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NEWS RELEASE **February 26, 2013**

BLACKPEARL ANNOUNCES FOURTH QUARTER AND FULL YEAR 2012 FINANCIAL AND OPERATING RESULTS

CALGARY, ALBERTA – BlackPearl Resources Inc. ("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, 2012.

Highlights and accomplishments in 2012 included:

- Oil and gas production increased 23% in 2012 to 9,366 boe/day; Q4 2012 production was 9,067 boe/day, up 4% from the prior year;

- Oil and gas revenues increased 14% in 2012 to $205 million and cash flow from operations increased 6% to $83 million. Q4 2012 revenues were down 18% to $48 million compared to Q4 2011 and cash flow from operations in the fourth quarter was $18 million, a decrease of 36% from 2011;

- Net income decreased to $45,000 in 2012 compared with net income of $18.9 million in 2011; 2011 net income included a gain on disposition of certain oil and gas properties and a large deferred tax benefit;

- As reported on February 13, 2013, BlackPearl's oil and gas proved plus probable reserves increased 496% in 2012 to 213 million barrels of oil equivalent, before royalties and "best estimate" contingent resource for our three core properties were 582 million barrels of oil equivalent, before royalties (see cautionary statement on contingent resources below(1));

- At Blackrod, the 80,000 barrel per day SAGD commercial development application was filed in May 2012 with the Energy Resources Conservation Board (ERCB) and Alberta Environment. The first phase of the project is expected to be 20,000 barrels of oil per day. In addition, Sproule Unconventional Limited, our independent reserves evaluator, reclassified 180 million barrels of "best estimate" contingent resource to probable reserves pertaining to the first phase of SAGD development at Blackrod. In addition, detailed engineering design work for Blackrod commenced in the fourth quarter. We will expand the pilot in 2013, drilling an additional well pair during the first quarter.

- At Mooney, ASP (Alkali Surfactant Polymer) injection continued in 2012. As a result of re-pressurization of the reservoir, production increased most notably in the fourth quarter. In addition, we successfully drilled 16 horizontal wells in 2012 on phase two and three development lands at Mooney. Further drilling on these lands is planned in 2013. These wells will be produced conventionally and then added to the ASP flood in the future;

- At Onion Lake, in 2012 we drilled 43 vertical wells as part of our continuing primary development program. This program has identified further locations that we can add to our development drilling inventory as well as potentially expand our thermal development area. We will continue with our primary development program with 20 wells planned in 2013. Concurrently with our primary development, we continue to advance our Onion Lake thermal development plans and anticipate regulatory approval of our planned 12,000 barrel of oil per day SAGD project in the first half of 2013.

John Festival, President of BlackPearl, commenting on 2012 activities indicated that "our long term sustainable growth will come from our two large thermal projects and we made good strides advancing both of these projects in 2012. At Blackrod, we filed our development application with regulatory authorities and we gained valuable knowledge from operating the pilot well pair during the last twelve months. We will use what we learned from the first well pair to expand the pilot in 2013 and to assist in our commercial development design.

At Onion Lake, we continued to advance our thermal development plans through the regulatory review process which should culminate in obtaining project approvals in 2013. Potentially, we could have development approvals for both our Onion Lake and Blackrod thermal projects in 2013.

We were also pleased with the development of our conventional heavy oil program in 2012. We saw a very positive response from our ASP flood at Mooney late in the year and the initial drilling results on our expansion lands have been very good, which will allow us to expand the flood to these areas in the next 12 to 18 months. At Onion Lake, primary production in certain areas is maturing. As a result, we saw production declines at Onion Lake in 2012; however, we have a drilling inventory of over 100 wells and plan to continue primary development until we transition into our thermal project.

In 2013, we look forward to securing development financing for one or both of our thermal projects. We are evaluating a number of financing alternatives. Our aim is to balance minimizing dilution to our shareholders while not taking on excessive financial risk. We expect to provide our shareholders with our financing strategy over the next three or four months."

(1) 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.

