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NEWS RELEASE **February 27, 2014**

BLACKPEARL ANNOUNCES FOURTH QUARTER AND FULL YEAR 2013 FINANCIAL AND OPERATING RESULTS

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, 2013.

Highlights and accomplishments in 2013 included:

- Q4 2013 oil and gas production was 10,454 boe/day, up 15% from the same quarter in 2012; oil and gas production for the year increased 4% in 2013 to 9,730 boe/day;

- Q4 2013 revenues were up 14% to $54 million compared to Q4 2012 and funds flow from operations (a non-GAAP measure) in the fourth quarter was $21 million, an increase of 17% from the same quarter in 2012; oil and gas revenues for the year increased 9% in 2013 to $222 million and funds flow from operations increased 4% to $86 million;

- Q4 2013 net income was $0.2 million compared to a loss of $4.3 million in Q4 2012. Net income for the year increased to $6.4 million in 2013 compared with net income of $45,000 in 2012; 2013 net income included a gain of $3.6 million on the disposition of certain minor oil and gas properties;

- As reported on January 30, 2014, Sproule Unconventional Limited ("Sproule"), our independent reserves evaluator, increased BlackPearl's year-end 2013 oil and gas proved plus probable reserves 36% to 291 million barrels of oil equivalent, before royalties and contingent resources (best estimate) for our three core properties were 631 million barrels of oil equivalent, before royalties (see cautionary statement on contingent resources below);

- At Blackrod, we have been steaming the second pilot well pair since November and we expect to convert this well pair to steam assisted gravity drainage (SAGD) operation in March. We are testing a commercial well design after incorporating our learnings from the first pilot well pair. The first well pair has been operating for over two years and has produced in excess of 215,000 barrels of oil. Regulatory bodies are continuing to review our commercial development application. The 80,000 barrel per day SAGD commercial development application was filed in May 2012 with the Alberta Energy Regulator (formerly the Energy Resources Conservation Board and Alberta Environment). We are planning to build Blackrod in phases, with the first phase of the project expected to be 20,000 barrels of oil per day. At December 31, 2013, Sproule assigned 182 million barrels of probable reserves and 566 million barrels of contingent resources (best estimate) to the Blackrod project. This included 90 million barrels of contingent resources related to the acquisition last year of an additional 10 sections of land contiguous to our existing acreage position. We are planning to seek a joint venture arrangement at Blackrod to accelerate development.

- At Mooney, in 2013 we continued to see positive production response from the first phase of the ASP (Alkali Surfactant Polymer) flood. Production from the flood area was 2,164 bbls/day in Q4 2013 which were the highest production volumes since the ASP flood was initiated in 2011. Further production increases are anticipated in 2014 as more of the flooded area responds to the re-pressurization of the reservoir. In addition, we successfully drilled four horizontal wells in Q4 2013 on phase two lands and one well was drilled to delineate potential future phases at Mooney. Further drilling on phase two and three lands is planned in 2014. We are also planning to expand the ASP flood to the phase two lands in the second half of 2014.

- At Onion Lake, in 2013 we drilled 35 vertical wells as part of our continuing primary development program. We have a development drilling inventory of approximately 120 wells, with 20 to 25 wells planned in 2014. During 2013, we received regulatory approval for the 12,000 barrels of oil per day Onion Lake enhance oil recovery (EOR) project and commenced with associated commercial engineering designs. Subsequent to December 31, 2013, the Company's Board of Directors approved development of the first phase of the Onion Lake EOR project. This first phase is being designed for production of approximately 6,000 barrels of oil per day. Capital costs for the first phase are expected to be approximately $200 million, which includes some pre-investment in infrastructure for the second phase of development. Construction of the first phase will take 13 to 16 months, with initial steam injection targeted for mid-2015. In preparation for drilling horizontal wells for thermal operations we have shut-in some of our existing primary production at Onion Lake. This will impact our Onion Lake production during the first half of 2014 until we complete our summer drilling program.

John Festival, President of BlackPearl, commenting on activities indicated that "BlackPearl made some significant achievements in 2013. Receiving regulatory approval for our Onion Lake EOR project and securing the financing for the first phase of this project in early 2014 were important milestones for BlackPearl. The $80 million in equity financings we recently announced combined with an expansion of our existing credit facilities to $150 million ensures we have a fully financed capital program for the year. Our long term growth is tied to development of our thermal projects and it is exciting for our organization to begin construction of the first phase of this project this year.

We continued to see a positive response from our ASP flood at Mooney in 2013 which gives us the confidence to expand the flood to the phase two lands in 2014.

At Blackrod, a successful pilot operation combined with the applicable regulatory approvals, which we expect in 2014, should provide a very attractive opportunity as we seek a joint venture partner to accelerate commercial development of this project."

Financial and Operating Highlights

	Three months ended December 31,		Twelve months ended December 31,	
	2013	2012	2013	2012
Daily sales volumes [1]				
Oil (bbls/d) [2]	10,243	8,994	9,491	9,304
Natural gas (mcf/d)	1,266	440	1,434	374
Combined (boe/d)	10,454	9,067	9,730	9,366
Product pricing ($)				
Crude oil - per bbl	58.44	58.77	65.09	61.76
Natural gas - per mcf	3.50	3.18	3.16	2.45
Combined - per boe	57.67	58.45	64.11	61.45
($000s, except where noted)				
Oil and natural gas revenue – gross	54,072	47,569	222,157	204,525
Net income (loss) for the period	226	(4,277)	6,449	45
Per share, basic ($)	0.00	(0.01)	0.02	0.00
Per share, diluted ($)	0.00	(0.01)	0.02	0.00

Funds flow from operations [3]	20,735	17,684	86,206	82,595
Capital expenditures	22,749	34,635	93,491	139,548
Property dispositions	(5,011)	-	(5,011)	-
Working capital, end of period	(8,782)	(7,963)	(8,782)	(7,963)
Long term debt	-	-	-	-
Shares outstanding, end of period (000s)	300,425	295,766	300,425	295,766

(1) 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.

(2) 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.

(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.

FOURTH QUARTER 2013 ACTIVITIES

Oil and gas revenues were $54.1 million in the fourth quarter of 2013 compared to $47.6 million in the same quarter of 2012. The increase in revenues was primarily attributable to an increase in production on a boe basis.

Lower wellhead prices in Q4 2013 were the result of wider heavy oil differentials. The heavy oil differential (between WTI and Western Canadian Select) was US$32.21 per barrel in Q4 2013 compared to US$18.46 per barrel in the same quarter of 2012. Increased production and refinery shutdowns for maintenance contributed to the widening of the differential.

BlackPearl sold an average of 10,454 boe per day during the fourth quarter of 2013, an increase of 15% over the same quarter in 2012. The increase in sales volumes were mostly attributable to continued development drilling at Onion Lake and John Lake, as well as the continued positive re-pressurization response from the first phase of the ASP flood at Mooney.

Royalty rates decreased to 21% in the fourth quarter of 2013 compared to 23% in the same quarter of 2012, which reflects the proportionate increase in production from the Mooney field, which has lower royalties than our other producing areas due to incentive programs for EOR projects. Production costs increased by 26% in the fourth quarter of 2013 compared to the same quarter in 2012. The increase in production costs is attributable to increased costs at Onion Lake due to the relative maturity of the field and to injection and polymer costs associated with the ASP flood at Mooney. Prior to 2013, all operating costs associated with the ASP flood were capitalized while the reservoir was being re-pressurized. G&A expenses were $2.1 million in the fourth quarter compared to $2 million in the fourth quarter of 2012.

Funds flow from operations in the fourth quarter of 2013 was $20.7 million compared to $17.7 million in the fourth quarter of 2012. The increase in funds flow from operations was primarily due to the increase in production volumes as compared to the same quarter in 2012. Net income in the fourth quarter of 2013 was $0.2 million compared to a loss of $4.3 million in the fourth quarter of 2012. Net income in 2013 included a $3.6 million gain on the sale of one of our minor non-core assets and also included an asset impairment charge of $3 million related to our assets in the Salt Lake Saskatchewan area.

Capital expenditures in the fourth quarter of 2013 were $22.7 million, a 34% decrease compared to the fourth quarter of 2012. The decrease is a result of reduced drilling activity in Q4 2013.

Production

	Three months ended December 31,		Twelve months ended December 31,	
Production by Area (boe/d)	2013	2012	2013	2012
Onion Lake	5,186	4,857	4,797	5,947
Mooney	3,837	3,329	3,685	2,537
John Lake	1,066	649	898	573
Blackrod SAGD Pilot	262	221	236	272
Other	103	11	114	37
	10,454	9,067	9,730	9,366

Operating Statistics

	Three months ended December 31,		Twelve months ended December 31,	
($/boe)	2013	2012	2013	2012
Oil and natural gas revenue	57.67	58.45	64.11	61.45
Royalties	11.87	13.29	12.62	13.68
Transportation costs	1.77	3.07	2.77	2.76
Production costs	19.65	17.89	20.84	17.82
Operating netback(1)	24.38	24.20	27.88	27.19

(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.

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, 2013 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 general meeting of shareholders will be held on May 8, 2014 in Calgary Alberta.

2014 Guidance

BlackPearl also announced its initial financial and operating guidance for 2014. BlackPearl has established a capital expenditure budget of $260 - 270 million for 2014. Over 70% of the budget will be spent on the construction of the first phase of the thermal EOR project at Onion Lake. This first phase of the project will have design capacity for production of 6,000 barrels of oil per day. The project entails construction of central processing facilities for steam generation, water handling and oil treating, drilling 10 SAGD well pairs on two pads, drilling water source and disposal wells, as well as installation of water, steam and emulsion pipeline infrastructure. Our total cost estimate for this phase of the project is approximately $200 million. We anticipate construction will take 13 to 16 months and steam injection will begin in mid 2015. Construction of the thermal project will not impact our 2014 plans to continue primary development at Onion Lake and we expect to drill 20 to 25 vertical wells in 2014.

At Mooney, following the success of the initial phase of the ASP flood we are planning to expand the flood to the Phase 2 lands. We have drilled 33 horizontal wells to date on the Phase 2 lands and we have two remaining wells to be drilled on these lands to complete the flood patterns, which we plan to drill in the first quarter. Commencement of ASP injection will begin later in the year which will entail the conversion of about 18 wells from producers to ASP injectors. In 2014, we also expect to begin development drilling on the Phase 3 lands, with 10 to 12 horizontal wells planned, five of which will be drilled in the first quarter.

At Blackrod, we anticipate obtaining regulatory approval for the construction of the first 20,000 barrel per day phase of development of our commercial SAGD project in 2014. We will continue to monitor results from the initial pilot well pair which has been producing for over two years and has produced 215,000 barrels of oil. In addition, we look forward to the initial results from the second pilot well pair where we recently commenced steam injection. We are continuing to look for a joint venture partner for this large project that would allow us to accelerate commercial development.

Our total production is expected to average between 10,000 and 10,500 barrels of oil per day in 2014. This yearly production guidance incorporates lower first half 2014 production at Onion Lake due to the shut-in of some production in preparation for thermal operations and having some wells reach their economic limit in early 2014 after having produced an average of over 90,000 barrels of oil per well. Onion Lake production is expected to increase again after completion of our summer drilling program. Funds flow from operations is estimated to be between $80 and $85 million, based on a WTI oil price of US$92.00 per barrel and a WCS (a heavy oil reference price) price of C$76.60 per barrel.

In order to mitigate some of the risk of changes in commodity prices and reduce some of the volatility in our future revenue stream BlackPearl has entered into several WCS fixed price swaps. For the period from March to December 2014, we have hedged 3,500 barrels of oil per day (or approximately 35% of our current production) at an average WCS swap price of C$82.07 per barrel.

The capital program is expected to be funded from cash flow from operating activities, the Company's bank credit facilities and expected proceeds from the recently announced public offering and private placement of BlackPearl common shares.

Forward-Looking Statements

Certain of the statements made and information contained herein is forward-looking statements and forward looking information (collectively referred to as "forward-looking statements") within the meaning of 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 "anticipated", "plan", "planned", "continue", "continued", "estimate", "expect", "may", "will", "project", "potential", "could", "should" or similar words suggesting future events or future performance. In addition, statements relating to "reserves", "resources", or "contingent resources" are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources, as applicable, described exist in the quantities predicted or estimated and can be profitably produced in the future. In particular, this document contains forward-looking statements pertaining to the volumes of BlackPearl's proved and probable reserves, the volumes BlackPearl's contingent resources, potential production levels for the Blackrod SAGD project and the Onion Lake thermal project, the probable reserves and contingent resources assigned to the Blackrod project, anticipated production increases from the ASP flood at Mooney in 2014, timing for expansion of the Mooney ASP flood, the estimated drilling inventory at Onion Lake, and the capital costs, timing of construction and target date for initial steam injection for the first phase of the Onion Lake EOR project, the estimated capital budget of $260 to $270 million for 2014, the number of vertical wells to be drilled at Onion Lake in 2014, the number of wells to be drilled at Mooney and the timing for conversion of the phase 2 lands to ASP flood, timing to receive regulatory approval for the Blackrod SAGD project, estimated oil production levels for 2014, the estimated 2014 funds flow from operations of $80 to $85 million, expected proceeds from the recently announced public offering and private placement of BlackPearl common shares and the sufficiency of the recent financings to fund our capital program for the year.

The forward-looking information contained herein is based on expectations and assumptions by management regarding, among other things, 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, the ability to obtain financing on acceptable terms, availability of skilled labour and drilling and related equipment, general economic and financial market conditions 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.

Undue reliance should not be placed on 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.

By their very nature, forward-looking statements involve inherent risks and uncertainties (both general and specific) and risks that the goals or figures contained in forward-looking statements will not be achieved. These factors 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, 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 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. Further information regarding these risk factors may be found under "Risk Factors" in the Annual Information Form. Readers are cautioned that these factors and risks are difficult to predict and that the assumptions used in the preparation of such information, although considered reasonably accurate at the time of preparation, may prove to be incorrect. Readers are also cautioned that the foregoing list of factors is not exhaustive. Consequently, there is no representation by the Corporation that actual results achieved will be the same in whole or in part as those set out in the forward-looking information. Furthermore, the forward-looking statements contained in this report are made as of the date hereof, and the Corporation 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 news release 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. In the case of the contingent resources assigned to BlackPearl's three core projects the contingencies include the requirement for more evaluation drilling to better define the resource, the absence of submission of commercial SAGD development applications (for future phases of development at Blackrod), the likelihood of attaining regulatory approvals for commercial SAGD development (for our Onion Lake SAGD project), further establishment of increased oil production response from the ASP flood at Mooney and the uncertainty of the timing of production and development. There is no certainty that it will be commercially viable to produce any of the contingent resources. .These volumes are the arithmetic sums of the Best Estimate Resources for Blackrod, Mooney and Onion Lake. 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. Please refer to our Annual Information Form for a more detailed discussion of our contingent resources.

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. Cash 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.

For further information, please contact:

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BLACKPEARL RESOURCES INC.

2013

MANAGEMENT'S DISCUSSION AND ANALYSIS,
FINANCIAL STATEMENTS AND NOTES

FOR THE YEAR ENDED DECEMBER 31, 2013

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, 2013. These results are being compared with the year ended December 31, 2012. The MD&A should be read in conjunction with the Company's audited consolidated financial statements for the year ended December 31, 2013, together with the accompanying notes.

