or the Company's minor CGUs in 2015 due to Onion Lake and Blackrod having significant proved plus probable reserves and contingent resources and long reserve lives and the Company's minor CGUs consisting of primarily undeveloped land that has maintained its recoverable amount.

(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 rate 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 following significant assumptions were used for the purpose of estimating the decommissioning liability:

	2015	2014
Undiscounted abandonment costs ($000s)	**$83,335**	$66,893
Risk-free rate	**2.17%**	2.49%
Inflation rate	**1.5%**	2%
Average years to reclamation	**18**	10

(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 pricing model to determine the fair value of stock options granted. The Black-Scholes pricing model requires the Company to make certain assumptions including the expected life of the option, 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 option 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 financial statements are listed below.

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

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

In January 2016, the IASB issued IFRS 16, *"Leases"* ("IFRS 16") to replace IAS 17, *"Leases."* Under IFRS 16, a single recognition and measurement model will apply for lessees which will require recognition of assets and liabilities for most leases. IFRS 16 is effective for years beginning on or after January 1, 2019 with earlier adoption permitted. The Company is currently evaluating the impact of adopting IFRS 9 on the Company's consolidated financial statements.

RISK FACTORS

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, 2015. The following explains how 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 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 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 oil (in particular the heavy oil differential) and quoted market prices. The market price for heavy 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 oil and higher transportation costs (diluent is required to be purchased and blended with heavy oil to transport on most pipelines). The heavy oil differential is 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 95% of BlackPearl's production is from heavy oil and bitumen. It is difficult to predict future price differentials and any increase in heavy oil differentials could have an adverse effect on the Company's business, financial condition, results of operations and cash flows.

Fluctuations 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.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties regarding the supply and demand fundamentals for petroleum products due to the current state of the world's economies, actions taken by the Organization of the Petroleum Exporting Countries and various other oil producing nations, the ongoing risks facing the North American and global economies and new supplies of crude oil which may be created by the application of new drilling technology to unconventional resource plays and new supplies of crude oil which may be created by the application of new drilling technology to the unconventional resource plays.

Foreign Exchange Risk

The majority of our revenues are based on benchmark prices determined in US dollars and BlackPearl incurs most of its operating, capital and other costs in Canadian dollars. As a result, BlackPearl is impacted by exchange rate fluctuations between the US dollar and the Canadian dollar and any strengthening of the Canadian dollar relative to the US dollar could negatively impact revenues, cash flow and financial conditions.

Credit Facility Arrangements

BlackPearl currently has $150 million in bank credit facilities. As at December 31, 2015, the Company owed $88 million under these facilities. The credit agreement requires BlackPearl to comply with certain covenants and in the event the Company does not meet these covenants BlackPearl may be notified it is in default of the terms of the credit agreement and could be restricted in borrowing additional amounts or it may be required to repay all or a portion of the amounts owing.

In addition, the maximum amount we are permitted to borrow under these credit facilities is subject to periodic review by the lenders, typically semi-annually. BlackPearl's lenders generally review the Company's 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 the Company may be required to repay all or a portion of the amounts owing under these credit facilities.

The Company's ability to make payments on, and to refinance, its future indebtedness, and to fund planned capital expenditures will depend upon, amongst other matters, 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 repay amounts owing under these facilities the lenders could foreclose on the Company's assets and there is no assurance that 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 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 this 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 Reports, 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 this document, and the Annual Information Form or the Sproule Reports 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 and the Onion Lake thermal EOR project. 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 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 significant 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 risks

Government Regulations

The Company's operations are subject to various levels of government regulation. These regulations include matters related to land tenure, drilling, production practices, environmental protection, royalties, carbon tax, marketing and pricing 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. Necessary approvals have been obtained for commercial development of the first phase of the Onion Lake thermal project, but future phases of the project will require additional approvals. An application for the Blackrod SAGD project has been filed but approval has not been obtained. There is no assurance that a third party will not object to the development of these projects during the regulatory review process. In addition, once permits are issued there is no assurance that the approvals will not be repealed, or renewed, or that they will contain terms and conditions which make the Company's projects and operations uneconomic or cause the Company to significantly alter its projects and operations.

Royalty Regimes

The governments of Alberta and Saskatchewan receive royalties on production of natural resources from lands in which they own the mineral rights. At Onion Lake, our operations are conducted on the OLCN reserve, and the Company pays royalties to Indian Oil and Gas Canada based on production on reserve lands. The royalty paid at Onion Lake is equivalent to the prevailing government of Saskatchewan royalty rate (without reference to third tier, fourth tier, enhanced oil recovery royalties, holidays or other special incentives).

The government of Alberta has publicly indicated that it intends to review its existing royalty regime from time to time. There can be no assurance that the federal government and the governments of Alberta or Saskatchewan will not adopt a new royalty regime which will make the Company's projects uneconomic or that the regime currently in place will remain unchanged.

An increase in royalties would reduce the Company's earnings and cash flow and could make future capital investments or the Company's operations uneconomic.

In 2015 the new Alberta government established a Royalty Review Advisory Panel ("Panel") to review crown royalty rates applied to oil and gas production in the province. On January 29, 2016, the Alberta government announced the recommendations of the Panel. The details of the recommendations have not been finalized; however, the Panel recommended no changes to the oil sands royalty framework and the royalty framework for existing wells will continue for 10 years. The recommendations will likely have no impact on our Blackrod and John Lake properties as they are located in the oil sands and the royalties on the existing Mooney project will continue until 2026. It is not clear what royalty rates will be charged on new enhanced oil recovery projects, such as the expansion of our Mooney ASP flood. However, as the recommendations of the Panel have not been finalized and are still subject to change and as it is unclear what royalty rates will be charged at the expansion of our Mooney ASP flood; there is a risk these changes in crown royalty rates could reduce the Company's earnings and cash flow and could make future capital investments or the Company's operations uneconomic.

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 impact 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 legislation 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.

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 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 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.

In 2015, the Alberta government announced new climate change policies which included a carbon tax that will be applied across all sectors and a cap on oil sand emissions with a target of 100 megatonnes limit in any year by 2030. These new regulations could have a material adverse impact on the Company's earnings and cash flow and could make future capital investments or the Company's operations uneconomic. There is no assurance that these new regulations will not affect the development of the Blackrod SAGD project during the regulatory review process.

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, 2015.

It should be noted that while the Company's Chief Executive Officer and Chief Financial Officer believe that the Company's DC&P provide a reasonable level of assurance that they are effective, they do not expect that the DC&P will necessarily prevent all errors and 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.

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. They have, as at the financial year ended December 31, 2015, designed ICFR, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

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 as at December 31, 2015. Based on this evaluation, the officers concluded that as of December 31, 2015, the Company maintained effective ICFR.

It should be noted that a control system, including the Company's ICFR, no matter how well conceived can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the ICFR will prevent all errors or fraud.

There were no changes in the Company's ICFR during the year ended December 31, 2015 that materially affected, or are reasonably likely to materially affect, the Company's ICFR.

2015 GUIDANCE AND 2016 OUTLOOK

	2015		2016	
	Guidance	Actual	Initial Guidance	February Update
Production (boe/d)				
Annual average	8,000 – 9,000	8,330	10,000 – 10,500	9,000 – 10,000
Funds flow from operations [(1)] ($millions)	15 – 20	49	35 – 40	5 – 10
Capital expenditures ($millions)	70 – 75	69	15 – 20	10 – 15
Year-end debt ($millions)	125 – 130	88	70 – 75	90 - 95
Pricing Assumptions (annual average)				
Crude oil - WTI	US $55.00	US $48.80	US $50.00	US $35.00
Light/heavy differential	US $15.00	US $13.77	US$ 15.00	US$ 14.00
Foreign Exchange (Cdn$ to US$)	0.85	0.78	0.75	0.71

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

2015 Guidance Compared to Actual

BlackPearl's average oil and gas production of 8,330 boe/day was within the initial guidance range we provided for the year. After initial steaming was completed, the Onion Lake thermal EOR project commenced commercial production effective October 1, 2015 as expected, which led us to meeting our production guidance.

Funds flow from operations was above the guidance range primarily as a result of realized gains on risk management contracts which totalled $37 million during 2015. Without these realized gains on risk management contracts, funds flow from operations would have been slightly below the guidance range due to lower crude oil prices offset by narrower heavy oil differentials and a weaker Canadian dollar relative to the US dollar. These components resulted in our actual wellhead price averaging $35.00 per bbl compared to $39.21 per bbl assumed in our guidance. The low oil price environment led the Company to focus on reducing costs during the year which also partially offset the decrease in funds flow from operations due to lower oil prices. Cost reductions included negotiating lower service rates with various suppliers and contractors, deferring well servicing work, shutting-in specific wells in the Onion Lake area that were not economic at current oil prices, lowering chemical injection costs at Mooney and lowering general and administration costs. The higher than expected funds flow from operations were used to reduce debt levels which resulted in lower year-end debt than originally estimated.