Financial and Operating Highlights

	Three months ended December 31,		Twelve months ended December 31,	
	2012	2011	2012	2011
Daily sales volumes (1)				
Oil (bbls/d)	8,994	8,682	9,304	7,460
Natural gas (mcf/d)	440	317	374	960
Combined (boe/d)	9,067	8,735	9,366	7,620
($000s, except where noted)				
Revenues				
Oil and natural gas revenue – gross	47,569	58,160	204,525	179,443
Net income (loss) for the period	(4,277)	15,504	45	18,911
Per share, basic ($)	(0.01)	0.05	0.00	0.07
Per share, diluted ($)	(0.01)	0.05	0.00	0.06

Cash flow from operations (2)	17,684	27,791	82,595	77,717
Capital expenditures	34,635	56,974	139,548	192,634
Property dispositions	-	(3,500)	-	(6,100)
Working capital, end of period	(7,788)	37,825	(7,788)	37,825
Long term debt	-	-	-	-
Shares outstanding, end of period (000s)	295,766	284,802	295,766	284,802

(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) Cash flow from operations is a non-GAAP measure and, therefore, may not be comparable to similar measures used by other companies. It represents cash flow from operating activities before abandonment costs incurred and changes in non- cash working capital related to operations.

FOURTH QUARTER 2012 ACTIVITIES

Oil and gas revenues were $47.6 million in the fourth quarter of 2012 compared to $58.2 million in the same quarter of 2011. The decrease in revenues was primarily due to a significant drop in the average wellhead prices received.

Lower wellhead prices in Q4 2012 were the result of lower oil prices and wider heavy oil differentials. The WTI oil price in Q4 2012 was US$88.51 per barrel compared to US$94.03 per barrel in 2011 and the heavy oil differential (between WTI and Western Canadian Select) was $18.46 per barrel in Q4 2012 compared to $10.70 per barrel in 2011. Increased production in Canada and the US, together with pipeline constraints and refinery outages contributed to the decrease in North American oil prices.

BlackPearl sold an average of 9,067 boe per day during the fourth quarter of 2012, an increase of 4 percent over the same quarter in 2011. The increase in sales volumes are mostly attributable to continued development drilling at Onion Lake and Mooney, as well as the re-pressurization response from the first phase of the ASP flood at Mooney, partially offset by natural declines at Onion Lake.

Royalty rates decreased to 23% in the fourth quarter of 2012 compared to 25% in the same quarter of 2011. The decrease in the royalty rate in 2012 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 and the lower initial royalty rates for drilling new wells. Operating costs were generally comparable in Q4 2012 and 2011.Transportation costs increased significantly in Q4 2012 from the prior year primarily due to increased production volumes from the Mooney area where travel distances to sales delivery points are greater than our other areas. G&A expenses increased due to one-time costs related to applying to have the Company’s Swedish Depository Receipts listed on the main market exchange in Sweden.

Cash flow from operations in the fourth quarter of 2012 was $17.7 million compared to $27.8 million in the fourth quarter of 2011. The decrease in cash flow from operations was primarily due to the drop in average wellhead prices received. We had a net loss in the fourth quarter of 2012 of $4.3 million compared to net income of $15.5 million in 2011. The decrease in net income is primarily a result of a decrease in heavy oil prices, an impairment charge to two of our non-core properties of $5.0 million and the recognition of certain deferred tax benefits in 2011.

Capital expenditures in the fourth quarter of 2012 were $34.6 million, a 39 percent decrease compared to the fourth quarter of 2011. The decrease is a result of the reduced drilling activity in Q4 2012.

Production

(boe/day)	Three months ended December 31, 2012	2011	Twelve months ended December 31, 2012	2011
Onion Lake	4,857	6,805	5,947	6,272
Mooney	3,329	1,102	2,537	788
John Lake	649	413	573	343
Blackrod SAGD Pilot	221	178	272	57
Other	11	237	37	160
	9,067	8,735	9,366	7,620

Operating Statistics

	Three months ended December 31, 2012	2011	Twelve months ended December 31, 2012	2011
($ per boe)				
Oil and natural gas revenue	58.45	73.88	61.45	65.00
Royalties	13.29	18.13	13.68	16.49
Transportation costs	3.07	0.60	2.76	0.52
Operating costs	17.89	17.80	17.82	17.80
Netback(1)	24.20	37.35	27.19	30.19

(1) Operating netback is a non-GAAP measure. It 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.