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

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

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

Oil and Natural Gas Liquids		Natural Gas	
bbl	Barrel	Mcf	thousand cubic feet
bbls/d	barrels per day	MMcf	million cubic feet
Mbbls/d	thousand barrels per day	Mcf/d	thousand cubic feet per day
MMbbls	million barrels	Bcf	billion cubic feet
NGLs	natural gas liquids	MMBtu	Million british thermal units
boe	barrel of oil equivalent	GJ	Gigajoule
boe/d	barrel of oil equivalent per day		
WTI	West Texas Intermediate (a light oil reference price)		
WCS	Western Canadian Select (a heavy oil reference price)		
SAGD	Steam Assisted Gravity Drainage (a thermal recovery process)		
ASP	Alkali, Surfactant, Polymer		
EOR	Enhanced Oil Recovery		

Non-GAAP Financial Measures

Throughout this MD&A, the Company uses terms "funds flow from operations", "funds flow from operations per share – basic", "funds flow from operations per share – diluted" and "operating netback". 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 production sales less royalties, production costs and transportation costs, divided by total production for the period on a boe basis.

The following table reconciles non-GAAP measurement "Funds flow from operations" to "Cash flows 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 flows 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 average number of common shares outstanding for the period.

	Three months ended December 31		Year Ended December 31	
($000s)	2013	2012	2013	2012
Cash flows from operating activities [1]	23,772	33,973	80,698	79,862
Add (deduct):				
Decommissioning costs incurred	294	105	849	989
Changes in non-cash working capital related to operations	(3,331)	(16,394)	4,659	1,744
Funds flow from operations [2]	20,735	17,684	86,206	82,595

(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 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 and funds flow from operations per share do not have standardized meanings prescribed by Canadian GAAP and therefore may not be comparable to similar measures used by other companies. Management uses these non-GAAP measurements 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.

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 26, 2014.

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 OMX Stockholm market 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 with a planned thermal EOR project;
- Mooney, Alberta – a conventional heavy oil property using horizontal drilling and ASP flooding; and
- Blackrod, Alberta – a bitumen property located in the Athabasca oil sands region using the SAGD recovery process.

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

2013 SIGNIFICANT EVENTS

- Capital expenditures during 2013 were $93.5 million, with approximately $25.2 million spent at Blackrod, $21.2 million spent at Mooney, $20.8 million at Onion Lake, $15.2 million at the Onion Lake EOR project, $4.9 million at John Lake and $6.2 million in other areas. The focus of the 2013 capital program was the drilling of 35 conventional heavy oil wells at Onion Lake, five wells at Mooney, four horizontal wells at John Lake, one well at Salt Lake and a second SAGD pilot well pair at Blackrod. In addition, 2013 capital spending included preliminary commercial engineering designs at the Blackrod SAGD project and the Onion Lake EOR project and the capitalization of certain chemical costs at Mooney related to the Phase 1 ASP flood.

- Included as part of capital expenditures, the Company acquired additional oil sands acreage and certain petroleum and natural gas assets in the Blackrod area for $4.9 million in 2013. At December 31, 2013, our independent reserve evaluators assigned 90 million bbl of contingent resources (best estimate) to this acquisition (see cautionary statement on contingent resources on page 29).

- Oil and gas sales during 2013 were $222.2 million and funds flow from operations (non-GAAP measure) was $86.2 million. Net income was $6.4 million for the year ended December 31, 2013.

- The Company did not undertake any equity issuances in 2013; however, 4,659,000 common shares were issued pursuant to the exercise of stock options during the year which generated net proceeds of $3.7 million for the Company.

- At December 31, 2013, BlackPearl had a working capital deficiency of $8.8 million and no amounts drawn on the Company's long-term debt, leaving $115.0 million available to be drawn under the Company's existing credit facilities.

- BlackPearl reached an agreement with Onion Lake Energy ("OLE"), a company owned by the Onion Lake Cree Nation, to exchange its working interest in the Onion Lake EOR project for a gross overriding royalty. The existing working interest participation by OLE will continue for all primary production operations.

- On October 18, 2013, BlackPearl disposed of certain non-core assets for cash consideration of $5.0 million. The assets sold were conventional non-producing heavy oil properties in Saskatchewan.

- BlackPearl increased its proved plus probable oil and gas reserves by 36% to 291 million boe, before royalties, as at December 31, 2013. 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.

- Sproule also attributed contingent resources (best estimate) of 631 million boe, before royalties, to the Company's working interest in its three core properties (see cautionary statement on contingent resources on page 29). The estimated pre-tax net present value of the future net cash flows of contingent resources (best estimate), discounted at 10% per annum was $2.1 billion.

- Subsequent to December 31, 2013, the Company's Board of Directors approved development of the first phase of the Onion Lake EOR project. The first phase of development is being designed for production of approximately 6,000 bbls/d of oil.

- Subsequent to December 31, 2013, the Company entered into an agreement with a syndicate of underwriters whereby they have agreed to purchase for resale to the public, on a bought deal basis, 26,500,000 common shares of BlackPearl at $2.65 per share for aggregate gross proceeds of $70.2 million. In addition, the underwriters have been granted an over-allotment option, which may be exercised in whole or in part up to 30 days after closing of the offering, to purchase up to 3,975,000 additional common shares at a price of $2.65 per common share. If the over-allotment is fully exercised, gross additional proceeds would be $10.5 million. The Company also intends to issue by private placement an additional 3,773,585 common shares at $2.65 per share representing gross proceeds of $10 million. The Company intends to use the net proceeds from the offering and the private placement to fund ongoing capital expenditures, including the first phase of the Onion Lake EOR project and for general corporate purposes. In addition, the Company's lending syndicate has agreed to increase the Company's existing credit facilities from $115 million to $150 million upon completion of the offering and the private placement.

ANNUAL FINANCIAL INFORMATION

($000s, except where noted)	2013	2012	2011
Total oil and gas sales	222,157	204,525	179,443
Net income	6,449	45	18,911
Per share – basic ($)	0.02	0.00	0.07
Per share – diluted ($)	0.02	0.00	0.06
Funds flow from operations (1)	86,206	82,595	77,717
Per share – basic ($)	0.29	0.29	0.27
Per share – diluted ($)	0.29	0.28	0.26
Capital expenditures	93,491	139,548	192,634
Total assets at year end	652,216	620,725	606,521
Common shares outstanding *(000s)*	300,425	295,766	284,802

(1) Funds flow from operations is a non-GAAP measure that represents cash flow from operating activities before abandonment costs incurred and changes in non-cash working capital related to operations. Funds flow from operations and funds flow from operations per share do not have standardized meanings prescribed by Canadian GAAP and therefore may not be comparable to similar measures used by other companies. Management uses these non-GAAP measurements 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.

SELECTED QUARTERLY INFORMATION

	2013				2012			
($000s, except where noted)	Dec 31	Sep 30	Jun 30	Mar 31	Dec 31	Sep 30	Jun 30	Mar 31
Production (boe/d) (1)	10,454	9,382	9,986	9,087	9,067	9,340	9,471	9,581
Oil and gas sales	54,072	69,092	58,322	40,671	47,569	50,081	49,099	57,776
Oil and gas sales ($/boe)	57.67	82.72	66.20	50.13	58.45	60.34	58.82	67.98
Production costs	18,420	16,664	18,413	18,702	14,563	14,104	13,950	16,684
Production costs ($/boe)	19.65	19.95	20.90	23.05	17.89	16.99	16.71	19.63
Net income (loss)	226	9,270	2,597	(5,644)	(4,277)	530	218	3,574
Per share, basic and diluted ($)	0.00	0.03	0.01	(0.02)	(0.01)	0.00	0.00	0.01
Capital expenditures	22,749	24,326	27,315	19,101	34,635	28,991	32,453	43,469
Funds flow from operations (2)	20,735	32,609	22,823	10,039	17,684	20,781	19,765	24,365
Per share, basic ($)	0.07	0.11	0.08	0.03	0.06	0.07	0.07	0.09
Per share, diluted ($)	0.07	0.11	0.08	0.03	0.06	0.07	0.07	0.08
Cash flows from operating activities (3)	23,772	33,090	20,592	3,244	33,973	11,483	13,649	20,757
Total assets (end of period)	652,216	648,554	647,839	613,738	620,725	612,083	608,610	608,546
Weighted average shares outstanding, basic *(000s)*	298,843	296,244	296,113	296,052	288,760	285,344	285,272	285,122
Weighted average shares outstanding, diluted *(000s)*	300,768	298,584	299,693	300,768	294,525	299,148	299,863	300,796

(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) 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 and funds flow from operations per share do not have standardized meanings prescribed by Canadian GAAP and therefore may not be comparable to similar measures used by other companies. Management uses these non-GAAP measurements 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.

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

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 costs have increased in 2013 as the Company has begun to expense injection and polymer costs related to the ASP flood at Mooney. Prior to 2013 these costs were being capitalized while the reservoir was being re-pressurized.

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		2013				2012			
	2013	2012	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Average Crude Oil Prices										
West Texas Intermediate (WTI) (US$/bbl)	97.98	94.25	97.46	105.83	94.29	94.34	88.51	92.17	93.44	102.88
Western Canadian Select (WCS) (Cdn$/bbl)	74.98	73.09	68.43	91.75	76.68	62.96	69.43	70.02	71.29	81.61
Differential – WCS/WTI (US$/bbl)	25.23	21.11	32.21	17.48	19.36	31.95	18.46	21.71	23.08	21.44
Differential – WCS/WTI (%)	26.0%	22.3%	33.1%	16.5%	20.6%	33.8%	20.8%	23.6%	24.5%	20.8%
Average Natural Gas Prices										
AECO gas (Cdn$/GJ)	3.00	2.28	2.99	2.67	3.40	2.92	2.90	2.08	1.74	2.39
Average Foreign Exchange (Cdn$ to US$)	0.970	1.000	0.950	0.962	0.977	0.991	1.009	1.005	0.990	0.999

Crude oil prices are based on 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 Western Canadian Select oil prices, which have an average gravity of about 20.5 degrees API.

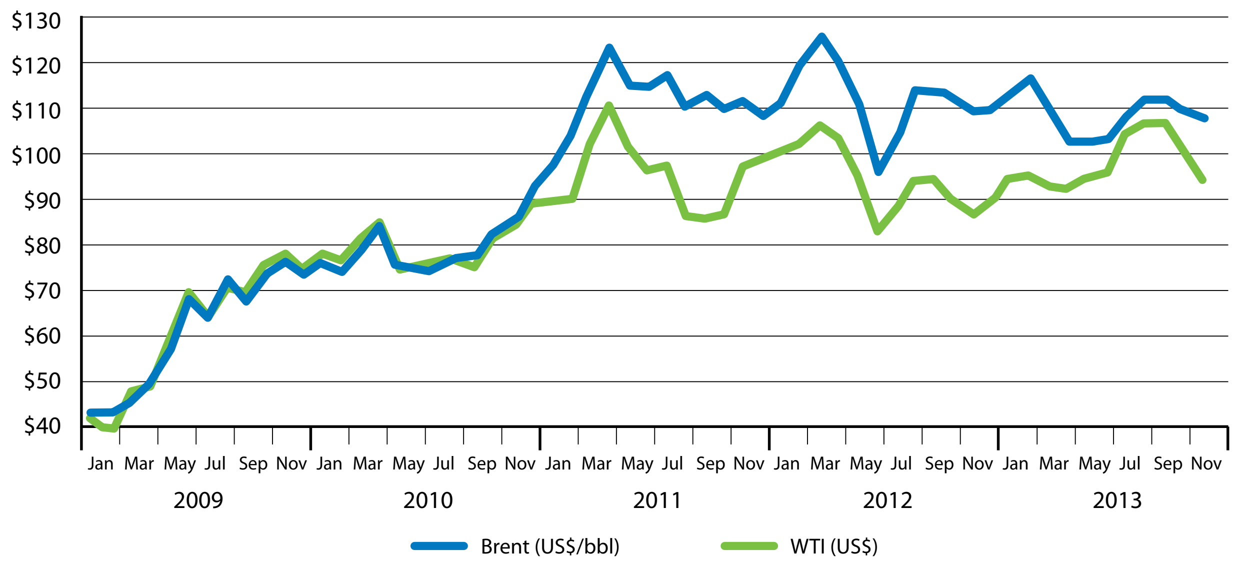
WCS oil prices are generally lower than WTI oil prices due to the higher cost of refining a bbl of heavy oil compared to light oil. This difference between the reference price for light oil and heavy oil is commonly referred to as the light to heavy differential.

Crude oil prices decreased in the fourth quarter of 2013 which has been attributed to easing of tensions in the Middle East and concerns over a slow down in the US economy which would impact oil demand. In Q4 2013 the price of WTI oil averaged US$97.46 per bbl and the light to heavy price differential widened to $US32.21 per bbl due, in part, to refinery shutdowns for maintenance.

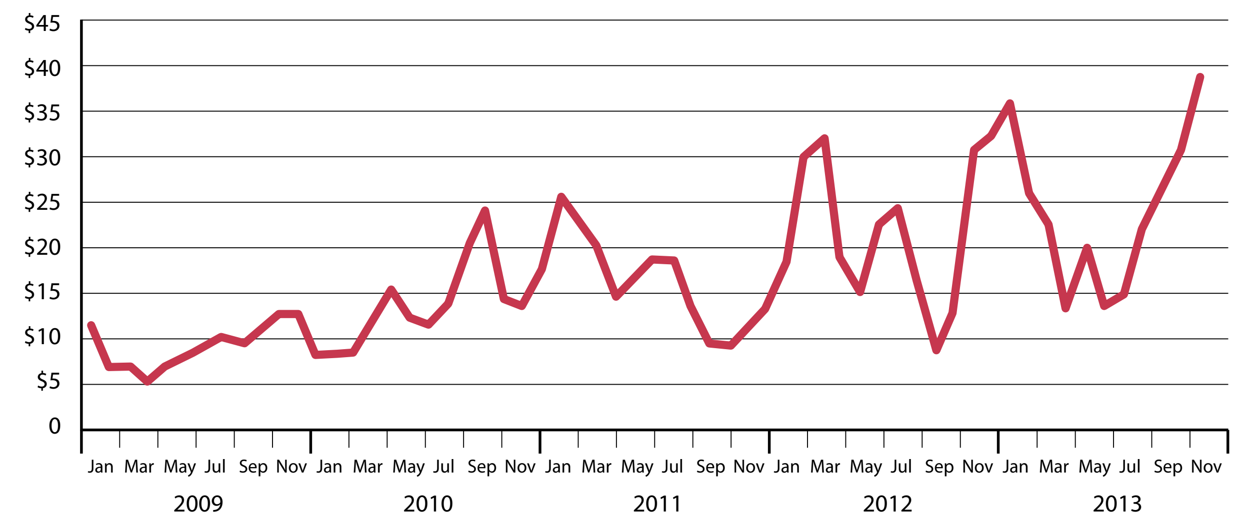
WTI oil prices averaged US$97.98 per bbl in 2013, up from US$94.25 per bbl in 2012. WCS oil prices were also up in 2013 averaging $74.98 per bbl in 2013 compared to $73.09 per bbl in 2012.