Capital expenditures of $69 million in 2015 were comparable to our guidance range of $70 to $75 million. The major focus was the construction of the first phase of the Onion Lake thermal EOR project which was completed during the second quarter and accounted for over 90% of our capital expenditures in 2015. Planned expansion of the of ASP flood at Mooney and conventional heavy oil drilling at Onion Lake and John Lake have been deferred due to the current low oil price environment.

2016 February Update

Our initial guidance for 2016 was released in December 2015 and as a result of the continued decrease in crude oil prices, we have updated our 2016 guidance. Our focus for the year will continue to be maintaining a strong balance sheet by limiting our capital spending until we see signs of a sustained price recovery. In 2016, we are planning to spend $10 to $15 million on capital projects down from our initial guidance which was to spend between $15 and $20 million. Budgeted capital spending includes preliminary planning for the second 6,000 bbl/d phase at the Onion Lake thermal EOR project, continuing to operate the Blackrod SAGD pilot throughout the year, and maintenance capital in all our core areas. Expansion of the Mooney ASP flood has been deferred until oil prices improve. The Company continues to have the flexibility to expand or defer our capital program as economic conditions change.

The capital program is expected to be funded from our anticipated funds flow from operations and our existing credit facilities. Funds flow from operations was initially budgeted to be between $35 and $40 million, but as a result of lower crude oil prices, we have updated our funds flow from operations to be between $5 and $10 million. This decrease in funds flow from operations resulted in our updated year end debt levels to be between $90 and $95 million, an increase from our initial guidance of $70 to $75 million.

Although we have elected to limit capital spending in 2016, our oil production will continue to grow during the year, primarily due to the continued ramp-up in production from the first phase of the Onion Lake thermal EOR project, which began producing commercially in the fourth quarter of 2015. This growth in thermal production will offset expected declines in our conventional production due to limited re-investment in these properties. Our initial guidance for 2016 production was to average between 10,000 and 10,500 bbls/d. Due to the continued decrease in crude oil prices; the Company has decided to temporarily shut-in approximately 75% of the production from wells at the first phase of the Mooney ASP flood (approximately 1,000 bbls/day) and defer the expansion of the Mooney ASP flood until oil prices improve. As a result, we have updated our 2016 production guidance to average between 9,000 and 10,000 bbls/d. Exit production levels for 2016 are expected to be within that same range. We will continue to monitor crude oil prices and make changes to our capital spending programs and operations as we believe are required. This may include shutting-in more of our higher operating cost wells until oil prices improve.

Sensitivities for 2016 February Update

The significant factors that would affect forecast cash flows and net income (loss) include commodity prices, heavy oil differentials, exchange rates and production volumes.

($millions)	Funds Flow	Net Income (Loss)
Price change		
CDN$5 per bbl change in our realized oil price	13.8	10.1
CDN$1 per bbl change in production costs	3.5	2.6
Exchange rate		
$0.02 change in US/CDN rate	1.7	1.2
Production rate		
500 bbl per day change	(0.1)	(0.1)

FORWARD-LOOKING STATEMENTS

This report contains certain forward-looking statements and forward-looking information (collectively referred to as "forward-looking statements") within the meaning of applicable Canadian securities laws. All statements other than statements of historical fact are forward-looking statements. Forward-looking information typically contains statements with words such as "anticipate", "anticipated", "approximately", "planning", "planned", "could", "continue", "continues", "continued", "estimate", "estimates", "estimated", "forecast", "likely", "expect", "expects", "expected", "may", "intention", "intends", "intended", "indications", "impact", "new", "will", "in the event", "going forward", "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:

- Potential production levels and anticipated timing of peak oil production at the Onion Lake thermal EOR project as discussed in the 2015 Significant Events section;
- Proposed changes to Alberta crown royalty rates and the potential effect on the Company as discussed in the 2015 Significant Events section;
- The volumes and estimated value of the Company's proved and probable reserves as discussed in the 2015 Significant Events section;
- The volumes and estimated value of the Company's contingent resources as discussed in the 2015 Significant Events section;
- Future oil and gas prices and take-away options and their impact on the Company as discussed in the Commodity Prices section;
- Expected future gas prices and their impact on costs related to our thermal projects as discussed in the Commodity Prices section;
- The estimated change in funds flow from operations for 2015 due to changes in key variables as discussed in the Commodity Prices section;
- Expected production growth and anticipated timing of peak oil production at the Onion Lake thermal EOR project as discussed in the Oil and Gas Production, Oil and Gas Pricing and Oil and Gas sales section;

- The expected continued decrease in production from our non-thermal areas as discussed in the Oil and Gas Production, Oil and Gas Pricing and Oil and Gas sales section;
- Expected royalties to be paid on revenues from the Onion Lake thermal EOR project as discussed in the Royalties section;
- Proposed changes to Alberta crown royalty rates with the potential for no effect on Blackrod, John Lake and on the existing Mooney project but unknown effect on the expansion of the Mooney ASP flood as discussed in the Royalties section;
- Expected decrease in production costs per boe as the Onion Lake thermal EOR project ramps-up and reaches design capacity as discussed in the Production Costs section;
- Expected stock-based compensation expense for 2016, 2017 and 2018 as discussed in the Stock-based Compensation section;
- Expected increase on the interest rate charged on our debt in 2016 as a result of carrying a higher debt to EBITDA ratio as discussed in the Finance Costs section;
- Potential future asset impairments as discussed in the Depletion and Depreciation section;
- Expected cash taxes to be paid in 2016 in the Income Taxes section;
- Expectation that if oil prices improve, the Company would be in a position to resume our capital programs as discussed in the Liquidity and Capital Resources section;
- The estimated capital costs of the second phase of the Onion Lake thermal EOR project and the first phase of the thermal Blackrod SAGD project as discussed in the Liquidity and Capital Resources section;
- Potential production levels from the second phase of the Onion Lake thermal EOR project and the first phase of the thermal Blackrod SAGD project as discussed in the Liquidity and Capital Resources section;
- Methods, sources and timing of financing and development of the second phase of the Onion Lake thermal EOR project and the first phase of the thermal Blackrod SAGD project as discussed in the Liquidity and Capital Resources section;
- The Company's expectation that it will not be paying dividends in the near term as discussed in the Liquidity and Capital resources section;
- The Company's expectation that the revolving and operating lines of credit will be extended at the next review as discussed in the Contractual Obligations and Commitments section;
- 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, 2015 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.

Other Supplementary Information

1. List of directors and officers at February 25, 2016

a. Directors:

John Craig
John Festival
Brian Edgar
Keith Hill
Vic Luhowy

b. Officers:

John Craig, Chairman
John Festival, President and Chief Executive Officer
Don Cook, Chief Financial Officer and Corporate Secretary
Chris Hogue, Vice President Operations
Ed Sobel, Vice President Exploration

2. Financial Information

The report for the period ended March 31, 2016 is expected to be published on or before May 15, 2016.

3. Other Information

Address (Corporate head office):
BlackPearl Resources Inc.
700, 444 – 7 Avenue S.W.
Calgary, Alberta T2P 0X8
Canada
Telephone: +1.403.215.8313
Fax: +1.403.265.8324
Website: www.blackpearlresources.ca

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

For further information, please contact:

John Festival - President and Chief Executive Officer, +1.403.215.8313
Don Cook – Chief Financial Officer, +1.403.215.8313

MANAGEMENT'S REPORT

The accompanying Consolidated Financial Statements of BlackPearl Resources Inc. and related financial information presented in this financial report are the responsibility of Management and have been approved by the Board of Directors. The Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards. The Consolidated Financial Statements and related financial information reflect amounts which must, of necessity, be based upon informed estimates and judgments of Management with appropriate consideration to materiality. All financial information contained in the financial report is consistent, where appropriate, with that contained in the Consolidated Financial Statements.

The Company has developed and maintains systems of internal controls, policies and procedures in order to provide reasonable assurance as to the reliability of the financial records and the safeguard of assets. Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statements preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies or procedures may deteriorate.

PricewaterhouseCoopers LLP, an independent external auditor, has been engaged, as appointed by the shareholders of the Company, to audit and provide their independent audit opinion on the Corporation's financial statements as at and for the year ended December 31, 2015. They review Black Pearl Resources Inc.'s systems of internal controls and conduct their work to the extent they deem appropriate. The auditor's report dated February 24, 2016 and included in the Consolidated Financial Statements, outlines the nature of their audit and expresses their opinion on the financial statements.

The Board of Directors has established an Audit Committee. The Audit Committee reviews with Management and the external auditors any significant financial reporting issues, the financial statements, and any other matters of relevance to the parties. The Audit Committee meets quarterly to review and approve the interim financial statements prior to their release, as well as annually to review the Company's annual financial statements and Management's discussion and analysis, and to recommend their approval to the Board of Directors. The external auditors have unrestricted access to the Company, the Audit Committee and the Board of Directors.

(signed)

John L. Festival
President and Chief Executive Officer

(signed)

Donald W. Cook
Chief Financial Officer

February 24, 2016

INDEPENDENT AUDITOR'S REPORT

To the Shareholders of BlackPearl Resources Inc.