2013 Guidance

Our plans and outlook for 2013 are outlined below. Typically these plans will be modified throughout the year as conditions and circumstances change.

2013 Guidance	Initial Guidance	February Update
Production (boe/d)		
Annual average	10-500 – 11,000	9,000 – 10,000
Exit	11,000 – 12,000	10,000 – 10,500
Cashflow from operations ($millions)	75 - 85	50 – 60
Capital expenditures ($millions)	140 - 160	125 – 140
Year-end debt ($millions)	80 - 90	80 – 90
Year-end working capital ($millions)	0 - 5	0 – 5
Pricing Assumptions (annual average)		
Crude oil - WTI	US$88	US$95
Light/heavy differential	US$18	US$27
Foreign Exchange (Cdn$ to US$)	1.00	1.00

Our initial guidance for 2013 anticipated a capital spending program of $140 to $160 million. As a result of a significant decrease in heavy oil prices during the first quarter of 2013 we elected to defer some of our first quarter capital spending. As a result, we have decreased our estimated 2013 capital spending to between $125 and $140 million. The Blackrod project continues to dominate our 2013 capital expenditure program, accounting for over 45% of our revised budget. Our plans in 2013 for the Blackrod area remain unchanged. We plan to expand the existing pilot with a second well pair, continue with detailed engineering design for the first phase of development and order long lead equipment items for the central processing facility. At Mooney we will continue development of the phase two lands with 15 to 20 horizontal wells planned; a decrease from our original plan of drilling 20 to 25 wells. At Onion Lake we will continue primary development with 20 vertical wells planned. We have also reduced spending on some of our minor non-core assets.

Cash flow from operations is expected to be between $50 and $60 million. The decrease in our estimated cash flow from operations from our initial guidance reflects lower forecast oil prices in the first quarter of 2013 and reduced capital spending which impacts our production guidance.

It is expected that this capital program will be funded from anticipated cash flow from operations and the Company's credit facilities.

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, 2012 as evaluated by Sproule Unconventional Limited 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 9, 2013 in Calgary Alberta.

Forward-Looking Statements

This news release contains certain forward-looking statements and forward-looking information (collectively referred to as "**forward-looking statements**") within the meaning of applicable Canadian securities laws. All statements other than statements of historical fact are forward-looking statements. Forward-looking statements typically contain words such as "anticipate", "believe", "plan", "continuous", "estimate", "expect", "may", "will", "project", "scheduled", "should", 'predict", "targeting", "seek", "intend", "could", "potential", "outlook" or similar words suggesting future outcomes. In particular, but without limiting the foregoing, this news release contains forward-looking statements pertaining to our business plans and strategies; capital expenditure and drilling programs; timing for receipt of regulatory approvals for our Onion Lake thermal project and the first phase of development at our Blackrod SAGD project, ability and expected timing to finance our capital expenditure programs, particularly the thermal projects at Blackrod and Onion Lake; anticipated oil and gas production levels from the Onion Lake thermal project and the Blackrod SAGD project; future oil and gas prices and their impact on BlackPearl; and corporate guidance for 2013 included in the "2013 Guidance" section of this release.

In addition, statements relating to "reserves" or "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 described exist in the quantities predicted or estimated and can be profitably produced in the future.

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

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

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

For further information, please contact:

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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, 2012. These results are being compared with the year ended December 31, 2011. The MD&A should be read in conjunction with the Company's audited consolidated financial statements for the year ended December 31, 2012, 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		

This report includes terms commonly used in the oil and natural gas industry, such as cash flow and cash flow from operations which represent cash flow from operating activities expressed before abandonment costs incurred and changes in non-cash working capital related to operations, as well as cash flow per share (cash flow from operating activities before abandonment costs incurred and changes in non-cash working capital related to operations divided by the average number of common shares outstanding for the period) and operating netback (production revenues less royalties, production expenses and transportation costs, divided by total production for the period on a boe basis). 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 if incurred in the future. These terms do not have standardized meanings prescribed by GAAP and therefore may not be comparable with the calculation of similar measures by other entities. Consequently, these are referred to as non-GAAP measures.