Take-away capacity, or the ability to get products to market, has become a significant issue for oil producers in North America, particularly in Canada. Despite some recent oil pipeline capacity expansions, as a result of an increase in Canadian oil sands production, as well as an increase in production of light oil in Canada and the US, the overall pipeline capacity in North America is tight. To alleviate some of the pipeline congestion, an increasing number of producers have elected to transport their crude oil by rail. Improved pricing opportunities, in conjunction with improved delivery point flexibility, has made rail an attractive transportation option. In Canada, it is estimated that approximately 175,000 bbls/d of oil were transported by rail by the end of 2013 and some estimates suggest this will increase to over 700,000 bbls/d in two years. BlackPearl transports some of its Onion Lake and Mooney volumes by rail to the Gulf Coast and West Coast to avoid these pipeline bottlenecks and improve our sales prices for our oil. Currently, BlackPearl is railing between 3,000 and 3,500 bbls/d.

Pipeline capacity constraints have resulted in North American oil prices being discounted to world oil prices. The following table shows the increased price differences between world (Brent) oil prices and North American (WTI) oil prices (similar quality crudes) over the last five years, due in part to the transportation bottlenecks in North America.



Transportation constraints have also impacted heavy oil prices. The following table shows the increase in heavy oil price differentials in Canada over the last five years, again, due in part to pipeline capacity limitations.



Currently, there are several pipeline proposals that could help to alleviate access problems from Western Canada's Sedimentary Basin to international markets, including the Keystone XL Pipeline (which could carry up to 585,000 bbls/d of oil to the Gulf Coast), the Northern Gateway Pipeline (which could carry up to 525,000 bbls/d of oil to Canada's west coast) and the expansion of the existing Trans Mountain Express Pipeline (proposal is to expand capacity to carry up to 890,000 bbls/d of oil to ports in Vancouver, from the current capacity of approximately 300,000 bbls/d). In addition, there is a proposal to reverse and expand Enbridge's Line 9 pipeline from North Westover, Ontario, to Montreal, Quebec, which could deliver approximately 300,000 bbls/d of oil to Quebec refineries and, if expanded, deliver oil to the east coast of Canada. All of these proposals would improve market access for Canadian crude oil; however, none of the pipelines have received regulatory approval for development. In general, these pipeline applications have garnered significant opposition from environmental and other groups and there is no assurance that any of these projects will get built.

Natural gas prices increased in 2013 averaging $3.00/GJ compared to $2.28/GJ in 2012. BlackPearl produces very little natural gas and therefore prices do not have a significant impact on our current oil and gas sales. However, we do consume gas in our Blackrod pilot operations and as we move toward commercial development of our two thermal projects the cost of gas will have a significant impact on our cost structure.

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 2013 which has had a positive impact on our revenues and cash flows. The exchange rate between the Canadian dollar and the US dollar averaged Cdn$1 = US$0.97 during 2013 compared to Cdn$1 = US$1.00 in 2012. The Canadian dollar has continued to weaken relative to the US dollar in 2014, currently near Cdn$1 = US$0.90, which will have positive impact on our revenues and cash flows.

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

	Three months ended December 31		Year Ended December 31	
	2013	2012	2013	2012
Daily production/sales volumes (1)				
Oil (bbls/d)	9,981	8,773	9,255	9,032
Natural gas (Mcf/d)	1,266	440	1,434	374
Combined (boe/d)	10,192	8,846	9,494	9,094
Bitumen – Blackrod (bbls/d) (2)	262	221	236	272
Total production (boe/d)	10,454	9,067	9,730	9,366
Product pricing				
Oil ($/bbl)	58.44	58.77	65.09	61.76
Natural gas ($/Mcf)	3.50	3.18	3.16	2.45
Combined ($/boe)	57.67	58.45	64.11	61.45
Sales ($000s)				
Oil and gas sales – gross	54,072	47,569	222,157	204,525
Royalties	(11,128)	(10,814)	(43,724)	(45,525)
Oil and gas sales – net	42,944	36,755	178,433	159,000

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

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

Oil and natural gas sales increased 9% in 2013 to $222.2 million from $204.5 million in 2012. The increase in oil and gas sales is attributable to a 4% increase in average sales prices received in 2013 compared to 2012 and a 4% increase in production (on a boe basis). Sales increased 14% in the fourth quarter of 2013 compared to the same quarter in 2013 mainly due to a 15% increase in production (on a boe basis), partially offset by a decrease in the average sales price received.

The increase in 2013 oil production is primarily a result of new production from 35 wells drilled in 2013 at Onion Lake, four wells drilled in 2013 at John Lake and an initial re-pressurization response from the first phase of the ASP flood at Mooney. As a result of re-pressurization of the reservoir, production from the ASP flooded areas at Mooney increased to 1,864 boe/d in 2013 compared to 992 boe/d in 2012. We anticipate continuing positive production response from the ASP flood.

The increase in production in Q4 2013 compared to the same period in 2012 is primarily a result of new production from the wells drilled at John Lake and Onion Lake during the year and the continuing positive production response from the first phase of the ASP flood at Mooney. Production from phase one of the ASP flood at Mooney increased to 2,164 boe/d in the fourth quarter of 2013 compared to 1,924 boe/d in the same period in 2012.

On a boe basis, 97% of the Company's oil and natural gas production in 2013 was heavy oil or bitumen. The Onion Lake area accounted for 49% and the Mooney area accounted for 38% of total production in 2013.

	Three months ended December 31		Year Ended December 31	
Production by Area (boe/d)	2013	2012	2013	2012
Onion Lake	5,186	4,857	4,797	5,947
Mooney	3,837	3,329	3,685	2,537
John Lake	1,066	649	898	573
Other	103	11	114	37
Blackrod	262	221	236	272
	10,454	9,067	9,730	9,366

In 2011, BlackPearl commenced its SAGD pilot project at Blackrod. The pilot includes a single horizontal well pair and associated steam and water handling facilities. The pilot is being undertaken to provide operating data to design the commercial development of the Blackrod lands. All sales and expenses from the pilot are being recorded as an adjustment to the capitalized costs of the project until the technical feasibility and commercial viability of the project is established. Technical feasibility and commercial viability are confirmed when reserves are recognized, regulatory approval has been obtained and our Board of Directors has sanctioned commercial development. As of December 31, 2013, BlackPearl had not received regulatory approval for the commercial Blackrod project. During 2013, the pilot produced on average 236 bbls/d of bitumen and the net revenues capitalized were a loss of $3.2 million ($3.3 million loss in 2012). A second pilot well pair was drilled during the first quarter of 2013. Steam injection in this well pair commenced in the fourth quarter and initial oil production is anticipated six to twelve months after initial steam injection.

Royalties

	Three months ended December 31		Year Ended December 31	
	2013	2012	2013	2012
Royalties *($000s)*	11,128	10,814	43,724	45,525
Per boe ($)	11.87	13.29	12.62	13.68
As a percentage of oil and gas sales	21%	23%	20%	22%

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 as a percentage of revenue decreased to 20% of revenues in 2013 from 22% of revenues in 2012 and in the fourth quarter of 2013 royalties were 21% of revenues compared to 23% of revenues in the same quarter in 2012. The decrease in the royalty as a percentage of revenue and royalty per boe in 2013 compared to 2012 is mainly attributable to an increase in the proportion of our production that is coming from the Mooney field (38% of total production in 2013 compared to 27% in 2012), which has lower royalties due to the royalty incentive programs established for EOR projects in Alberta.

Provincial governments have established royalty incentive programs to encourage producers to initiate tertiary recovery schemes on existing fields. The Mooney ASP flood has been approved for one of these incentive programs and therefore, during the pre-payout period, it is expected that royalties in the ASP flood area at Mooney will have a royalty burden of 10% or less. In addition, the horizontal wells drilled at Mooney on the non-ASP flood areas have a 5% crown royalty rate for the first

12 months of production or 50,000 bbls of production. As this royalty incentive expires on wells in the non-ASP flooded areas of Mooney, the well's royalty rate will increase substantially (to a maximum of 40%) due to the relatively higher production volumes from these wells. These wells will eventually be incorporated into the ASP flood and would then be eligible for the provincial incentives for EOR projects. The Alberta government has proposed changes to their EOR royalty incentive program. Our initial assessment of the proposed changes is that any changes would be neutral to slightly positive to BlackPearl and the Mooney ASP flood. We have been given no indication when or if these proposed changes will be approved by the provincial government.

Transportation Costs

	Three months ended December 31		Year Ended December 31	
	2013	2012	2013	2012
Transportation costs *($000s)*	1,657	2,496	9,588	9,203
Per boe ($)	1.77	3.07	2.77	2.76

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 or as a result of production being shipped as emulsion rather than clean marketable oil. Costs related to trucking emulsion are classified as production costs rather than transportation costs.

Transportation costs increased by 4% from $9.2 million in 2012 to $9.6 million in 2013 due to increased production volumes in 2013. Transportation costs decreased in Q4 2013 compared to the same period in 2012 due to an increase in emulsion trucking costs during Q4 2013 which is included in production costs.

Production Costs

	Three months ended December 31		Year Ended December 31	
	2013	2012	2013	2012
Production costs *($000s)*	18,420	14,563	72,199	59,301
Per boe ($)	19.65	17.89	20.84	17.82

Production costs increased by 22% in 2013 to $72.2 million from $59.3 million in 2012. On a per boe basis, production costs increased 17% in 2013 to $20.84 per boe from $17.82 per boe in 2012. Production costs increased in Q4 2013 compared to the same period in 2012 by 26% and on a per boe basis by 10%.

The increase in production costs is attributable to increased costs at Onion Lake due to the relative maturity of the field (higher repairs, maintenance and workover costs) and to injection and polymer costs associated with the ASP flood at Mooney. Prior to 2013, all operating costs associated with the ASP flood were being capitalized while the reservoir was being re-pressurized. By 2013, oil production in the flooded area was increasing which indicated the reservoir was re-pressurized. As a result, in 2013, we began to expense all costs associated with injection and polymer costs. In 2013, we continued to capitalize certain other chemical costs (e.g. alkali and surfactant) as we had not observed any response from these chemicals. Subsequent to December 31, 2013, we have begun to see a consistent response from these chemicals and therefore, in 2014, we will begin expensing all chemical costs associated with the first phase of the ASP flood. A breakdown of ASP related expenses is provided on the following page.

($000s)	Three months ended December 31 2013	2012	Year Ended December 31 2013	2012
Polymer costs	1,009	1,832	5,966	4,400
Other chemical costs	2,614	1,261	9,576	9,996
Injection costs	677	1,085	2,867	4,682
Total ASP costs	4,300	4,178	18,409	19,078
ASP costs capitalized	(2,614)	(4,178)	(9,576)	(19,078)
ASP costs expensed in production costs	1,686	–	8,833	–

Operating Netback [1]

($/boe)	Three months ended December 31 2013	2012	Year Ended December 31 2013	2012
Revenues	57.67	58.45	64.11	61.45
Royalties	11.87	13.29	12.62	13.68
Transportation costs	1.77	3.07	2.77	2.76
Production costs	19.65	17.89	20.84	17.82
Operating netback per boe	24.38	24.20	27.88	27.19

(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 boe sold. Operating netback increased by 3% from $27.19 per boe in 2012 to $27.88 per boe in 2013. The increase is primarily attributable to the increase in realized crude oil prices and lower royalties, partially offset by higher production costs.

General and Administrative Expenses (G&A)

($000s, except per boe)	Three months ended December 31 2013	2012	Year Ended December 31 2013	2012
Gross G&A expense	2,549	2,625	10,503	9,819
Operator recoveries	(480)	(641)	(1,869)	(2,338)
Net G&A expense	2,069	1,984	8,634	7,481
Per boe ($)	2.21	2.44	2.49	2.25

General and administrative expenses consist primarily of salaries and wages of employees, office rent, computer services, legal, accounting and consulting fees. Gross general and administrative expenses increased by 7% from $9.8 million in 2012 to $10.5 million in 2013. The increase in gross G&A is primarily attributable to higher performance incentive payments to staff in 2013 compared to 2012. Net general and administrative expense increased by 15% from $7.5 million in 2012 to $8.6 million in 2013. The increase in net G&A is attributable to the performance incentive payments and reduced overhead recoveries as a result of lower capital expenditures in 2013.

Stock-Based Compensation

($000s, except per boe)	Three months ended December 31 2013	2012	Year Ended December 31 2013	2012
Gross stock-based compensation	644	1,390	3,828	6,390
Capitalized stock-based compensation	(16)	(374)	(408)	(374)
Net stock-based compensation	628	1,016	3,420	6,016
Per boe ($)	0.67	1.25	0.99	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 options pricing model.

The decrease in stock-based compensation expense in 2013 reflects a lower option value assigned to each grant of options. On a per boe basis, stock-based compensation has been dropping as a result of production levels increasing at a higher rate than the increase in expenses. In 2013, 3,545,500 options were granted and 4,659,000 options were exercised.

During 2013, $0.3 million of stock-based compensation costs were capitalized to property, plant and equipment related to options granted to staff directly related with the development activities at the Onion Lake EOR project. In addition, $0.1 million of stock-based compensation costs were capitalized to exploration and evaluation assets related to options granted to staff directly related with the development activities at Blackrod.

Finance Costs

	Three months ended December 31		Year Ended December 31	
($000s)	2013	2012	2013	2012
Gross interest & financing charges	177	156	1,069	827
Capitalized interest & financing charges	(8)	–	(226)	–
Net interest & financing charges	169	156	843	827
Accretion of decommissioning liabilities	364	153	1,094	741
Debt financing costs	(80)	–	1,012	–
Total finance costs	453	309	2,949	1,568

The increase in finance costs in 2013 compared to 2012 is primarily attributable to debt financing costs (primarily legal expenses) related to the proposed $350 million second-lien senior secured term loan facility that was to be used to finance the development of the Onion Lake EOR project. Due to the volatility in the debt capital markets, we elected not to proceed with this financing.

Interest costs relate to borrowings during the year under our credit facilities. In 2013, $0.2 million of interest costs related to the construction of the thermal projects were capitalized.

Depletion and Depreciation

	Three months ended December 31		Year Ended December 31	
	2013	2012	2013	2012
Depletion and depreciation *($000s)*	19,788	16,753	72,083	69,576
Per boe ($)	21.10	20.58	20.80	20.90

The Company's properties are depleted on a unit of production basis using estimated proven plus probable reserves. Depletion and depreciation expense increased by 4% to $72.1 million in 2013 compared to $69.6 million in 2012. Depletion and depreciation expense increased in Q4 2013 compared to the same period in 2012 by 18%. The increase in depletion is a result of increased production volumes in 2013. On a boe basis, depletion and depreciation expense remained largely unchanged at $20.80 per boe in 2013 compared to $20.90 per boe in 2012.

As of December 31, 2013, $16.0 million of expenditures included in property, plant and equipment that relate to the Onion Lake EOR project are not subject to depletion until production at this project begins.

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. As indicators periodically dictate and at minimum on an annual basis, the net book values of these CGU's are tested for impairment. As a result of well operating performance, it was determined that the net book value of one of the Company's minor CGUs (Salt Lake in Saskatchewan) exceeded the estimated recoverable amount (using after tax cash flows from proved plus probable reserves at 10%) and the Company recognized a $3.0 million impairment charge.