We have audited the accompanying consolidated financial statements of BlackPearl Resources Inc. and its subsidiaries, which comprise the consolidated balance sheets as at December 31, 2015 and December 31, 2014, and the consolidated statements of comprehensive income (loss), changes in equity, and cash flows for the years then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of BlackPearl Resources Inc. and its subsidiaries as at December 31, 2015 and December 31, 2014 and their financial performance and their cash flows for the years then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

PricewaterhouseCoopers LLP

Chartered Professional Accountants

February 24, 2016

Calgary, Alberta

CONSOLIDATED BALANCE SHEETS

(audited) *(Cdn$ in thousands)*	Note	December 31, 2015	December 31, 2014
Assets			
Current assets			
Cash and cash equivalents	5	$ 2,300	$ 2,918
Trade and other receivables	6	10,801	18,467
Inventory		605	638
Prepaid expenses and deposits		1,283	1,000
Fair value of risk management assets	16	10,548	20,628
		25,537	43,651
Exploration and evaluation assets	7	169,493	166,344
Property, plant and equipment	8	613,314	627,778
		$ 808,344	$ 837,773
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	9	$ 13,939	$ 61,036
Current portion of decommissioning liabilities	10	535	852
		14,474	61,888
Fair value of risk management liabilities	16	1,223	–
Decommissioning liabilities	10	66,392	59,831
Long-term debt	11	88,000	29,000
Deferred tax liabilities	13	–	8,018
		170,089	158,737
Shareholders' equity			
Share capital	12	970,134	970,134
Contributed surplus		39,800	33,788
Deficit		(371,679)	(324,886)
		638,255	679,036
		$ 808,344	$ 837,773

Commitments and contingencies (note 15)

See accompanying notes to consolidated financial statements

Signed on behalf of the Board:

(signed)

John H. Craig
Chairman and Director

(signed)

Brian D. Edgar
Director

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(audited)

(Cdn$ in thousands, except for per share amounts)	Note	Year ended December 31, 2015	Year ended December 31, 2014
Revenue			
Oil and gas sales		$ 96,271	$ 228,345
Royalties		(16,067)	(43,870)
Net oil and gas revenue		80,204	184,475
Gain on risk management contracts	16	25,924	22,498
		106,128	206,973
Expenses			
Production		56,246	82,051
Transportation		3,194	6,132
General and administrative		7,676	8,442
Depletion and depreciation	8	51,950	66,794
Impairment of property, plant and equipment	8	33,000	–
Finance costs	17	3,078	2,038
Stock-based compensation	12	5,866	5,891
Foreign currency exchange gain		(141)	(19)
		160,869	171,329
Other income			
Interest income		53	531
Income (loss) before income taxes		(54,688)	36,175
Income taxes			
Current income tax	13	123	118
Deferred income tax (recovery)	13	(8,018)	9,232
		(7,895)	9,350
Net and comprehensive income (loss) for the year		$ (46,793)	$ 26,825
Income (loss) per share			
Basic	12	$ (0.14)	$ 0.08
Diluted	12	$ (0.14)	$ 0.08

See accompanying notes to consolidated financial statements

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(audited)

(Cdn$ in thousands)				Year ended December 31, 2015
	Share Capital	Contributed Surplus	Deficit	Total Equity
Balance – January 1, 2015	$ 970,134	$ 33,788	$ (324,886)	$ 679,036
Net and comprehensive loss for the year	–	–	(46,793)	(46,793)
Stock-based compensation	–	6,012	–	6,012
Balance – December 31, 2015	**$ 970,134**	**$ 39,800**	**$ (371,679)**	**$ 638,255**

				Year ended December 31, 2014
	Share Capital	Contributed Surplus	Deficit	Total Equity
Balance – January 1, 2014	$ 881,949	$ 28,699	$ (351,711)	$ 558,937
Net and comprehensive income for the year	–	–	26,825	26,825
Stock-based compensation	–	6,149	–	6,149
Shares issued on equity offering	88,440	–	–	88,440
Share issue costs	(3,361)	–	–	(3,361)
Shares issued on exercise of stock options	2,046	–	–	2,046
Transfer to share capital on exercise of stock options	1,060	(1,060)	–	–
Balance – December 31, 2014	$ 970,134	$ 33,788	$ (324,886)	$ 679,036

See accompanying notes to consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

(audited)

(Cdn$ in thousands)	Note	Year ended December 31, 2015	Year ended December 31, 2014
Operating activities			
Net and comprehensive income (loss) for the year		$ (46,793)	$ 26,825
Items not involving cash:			
Depletion and depreciation	8	51,950	66,794
Impairment of property, plant and equipment	8	33,000	–
Accretion of decommissioning liabilities	17	1,646	1,532
Stock-based compensation	12	5,866	5,891
Foreign exchange loss		8	77
Deferred income tax (recovery)	13	(8,018)	9,232
Unrealized loss (gain) on risk management contracts	16	11,303	(20,628)
Decommissioning costs incurred	10	(531)	(963)
Changes in non-cash working capital	17	13,913	(10,372)
Cash flow from operating activities		62,344	78,388
Financing activities			
Proceeds on issue of common shares, net of costs	12	–	86,316
Proceeds on issue of long-term debt	11	68,000	29,000
Repayment of long-term debt	11	(9,000)	–
Cash flow from financing activities		59,000	115,316
Investing activities			
Capital expenditures – exploration and evaluation assets	7	(3,477)	(8,877)
Capital expenditures – property, plant and equipment	8	(64,885)	(226,231)
Changes in non-cash working capital	17	(53,451)	36,016
Cash flow used in investing activities		(121,813)	(199,092)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		(149)	(96)
Decrease in cash and cash equivalents		(618)	(5,484)
Cash and cash equivalents, beginning of year		2,918	8,402
Cash and cash equivalents, end of year		$ 2,300	$ 2,918

See accompanying notes to consolidated financial statements

(tabular amounts in thousands of Cdn$, except as noted)
(audited)

1. GENERAL INFORMATION

BlackPearl Resources Inc. (together with its subsidiaries collectively referred to as the "Company" or "BlackPearl") is engaged in the business of oil and gas exploration, development and production in North America. The Company's primary focus is on heavy oil and oil sands projects in Western Canada. The Company's common shares are listed and traded on the TSX Exchange under the trading symbol "PXX". The Company's Swedish Depository Receipts trade on the NASDAQ Stockholm exchange under the symbol "PXXS". BlackPearl is incorporated under the Canada Business Corporations Act and is located in Canada. The address of its registered office is 700, 444 – 7th Avenue SW, Calgary, Alberta, T2P 0X8.

2. BASIS OF PREPARATION

The Company prepares its consolidated financial statements in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB).

The policies applied in these consolidated financial statements are based on IFRS issued, effective and outstanding as of February 24, 2016, the date they were approved and authorized for issuance by the Board of Directors ("the Board").

3. SIGNIFICANT ACCOUNTING POLICIES

The significant accounting policies used in the preparation of these consolidated financial statements are described below.

Basis of measurement

The consolidated financial statements have been prepared on a historical cost basis except for risk management contracts which are measured at fair value.

Consolidation

The consolidated financial statements of the Company comprise the financial statements of BlackPearl and its subsidiaries as at December 31, 2015. All intercompany transactions, balances and unrealized gains and losses from intercompany transactions are eliminated in full on consolidation. Subsidiaries are entities controlled by the Company. The Company controls an entity when it is exposed to, or has rights to, variable returns from its investment with the entity and has the ability to affect those returns through its power over the entity.

Joint arrangements

A portion of the Company's activities are owned and operated jointly with other parties. All the Company's joint arrangements are classified as joint operations. These consolidated financial statements reflect only the Company's appropriate share of the joint operation's controlled assets and liabilities it has incurred, its share of any liabilities jointly incurred, income from the sale or use of its share of the joint operation's output, together with its share of expenses incurred by the joint operation and any expenses it incurs in relation to its interest in the joint arrangement and a share of production in such activities.

Financial instruments

The Company's financial instruments include cash and cash equivalents, trade and other receivables, deposits within prepaid expenses and deposits, risk management assets and liabilities, accounts payable and accrued liabilities and long-term debt. Financial instruments are initially classified into one of the following five categories: fair value through profit or loss, loans and receivables, held to maturity investments, available-for-sale financial assets or financial liabilities measured at amortized costs. Financial instruments are initially measured at fair value, except in the case of financial liabilities measured at amortized costs which are initially measured at fair value less directly attributable transaction costs.

The subsequent measurement of financial assets and financial liabilities depends on their classification as described below:

(i) Financial assets and liabilities at fair value through profit or loss

Financial assets and liabilities at fair value through profit or loss are either 'held-for-trading' or have been designated at fair value through profit or loss. In both cases the financial assets and liabilities are measured at fair value with changes in fair value recognized in net income.

(ii) Loans and receivables

Loans and receivables are financial assets with fixed or determinable payments that are not quoted in an active market. After initial measurement, these assets are measured at amortized cost at the settlement date using the effective interest method of amortization.

(iii) Held-to-maturity

Held-to-maturity investments are measured at amortized cost at the settlement date using the effective interest method of amortization.

(iv) Available-for-sale

Available for sale financial instruments are measured at fair value, with changes in the fair value recognized in other comprehensive income. When an active market is non-existent, fair value is determined using a valuation technique. When fair value cannot be reliably measured, such assets are carried at cost.

(v) Financial liabilities at amortized cost

These financial liabilities are initially measured at fair value, net of any transactions costs. Subsequently, these liabilities are measured at amortized cost using the effective interest rate method of amortization.

The Company has no financial assets or financial liabilities that give rise to other comprehensive income. Financial assets and financial liabilities are offset and the net amount reported in the consolidated balance sheet if there is a currently enforceable legal right to offset the recognized amounts and there is an intention to settle on a net basis. Financial assets and financial liabilities are classified as current if they are assumed to be settled within one year; otherwise they are classified as non-current.

Risk management contracts

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

Cash and cash equivalents

Cash and cash equivalents include cash on hand, deposits held with banks, and other short-term highly liquid investments with original maturities of three months or less.

Inventory

Inventory is carried at the lower of cost and net realizable value on a weighted average cost basis. The cost of inventory includes all cost incurred in the normal course of business to bring each product to its present location and condition. Net realizable value is the estimated selling price in the ordinary course of business less any expected selling costs. If the carrying amount exceeds net realizable value, a write-down is recognized. The write-down may be reversed in a subsequent period if circumstances which caused it no longer exist and the inventory is still on hand.

Exploration and evaluation costs

Exploration and evaluation (E&E) activity involves the search for hydrocarbon resources, the determination of technical feasibility and the assessment of commercial viability of an identified resource. E&E costs are capitalized for projects prior to their technical feasibility and commercial viability being determined. These costs may include costs of license acquisition, technical services and studies, seismic acquisition, exploration drilling and testing, directly attributable overhead and administration expenses including remuneration of production personnel and supervisory management, the projected decommissioning costs and any activities in relation to evaluating the technical feasibility and commercial viability of extracting mineral resources. Costs incurred prior to acquiring the legal rights to explore an area are charged directly to net income as exploration and evaluation expense. Assets classified as E&E are not depleted or depreciated.

All capitalized E&E costs are subject to technical, commercial and management review, as well as a review for indicators of impairment at least once a year. This is to confirm the continued intent to develop or otherwise extract value from the resource. When an E&E area is determined not to be technically feasible or commercially viable, or the Company decides not to continue with its activity, the unrecoverable E&E costs are charged to net income as exploration and evaluation expense.

Once technical feasibility and commercial viability are confirmed, the E&E asset is first assessed for impairment and if required, any impairment loss is recognized. The remaining carrying amount of the E&E asset is then reclassified to property, plant and equipment. Technical feasibility and commercial viability is established when significant proved reserves are recognized and regulatory approval has been obtained.

Property, plant and equipment

Property, plant and equipment are stated at cost, less accumulated depletion and depreciation and accumulated impairment losses. All costs directly associated with the development of petroleum and natural gas reserves are capitalized on an area by area basis. Development costs include expenditures for areas where technical feasibility and commercial viability has been determined. These costs include proved property acquisitions, development drilling, completion, gathering and infrastructure, decommissioning costs and transfers of exploration and evaluation assets. Borrowing costs incurred during the construction of qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use.

Costs accumulated within each area are depleted using the unit-of-production method based on proved and probable reserves using estimated future prices and costs. Costs subject to depletion include estimated future costs to be incurred in developing proved and probable reserves. These estimates are reviewed by independent reserve engineers at least annually.

Corporate assets consist primarily of office equipment, leasehold improvements and computer equipment/software and are stated at cost less accumulated depreciation. Depreciation of these corporate assets is calculated using the declining-balance method.

For property dispositions, measurement is at fair value, unless the transaction lacks commercial substance or fair value cannot be reliably measured. Where the exchange is measured at fair value, a gain or loss is recognized in net income.

At each reporting period, a review is done to ensure that the asset's residual values, useful lives and methods of depletion/depreciation are appropriate. If necessary, changes are made prospectively.

Cash generating unit (CGU)

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 inflows that are largely independent of cash inflows from other assets or groups of assets.

Impairment

Non-financial assets

The carrying value of the Company's non-financial 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. These indicators include, but are not limited to, extended decreases in prices or margins for oil and gas commodities or products, market capitalization, a significant downward revision in estimated reserves or an upward revision in future development costs. If indicators of impairment exist, the recoverable amount of the asset or CGU is estimated.

The recoverable amount of individual assets and CGUs is the greater of their fair value less costs of disposal and its value in use. Fair value less costs of disposal is determined to be the amount for which the asset could be sold in an arm's length transaction, less the costs of disposal. Value in use is determined by estimating the present value of the future net cash flows expected to be derived from the continued use of the asset or CGU. 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. If the carrying value of the asset or CGU exceeds the recoverable amount, the asset or CGU is considered impaired and is written down to its recoverable amount with impairment recognized in net income.

An assessment is made at each reporting date to determine whether there is an indication that previously recognized impairment losses no longer exist or have decreased. If indication exists, the Company estimates the asset's or CGU's recoverable amount. A previously recognized impairment loss is reversed only if there has been a change in assumptions used to determine the asset's recoverable amount since the last impairment loss was recognized. In this event, the carrying amount of the asset or CGU is increased to its revised recoverable amount with an impairment reversal recognized in net income. The recoverable amount is limited to the original carrying amount less depletion and depreciation as if no impairment had been recognized for the asset or CGU for prior periods.

Financial assets

The Company will assess at each reporting period whether there is any objective evidence that a financial asset, other than those measured at fair value, is impaired. A financial asset is deemed to be impaired if there is objective evidence of impairment as a result of one or more events that has occurred since the initial recognition of the asset that has a negative impact on the estimated future cash flows of the financial asset.

When assessing impairment of the Company's financial assets carried at amortized cost, the carrying value of the financial assets is compared to the present value of estimated future cash flows, discounted using the instrument's original effective interest rate. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost, the reversal is recognized in income or loss.

Decommissioning liabilities

Decommissioning liabilities include present legal or constructive obligations as a result of past events where the Company will be required to retire tangible long-lived assets such as producing well sites and facilities. The obligation generally arises when the asset is installed or the ground/environment is disturbed at the field location. When the liability is initially recognized, the amount represents management's estimate of the present value of the estimated future expenditures to abandon and reclaim the Company's net ownership in wells and facilities as well as an estimate of the future timing of the costs to be incurred. When a liability is recorded, the carrying amount of the related asset is increased by the same amount.

These costs are subsequently depleted as part of the costs of the item of property, plant and equipment. Any changes in the estimated timing of the decommissioning, or decommissioning costs estimates, or changes in the discount rate used to calculate the present value of future expenditures are accounted for prospectively by recording an adjustment to the provision for decommissioning liabilities and a corresponding adjustment to property, plant and equipment.

Increases in decommissioning liabilities resulting from the passage of time are recorded as a finance cost in the consolidated statement of comprehensive income (loss). Actual expenditures incurred are charged against the accumulated decommissioning liability as incurred. The provision is re-measured at each reporting period in order to reflect the inflation and risk-free rate in effect at that time.

Stock-based compensation

Periodically, the Company will grant stock options in exchange for the provision of services from certain employees, directors, officers and consultants. The Company follows the fair value method of valuing stock option grants using the Black-Scholes pricing model. Stock-based compensation expense is determined based on the estimated fair value of shares on the date of grant. Forfeitures are estimated at the grant date and are subsequently adjusted to reflect actual forfeitures. The expense is recognized over the service period, with a corresponding increase to contributed surplus. The Company capitalizes the qualifying portion of the stock-based compensation directly attributable to the development activities of exploration and evaluation and property, plant and equipment assets with a corresponding decrease to stock-based compensation expense. At the time the stock options are exercised, the issuance of common shares is recorded as an increase to shareholders' capital and a corresponding decrease to contributed surplus.

Contingencies

When a contingency is substantiated by confirming events, can be reliably measured and will likely result in an economic outflow; a liability is recognized in the consolidated financial statements as the best estimate required to settle the obligation. A contingent liability is disclosed when the possibility is considered more than remote but not yet probable, where the existence of an obligation will only be confirmed by future events, or where the amount of a present obligation cannot be measured reliably or will likely not result in an economic outflow. Contingent assets are only disclosed when the inflow of economic benefits is probable. When the economic benefit becomes virtually certain, the asset is no longer contingent and is recognized in the consolidated financial statements.

Income tax

Income tax expense is comprised of current and deferred tax. Income tax is recognized in the statement of comprehensive income (loss) except to the extent that it relates to items recognized directly in equity, in which case the income tax is also recognized directly in equity.

Current income tax assets and liabilities for the current and prior periods are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted or substantively enacted at the reporting date in the countries where the Company operates and generates taxable income.

In general, deferred tax is recognized using the balance sheet method, providing for temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the consolidated financial statements at the reporting date. Deferred income tax is determined on a non-discounted basis using tax rates and laws that have been enacted or substantively enacted at the balance sheet date and are expected to apply when the deferred tax asset or liability is settled. Deferred tax assets are recognized to the extent that it is probable that the assets can be recovered and any deferred income tax assets and/or liabilities are presented as non-current.

Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset and the deferred tax amounts relate to income taxes levied by the same tax authority on the same taxable entity. The Company intends to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

Deferred income tax is provided on temporary differences arising on investments in subsidiaries and associates, except, in the case of subsidiaries, where the timing of the reversal of the temporary difference is controlled by the Company and it is probable that the temporary difference will not reverse in the foreseeable future.

Revenue recognition

Revenue is recognized when the significant risks and rewards of ownership have been transferred to the customer, the revenue can be reliably measured and it is probable that the economic benefits will flow to the Company. This takes place once delivery has occurred, the sales price is fixed or determinable and collectability is reasonably assured. Risk and rewards of ownership have been transferred to the customer at the time the product is shipped and delivered to the customer and, depending on the delivery conditions, title and risk have passed to the customer and acceptance of the product, when contractually required, has been obtained. Revenue is measured at the fair value of the consideration received or receivable, excluding discounts, sales taxes, excise duties and similar levies based on the price specified in the sales contract.

Share capital

Common shares are classified as equity. Incremental costs directly attributable to the issuance of shares are recognized as a deduction, net of tax, from equity.

Income (loss) per share

Basic income (loss) per share is calculated by dividing the net income (loss) for the period attributable to equity owners of BlackPearl by the weighted average number of common shares outstanding during the period. Diluted income (loss) per share is calculated by adjusting the weighted average number of common shares outstanding for dilutive instruments, such as stock options, using the treasury stock method. The treasury stock method assumes proceeds from dilutive instruments are used to purchase common shares at the average market price during the period.

Finance costs

The Company's finance costs include interest and financing charges, accretion of decommissioning liabilities and debt financing costs. Interest and financing charges are recognized using the effective interest method.

Borrowing costs

Borrowing costs directly attributable to the acquisition, construction or production of an asset that necessarily takes a substantial period of time to get ready for its intended use are capitalized as part of the cost of the respective assets until such time the asset is substantially ready for its intended use. Borrowing costs consist of interest and other costs that an entity incurs in connection with the borrowing of funds. All other borrowing costs are recognized in the statement of comprehensive income (loss) in the period in which they are incurred.

Foreign currency translation

Items included in the financial statements are measured using the currency of the primary economic environment in which the Company operates (the "functional currency"). The financial statements are presented in Canadian dollars, which is the Company's functional currency.

Foreign currency transactions are translated into Canadian dollars at exchange rates prevailing at the dates of the transactions. At each balance sheet date, monetary assets and liabilities denominated in a foreign currency are translated into Canadian dollars at rates of exchange in effect at the end of the period. Foreign currency differences arising on translation are recognized in income or loss.

Accounting standards issued but not yet applied

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

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

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

In January 2016, the IASB issued IFRS 16, *"Leases"* ("IFRS 16") to replace IAS 17, *"Leases."* Under IFRS 16, a single recognition and measurement model will apply for lessees which will require recognition of assets and liabilities for most leases. IFRS 16 is effective for years beginning on or after January 1, 2019 with earlier adoption permitted. The Company is currently evaluating the impact of adopting IFRS 9 on the Company's consolidated financial statements.

4. 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) Significant accounting judgements

Areas where management exercise 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 assets and property, plant and equipment assets are aggregated into CGUs. CGUs are defined as the lowest level of integrated assets for which there are separately identifiable cash inflows that are largely independent of cash inflows 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 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 commercial viability and technical feasibility is established. Technical feasibility and commercial viability is established when significant proved reserves are recognized and regulatory approval has been obtained.

(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 Canadian Oil and Gas Evaluation Handbook (COGEH). 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.

(ii) Impairment

The carrying value of the Company's non-financial 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. The discount rates used to assess CGU impairment in 2015 is disclosed in Note 8 of the consolidated financial statements.

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 used to assess CGU impairment in 2015 is disclosed in Note 8 of the consolidated financial statements.

(iii) Decommissioning liabilities

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 rate 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 rate used in determining decommissioning liabilities at December 31, 2015 are disclosed in Note 10 of the consolidated financial statements.

(iv) Deferred tax

Judgment is required in the calculation of deferred taxes in applying tax laws and regulations, estimating the timing of reversals 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 flows 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 deferred tax assets and liabilities, 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 of the option, 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 option 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).

5. CASH AND CASH EQUIVALENTS

	2015	2014
Cash at financial institutions	$ 2,300	$ 2,918

Cash at financial institutions earns interest at floating rates based on daily deposit rates. As of December 31, 2015, US $0.9 million (2014 – US $1.0 million) is included in cash at financial institutions. The Company only deposits cash with major financial institutions of high quality credit ratings.

6. TRADE AND OTHER RECEIVABLES

	2015	2014
Trade accounts receivable	$ 6,264	$ 12,249
Receivables from joint operation partners	304	309
Allowance for doubtful accounts	(285)	(285)
Net accounts receivable	6,283	12,273
Royalty reimbursement from enhanced oil recovery incentive programs	–	1,038
Receivable from risk management contracts	4,228	4,059
Other receivables	290	1,097
Total trade and other receivables	$ 10,801	$ 18,467

Aging of trade and other receivables are as follows:

At December 31, 2015	Current	31 to 60 days	61 to 90 days	Over 90 days	Total
Trade accounts receivable	$ 6,264	$ –	$ –	$ –	$ 6,264
Receivables from joint operation partners	3	6	2	293	304
Allowance for doubtful accounts	–	–	–	(285)	(285)
Receivable from risk management contracts	4,228	–	–	–	4,228
Other receivables	290	–	–	–	290
Total trade and other receivables	$ 10,785	$ 6	$ 2	$ 8	$ 10,801

At December 31, 2014	Current	31 to 60 days	61 to 90 days	Over 90 days	Total
Trade accounts receivable	$ 12,232	$ 9	$ 8	$ –	$ 12,249
Receivables from joint operation partners	13	5	1	290	309
Allowance for doubtful accounts	–	–	–	(285)	(285)
Royalty reimbursement from enhanced oil recovery incentive programs	–	–	–	1,038	1,038
Receivable from risk management contracts	4,059	–	–	–	4,059
Other receivables	1,097	–	–	–	1,097
Total trade and other receivables	$ 17,401	$ 14	$ 9	$ 1,043	$ 18,467

7. EXPLORATION AND EVALUATION ASSETS

At January 1, 2014	$ 161,408
Expenditures	7,250
Acquisition	1,627
Change in decommissioning provision	609
Transfers to property, plant & equipment	(4,550)
At December 31, 2014	166,344
Expenditures	3,477
Change in decommissioning provision	(328)
At December 31, 2015	$ 169,493

The Company's exploration and evaluation assets consist predominately of costs pertaining to the Blackrod SAGD pilot project in northern Alberta. These assets are not subject to depletion or depreciation but they are reviewed for possible impairment. During 2015, no assets were considered to be impaired.

The transfer of exploration and evaluation assets to property, plant and equipment occurs when commercial viability and technical feasibility is established. Technical feasibility and commercial viability is established when significant proved reserves are recognized and regulatory approval has been obtained. During the year ended December 31, 2015 the Company capitalized net operating revenues totalling a loss of $2.1 million (2014 – loss of $2.4 million) related to the Blackrod SAGD pilot project. The Company did not capitalize any general and administrative costs related to exploration activities during the year ended December 31, 2015 (2014 – $Nil).

8. PROPERTY, PLANT AND EQUIPMENT

	Oil and natural gas properties	Corporate	Total
Cost			
At January 1, 2014	$ 935,063	$ 3,442	$ 938,505
Expenditures	226,177	54	226,231
Capitalized stock-based compensation	258	–	258
Change in decommissioning provision	4,122	–	4,122
Transfers from exploration & evaluation assets	4,550	–	4,550
At December 31, 2014	1,170,170	3,496	1,173,666
Expenditures	64,874	11	64,885
Capitalized stock-based compensation	146	–	146
Change in decommissioning provision	5,455	–	5,455
At December 31, 2015	$ 1,240,645	$ 3,507	$ 1,244,152
Accumulated depletion and depreciation			
At January 1, 2014	$ 476,976	$ 2,118	$ 479,094
Depletion and depreciation	66,598	196	66,794
At December 31, 2014	543,574	2,314	545,888
Depletion and depreciation	51,781	169	51,950
Impairment	33,000	–	33,000
At December 31, 2015	$ 628,355	$ 2,483	$ 630,838
Net book value			
December 31, 2014	$ 626,596	$ 1,182	$ 627,778
December 31, 2015	$ 612,290	$ 1,024	$ 613,314

The calculation of depletion for the year ended December 31, 2015 included estimated future development costs of $596 million (2014 – $138 million) associated with the development of the Company's proved plus probable reserves. During the year ended December 31, 2015, the Company capitalized borrowing costs of $2.1 million (2014 – $0.6 million) to development activities. The Company did not capitalize any general and administrative costs related to development activities during the year ended December 31, 2015 (2014 – $Nil).