Interest Income

	Three months ended December 31		Year Ended December 31	
($000s)	2013	2012	2013	2012
Interest income	13	21	44	315

Interest income consists of interest earned on excess cash held by the Company. Interest income has decreased as a result of lower average cash balances maintained by the Company in 2013 compared to 2012.

Income Taxes

	Three months ended December 31		Year Ended December 31	
($000s)	2013	2012	2013	2012
Current income and other tax recoveries	27	(41)	71	(76)
Deferred income tax (recovery)	354	(1,042)	3,734	1,932
Total income tax	381	(1,083)	3,805	1,856

BlackPearl did not pay cash income taxes in 2013 and does not expect to pay income taxes in 2014 as we have sufficient tax pools to shelter expected income. The current income tax expense for 2013 is a result of capital tax.

Deferred income tax expense was $3.7 million for 2013, for an effective tax rate of 37%. The high effective tax rate is due primarily to the non-deductibility (for tax purposes) of stock-based compensation.

The Company has the following estimated tax pools as at:

($000s, except for left-hand column)	Rate %	Dec 31, 2013	Dec 31, 2012
Canadian exploration expenses	100	34,798	33,862
Canadian development expenses	30	124,604	134,527
Canadian oil and gas property expenses	10	16,579	16,234
Undepreciated capital costs	10-30	191,459	159,323
Non-capital losses (various expiry dates)	100	226,856	247,489
Share issuance costs	5 years	659	1,785
Total estimated tax pools		594,955	593,220

Approximately $31 million of the Canadian resource pools are restricted due to the successor rules in Canada and may not be fully utilized.

Gain on Disposition of Petroleum and Natural Gas Properties

	Three months ended December 31		Year Ended December 31	
($000s)	2013	2012	2013	2012
Gain on disposition of petroleum and natural gas properties	3,636	–	3,636	–

During 2013, the Company completed a minor property disposition of certain non-core assets for cash consideration of $5.0 million that resulted in a gain of $3.4 million. The assets sold were conventional non-producing heavy oil properties in Saskatchewan. The remaining gain on dispositions relates to minor sales of specific petroleum and natural gas equipment.

Derivative Financial Instruments

The Company will periodically enter into derivative financial instrument contracts in order to ensure a certain level of cash flow to fund planned capital projects. BlackPearl's strategy focuses on swaps and fixed price contracts to limit exposure to fluctuations in oil prices. The Company's financial derivative 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.

Throughout 2013 the Company did not use derivative financial instruments to manage its exposure. Subsequent to December 31, 2013, the Company entered into the following derivative commodity contracts:

Subject of Contract	Volume	Term	Reference	Strike Price	Option Traded
Oil	2,500 bbls/d	March 1, 2014 to December 31, 2014	CDN$ WCS	CDN$ 82.10/bbl	Swap
Oil	1,000 bbls/d	March 1, 2014 to December 31, 2014	CDN$ WCS	CDN$ 82.00/bbl	Swap

The Company has been able to adjust its capital spending on its conventional heavy oil projects to reflect changes in oil prices and cash flow. However, going forward our thermal projects involve more extensive planning and significantly higher capital costs and it's difficult to make adjustments once construction commences. Therefore as the focus of our capital spending program transitions more toward our thermal projects we want to reduce some of the volatility in our cash flows. Accordingly, we have begun to hedge the oil price on a portion of our production in 2014.

RESULTS OF OPERATIONS

	Three months ended December 31		Year Ended December 31	
	2013	2012	2013	2012
Net income (loss) *($000s)*	226	(4,277)	6,449	45
Per share, basic ($)	0.00	(0.01)	0.02	0.00
Per share, diluted ($)	0.00	(0.01)	0.02	0.00

For the year ended December 31, 2013, the Company generated net income of $6.4 million compared to net income of $45,000 in 2012. For the quarter ended December 31, 2013, the Company generated net income of $0.2 million compared to a loss of $4.3 million in the same period in 2012. The increase in income in 2013 is primarily a result of higher production volumes and higher wellhead sales prices in 2013 and the gain the Company recorded on the disposition of a minor property, partially offset by an impairment charge to a non-core CGU of $3.0 million.

	Three months ended December 31		Year Ended December 31	
	2013	2012	2013	2012
Funds flow from operations (1) *($000s)*	20,735	17,684	86,206	82,595
Per share, basic ($)	0.07	0.06	0.29	0.29
Per share, diluted ($)	0.07	0.06	0.29	0.28

(1) 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 and funds flow from operations per share do not have standardized meanings prescribed by Canadian GAAP and therefore may not be comparable to similar measures used by other companies. Management uses these non-GAAP measurements 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.

Funds flow from operations increased by 4% to $86.2 million in 2013 compared to $82.6 million in 2013. The increase is funds flow in 2013 reflects higher production volumes and higher wellhead sales prices in 2013.

Funds flow from operations in the fourth quarter of 2013 was $20.7 million compared to $17.7 million in the fourth quarter of 2012. The increase in funds flow from operations in Q4 2013 was primarily due to the increase in production volumes compared to the same period in 2012.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2013, the Company had a working capital deficiency (current assets less current liabilities) of $8.8 million. The working capital deficiency will be funded from cash flows from operating activities or the undrawn amount on our credit facilities.

At December 31, 2013, the Company had issued letters of credit in the amount of $20,000; leaving $115 million available to be drawn under the credit facilities. The amount available under these facilities ("Borrowing Base") is re-determined by the lenders at least twice a year and is primarily based on our oil and gas reserves, forecast commodity prices, the current economic environment and other factors as determined by the lenders. The most recent credit facilities review occurred in February 2014 and the aggregate borrowing base determined by the lenders increased from $115 million to $150 million, contingent on the successful completion of the offering and private placement of BlackPearl common shares. The next scheduled Borrowing Base redetermination is to occur by November 30, 2014. In the event the lenders elected not to renew the credit facilities during the credit facilities review any amounts outstanding on the facilities would be due and payable in full by May 30, 2015.

Pursuant to the terms of the credit agreement, the only financial covenant in the credit facilities is 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, from 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. BlackPearl was in compliance with this covenant throughout the year ended 2013. The credit facilities are secured by a floating and fixed charge debenture. The terms of our credit agreement also restrict the payment of cash dividends to shareholders.

We expect to fund the ongoing development of our conventional heavy oil projects at Mooney, Onion Lake and other minor project areas from cash flow from operating activities and amounts available under the credit facilities. We are also able to scale back our capital expenditure program on these projects relatively easily if circumstances warrant it.

During the second quarter of 2013, the Company announced its intention to pursue a US$350 million second-lien senior secured term loan facility to fund development of the Onion Lake EOR project. Due to the volatility in the debt capital markets, the Company subsequently elected to not proceed with the establishment of this facility. The Company amended its business plan and decided to construct the Onion Lake EOR project in phases. The first phase of the project is being designed for production of 6,000 bbls/d of oil and capital costs are expected to be approximately $200 million. Funding for the first phase of the project will come from the recently expanded credit facilities, proceeds from the recently announced $70.2 million public offering of common shares, the intended private placement of $10 million of common shares and cash flow from operating activities. BlackPearl's Board of Directors has approved development of the first phase of the project and construction is expected to take 15 to 18 months.

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 of oil. We have not completed detailed cost estimates for this phase but our internal estimates suggest initial capital costs will be approximately $800 million. Timing of development of this project is dependent on additional financing. We currently do not have the financing necessary to initiate development of this project. It is unlikely we could finance two thermal projects at the same time and therefore Blackrod will likely be deferred until the Onion Lake EOR project is completed. We will look at joint venture opportunities to accelerate development of this project.

CAPITAL EXPENDITURES

During the year ended December 31, 2013, capital spending was $93.5 million, a decrease from $139.5 million in 2012. The main components of the 2013 capital program was the drilling of 35 conventional heavy oil wells at Onion Lake, five wells at Mooney, four horizontal wells at John Lake, one well at Salt Lake, as well as a second SAGD pilot well pair at Blackrod. In addition, capital spending included preliminary commercial engineering designs at the Blackrod SAGD project and the Onion Lake EOR project and the capitalization of certain chemical costs at Mooney related to Phase 1 of the ASP flood. Also included in capital spending, the Company acquired additional oil sands acreage and certain petroleum and natural gas assets in the Blackrod area for $4.9 million during the year.

Capital expenditures in the fourth quarter of 2013 were $22.7 million, a decrease of 34 percent compared to the fourth quarter of 2012. Capital expenditures during Q4 2013 include drilling 5 wells at Mooney, preliminary commercial designs at the Onion Lake EOR project, continued capitalization of certain chemical costs related to the ASP flooding at Mooney and the Blackrod SAGD operations.

	Three months ended December 31		Year Ended December 31	
($000s)	2013	2012	2013	2012
Land	1,060	44	2,085	591
Seismic	(54)	40	937	671
Drilling and completion	12,137	24,445	51,824	83,454
Equipment	9,535	10,084	33,499	51,780
Other	71	22	89	52
Total	22,749	34,635	88,434	136,548
Property acquisitions	–	–	5,057	3,000
Total capital expenditures	22,749	34,635	93,491	139,548
Property dispositions	(2,302)	–	(2,302)	–
Net capital expenditures	20,447	34,634	91,189	139,548

In 2013, the Company disposed of certain non-core assets for cash consideration of $5.0 million. The assets sold were conventional non-producing heavy oil properties in Saskatchewan.

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, 2013. These obligations are expected to be funded from cash flow from operating activities.

($000s)	2014	2015	2016	2017	2018	Thereafter
Operating leases (1)	1,928	1,780	1,287	–	–	–
Electrical service agreements (2)	1,003	1,003	520	119	119	2,225
Decommissioning liabilities (3)	838	897	1,960	1,027	1,099	58,040
	3,769	3,680	3,767	1,146	1,218	60,265

(1) The Company has 33 months remaining on an operating lease for office space as at December 31, 2013. 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 lease obligation, BlackPearl would be required to pay a maximum additional $8.4 million (including an estimate for operating costs) over the next 33 months. At December 31, 2013, no amounts were owed (2012 – no amounts owing).

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

(3) 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 $63.9 million as at December 31, 2013. Decommissioning programs are undertaken regularly in accordance with applicable legislative requirements.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The financial instruments on the Company's balance sheet include cash and cash equivalents, trade and other receivables, deposits within prepaid expenses and deposits and accounts payable and accrued liabilities. The Company manages its risk through its policies and procedures and subsequent to December 31, 2013, the Company began to use derivative financial instruments to manage some of these risks.

The carrying value of cash and cash equivalents, trade and other receivables, deposits within prepaid expenses and deposits and accounts payable and accrued liabilities approximates their fair value due to the short-term nature of these instruments. The Company has not designated its derivative financial instrument contracts as effective accounting hedges, and thus has not applied hedge accounting, even though the Company considers all derivative financial instrument contracts to be economic hedges. As a result, all derivative financial instrument contracts are classified at fair value through profit or loss and recorded on the statement of comprehensive income at fair value. Transaction costs are recognized in profit or loss when incurred.

Foreign Currency Risk

Foreign currency risk is the risk that a variation in exchange rates between the Canadian dollar and the U.S. dollar will affect the Company's operating and financial results. As at December 31, 2013, the Company held US $1.1 million (2012 – US $702,000) cash and cash equivalents, US $122,000 (2012 – $Nil) prepaid expenses and deposits and US $126,000 (2012 – US $950,000) accounts payable and accrued liabilities.

As at December 31, 2013, if the Cdn$-US$ exchange rates had been $0.10 lower with all other variables held constant, after tax income for the period would have been approximately $111,000 lower, due to an increase in the foreign exchange loss. An equal opposite impact would have occurred to net income 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, 2013, the Company held $8.4 million in cash at various major financial institutions throughout Canada and the United States. At December 31, 2013, two Canadian financial institutions held approximately 88% of BlackPearl's cash and short-term deposits. Cash balances in excess of the Company's day-to-day requirements are invested in short-term deposits of less than 30 days.

The Company's trade receivables are primarily with oil and gas marketers, a government agency and joint venture partners. Receivables from oil and natural gas marketers are generally collected on the 25th day of the month following production. The Company attempts to mitigate this risk by assessing the financial strength of its counterparty and entering into relationships with larger purchasers with established credit history.

The Company has a $4.1 million receivable related to the Alberta government's Enhanced Recovery of Oil Royalty Reduction Regulation program. This program provides companies with a reduction of royalties' payable in respect to oil obtained under an enhanced recovery approved scheme until incremental costs related to the EOR project are recovered. These amounts are not considered impaired based on the credit worthiness of the Alberta government and the approval the Company has received on its enhanced oil recovery activities at Mooney.

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.

Derivative financial instruments consist of commodity contracts used to manage the Company's exposure to fluctuations in commodity prices. The Company manages the credit risk exposure related to derivative financial instruments by selecting investment grade counterparties and by not entering into contracts for trading or speculative purposes.

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 the long-term debt, which was undrawn as of December 31, 2013.

Cash is held in highly liquid, short-term investments and therefore the risk to changes in interest rates is low. At December 31, 2013, if interest rates had been one percentage point (100 basis points) higher, with all other variables held constant, after tax income for the period would have been approximately $21,000 higher.

At December 31, 2013, the Company had not drawn on its credit facilities and therefore the Company was not subject to interest rate risk.

Liquidity Risk

Liquidity risk is the risk the Company is unable to meet its financial obligations as they come due. The Company uses operating cash flows, credit facilities and equity offerings to fund its capital requirements.

The Company manages this risk by maintaining a conservative balance sheet and regularly monitoring and adjusting its capital spending program to minimize the risk that it cannot meet its financial obligations. As at December 31, 2013, the Company had a working capital deficiency of $8.8 million and undrawn $115 million credit facilities. The Company believes it has sufficient funding from these sources to meet its existing obligations.

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 3% 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.

Throughout 2013 the Company did not use derivative financial instruments to manage its exposure to commodity price risk. Subsequent to December 31, 2013, the Company has attempted to mitigate a portion of the commodity price risk through the use of various derivative financial instruments.

Derivative financial instruments are recorded on the statement of comprehensive income at fair value at each reporting period with the change in fair value being recognized as an unrealized gain or loss.

OFF-BALANCE-SHEET ARRANGEMENTS

The Company had no off-balance-sheet arrangements during the year ended 2013 or 2012. We do utilize 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 2013 or 2012. Key management compensation has been disclosed in the Company's financial statements (note 16).

OUTSTANDING SHARE DATA AND STOCK OPTIONS

As at February 26, 2014, the Company had 300,800,808 common shares outstanding and 14,004,834 stock options outstanding under its stock-based compensation program.

OUTSTANDING LONG-TERM DEBT DATA

As at February 26, 2014, the Company had no amounts drawn under its existing credit facilities and had issued letters of credit in the amount of $20,000; leaving $114,980,000 available to be drawn under these credit facilities.