At December 31, 2015, the Company performed impairment calculation on our CGUs to assess whether their respective carrying values were recoverable. Recoverable amounts used in assessing impairment were calculated at their fair value less costs of disposal using an after tax discounted cash flow model with a discount rate ranging from 10% to 13%. The discount rate used varied based on the nature of the assets held in each CGU to determine the fair value at the measurement date. At December 31, 2015, the Company had five CGU's (2014 – five), two CGU's for some of our minor properties and one for each of our core areas which include Onion Lake, Mooney and Blackrod.

For the year ended December 31, 2015, primarily attributable to the current low oil price environment and the resulting decline in future oil prices used in the independent reserve evaluation, an impairment loss of $33.0 million (2014 – $Nil) at the Mooney CGU was recognized in the Consolidated Statement of Comprehensive Income (Loss). No impairment was recorded at any of the Company's other core CGUs or the Company's minor CGUs in 2015 due to Onion Lake and Blackrod CGUs having significant proved plus probable reserves and contingent resources and long reserve lives and the Company's minor CGUs consisting of primarily undeveloped land that has maintained its recoverable amount.

A one percent increase in the assumed discount rate would result in an additional impairment of $10.3 million in 2015 (2014 – $Nil) while a ten percent decrease to the forward commodity price estimates would result in an additional impairment of $36.3 million in 2015 (2014 – $Nil) at the Mooney CGU. A one percent increase in the assumed discount rate or a ten percent decrease to the commodity price estimates would not result in an impairment at any of the Company's other core CGUs or the Company's minor CGUs in 2015 (2014 – $Nil).

The following represents the prices that were used in the December 31, 2015 impairment tests:

Price Forecasts [1]				
Year	WTI [2] Cushing 40° API	WCS [3] 20.5° API	Alberta AECO-C Spot	Exchange rate
	(US$/bbl)	(CDN$/bbl)	(CDN$/MMBtu)	(US$/CDN$)
2016	45.00	45.26	2.25	0.75
2017	60.00	57.96	2.95	0.80
2018	70.00	65.88	3.42	0.83
2019	80.00	75.11	3.91	0.85
2020	81.20	77.03	4.20	0.85
2021	82.42	78.19	4.28	0.85
2022	83.65	79.36	4.35	0.85
2023	84.91	80.55	4.43	0.85
2024	86.18	81.76	4.51	0.85
2025	87.48	82.99	4.59	0.85
2026	88.79	84.23	4.67	0.85
Escalation rate of 1.5% thereafter [4]				

(1) The benchmark prices listed above as determined by the Company's independent reserve evaluators, Sproule Unconventional Limited, are adjusted for quality differentials, heat content, distance to market and other factors in performing the impairment test for each CGU.

(2) West Texas Intermediate (a light oil reference price).

(3) Western Canadian Select (a heavy oil reference price.)

(4) Percentage change represents the change in each year after 2026 to the end of the reserve life.

9. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	2015	2014
Trade payables and accrued liabilities	$ 13,371	$ 60,065
Payables to joint operation partners	218	570
Other payables	350	401
Total accounts payable and accrued liabilities	$ 13,939	$ 61,036

Trade payables are non-interest bearing and are normally settled on a 30 to 60 day term.

10. DECOMMISSIONING LIABILITIES

The Company's decommissioning liability is an estimate of the reclamation and abandonment costs arising from the Company's ownership interest in oil and gas assets, including well sites, gathering systems, batteries, processing and thermal facilities. The total undiscounted amount of the estimated cash flows required to settle the liability is approximately $83.3 million (2014 – $66.9 million). The estimated net present value of the decommissioning liability was calculated using an inflation factor of 1.5% (2014 – 2.0%) and discounted using a risk-free rate of 2.2% (2014 – 2.5%). Settlement of the liability, which may extend up to 40 years in the future, is expected to be funded from general corporate funds at the time of retirement. The revision in the inflation rate in 2015 resulted from the current and forecasted economic climate and is consistent with the estimates in the Company's independent reserves report.

Changes to the decommissioning liability were as follows:

	2015	2014
Decommissioning liability, beginning of year	$ 60,683	$ 55,384
New liabilities recognized	15,067	4,261
Liabilities acquired	–	470
Reduction in liabilities due to asset dispositions	–	(210)
Decommissioning costs incurred	(531)	(963)
Change in estimated costs of decommissioning	(7,670)	–
Change in inflation rate	(4,883)	–
Change in discount rate	2,615	209
Accretion expense	1,646	1,532
Decommissioning liability, end of year	66,927	60,683
Less current portion of decommissioning liability	(535)	(852)
Non-current portion of decommissioning liability	$ 66,392	$ 59,831

11. LONG-TERM DEBT

At December 31, 2015 the Company had credit facilities of $150 million, consisting of a $140 million syndicated revolving line of credit (2014 – $140 million) and a non-syndicated operating line of credit of $10 million (2014 – $10 million). At December 31, 2015, the Company had drawn $88 million (2014 – $29 million) under these credit facilities as well as letters of credit issued in the amount of $20,000 (2014 – $20,000); leaving $62 million (2014 – $121 million) available to be drawn under these facilities. The facilities are secured by a floating and fixed charge debenture on the assets of the Company. The amount available under these facilities ("Borrowing Base") is re-determined at least twice a year and is primarily based on the Company's oil and gas reserves, the lending institution's forecast commodity prices, the current economic environment and other factors as determined by the syndicate of lending institutions. The next scheduled Borrowing Base redetermination is to occur by May 31, 2016. If the total advances made under the credit facilities are greater than the re-determined Borrowing Base, the Company has 60 days to repay the difference. The facilities are also subject to annual reviews by the lenders and the next scheduled review is to be completed by May 31, 2016. In the event the lenders elected not to renew the credit facilities during the annual review, any amounts outstanding on the facilities would be due and payable in full by May 27, 2017.

Pursuant to the terms of the credit agreement, advances may be made, at the Company's option, as direct advances, LIBOR advances, banker's acceptances or standby letters of credit/guarantees. These advances bear interest depending on the type of advancement at the lender's prime rate, banker's acceptance rate or LIBOR rates, plus applicable margins. The applicable margin charged by the lender is dependent upon the Company's debt to EBITDA ratio calculated at the Company's previous fiscal quarter end. The applicable margins range between 2.00% and 3.50%. The lending agreement defines debt as any advances outstanding on the credit facilities plus any outstanding letters of credit/guarantee. The lending agreement defines EBITDA as comprehensive income (loss) before income tax, financing charges, non-cash items deducted in determining comprehensive income (loss), unrealized gains or losses on risk management contracts and any income/losses attributable to assets acquired or disposed of when determining net comprehensive income (loss) for the period as indicated on the Company's consolidated statement of comprehensive income (loss). The Company also incurs a standby fee for undrawn amounts.

Pursuant to the terms of the credit agreement, the Company is required to maintain a working capital ratio of 1:1 at the end of each fiscal quarter. Working capital as defined in the lending agreement is current assets, as indicated on the Company's consolidated balance sheet, plus any undrawn amount on the credit facilities compared to current liabilities from the Company's consolidated balance sheet. In addition, amounts related to risk management contracts are excluded from the calculation of current assets and current liabilities. The Company had a working capital ratio of 5.3:1 at December 31, 2015 (2014 – 2.3:1) and was in compliance with this covenant throughout 2015.

12. SHARE CAPITAL

(a) Authorized

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

(b) Common Shares Issued

	Number of Shares	Attributed Value
Balance as at January 1, 2014	300,424,808	$ 881,949
Shares issued on equity offering	33,373,585	88,440
Share issue costs, net of tax benefits of $806	–	(3,361)
Shares issued on exercise of stock options	1,839,833	2,046
Transferred from contributed surplus on exercise of stock options	–	1,060
Balance as at December 31, 2014 and 2015	335,638,226	$ 970,134

(c) Stock Options Outstanding

The Company has a stock option plan (the "Plan") available to directors, officers, employees and certain consultants of the Company. Under the Plan, the number of common shares to be reserved and authorized for issuance pursuant to options granted under the Plan cannot exceed 10% of the total number of issued and outstanding shares in the Company. The term and the vesting period of any options granted are determined at the discretion of the Board. The maximum term for options granted is ten years; however, all of the options granted by the Company have a term of five years or less. The exercise price of the option cannot be less than the five-day volume weighted average trading price of the common shares immediately preceding the day the option is granted.