PROPOSED TRANSACTIONS

As of February 26, 2014, the Company entered into an agreement with a syndicate of underwriters whereby they have agreed to purchase for resale to the public, on a bought deal basis, 26,500,000 common shares of BlackPearl at $2.65 per share for aggregate gross proceeds of $70.2 million. In addition, the underwriters have been granted an over-allotment option, which may be exercised in whole or in part up to 30 days after closing of the offering, to purchase up to 3,975,000 additional common shares at a price of $2.65 per common share. If the over-allotment is fully exercised, gross additional proceeds would be $10.5 million. The Company also intends to issue by private placement an additional 3,773,585 common shares at $2.65 per share representing gross proceeds of $10 million. In addition, the Company's lending syndicate has agreed to increase the Company's existing credit facilities from $115 million to $150 million upon completion of the offering and the private placement.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements requires management to make estimates and assumptions that affect reported assets and liabilities, disclosure of contingencies and revenues and expenses. Management is also required to adopt accounting policies that require the use of significant estimates. Actual results could differ materially from those estimates. A comprehensive discussion of the significant accounting policies adopted by BlackPearl can be found in notes 2 through 5 to the consolidated financial statements.

Management believes the most critical accounting policies, including judgments in their application, which may have an impact on the Company's financial results, relate to the accounting for property, plant and equipment and decommissioning liabilities. The rate at which the Company's assets are depleted and depreciated or otherwise written off and the decommissioning liability provided for, with the associated accretion expensed to the income statement, are subject to a number of judgments about future events, many of which are beyond management's control. In addition, recognition of oil and gas reserves is central to much of the accounting for an oil and natural gas company, as described below.

The following areas contain significant judgments, estimates and assumptions made by management:

(i) *Oil and natural gas reserves* – Estimating reserves is a subjective process. It requires significant judgments using geological, engineering and economic data. The important assumptions made in preparing an estimate of oil and gas reserves include expected reservoir performance, future rates of production, oil and natural gas price forecasts, future operating and development costs, timing of expenditures and future fiscal regimes. These estimates can change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions change. The Company's oil and natural gas reserves are evaluated by Sproule Unconventional Limited, an independent reserves evaluator.

Reserves estimates can have a significant impact on net income, as they are a key component in the calculation of depletion and impairment testing as discussed below. The reserve estimates are also used in determining the Company's borrowing base for its credit facilities.

(ii) *Depletion and depreciation expense* – BlackPearl tracks all capital costs for development projects at the area asset level (unit-of-account). The aggregate of the capitalized costs and future development costs is amortized on the unit-of-production method based on estimated proved and probable reserves. Changes in estimated proved and probable reserves or future development costs have a direct impact on depletion and depreciation expense. If our proved and probable reserve estimates change by 10%, our depletion expense would have changed by approximately $2.0 million, assuming no other changes to our reserves.

Certain costs related to exploration and evaluation assets (E&E) 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 management determines that the projects are technically feasible and commercially viable or that their value is impaired. Technical feasibility and commercial viability are confirmed when reserves are recognized, regulatory approval has been obtained and our Board of Directors has sanctioned the development. At December 31, 2013, $161.4 million has been excluded from depletion and has been shown separately on the Company's balance sheet.

Certain costs related to property, plant and equipment have been excluded from costs subject to depletion. These costs relate to the Onion Lake EOR project which is still under construction and has no associated production to date. At December 31, 2013, $16.0 million has been excluded from depletion and has been disclosed separately in the Company's financial statement notes.

(iii) *Impairment testing* – BlackPearl is required to review the carrying value of exploration and evaluation assets (E&E) and all property, plant, and equipment (PPE) for potential impairment. Throughout the year, the Company analyzes

the carrying value of its E&E and PPE at the cash generating unit level (CGU), and considers potential indicators of impairment such as, among other things, current market conditions, current and forecasted heavy oil prices and the profitability of each CGU. Each CGU is explicitly tested for impairment, at a minimum, on an annual basis. In 2013 and 2012 we have five CGU's, one for each of our core areas and two CGU's for some of our minor properties.

The impairment test is based on estimates of reserves prepared by qualified independent evaluators including production rates, crude oil and natural gas prices, future costs and other relevant assumptions. By their nature, reserve estimates are subject to measurement uncertainty and the impact of impairment test calculations on the consolidated financial statements of changes to reserve estimates could be material.

At December 31, 2013, the carrying values of each of the Company's CGUs were compared to the net present value of proved and probable reserves and contingent resources, after tax, discounted at a rate of 10%. As a result of well operating performance, one of our minor CGUs (Salt Lake in Saskatchewan) was impaired and the Company wrote-down the carrying value of this CGU by $3.0 million in 2013.

(iv) *Decommissioning liability* – the decommissioning liability is estimated based on existing laws, contracts or other policies. The fair value of the liability is based on estimated future costs for abandonment and reclamation, discounted at a risk-free rate. The costs are included in property, plant and equipment and amortized over their useful life. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to income and for revisions to the estimated future cash flows. The estimates or assumptions required to calculate the decommissioning liability include, among other items, abandonment and reclamation amounts, inflation rates, risk-free discount rates and timing of retirement of assets. These assumptions are assessed annually, at a minimum, for reasonability and are revised when required to provide a more accurate estimate of the liability. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material.

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

	2013	2012
Undiscounted abandonment costs *($000s)*	$ 63,861	$ 39,656
Risk-free rate	2.55%	2.25%
Inflation rate	2%	2%
Average years to reclamation	9	9

(v) *Income taxes* – the Company records deferred tax assets and liabilities based on temporary differences between the carrying value and tax basis of the Company's assets and liabilities. Deferred tax provisions require estimating the timing of these temporary differences and estimating whether tax assets will be realized before expiry.

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded. In addition, the Company is required to estimate whether it will be able to utilize all of its existing tax pools before their expiry.

(vi) *Stock-based compensation* – The Company uses the Black-Scholes pricing model when determining the fair value to account for stock options. The determination of the amounts for stock-based compensation is based on estimates of stock volatility, risk-free interest rates and the expected lives of the option. By their nature, these estimates are subject to measurement uncertainty and a change in these estimates would impact the valuation of new options and could result in a different amount for stock-based compensation expense and contributed surplus.

(vii) *Derivative financial instruments* – The Company's estimate of the fair value of derivative financial instruments is dependent on estimated forward prices and volatility in those prices.

(viii) *Other estimates*

a. The Company is required to make certain estimates for revenues, royalties, operating costs and capital expenditures as at a specific reporting date if actual amounts for these items have not been received.

b. The estimated fair value of the Company's financial assets and liabilities, are by their nature, subject to measurement uncertainty.

CHANGES IN ACCOUNTING POLICIES

The Company has adopted the following new and amended standards with a date of initial application of January 1, 2013.

IFRS 10: Consolidated Financial Statements – IFRS 10 introduces a new control model that focuses on whether the Company has power over an investee, exposure or rights to variable returns from its involvement with the investee and ability to use its power to affect returns. The Company reassessed control based on IFRS 10 for its investees at January 1, 2013 and concluded that no changes were required to the Company's financial statements as the previous consolidation method adheres to this standard.

IFRS 11: Joint Arrangements – Under IFRS 11, the Company is required to classify its interest in joint arrangements as either joint operations or joint ventures. When making this assessment, the Company considers the structure of the arrangements, the legal form of any separate vehicles, the contractual terms of the arrangements and other factors and circumstances. The Company reassessed its joints arrangements based on IFRS 11 for all its arrangements at January 1, 2013 and concluded that all the Company's joint arrangements were joint operations. This resulted in no changes to the Company's financial statements due to the fact that under IFRS 11 the parties under a joint operation have rights to their share of the assets and the obligation to their share of the liabilities relating to the joint arrangement, which was the method previously used.

IFRS 13: Fair Value Measurement – IFRS 13 establishes a single framework for measuring fair value and making disclosures about fair value measurements when such measurement are required or permitted by other IFRSs. It unifies the definition of fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. It replaces and expands the disclosure requirements about fair value measurements in other IFRSs, including IFRS 7. As a result, the Company has included additional disclosures in this regard. Notwithstanding, the change to IFRS 13 had no significant impact on measurements of the Company's assets and liabilities.

IAS 28: Investments in Associates and Joint Ventures – IAS 28 describes the application of the equity method to investments in joint ventures in addition to associates. The revised standard has no impact on the Company's financial statements as the Company has no associates or joint ventures that are accounted for under the equity method.

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

The standards and interpretations that are issued but not yet effective up to the date of issuances of the Company's December 31, 2013 year end financial statements are listed below.

IFRS 9: Financial Instruments: Classification and Measurement – The IASB intends to replace International Accounting Standard 39, "Financial Instruments: Recognition and Measurement" with IFRS 9, "Financial Instruments". IFRS 9 will be published in three phases, of which two phases have been published.

Phases one and two address accounting for financial assets and financial liabilities, and hedge accounting, respectively. The third phase will address impairment of financial instruments.

For financial assets, IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. For financial liabilities, IFRS 9 retains most of the IAS 39 requirements; however, where the fair value option is applied to financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in OCI rather than net earnings, unless this creates an accounting mismatch.

IFRS 9 introduces a simplified hedge accounting model, aligning hedge accounting more closely with risk management. In addition, improvements have been made to hedge accounting and risk management disclosure requirements. The Company does not currently apply hedge accounting.

A mandatory effective date for IFRS 9 in its entirety will be announced when the project is closer to completion. Early adoption of the two completed phases is permitted if adopted in their entirety at the beginning of a fiscal period. The Company is currently evaluating the impact of adopting IFRS 9 on the Company's financial statements.

IAS 32: Financial Instruments: Presentation – In 2011, the IASB issued amendments to IAS 32 clarifying the meaning of "currently has a legal enforceable right to set-off" and the application of the IAS 32 offsetting criteria to settlement systems which apply gross settlement mechanisms that are not simultaneous. These amendments are required to be adopted for periods beginning January 1, 2014 and will require minimal disclosure changes in the Company's financial statements.

IAS 36: Impairment of Assets – In 2013, the IASB issued amendments to IAS 36 that requires entities to disclose the recoverable amount of impaired Cash Generating Units ("CGU"). The amendment is required to be adopted for periods beginning January 1, 2014 and will require minimal disclosure changes in the Company's financial statements.

RISKS AND UNCERTAINTIES

The Company is exposed to a number of risks and uncertainties inherent in exploring for, developing and producing crude oil and natural gas. These risks and uncertainties include, but are not limited to, the following:

Financial risks

- Risk of fluctuating oil, natural gas prices and the cost of diluent;
- Risk of not meeting covenants associated with the Company's credit facilities;
- Risk of lenders reducing the amount of credit per the Company's credit facilities;
- Risk of the Company's ability to make payments on, and to refinance, its future indebtedness;
- Risk associated with securing the needed capital to carry out the Company's operations;
- Availability of adequate debt, equity financing and cash flow to fund planned expenditures;
- Risk of fluctuating foreign currency exchange rates;
- Risk of changes to interest rates;
- Risk of a third party failing to meet its obligations;
- Risk of potential financial loss associated with derivative financial instruments;
- Global economic conditions and financial uncertainty; and
- Risk of capital costs over-runs on large development projects.

Operational risks

- Ability to find, acquire, develop and commercially produce oil and natural gas reserves;
- Ability to explore and develop any oil and natural gas reserves the Company may have;
- Ability to generate or raise sufficient capital to make the necessary investments to replace or expand the Company's oil and gas reserves;
- Risk that expenditures made on future exploration, development or acquisition by the Company will not result in new discoveries of oil or natural gas in commercial quantities;
- Uncertainties associated with estimating the quantity of reserves and resources and the associated cash flows;
- Risk of market price fluctuations which may render the recovery of the reserves and resources uneconomic;
- Risk the Company's undeveloped reserves and resources may not be ultimately produced within the time period the Company has planned, at the costs the Company has budgeted or at all;
- Risks associated with the early stages of development of some of our large thermal projects;
- Uncertainties of the SAGD bitumen and ASP flood recovery processes;
- Risks and hazards typically associated with such oil and gas operations, including hazards such as fire, explosion, blowouts, mechanical or pipe failure, sour gas releases, cratering and oil spills, acts of vandalism, or other unexpected or dangerous conditions, each of which could result in substantial damage to oil and natural gas wells, producing facilities, other property and the environment or in personal injury;
- Risk of a termination of a lease, license or permit;
- Reliance on third parties for pipeline, processing facilities and other infrastructure;
- Uncertainties in regards to the supply of chemicals and diluent;
- Uncertainties in regards to the supply of water for our SAGD projects;
- Unforeseen title defects in the leases we hold; and
- Risks associated with future abandonment and reclamation costs.

Regulatory risks

- Risk of changes in government policies, especially related to royalty legislation, income tax laws, incentive programs, operating practices and environmental protection, social instability or other political, economic or diplomatic developments in its operations;
- Environmental and safety risks related to its oil and gas properties;
- Risk from aboriginal claims; and
- Risk related to royalty regimes and changes to royalty regimes.

Other risks

- Risks of legal and regulatory claims;
- Geo-political risks;
- The risk of relying on key personnel;
- Conflict of interest risks;
- Risk of managements estimates and assumptions;

- Risks that the Company's insurance coverage is insufficient or unavailable to cover all loses that may occur in the Company's operations; and
- Competition for, among other things, capital, undeveloped land, skilled labor and equipment leading to capital cost over-runs.

Further information regarding these risks may be found under "Risk Factors" in the Company's Annual Information Form. Many of the previously mentioned risks 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.

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, 2013.

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, 2013, 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, 2013. Based on this evaluation, the officers concluded that as of December 31, 2013, 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, 2013 that materially affected, or are reasonably likely to materially affect, the Company's ICFR.

OUTLOOK

	2014 Initial Guidance
Production (boe/d)	
Annual average	10,000 – 10,500
Funds flow from operations ($millions)	80 – 85
Capital expenditures ($millions)	260 – 270
Year-end debt ($millions)	95 – 105
Pricing Assumptions (annual average)	
Crude oil – WTI	US $92.00
Light/heavy differential	US $21.00
Foreign Exchange (Cdn$ to US$)	0.94

In 2014, we are planning to spend $260 to $270 million on capital projects. Our major focus in 2014 will be the construction of the Onion Lake EOR project, where we plan to spend up to $185 million on the first phase of the project. We will continue with the on-going development of our existing projects, including drilling 20 to 25 conventional wells at Onion Lake, conversion of the phase two lands at Mooney to ASP flood, as well as new horizontal drilling on phase 3 expansion lands at Mooney.

The capital program is expected to be funded from a combination of funds flow from operations, which we are budgeting to be between $80 and $85 million, our expanded $150 million credit facilities, proceeds from the recently announced public offering ($70.2 million) and intended private placement ($10 million) of BlackPearl common shares. We expect our year-end debt to be between $95 and $105 million.

Oil and gas production is expected to average between 10,000 and 10,500 boe/d in 2014. This yearly production guidance incorporates lower first half 2014 production at Onion Lake due to the shut-in of some production in preparation for thermal operations and having some wells reach their economic limit in early 2014 after having produced an average of over 90,000 barrels of oil per well. Onion Lake production is expected to increase again after completion of our summer drilling program. Production costs will be higher in 2014 than last year as we begin expensing all costs associated with the first phase of the ASP flood at Mooney.

Sensitivities

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

The following table summarizes the approximate effect changes in these factors could have on the Company's 2014 performance:

($millions)	Funds Flow	Net Income
Price change		
CDN$5 per bbl change in our realized oil price	13.1	8.2
CDN$1 per bbl change in production costs	3.4	2.5
Exchange rate		
$0.02 change in US/CDN rate	2.5	1.6
Production rate		
500 bbl per day change	3.9	0.5

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", "plan", "potential", "could", "continue", "continuing", "estimate", "estimates", "forecast", "likely", "expect", "expected", "may", "intend", "intends", "intended", "intention", "deferred", "sometime", "successful", "will", "project", "proposed", "timing", "in the event", "move toward", "should", "scheduled", "outlook" or similar words suggesting future outcomes.

In addition, statements relating to "reserves", "resources" or "contingent resources" are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resource described exist in the quantities predicted or estimated and can be profitably produced in the future.

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:

- Estimated oil shipments by rail in Canada included under the Business Environment section;
- The volumes and estimated value of BlackPearl's proved and probable reserves in the 2013 significant events section;
- The volumes and estimated value of BlackPearl's contingent resources in the 2013 significant events section;
- The closing of the announced public offering and intended private placement on or about March 18, 2014 and the use of proceeds from these financings in the 2013 significant events section and proposed transactions section;
- Expected future gas prices and their impact on costs related to our thermal projects as discussed per the Commodity Prices section;
- Future oil and gas prices and their impact on BlackPearl as discussed per the Commodity Prices section;
- Anticipated timing of a production response from the Mooney ASP flood as discussed in the Oil and Gas Production, Oil and Gas Pricing and Oil and Gas Sales section;
- Anticipated timing of production at the second pilot well pair at Blackrod as discussed in the Oil and Gas Production, Oil and Gas Pricing and Oil and Gas Sales section;
- Expected cash taxes to be paid in 2014 in the Income Taxes section;

- The estimated capital costs for the first phase of thermal development at Blackrod and the first phase of thermal development at Onion Lake as discussed under the Liquidity and Capital Resources section;
- Methods, sources and timing to finance capital expenditure programs, particularly for the thermal projects at Blackrod and Onion Lake as discussed under the Liquidity and Capital resources section;
- Potential production levels for the Blackrod SAGD project and the Onion Lake thermal project in the Liquidity and Capital resources section; and
- All of the statements under the Outlook section and the table presented since they are estimates of future conditions and results.

The forward-looking information is based on expectations and assumptions by management regarding 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, the ability to obtain financing on acceptable terms, availability of skilled labour and drilling and related equipment, general economic and financial market conditions 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.

Undue reliance should not be placed on 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.

By their very nature, forward-looking statements involve inherent risks and uncertainties (both general and specific) and risks that the goals or figures contained in forward-looking statements will not be achieved. These factors 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, customary conditions including receipt of necessary regulatory and stock exchange approvals on 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 financial instruments, 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. Further information regarding these risk factors may be found under "Risk Factors" in the Annual Information Form.

Readers are cautioned that these factors and risks are difficult to predict and that the assumptions used in the preparation of such information, although considered reasonably accurate at the time of preparation, may prove to be incorrect. Readers are also cautioned that the foregoing list of factors is not exhaustive. Consequently, there is no representation by the Corporation that actual results achieved will be the same in whole or in part as those set out in the forward-looking information. Furthermore, the forward-looking statements contained in this report are made as of the date hereof, and the

Corporation 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. In the case of the contingent resources assigned to BlackPearl's three core projects the contingencies include:

- At Blackrod the requirement for more evaluation drilling, as required by regulatory process, to define the reservoir characteristics to assist in the implementation and operating of the SAGD process, the absence of submission of an application to expand the commercial SAGD development and the uncertainty of timing of production and development.
- At Onion Lake the absence of approval to extend the SAGD development area, the requirement for more evaluation drilling to define the reservoir characteristics of the resource to assist in the implementation and operating of the SAGD recovery process, the uncertainty of company commitment for expansion of the commercial SAGD development and the uncertainty of timing of production and development.
- At Mooney the requirement for more evaluation wells to further define reservoir and fluid characteristics, further establishment of increased production response from the ASP flood in Phase One, which began July 2011 and the uncertainty of timing of producing and development of the entire field.

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. Please refer to our Annual Information Form for a more detailed discussion of these contingencies.

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, 2013. 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 26, 2014 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 26, 2014

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, 2013 and December 31, 2012, and the consolidated statements of comprehensive income, 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, 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, 2013 and December 31, 2012, and their financial performance and their cash flows for the years then ended in accordance with International Financial Reporting Standards.

PricewaterhouseCoopers LLP

Chartered Accountants
February 26, 2014

Calgary, Alberta

CONSOLIDATED BALANCE SHEETS

(audited)

(Cdn$ in thousands)	Note	December 31, 2013	December 31, 2012
Assets			
Current assets			
Cash and cash equivalents	6	$ 8,402	$ 16,977
Trade and other receivables	7	20,586	16,708
Prepaid expenses and deposits		963	878
		29,951	34,563
Trade and other receivables	7	1,038	–
Deferred tax assets	15	408	4,142
Exploration and evaluation assets	8	161,408	134,721
Property, plant and equipment	9	459,411	447,299
		$ 652,216	$ 620,725
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	11	$ 37,895	$ 42,351
Current portion of decommissioning liabilities	13	838	175
		38,733	42,526
Decommissioning liabilities	13	54,546	33,197
		93,279	75,723
Shareholders' equity			
Share capital	14	881,949	876,400
Contributed surplus		28,699	26,762
Deficit		(351,711)	(358,160)
		558,937	545,002
		$ 652,216	$ 620,725

Commitments and contingencies (note 17)

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

(audited)

(Cdn$ in thousands, except for per share amounts)	Note	Year ended December 31, 2013	Year ended December 31, 2012
Revenue			
Oil and gas sales		$ 222,157	$ 204,525
Royalties		(43,724)	(45,525)
		178,433	159,000
Expenses			
Production		72,199	59,301
Transportation		9,588	9,203
General and administrative		8,634	7,481
Depletion and depreciation	9	72,083	69,576
Impairment of property, plant and equipment	9	3,000	5,000
Finance costs	19	2,949	1,568
Stock-based compensation	14	3,420	6,016
Foreign currency exchange loss (gain)		(14)	61
		171,859	158,206
Other income			
Interest income		44	315
Gain on disposition of petroleum and natural gas properties	10	3,636	–
Gain on disposition of investment in MAV II Notes		–	792
		3,680	1,107
Income before income taxes		10,254	1,901
Income taxes			
Current income tax (recovery)	15	71	(76)
Deferred income tax	15	3,734	1,932
		3,805	1,856
Net and comprehensive income for the year		$ 6,449	$ 45
Income per share			
Basic	14	$ 0.02	$ 0.00
Diluted	14	$ 0.02	$ 0.00

See accompanying notes to consolidated financial statements

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(audited)

(Cdn$ in thousands)

Year ended December 31, 2013

	Share Capital	Contributed Surplus	Deficit	Total Equity
Balance – January 1, 2013	$ 876,400	$ 26,762	$ (358,160)	$ 545,002
Net and comprehensive income for the year	–	–	6,449	6,449
Stock-based compensation	–	3,827	–	3,827
Shares issued on exercise of stock options	3,659	–	–	3,659
Transfer to share capital on exercise of stock options	1,890	(1,890)	–	–
Balance – December 31, 2013	$ 881,949	$ 28,699	$ (351,711)	$ 558,937

Year ended December 31, 2012

	Share Capital	Contributed Surplus	Deficit	Total Equity
Balance – January 1, 2012	$ 864,633	$ 23,694	$ (358,205)	$ 530,122
Net and comprehensive income for the year	–	–	45	45
Stock-based compensation	–	6,390	–	6,390
Shares issued on exercise of stock options and warrants	8,445	–	–	8,445
Transfer to share capital on exercise of stock options and warrants	3,322	(3,322)	–	–
Balance – December 31, 2012	$ 876,400	$ 26,762	$ (358,160)	$ 545,002

See accompanying notes to consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

(audited)

(Cdn$ in thousands)	Note	Year ended December 31, 2013	Year ended December 31, 2012
Operating activities			
Net and comprehensive income for the year		$ 6,449	$ 45
Items not involving cash:			
Depletion and depreciation	9	72,083	69,576
Accretion of decommissioning liabilities	13	1,094	741
Stock-based compensation	14	3,420	6,016
Foreign exchange loss		62	77
Deferred income taxes	15	3,734	1,932
Impairment of property, plant and equipment	9	3,000	5,000
Gain on disposition of petroleum and natural gas properties	10	(3,636)	–
Gain on disposition of investment in MAV II Notes		–	(792)
Decommissioning costs incurred	13	(849)	(989)
Changes in non-cash working capital	19	(4,659)	(1,744)
Cash flow from operating activities		80,698	79,862
Financing activities			
Proceeds on issue of long-term debt		25,000	–
Repayment of long-term debt		(25,000)	–
Proceeds on issue of common shares, net of costs	14	3,659	8,445
Cash flow from financing activities		3,659	8,445
Investing activities			
Capital expenditures - exploration and evaluation assets	8	(26,275)	(27,483)
Capital expenditures - property, plant and equipment	9	(66,808)	(111,691)
Proceeds from disposition of petroleum and natural gas properties	10	5,011	–
Proceeds from disposition of investment in MAV II Notes		–	3,587
Changes in non-cash working capital	19	(4,784)	4,601
Cash flow from investing activities		(92,856)	(130,986)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		(76)	(16)
Decrease in cash and cash equivalents		(8,575)	(42,695)
Cash and cash equivalents, beginning of year		16,977	59,672
Cash and cash equivalents, end of year		$ 8,402	$ 16,977

See accompanying notes to consolidated financial statements

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

1. GENERAL INFORMATION

BlackPearl Resources Inc. (collectively with its subsidiaries, 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 is listed and traded on the TSX Exchange under the trading symbol “PXX”. The Company’s Swedish Depository Receipts trade on the NASDAQ OMX Stockholm market under the symbol “PXXS”. BlackPearl is incorporated and 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 26, 2014, the date they were approved and authorized for issuance by the Board of Directors (“the Board”).

3. CHANGES IN ACCOUNTING POLICIES

Except for the changes below, the Company has consistently applied the accounting policies set out in note 4 to all periods presented in these consolidated financial statements. The Company has adopted the following new standards and amendments with a date of initial application of January 1, 2013.

IFRS 10: Consolidated Financial Statements – IFRS 10 introduces a new control model that focuses on whether the Company has power over an investee, exposure or rights to variable returns from its involvement with the investee and ability to use its power to affect returns. The Company reassessed control based on IFRS 10 for its investees at January 1, 2013 and concluded that no changes were required to the Company’s financial statements as the previous consolidation method adheres to this standard.

IFRS 11: Joint Arrangements – Under IFRS 11, the Company is required to classify its interest in joint arrangements as either joint operations or joint ventures. When making this assessment, the Company considers the structure of the arrangements, the legal form of any separate vehicles, the contractual terms of the arrangements and other factors and circumstances. The Company reassessed its joints arrangements based on IFRS 11 for all its arrangements at January 1, 2013 and concluded that all the Company’s joint arrangements were joint operations. This resulted in no changes to the Company’s financial statements due to the fact that under IFRS 11 the parties under a joint operation have rights to their share of the assets and the obligation to their share of the liabilities relating to the joint arrangement, which was the method previously used.

IFRS 13: Fair Value Measurement – IFRS 13 establishes a single framework for measuring fair value and making disclosures about fair value measurements when such measurement are required or permitted by other IFRSs. It unifies the definition of fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. It replaces and expands the disclosure requirements about fair value measurements in other IFRSs, including IFRS 7. As a result, the Company has included additional disclosures in this regard. Notwithstanding, the change to IFRS 13 had no significant impact on measurements of the Company's assets and liabilities.

IAS 28: Investments in Associates and Joint Ventures – IAS 28 describes the application of the equity method to investments in joint ventures in addition to associates. The revised standard has no impact on the Company's financial statements as the Company has no associates or joint ventures that are accounted for under the equity method.

4. 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 derivative financial instruments 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, 2013. 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 with other venturers, 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 and accounts payable and accrued liabilities. 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. Cash and cash equivalents, trade and other receivables and deposits within prepaid expenses and deposits are classified as loans and receivables.

(iii) Held-to-maturity

Held-to-maturity investments are measured at amortized cost at the settlement date using the effective interest method of amortization. The Company currently holds no held-to-maturity investments.

(iv) Available-for-sale

Available-for-sale financial assets are instruments that are classified in this category or not classified in any other category. They are measured at fair value at the settlement date, with changes in the fair value recognized in other comprehensive income.

(v) Financial liabilities at amortized cost

These financial liabilities are measured at amortized cost at the settlement date using the effective interest rate method of amortization. Accounts payable and accrued liabilities are classified as financial liabilities at amortized cost.

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 carried at amortized cost 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.

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.

The Company enters into certain derivative financial instrument contracts in order to manage the exposure to market risks from fluctuations in commodity prices. These instruments are not used for trading or speculative purposes. The Company has not designated its derivative financial instrument contracts as effective accounting hedges, and thus has not applied hedge accounting, even though the Company considers all derivative financial instrument contracts to be economic hedges. As a result, all derivative financial instrument contracts are classified at fair value through profit or loss and recorded on the statement of comprehensive income at fair value. Transaction costs are recognized in profit or loss when incurred.

The fair value of forward contracts and swaps is determined by discounting the difference between the contracted prices and published forward price curves as at the balance sheet date, using the remaining contracted volumes and a credit adjusted interest rate. The fair value of options is based on option models that use published information with respect to volatility, prices and interest rates.

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.

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 such 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 are confirmed when reserves are recognized, regulatory approval has been obtained and our Board has sanctioned the development.

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 these 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, a gain or loss is recognized in net income. Exchanges of properties are measured 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.

Impairment of non-financial assets

The carrying value of the Company's non-financial assets is 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 are based on the higher of their fair value less costs of disposal and value-in-use. 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.

Exploration and evaluation costs and property, plant and equipment costs are aggregated into CGUs based on their ability to generate largely independent cash flows. The recoverable amount of an asset or CGU is the greater of its 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.

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.

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 and a corresponding adjustment to property, plant and equipment.

Increases in decommissioning liabilities resulting from the passage of time are recorded as a finance expense in the consolidated statement of comprehensive income. 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

The Company follows the fair value method of valuing stock options 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 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 they relate to income taxes levied by the same tax authority on the same taxable entity, or on a different tax entities, but they intend 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 it is probable that the economic benefits will flow to the Company and revenue can be reliably measured. This takes place once delivery has occurred, the sales price is fixed or determinable, and collectability is reasonably assured. These criteria are generally met 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 from equity.

Income per share

Basic income per share is calculated by dividing the net income for the period attributable to equity owners of BlackPearl by the weighted average number of common shares outstanding during the period. Diluted income per share is calculated by adjusting the weighted average number of common shares outstanding for dilutive instruments 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. The Company's potentially dilutive instruments comprise stock options.

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 assets are substantially ready for their 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 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 Corporation's functional currency.

Foreign currency transactions are translated into Canadian dollars at exchange rates prevailing at the dates of the transactions. 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 issuances of the Company's financial statements are listed on the following page.

IFRS 9: Financial Instruments: Classification and Measurement – The IASB intends to replace International Accounting Standard 39, "Financial Instruments: Recognition and Measurement" with IFRS 9, "Financial Instruments". IFRS 9 will be published in three phases, of which two phases have been published.

Phases one and two address accounting for financial assets and financial liabilities, and hedge accounting, respectively. The third phase will address impairment of financial instruments.