The following table summarizes stock options outstanding:

	Number of Options	Weighted Average Exercise Price ($)
Outstanding at January 1, 2014	14,606,499	3.26
Granted	12,124,500	2.30
Exercised	(1,839,833)	1.11
Forfeited	(1,343,498)	3.58
Expired	(2,631,333)	2.21
Outstanding at December 31, 2014	20,916,335	3.00
Granted	11,458,500	0.84
Forfeited	(666,666)	2.71
Expired	(2,053,000)	4.89
Outstanding at December 31, 2015	29,655,169	2.04

Options outstanding and exercisable as at December 31, 2015 are summarized below:

	Options Outstanding			Options Exercisable		
Range of Exercise Prices ($)	Number of Options Outstanding	Weighted Average Exercise Price ($)	Weighted Average Remaining Life (Years)	Number of Options Exercisable	Weighted Average Exercise Price ($)	Weighted Average Remaining Life (Years)
0.71 – 1.50	11,313,500	0.84	4.47	1,412,876	0.71	4.94
1.51 – 3.00	14,395,669	2.31	3.18	7,062,414	2.19	3.19
3.01 – 4.50	1,786,500	3.70	1.50	1,786,500	3.70	1.50
4.51 – 6.00	1,844,500	4.92	0.88	1,844,500	4.92	0.88
6.01 – 7.66	315,000	6.91	0.44	315,000	6.91	0.44
	29,665,169	2.04	3.40	12,421,290	2.76	2.74

The fair value of common share options granted is estimated on the date of grant using the Black-Scholes option pricing model. During the year ended December 31, 2015, 11,458,500 options were granted (2014 – 12,124,500). The fair value of these options was estimated using the following weighted average assumptions:

Assumptions	**Year ended December 31, 2015**	Year ended December 31, 2014
Risk free interest rate (%)	**0.7**	1.3
Dividend yield (%)	**0.0**	0.0
Expected life (years)	**3.7**	3.7
Expected volatility (%)	**53.9**	50.7
Forfeiture rate (%)	**12.9**	14.8
Weighted average fair value of options	**$ 0.34**	$ 0.89

(d) Stock-based Compensation

	Year ended December 31, 2015	Year Ended December 31, 2014
Gross stock-based compensation	**$ 6,073**	$ 6,422
Recoveries from forfeitures	**(61)**	(273)
Net stock-based compensations before capitalization	**6,012**	6,149
Stock-based compensation capitalized to property, plant and equipment	**(146)**	(258)
Net stock-based compensation	**$ 5,866**	$ 5,891

(e) Income (loss) per Share

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

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

	Year ended December 31, 2015	Year Ended December 31, 2014
Net and comprehensive income (loss)	$ (46,793)	$ 26,825
Weighted average number of common shares – basic	335,638	327,806
Dilutive effect:		
Outstanding options	–	158
Weighted average number of common shares – diluted	335,638	327,964
Basic income (loss) per share	$ (0.14)	$ 0.08
Diluted income (loss) per share	$ (0.14)	$ 0.08

For the year ended December 31, 2015, the Company used a weighted average market closing price of $0.93 (2014 – $2.05) per share to calculate the dilutive effect of stock options. For the year ended December 31, 2015, all outstanding options were anti-dilutive (2014 – 18,752,341) and were not included in the calculation of diluted loss per share.

13. INCOME TAXES

(a) Income tax expense

The provision for income taxes reflects an effective income tax rate which differs from federal and provincial statutory tax rates. The main differences are as follows:

	Year ended December 31, 2015	Year Ended December 31, 2014
Income (loss) before income taxes	$ (54,688)	$ 36,175
Corporate income tax rate	26.40%	25.78%
Computed income tax expense (recovery)	$ (14,438)	$ 9,326
Increase (decrease) resulting from:		
Changed in unrecognized deferred income tax assets	5,019	(1,459)
Non-deductible expenses	1,549	1,519
Changed in enacted tax rates	(148)	–
Other	–	(154)
Current income tax expense	123	118
Income tax expense (recovery)	$ (7,895)	$ 9,350

(b) Deferred income tax

The movement in deferred income tax liabilities and assets is as follows:

	January 1, 2015	(Charges) / credits due to other	(Charged) / credited to earnings	December 31, 2015
Deferred income tax assets:				
Decommissioning liabilities	$ 15,509	$ –	$ 2,492	$ 18,001
Income tax losses carried forward	55,390	–	19,021	74,411
Share issue costs	694	–	(145)	549
	71,593	–	21,368	92,961
Deferred income tax liabilities:				
Property, plant and equipment	(74,316)	–	(16,127)	(90,443)
Risk management contracts	(5,295)	–	2,777	(2,518)
	(79,611)	–	(13,350)	(92,961)
Net deferred income tax assets (liabilities)	$ (8,018)	$ –	$ 8,018	$ –

	January 1, 2014	(Charges) / credits due to other	(Charged) / credited to earnings	December 31, 2014
Deferred income tax assets:				
Decommissioning liabilities	$ 14,133	$ –	$ 1,376	$ 15,509
Income tax losses carried forward	58,196	–	(2,806)	55,390
Share issue costs	169	806	(281)	694
	72,498	806	(1,711)	71,593
Deferred income tax liabilities:				
Property, plant and equipment	(72,090)	–	(2,226)	(74,316)
Risk management contracts	–	–	(5,295)	(5,295)
	(72,090)	–	(7,521)	(79,611)
Net deferred income tax assets (liabilities)	$ 408	$ 806	$ (9,232)	$ (8,018)

(c) Unrecognized deferred tax assets

As at December 31, 2015, the Company had $276 million (2014 – $216 million) non-capital losses set to expire no earlier than 2026.

Certain deferred income tax assets have not been recognized as it not probable that future taxable profit will be available against which the benefits can be utilized. These tax assets relate to non-producing assets located in the United States and certain resources pools in Canada that are restricted through successor rules.

The Company has temporary differences associated with its investments in its foreign subsidiaries. The Company has no deferred tax liabilities in respect of these temporary differences.

The current income tax expense for 2015 and 2014 is Saskatchewan capital tax.

14. SALARY AND OTHER COMPENSATION EXPENSES

(a) Employee compensation expenses

The following table provides a breakdown of gross salaries, benefits, stock-based compensation and other compensation expenses included in the consolidated statements of comprehensive income (loss):

	Year ended December 31, 2015	Year Ended December 31, 2014
Production expense (1)	$ 1,451	$ 1,371
General and administrative expense	4,138	5,382
Stock-based compensation	5,866	5,891
	$ 11,455	$ 12,644

(1) Excludes amounts paid to contractors and consultants.

(b) Key management compensation

Key management includes the Company's directors and officers. At December 31, 2015, directors and senior management consisted of eight individuals (2014 – nine individuals).

The following table summarizes the compensation of key management:

	Year ended December 31, 2015	Year Ended December 31, 2014
Salary and employee benefits	$ 1,196	$ 1,669
Stock-based compensation	2,844	3,020
	$ 4,040	$ 4,689

15. COMMITMENTS AND CONTINGENCIES

	2016	2017	2018	2019	2020	Thereafter
Operating leases (1)	$ 1,610	$ 270	$ 220	$ 84	$ –	$ –
Electrical service agreement (2)	520	119	119	119	119	1,987
Transportation service agreement (3)	135	135	135	135	33	–
Decommissioning liabilities (4)	535	394	455	333	8,619	72,999
Long-term debt (5)	3,344	89,393	–	–	–	–
	$ 6,144	$ 90,311	$ 929	$ 671	$ 8,771	$ 74,986

(1) The Company's most significant operating lease is for office space. As at December 31, 2015 the Company had nine months remaining on its office lease. The Company's office lease was executed jointly with another party. Under the terms of the lease, BlackPearl and the other party are joint and severally liable for the obligations pursuant to the lease. Accordingly, if the other party is unable to fulfill their share of the lease obligation, BlackPearl would be required to pay a maximum additional amount of $2.4 million (including an estimate for operating costs) over the next 9 months. At December 31, 2015, no amounts were owed (2014 – no amounts owing).

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

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

(4) The Company also has ongoing obligations related to the decommissioning of well sites and facilities which have reached the end of their economic lives. The undiscounted estimated obligations associated with the retirement of the Company's oil and gas properties were $83.3 million as at December 31, 2015. Decommissioning programs are undertaken regularly in accordance with applicable legislative requirements.

(5) Based on the existing terms of the Company's revolving and operating lines of credit, the first possible mandatory repayment date (assuming no changes in the Borrowing Base amount – see note 11) may come in 2017 assuming these facilities are not extended during the scheduled credit facility review in May 2016. At this time management expects the facility will be extended. Amounts include principal and interest. Interest is based on rates existing at December 31, 2015.

16. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments as at December 31, 2015 include cash and cash equivalents, trade and other receivables, deposits within prepaid expenses and deposits, accounts payable and accrued liabilities, risk management assets and liabilities and long-term debt.

(a) Fair value of financial instruments

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

		December 31, 2015		December 31, 2014	
	Measurement Level	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial Assets					
Loans and receivables:					
Cash and cash equivalents	1	$ 2,300	$ 2,300	$ 2,918	$ 2,918
Trade and other receivables	2	$ 10,801	$ 10,801	$ 17,429	$ 17,429
Deposits	2	$ 409	$ 409	$ 427	$ 427
Financial assets at fair value through profit or loss:					
Risk management assets	2	$ 10,548	$ 10,458	$ 20,628	$ 20,628
Financial liabilities					
Financial liabilities at amortized cost:					
Accounts payable and accrued liabilities	2	$ 13,939	$ 13,939	$ 61,036	$ 61,036
Long-term debt	2	$ 88,000	$ 88,000	$ 29,000	$ 29,000
Financial liabilities at fair value through profit or loss:					
Risk management liabilities	2	$ 1,223	$ 1,233	$ –	$ –

The fair values of financial instruments have been determined by various valuation methods as defined below:

- Level 1: fair value is based on quoted prices (unadjusted) in active markets for identical assets or liabilities;
- Level 2: fair value is based on inputs other than quoted prices included within level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices); and
- Level 3: fair value is based on inputs for the asset or liability that are not based on observable market data (unobservable inputs).