For financial assets, IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. For financial liabilities, IFRS 9 retains most of the IAS 39 requirements; however, where the fair value option is applied to financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in OCI rather than net earnings, unless this creates an accounting mismatch.

IFRS 9 introduces a simplified hedge accounting model, aligning hedge accounting more closely with risk management. In addition, improvements have been made to hedge accounting and risk management disclosure requirements. The Company does not currently apply hedge accounting.

A mandatory effective date for IFRS 9 in its entirety will be announced when the project is closer to completion. Early adoption of the two completed phases is permitted if adopted in their entirety at the beginning of a fiscal period. The Company is currently evaluating the impact of adopting IFRS 9 on the Company's financial statements.

IAS 32: Financial Instruments: Presentation – In 2011, the IASB issued amendments to IAS 32 clarifying the meaning of "currently has a legal enforceable right to set-off" and the application of the IAS 32 offsetting criteria to settlement systems which apply gross settlement mechanisms that are not simultaneous. These amendments are required to be adopted for periods beginning January 1, 2014 and will require minimal disclosure changes in the Company's financial statements.

IAS 36: Impairment of Assets – In 2013, the IASB issued amendments to IAS 36 that requires entities to disclose the recoverable amount of impaired Cash Generating Units ("CGU"). The amendment is required to be adopted for periods beginning January 1, 2014 and will require minimal disclosure changes in the Company's financial statements.

5. SIGNIFICANT ACCOUNTING JUDGEMENTS, ESTIMATES AND ASSUMPTIONS

The preparation of financial statements requires management to make judgments, estimates and assumptions based on currently available information that affect the reported amounts of assets, liabilities and contingent liabilities at the date of the consolidated financial statements and reported amounts of revenues and expense during the reporting period. Estimates and judgments are continuously evaluated and are based on management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. However, actual results could differ from those estimated. By their very nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of future periods could be material.

In the process of applying the Company's accounting policies, management has made the following judgments, estimates and assumptions which have the most significant effect on the amounts required in the consolidated financial statements:

(i) Depletion and reserves

Depletion is based on the proved plus probable reserves 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. The reserve estimates are based on current production forecasts, prices and economic conditions. 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.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental incentives/restrictions. 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. Revisions to reserve estimates can arise from changes in forecast oil and gas prices and reservoir performance. Such revisions can be either negative or positive.

(ii) CGU definition

Petroleum and natural gas properties, exploration and evaluation assets and other corporate assets are aggregated into cash-generating-units (CGUs) based on their ability to generate largely independent cash flows and are used for impairment testing. CGUs are determined by similar geological structure, shared infrastructure and geographical proximity. The determination of the Company's CGUs is subject to management's judgment.

(iii) Impairment (note 8 & note 9)

The recoverable amount of CGUs and individual assets are based on the higher of their value-in-use and fair value less costs of disposal. These calculations require the use of estimates and assumptions. 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 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. In 2013, the Company utilized a 10% discount rate (after tax) in its CGU impairment testing.

Commodity price changes impact the expected future cash flows which may require a material adjustment to the carrying value of tangible and intangible assets. The Company monitors internal and external indicators of impairment relating to its tangible and intangible assets. These indicators include changes in commodity prices, reserve volume and discount rates. Note 9 to the consolidated financial statements summarize the commodity price forecast used to assess CGU impairment in 2013.

(iv) Exploration and evaluation assets (note 8)

The decision to transfer exploration and evaluation assets to property, plant and equipment is when commercial viability and technical feasibility is established, regulatory and Board approval is received and management's determined to pursue commercial development which is based partially on proved and probable reserves.

(v) Decommissioning and restoration costs (note 13)

The calculation of decommissioning liabilities includes estimates of the future costs to settle the liability, the timing of the cash flows to settle the liability, the risk-free rate and future inflation rates. Decommissioning and restoration 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. The impact of differences between actual and estimated costs on the consolidated financial statements of future periods may be material. The decommissioning liability on the balance sheet represents management's best estimate of the present value of the future decommissioning costs required at that reporting date.

(vi) Deferred tax (note 15)

The Company follows the balance sheet method for calculating deferred taxes. Judgment is required in the calculation of current and deferred taxes in applying tax laws and regulations, estimating the time of the reversals of temporary differences and estimating the realizability of 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 current and deferred tax assets and liabilities, and current and deferred tax expense (recovery).

(vii) Stock-based compensation (note 14)

The Company uses the Black-Scholes pricing model when determining the fair value as management has determined this is the most appropriate valuation model. The Black-Scholes pricing model requires the Company to determine the most appropriate inputs including the expected life of the option, volatility, expected forfeitures and market prices surrounding the issuance of stock options. These estimates impact stock-based compensation expense and contributed surplus.

(viii) Derivative financial instruments (note 18)

The Company's estimate of the fair value of derivative financial instruments is dependent on estimated forward prices and volatility in those prices.

6. CASH AND CASH EQUIVALENTS

	2013	2012
Cash at banks	$ 8,402	$ 16,977

Cash at banks earn interest at floating rates based on daily bank deposit rates. As of December 31, 2013, US $1.1 million (2012 – US $0.7 million) is included in cash at banks. The Company only deposits cash with major banks of high quality credit ratings.

7. TRADE AND OTHER RECEIVABLES

	2013	2012
Trade accounts receivable	$ 16,845	$ 13,405
Receivables from joint venturers	305	866
Allowance for doubtful accounts	(285)	(815)
Net accounts receivable	16,865	13,456
Royalty reimbursement from enhanced oil recovery incentive programs	4,072	3,082
Other receivables	687	170
Total trade and other receivables	21,624	16,708
Less non-current portion of royalty reimbursement from enhanced oil recovery incentive programs	(1,038)	–
Current portion of trade and other receivables	$ 20,586	$ 16,708

Aging of trade accounts receivables are as follows:

	2013	2012
Current	$ 16,443	$ 13,255
31 to 60 days	322	50
61 to 90 days	46	15
Over 90 days	34	85
	$ 16,845	$ 13,405

8. EXPLORATION AND EVALUATION ASSETS

At January 1, 2012	$ 106,450
Expenditures	27,483
Capitalized stock-based compensation	374
Change in decommissioning provision	414
At December 31, 2012	134,721
Expenditures	24,181
Acquisition	2,094
Capitalized stock-based compensation	148
Change in decommissioning provision	264
At December 31, 2013	$ 161,408

The Company's exploration and evaluation assets consist predominately of costs pertaining to the Blackrod SAGD project in northern Alberta. These assets are not subject to depletion or depreciation but they are reviewed for possible impairment. During 2013, no costs were considered to be impaired.

The net operating revenues of the Blackrod SAGD pilot are being capitalized until the decision to transfer exploration and evaluation assets to property, plant and equipment is determined as discussed in note 5. During the year ended December 31, 2013, the Company capitalized net operating revenues totalling a loss of $3.2 million (2012 – $3.3 million). Included within the capitalized net operating revenues is $2.2 million (2012 – $1.6 million) in costs related to contractors who worked exclusively on the Blackrod SAGD project during the year ended December 31, 2013. Stock-based compensation associated with these contractors was capitalized for the year ended December 31, 2013 totalling $0.1 million (2012 – $0.4 million).

The Company capitalized interest and financing charges of $0.2 million during the year ended December 31, 2013 (2012 – $Nil). The Company did not capitalize any costs classified as general and administrative in respect to exploration activities during the year ended December 31, 2013 (2012 – $Nil).

9. PROPERTY, PLANT AND EQUIPMENT

	Petroleum and natural gas properties	Corporate	Total
Cost			
At January 1, 2012	$ 733,683	$ 3,300	$ 736,983
Expenditures	111,639	52	111,691
Change in decommissioning provision	2,786	–	2,786
At December 31, 2012	848,108	3,352	851,460
Expenditures	63,755	90	63,845
Acquisitions	2,963	–	2,963
Capitalized stock-based compensation	260	–	260
Change in decommissioning provision	22,279	–	22,279
Disposals	(2,302)	–	(2,302)
At December 31, 2013	$ 935,063	$ 3,442	$ 938,505
Accumulated depletion and depreciation			
At January 1, 2012	$ 327,932	$ 1,653	$ 329,585
Depletion and depreciation	69,324	252	69,576
Impairment	5,000	–	5,000
At December 31, 2012	402,256	1,905	404,161
Depletion and depreciation	71,870	213	72,083
Impairment	3,000	–	3,000
Disposals	(150)	–	(150)
At December 31, 2013	$ 476,976	$ 2,118	$ 479,094
Net book value			
December 31, 2012	$ 445,852	$ 1,447	$ 447,299
December 31, 2013	$ 458,087	$ 1,324	$ 459,411

The calculation of depletion for the year ended December 31, 2013 included estimated future development costs of $117 million (2012 – $164 million) associated with the development of the Company's proved plus probable reserves. The Company did not capitalize any costs classified as general and administrative in respects to development activities during the year ended December 31, 2013 (2012 – $Nil).

Property, plant and equipment includes $16.0 million (2012 – $0.8 million) of assets under construction pertaining to the Onion Lake Enhanced Oil Recovery (EOR) project that are not subject to depletion and depreciation. Included in the $16.0 million of property, plant and equipment that is not subject to depletion and depreciation is $2.3 million (2012 – $Nil) in costs related to contractors who worked exclusively on the Onion Lake EOR project during the year ended December 31, 2013. Stock-based compensation associated with these contractors was capitalized for the year ended December 31, 2013 totalling $0.3 million (2012 – $Nil).

The Company performed impairment test calculations at December 31, 2013 to assess whether the carrying value of the petroleum and natural gas properties were recoverable. As a result of well operating performance, an impairment loss of

$3.0 million (2012 – $5.0 million) on one of the Company's minor CGUs (Salt Lake in Saskatchewan) was recognized in the Consolidated Statement of Comprehensive Income based on the difference between the fair value less costs of disposal and the carrying amount of the CGU. A one percent increase in the assumed discount rate would result in an additional impairment of $0.1 million while a ten percent decrease to the forward commodity price estimated would result in an additional impairment of $0.1 million.

The following represent the prices that were used in the December 31, 2013 impairment tests:

	Average Price Forecast (1)			
Year	WTI Cushing 40° API	Western Canadian Select 20.5° API	Alberta AECO-C Spot	Exchange rate
	(US$/bbl)	(CDN$/bbl)	(CDN$/MMBtu)	(US$/Cdn$)
2014	94.65	77.81	4.00	1.060
2015	88.37	75.02	3.99	1.060
2016	84.25	75.29	4.00	1.060
2017	95.52	85.36	4.93	1.060
2018	96.96	86.64	5.01	1.060
2019	98.41	87.94	5.09	1.060
2020	99.89	89.26	5.18	1.060
2021	101.38	90.60	5.26	1.060
2022	102.91	91.96	5.35	1.060
2023	104.45	93.34	5.43	1.060
2024	106.02	94.74	5.52	1.060
	Escalation rate of 1.5% thereafter (2)			

(1) The benchmark prices listed above are adjusted for quality differentials, heat content, distance to market and other factors in performing the impairment test.

(2) Percentage change represents the change in each year after 2024 to the end of the reserve life.

10. PROPERTY ACQUISITION AND DISPOSITION

The Company completed a minor property acquisition during the year ended 2013 for net cash considerations of $4.9 million. The assets acquired included additional oil sands acreage in the Blackrod area, as well as minor natural gas production, pipelines and facilities that will be used in the commercial development of the Blackrod area. Decommissioning liabilities acquired as part of the property acquisition were $6.6 million. This property acquisition was completed with full tax pools and no working capital or debt obligations were assumed.

During the year ended 2013, the Company completed a minor property disposition of certain non-core assets for cash consideration of $5.0 million. The assets sold were conventional non-producing heavy oil properties in Saskatchewan. The Company also recognized a reduction in decommissioning liabilities of $0.8 million as part of the property disposition. This property disposition was completed with full tax pools.

11. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	2013	2012
Trade payables and accrued liabilities	$ 37,159	$ 41,681
Payables to joint venturers	359	483
Other payables	377	187
	$ 37,895	$ 42,351

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

12. LONG-TERM DEBT

At December 31, 2013 the Company's credit facilities consist of a $105 million syndicated revolving line of credit (2012 – $105 million) and a non-syndicated operating line of credit of $10 million (2012 – $10 million). 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, 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, 2014. The facilities are also subject to annual reviews by the lenders and the next scheduled review is to be completed by May 31, 2014. In the event the lenders elected not to renew the credit facilities during this borrowing base review, any amounts outstanding on the facilities would be due and payable in full by May 30, 2015.

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

At year end December 31, 2013, no amounts were drawn under these facilities; however, the Company has issued a $20,000 letter of credit; leaving $115.0 million available to be drawn under the credit facilities. The effective interest rate on the Company's borrowings under its credit facilities for the year ended 2013 was 7.5% (2012 – Nil), which is predominantly made up of standby fees on the undrawn amounts on the facilities and interest incurred on balances outstanding during the year.

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 as compared to current liabilities from the Company's consolidated balance sheet. The Company had a working capital ratio of 3.7:1 at December 31, 2013 (2012 – 3.5:1) and is in compliance with this covenant at year end.

13. 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 and processing facilities. The total undiscounted amount of the estimated cash flows required to settle the liability is approximately $63.9 million (2012 – $39.7 million). The estimated net present value of the decommissioning liability was calculated using an inflation factor of 2% (2012 – 2%) and discounted using a risk-free rate of 2.55% (2012 – 2.25%). Settlement of the liability, which may extend up to 40 years in the future, is expected to be funded from general corporate funds at the time of retirement.