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

(b) Risks associated with financial instruments

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

(i) Credit Risk

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

As at December 31, 2015, the Company held $2.3 million (2014 – $2.9 million) in cash at various major financial institutions throughout Canada and the USA; however, one Canadian financial institution held over 82% (2014 – 64%) of our cash and short-term deposits. The financial institution is a Canadian provincial crown corporation with a high investment grade rating and therefore we believe the credit risk is limited.

At December 31, 2015, 57% 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 2015, the Company did not experience any collection issues with its marketers.

In 2015, the Company had four customers (2014 – five) which individually accounted for more than 10 percent of its total oil and gas sales. Oil and gas sales to these collective customers represented approximately 80% (2014 – 73%) of the Company's total oil and gas sales in 2015.

Risk management assets consist of commodity contracts used to manage the Company's exposure to fluctuations in commodity prices. At December 31, 2015, the Company had a $4.2 million (2014 – $4.0 million) receivable related to its risk management contracts, which represents over 39% of total accounts receivables (2014 – 21%). 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 2015, the Company did not experience any collection issues with its risk management contracts.

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

(ii) Liquidity risk

Liquidity risk is the risk the Company is unable to meet its financial obligations as they come due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. The Company has an on-going cash flow planning and forecasting model to help determine the funds required to meet its operational needs at all times. In addition, the Company manages its liquidity risk by ensuring that it has access to multiple sources of capital including cash and cash equivalents, cash from operating activities, undrawn credit facilities and opportunities to issue additional equity. As at December 31, 2015, the Company had $62 million available on its credit facilities. Management believes that these sources will be adequate to settle the Company's financial liabilities and commitments.

The maturity dates for the Company's undiscounted cash outflows related to financial liabilities are as follows:

	<6 Months	6 months - 1 Year	1 - 2 Years
Accounts payable and accrued liabilities	$ 13,939	–	–
Risk management liabilities	–	–	1,223
Long-term debt (1)	1,672	1,672	$ 89,393

(1) Includes principal and interest. Interest is based on rates existing at December 31, 2015.

(iii) Interest Rate Risk

Interest rate risk refers to the risk that a financial instrument, or cash flows associated with the instrument, will fluctuate due to changes in market interest rates. The Company is exposed to interest rate risk related to interest expense on its credit facilities due to the floating interest rate charged on advances. For the year ended December 31, 2015, if interest rates had been 1 percent higher with all other variables held constant, after tax net loss for the period would have been approximately $207,000 higher (2014 – $12,000 lower). In addition, the Company is exposed to interest rate risk on its excess cash balances. As at December 31, 2015, if interest rates had been 1 percent higher with all other variables held constant, after tax net loss for the year ended December 31, 2015 would have been approximately $55,000 lower (2014 – $71,000 higher). The Company has not entered into any fixed rate contracts to mitigate its interest rate risk.

(iv) Foreign currency exchange risk

The Company is exposed to risks arising from fluctuations in foreign currency exchange rates and the volatility of those rates. This exposure primarily relates to: (i) revenues received for the sale of its crude oil production are primarily denominated in US dollars; (ii) certain expenditure commitments, deposits, accounts receivable, and accounts payable are denominated in US dollars; and to a lesser extent (iii) its operations in the United States. A significant change in the currency exchange rates between the US and Canadian dollar could have a material impact on the Company's revenues and net earnings. As at December 31, 2015, the Company has not entered into any fixed rate contracts to mitigate its currency risks.

As at December 31, 2015, the Company held US $0.9 million (2014 – US $1.0 million) cash and cash equivalents, US $21,000 (2014 – $Nil) trade and other receivables and US $254,000 (2014 – US $35,000) accounts payable and accrued liabilities.

If exchange rates to convert from US dollars to Canadian dollars had been $0.10 lower with all other variables held constant, after tax net loss for the year would have been approximately $62,000 higher (2014 – $89,000 lower) as a result of the re-valuation of the Company's US dollar denominated financial assets and liabilities as at December 31, 2015. An equal opposite impact would have occurred to net loss had exchange rates been $0.10 higher.

(v) Commodity price risk

Commodity price risk is the risk that future cash flows will fluctuate as a result of changes in the price of oil and natural gas. Commodity prices are impacted by world economic events that affect supply and demand, which are generally beyond the Company's control. Changes in crude oil prices may significantly affect the Company's results of operations, cash generated from operating activities, capital spending and the Company's ability to meet its obligations. The majority of the Company's production is sold under short-term contracts; consequently BlackPearl is at risk to near term price movements. The Company manages this risk by constantly monitoring commodity prices and factoring them into operational decisions, such as contracting or expanding its capital expenditures program. Natural gas currently represents less than 5% (2014 – 5%) of the Company's total production and, as a result, any fluctuation in natural gas prices would have a nominal effect on current revenues.

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

Risk management amounts recognized during 2015 were as follows:

	Year ended December 31, 2015	Year Ended December 31, 2014
Realized gain on risk management contracts	$ 37,227	$ 1,870
Unrealized gain (loss) on risk management contracts	(11,303)	20,628
Gain on risk management contracts	$ 25,924	$ 22,498

The table below summarizes the Company's outstanding commodity contracts as at December 31, 2015:

Subject of Contract	Volume	Term	Reference	Strike Price	Option Traded	Fair value
2016						
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	CDN$ WCS	CDN$ 51.15/bbl	Swap	$ 4,486
Oil	2,000 bbls/d	January 1, 2016 to December 31, 2016	CDN$ WCS	CDN$ 47.60/bbl	Swap	6,441
Oil	2,000 bbls/d	January 1, 2016 to December 31, 2016	USD$ WTI	USD$ 65.00/bbl	Sold Call	(379)
2017						
Oil	1,000 bbls/d	January 1, 2017 to December 31, 2017	USD$ WTI	USD$ 60.00/bbl	Sold Call	(1,223)
Total						$ 9,325
Current portion of fair value of contracts						$ 10,548
Non-current portion of fair value of contracts						$ (1,223)

As at December 31, 2015, a 10% decrease to the price outlined in the contracts above used to calculate unrealized gains and losses for the risk management contracts would result in a $5.9 million decrease (2014 – $2.6 million increase) in after tax net loss.

(c) Capital Management

The Company's objective when managing capital is to safeguard our ability to continue as a going concern in order to pursue the development of our oil and gas properties and to maintain a capital structure that optimizes the cost of capital at an acceptable risk. The Company's capital structure consists of working capital, long-term debt and shareholders' equity. Additional funding will likely be required to continue to develop some of the Company's thermal assets as the existing credit facilities and cash flows from operating activities will not be sufficient to fully fund their development given the relatively large capital expenditures required to bring the assets into production. The Company will evaluate funding options for these projects, which includes acquiring additional debt financing, further equity offerings, entering into joint venture agreements and/or using proceeds from the disposition of properties.

In order to maintain or adjust its capital structure, the Company may from time to time issue additional common shares. In addition, the Company's credit facilities are based on its petroleum and natural gas reserves whose values are impacted by, among other things, global commodity prices. The Company will adjust its capital spending if access to external capital sources is unavailable. In order to manage the balance in the Company's capital structure, some of the financial tests that BlackPearl considers are debt-to-equity ratios, debt-to-cash-flow from operating activities and interest coverage tests, which is calculated as earnings before interest, taxes, depletion, depreciation and amortization (EBITDA) over interest expense. We target to maintain a debt to EBITDA ratio of less than 1.5; however, during the construction phase of our large assets and before production commences or during a period of low commodity prices, this will likely be exceeded. At December 31, 2015, this ratio was 1.7 (2014 – 0.3). To facilitate the management and control of these ratios, the Company prepares annual operating and capital budgets. These budgets are generally updated quarterly or more frequently if circumstances change.

The Company's current policy is to not pay dividends but rather to reinvest its earnings back into the business.

17. SUPPLEMENTARY INFORMATION

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

	Year ended December 31, 2015	Year ended December 31, 2014
Cash interest paid	$ 3,498	$ 1,140
Cash taxes paid	$ 123	$ 118

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

	Year ended December 31, 2015	Year ended December 31, 2014
Gross interest and financing charges	$ 3,498	$ 1,140
Capitalized interest and financing charges	(2,066)	(634)
Net interest and financing charges	1,432	506
Accretion of decommissioning liabilities	1,646	1,532
Finance costs	$ 3,078	$ 2,038

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

	Year ended December 31, 2015	Year ended December 31, 2014
Changes in non-cash working capital:		
Trade and other receivables	$ 7,666	$ 3,006
Inventory	33	(638)
Prepaid expenses and deposits	(283)	(37)
Accounts payable and accrued liabilities	(46,954)	23,313
	$ (39,538)	$ 25,644
Relating to:		
Operating activities	$ 13,913	$ (10,372)
Investing activities	(53,451)	36,016
Changes in non-cash working capital	$ (39,538)	$ 25,644