Changes to the decommissioning liability were as follows:

	2013	2012
Decommissioning liability, beginning of year	$ 33,372	$ 30,420
New liabilities recognized	2,103	3,214
Liabilities acquired	6,589	–
Reduction in liabilities due to asset dispositions	(789)	(14)
Decommissioning costs incurred	(849)	(989)
Change in estimated costs of decommissioning	14,815	–
Change in discount rate	(951)	–
Accretion expense	1,094	741
Decommissioning liability, end of year	55,384	33,372
Less current portion of decommissioning liability	(838)	(175)
Non-current portion of decommissioning liability	$ 54,546	$ 33,197

14. 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, 2012	284,802,011	$ 864,633
Shares issued on exercise of warrants	9,645,196	5,787
Shares issued on exercise of stock options	1,318,601	2,658
Transferred from contributed surplus on exercise of stock options and warrants	–	3,322
Balance as at December 31, 2012	295,765,808	876,400
Shares issued on exercise of stock options	4,659,000	3,659
Transferred from contributed surplus on exercise of stock options	–	1,890
Balance as at December 31, 2013	300,424,808	$ 881,949

(c) Stock Options Outstanding

The Company has a stock option plan (the "Plan") available to directors, officers, employees and certain consultants of the Company and its subsidiaries. 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 of directors. 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 and vest at a rate of one third on each of the three anniversaries from the date of the grant. 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, 2012	16,528,665	2.68
Granted	3,079,500	3.73
Exercised	(1,318,601)	2.02
Forfeited	(728,665)	5.06
Expired	(177,900)	3.80
Outstanding at December 31, 2012	17,382,999	2.81
Granted	3,545,500	2.39
Exercised	(4,659,000)	0.79
Forfeited	(1,638,000)	3.69
Expired	(25,000)	1.75
Outstanding at December 31, 2013	14,606,499	3.26

Options outstanding and exercisable as at December 31, 2013 are summarized below:

	Options Outstanding			Options Exercisable		
Range of Exercise Prices ($)	Number of Options	Weighted Average Exercise Price ($)	Weighted Average Remaining Life (Years)	Number of Options	Weighted Average Exercise Price ($)	Weighted Average Remaining Life (Years)
0.63 – 1.50	1,473,500	0.82	0.22	1,473,500	0.82	0.22
1.51 – 3.00	6,280,499	2.31	2.62	3,114,333	2.24	0.91
3.01 – 4.50	2,272,500	3.68	3.45	790,529	3.65	3.33
4.51 – 6.00	4,265,000	5.00	2.38	3,568,520	5.02	2.28
6.01 – 7.66	315,000	6.91	2.43	210,001	6.91	2.43
	14,606,499	3.26	2.43	9,156,883	3.32	1.58

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, 2013, 3,545,500 options were granted (2012 – 3,079,500). The fair value of these options was estimated using the following weighted average assumptions:

Assumptions	Year Ended December 31, 2013	Year Ended December 31, 2012
Risk free interest rate (%)	1.1	1.2
Expected life (years)	3.5	3.2
Expected volatility (%)	49.3	53.9
Forfeiture rate (%)	14.2	14.6
Weighted average fair value of options	$ 0.90	$ 1.43

(e) Stock-based Compensation

For the year ended December 31, 2013, gross stock-based compensation of $4,311,000 (2012 – $6,676,000) consists of $148,000 capitalized to exploration and evaluation assets (2012 – $374,000), $260,000 capitalized to property, plant and equipment (2012 – $Nil) and $3,420,000 (2012 – $6,016,000), net of recoveries from forfeitures of $484,000 (2012 – $286,000), has been recorded in the consolidated statements of comprehensive income.

(f) Income per Share

Basic income per share amounts are calculated by dividing net comprehensive income for the year by the weighted average number of common shares outstanding during the year.

The following table shows the calculation of basic and diluted income per share for the years ended:

	2013	2012
Net comprehensive income	$ 6,449	$ 45
Weighted average number of common shares – basic	296,819	286,130
Dilutive effect:		
Outstanding options	3,327	6,528
Weighted average number of common shares – diluted	300,146	292,658
Basic income per share	$ 0.02	$ 0.00
Diluted income per share	$ 0.02	$ 0.00

The Company used an average market price of $2.19 (2012 – $3.79) per share to calculate the dilutive effect of stock options. In 2013, 12,921,529 options were anti-dilutive (2012 – 6,531,106) and were not included in the calculation of diluted net income per share.

15. 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:

	2013	2012
Income before income taxes	$ 10,254	$ 1,901
Corporate income tax rate	25.76%	25.95%
Computed income tax expense	$ 2,641	$ 493
Increase (decrease) resulting from:		
Change in unrecognized deferred income tax assets	451	2,225
Non-deductible expenses and others	896	1,561
Foreign exchange	–	(7)
Change in enacted tax rates	(254)	(2,340)
Current income tax (recovery)	71	(76)
Income tax expense	$ 3,805	$ 1,856
Effective tax rate	37.11%	97.63%

The high effective tax rate is due primarily to the non-deductibility (for tax purposes) of stock-based compensation.

(b) Deferred tax assets:

At December 31, 2013, deferred tax assets of $0.4 million (2012 – $4.1 million) have been recognized in the consolidated financial statements.

Management considers it probable that future taxable profits will be available against which the tax benefits relating to the following items will be utilized:

	2013	2012
Property, plant and equipment	$ (72,089)	$ (66,737)
Decommissioning liability	14,133	8,271
Share issue costs	169	448
Non-capital losses	58,195	62,160
Deferred tax assets	$ 408	$ 4,142

Factors that influenced the decision to recognize the deferred tax asset include positive net income in 2013 and a significant increase in proved and probable reserves and the estimated cash flows associated with the reserves.

(c) Unrecognized deferred tax assets:

Deferred tax assets have not been recognized in respect of the following items:

	2013	2012
Property, plant and equipment	$ 13,300	$ 13,961
Non-capital losses	16,461	15,611
Capital losses	332	144
	$ 30,093	$ 29,716

Deferred tax assets have not been recognized in respect of these items because it is not probable that future taxable profit will be available against which the benefits can be utilized. These tax assets relate to the non-producing assets located in the United States and certain resource pools in Canada that are restricted through the successor tax 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 Company had no current tax payable in 2013 or 2012.

16. 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 comprehensive statement of income:

	Year Ended December 31, 2013	Year Ended December 31, 2012
Production expense [1]	$ 1,178	$ 959
General and administrative expense	5,531	4,841
Stock-based compensation	3,420	6,016
	$ 10,129	$ 11,816

(1) Excludes compensation paid to contractors and consultants.

(b) Key management compensation

Key management includes the Company's directors and officers. At December 31, 2013, directors and senior management consisted of nine individuals (2012 – nine individuals). Compensation awarded to key management includes short-term employee benefits which consist of salary and benefits during the year. Compensation also includes stock-based compensation which is accounted for in accordance with IFRS 2 'Share Based Payments'.

The following table summarizes the compensation of key management compensation:

	Year Ended December 31, 2013	Year Ended December 31, 2012
Short-term employee benefits	$ 1,475	$ 1,198
Stock-based compensation	838	1,375
	$ 2,313	$ 2,573

17. COMMITMENTS AND CONTINGENCIES

	2014	2015	2016	2017	2018	Thereafter
Operating leases (1)	$ 1,928	$ 1,780	$ 1,287	$ –	$ –	$ –
Electrical service agreement (2)	1,003	1,003	520	119	119	2,225
	$ 2,931	$ 2,783	$ 1,807	$ 119	$ 119	$ 2,225

(1) The Company has 33 months remaining on an operating lease for office space as at December 31, 2013. 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 lease obligation, BlackPearl would be required to pay a maximum additional amount of $8.4 million (including an estimate for operating costs) over the next 33 months. At December 31, 2013, no amounts were owed (2012 – no amounts owing).

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

18. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments as at December 31, 2013 include cash and cash equivalents, trade and other receivables, deposits within prepaid expenses and deposits and accounts payable and accrued liabilities.

(a) Fair value of financial instruments

	As at December 31, 2013		As at December 31, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial Assets				
Loans and receivables:				
Cash and cash equivalents	$ 8,402	$ 8,402	$ 16,977	$ 16,977
Trade and other receivables	$ 17,552	$ 17,552	$ 13,626	$ 13,626
Deposits	$ 413	$ 413	$ 376	$ 376
Financial liabilities				
Financial liabilities at amortized cost:				
Accounts payable and accrued liabilities	$ 37,895	$ 37,895	$ 42,351	$ 42,351

Due to the short-term nature of the Company's financial instruments, the carrying amount of the instruments approximates their fair value amounts. Derivative financial instruments are recorded on the statement of comprehensive income at fair value at each reporting period with the change in fair value being recognized as an unrealized gain or loss. The Company's derivative financial instruments are measured in accordance with a three level hierarchy. The hierarchy groups financial assets and liabilities into three levels based on the significance of inputs used in measuring the fair value of the financial assets and liabilities. The fair value has the following levels:

- 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).

Subsequent to December 31, 2013, the Company entered into derivative financial instrument contracts (see Note 18 (b)(v)) that are valued using level 2 of the hierarchy.

(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.

The Company's trade receivables are primarily with oil and gas marketers, the Alberta government and joint venture partners. Receivables from oil and gas marketers are generally collected on the 25th day of the month following production. The Company attempts to mitigate this risk by assessing the financial strength of its counterparties and entering into relationships with larger purchasers with established credit history. During 2013, the Company did not experience any collection issues with its marketers. At December 31, 2013, over 78 percent of total accounts receivable are for crude oil sales revenue (2012 – 77 percent).

In 2013, the Company had four customers (2012 – three) which individually accounted for more than 10 percent of its total oil and gas sales. Oil and gas sales to these customers represented approximately 65% of the Company's total oil and gas sales in 2013 (2012 – 66%).

At December 31, 2013, the Company had a $4.1 million (2012 – $3.1 million) receivable related to the reimbursement of crown royalties as a result of an enhanced oil recovery incentive program from the Alberta government. These amounts are not considered impaired based on the credit worthiness of the Alberta government and the approval the Company has received on its enhanced oil recovery activities.

Receivables from joint venture partners arise when the Company conducts joint operations on behalf of its partners and invoices them for their share of costs. At December 31, 2013, the amount receivable from joint venture partners was $305,000 (2012 – $866,000). To mitigate the risk of non-payment from joint venture partners the Company can require partners to pay certain costs in advance as well as the Company has the ability to withhold production from partners in the event of non-payment. As at December 31, 2013, accounts receivable includes an allowance for doubtful accounts of $285,000 (2012 – $815,000) from joint interest partners. The majority of the Company's current operations do not have joint interest partners and therefore the credit risk from this group is considered low.

The Company typically does not obtain collateral or security from its joint venture partners or oil and gas marketers. The carrying amounts of accounts receivable represent the maximum credit exposure.

The Company is not the operator of certain oil and 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.

As at December 31, 2013, the Company held $8.4 million (2012 – $17.0 million) in cash at various major financial institutions throughout Canada and the USA. At December 31, 2013, two Canadian financial institutions held over 88% of our cash and short-term deposits.

Derivative financial instruments consist of commodity contracts used to manage the Company's exposure to fluctuations in commodity prices. The Company manages the credit risk exposure related to derivative financial instruments by selecting investment grade counterparties and by not entering into contracts for trading or speculative purposes.

(ii) Liquidity Risk

Liquidity risk is the risk the Company is unable to meet its financial obligations as they come due. The Company uses operating cash flows, long-term debt and equity offerings to fund its capital requirements.

The Company has managed this risk by maintaining a balance sheet with minimal use of long-term debt. As at December 31, 2013, the Company had undrawn $115 million credit facilities (note 12) and a working capital deficiency of $8.8 million (2012 – working capital deficiency of $8.0 million). The Company believes it has sufficient funding from these sources to meet its foreseeable obligations.

The maturity dates for the Company's financial liabilities are as follows:

	<6 Months	6 months -1 Year	1-2 Years
Accounts payable and accrued liabilities	$37,895	–	–

(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 in relation to interest expense on its revolving credit facility due to the floating interest rate charged on advances. At this time, the Company is not drawn on this facility and, as a result, the Company considers this risk to be limited. In addition, the Company is exposed to interest rate risk on its excess cash balances. As at December 31, 2013, if interest rates had been 1 percent higher with all other variables held constant, after tax net income for the year would have been approximately $21,000 (2012 – $82,000) higher.

(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) prices received for its crude oil are primarily determined in reference to U.S. dollars; (ii) certain expenditure commitments, deposits, accounts receivable, and accounts payable which are denominated in U.S. dollars; and to a lesser extent (iii) its operations in the United States. The Company manages this risk by monitoring foreign exchange rates and evaluating their effects on using Canadian or U.S. vendors as well as timing of transactions. As at December 31, 2013, the Company has not entered into any fixed rate contracts to mitigate its currency risks.

As at December 31, 2013, the Company held US $1.1 million (2012 – US $702,000) cash and cash equivalents, US $122,000 (2012 – $Nil) prepaid expenses and deposits and US $126,000 (2012 – US $950,000) accounts payable and accrued liabilities.

As at December 31, 2013, if exchange rates to convert from US dollars to Canadian dollars had been $0.10 lower with all other variables held constant, after tax net income for the year would have been approximately $111,000 lower (2012 – $25,000 higher). An equal opposite impact would have occurred to net income had exchange rates been $0.10 higher.

(v) Commodity price risk

Commodity price risk is the risk that future cash flows will fluctuate as a result of changes in the price of oil and natural gas. Commodity prices are impacted by world economic events that affect supply and demand, which are generally beyond the Company's control. Changes in crude oil prices may significantly affect the Company's results of operations, cash generated from operating activities, capital spending and the Company's ability to meet its obligations. The majority of the Company's production is sold under short-term contracts; consequently BlackPearl is at risk to near term price movements. The Company manages this risk by constantly monitoring commodity prices and factoring them into operational decisions, such as contracting or expanding its capital expenditures program. Natural gas currently represents less than 3% (2012 – 1%) 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.

Throughout 2013 the Company did not use derivative financial instruments to manage its exposure to commodity price risk. Subsequent to December 31, 2013, the Company has attempted to mitigate a portion of the commodity price risk through the use of various derivative financial instruments and has entered into the following commodity contracts:

Subject of Contract	Volume	Term	Reference	Strike Price	Option Traded
Oil	2,500 bbls/d	March 1, 2014 to December 31, 2014	CDN$ WCS	CDN$ 82.10/bbl	Swap
Oil	1,000 bbls/d	March 1, 2014 to December 31, 2014	CDN$ WCS	CDN$ 82.00/bbl	Swap

(c) Capital Management

The Company defines capital as working capital, total debt and equity. The current capital management strategy is designed so that anticipated cash flow from operating activities combined with the existing credit facilities will fund continued development of our existing operations. At December 31, 2013, the Company's $115 million available credit facilities were undrawn. Additional funding will be required to continue to develop 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 is currently evaluating funding options 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 would target to maintain a debt to cash flow ratio of less than 1.5; however, during the construction phase of our large assets and before production commences, this will likely be exceeded. 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.

19. SUPPLEMENTARY INFORMATION

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

	Year ended December 31, 2013	Year ended December 31, 2012
Cash interest paid	$ 1,069	$ 827
Cash taxes paid (refund)	$ 71	$ (76)

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

	Year ended December 31, 2013	Year ended December 31, 2012
Gross interest and financing charges	$ 1,069	$ 827
Capitalized interest and financing charges	(226)	–
Net interest and financing charges	843	827
Accretion of decommissioning liabilities	1,094	741
Debt financing costs	1,012	–
Finance costs	$ 2,949	$ 1,568

(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, 2013	Year ended December 31, 2012
Changes in non-cash working capital:		
Trade and other receivables	$ (4,916)	$ 6,607
Prepaid expenses and deposits	(85)	(61)
Accounts payable and accrued liabilities	(4,442)	(3,689)
	$ (9,443)	$ 2,857
Relating to:		
Operating activities	$ (4,659)	$ (1,744)
Investing activities	(4,784)	4,601
Change in non-cash working capital	$ (9,443)	$ 2,857

20. SUBSEQUENT EVENT

Subsequent to December 31, 2013, the Company entered into an agreement with a syndicate of underwriters whereby they have agreed to purchase for resale to the public, on a bought deal basis, 26,500,000 common shares of BlackPearl at $2.65 per share for aggregate gross proceeds of $70.2 million. In addition, the underwriters have been granted an over-allotment option, which may be exercised in whole or in part up to 30 days after closing of the offering, to purchase up to 3,975,000 additional common shares at a price of $2.65 per common share. If the over-allotment is fully exercised, gross additional proceeds would be $10.5 million. The Company also intends to issue by private placement an additional 3,773,585 common shares at $2.65 per share representing gross proceeds of $10 million. In addition, the Company's lending syndicate has agreed to increase the Company's existing credit facilities from $115 million to $150 million upon completion of the offering and the private placement.