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, 2013.

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 the potential for a thermal SAGD project in the future;
- Mooney, Alberta – a conventional heavy oil property using horizontal drilling and ASP flooding; and
- Blackrod, Alberta – a bitumen property 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 the SAGD thermal recovery process.

Under BlackPearl's current business plan, management intends to sell the Company's non-core assets to help fund development of the three core areas. In the last 24 months, the Company disposed of several properties containing minimal reserves. Additional non-core asset sales are planned; however, additional work may be undertaken on these remaining properties prior to bringing them to market.

2012 SIGNIFICANT EVENTS

- Capital expenditures during 2012 were $139.5 million, with approximately $67.5 million spent at Mooney, $35.8 million at Onion Lake, $27.9 million spent at Blackrod and $8.0 million at John Lake. The focus of the 2012 capital program was the construction of the heavy oil battery and ASP injection costs at Mooney, costs associated with the commercial development application and preliminary engineering design for Blackrod, as well as drilling 43 wells at Onion Lake, 16 wells at Mooney, 10 wells at Blackrod and 5 wells at John Lake.

- The 80,000 bbl/d SAGD commercial development application at Blackrod was filed in May with the Energy Resources Conservation Board (ERCB) and Alberta Environment. The first phase of the project is expected to be 20,000 bbls/d. In addition, Sproule Unconventional Limited, our independent reserves evaluator, reclassified 180 million barrels of "best estimate" contingent resource to probable reserves pertaining to the first phase of SAGD development at Blackrod (see cautionary statement on contingent resources on page 25).

- Oil and gas revenues during 2012 were $204.5 million and cash flow from operations was $82.6 million. Lower realized crude oil prices were offset by higher production volumes in 2012. Net income was $45,000 for the year ended December 31, 2012.

- The Company did not undertake any equity issuances in 2012; however, 10,963,797 common shares were issued pursuant to the exercise of stock options and warrants during the year which generated net proceeds of $8.4 million for the Company.

- In May, the Company expanded its credit facilities from $25 million to $115 million. At December 31, 2012, no amounts were outstanding under these credit facilities and BlackPearl had no long-term debt.

- In November, the Company applied for and received approval to list its Swedish Depository Receipts on the NASDAQ OMX Stockholm Exchange, the main market exchange in Sweden. As a result, the Swedish Depository Receipts no longer trade on the First North market exchange in Sweden.

- BlackPearl increased its proved plus probable reserves by 496% to 213.3 million boe, before royalties, as at December 31, 2012. This amount was determined by BlackPearl's independent reserve evaluators, Sproule Unconventional Limited ("Sproule"). Sproule also attributed "best estimate" contingent resources of 583 million boe, before royalties, to the Company's working interest in its three core properties (see cautionary statement on contingent resources on page 25).

ANNUAL FINANCIAL INFORMATION

($000s, except where noted)	2012	2011	2010
Total oil and gas sales	204,525	179,443	142,867
Net income (loss)	45	18,911	(86)
Per share – basic ($)	0.00	0.07	0.00
Per share – diluted ($)	0.00	0.06	0.00
Cash flow from operations (1)	82,595	77,717	63,511
Per share – basic ($)	0.29	0.27	0.24
Per share – diluted ($)	0.28	0.26	0.24
Capital expenditures	139,548	192,634	95,829
Total assets at year end	620,725	606,521	572,410
Common shares outstanding *(000s)*	295,766	284,802	283,215

(1) Cash 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. Cash flow from operations and cash 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

	2012				2011			
($000s, except where noted)	Dec. 31	Sept. 30	June 30	Mar. 31	Dec. 31	Sept. 30	June 30	Mar. 31
Production (boe/d) (2)	9,067	9,340	9,471	9,581	8,735	8,113	6,545	7,015
Oil and gas sales	47,569	50,081	49,099	57,776	58,160	44,564	42,044	34,675
Oil and gas sales ($/boe)	58.45	60.34	58.82	67.98	73.88	59.70	70.59	54.92
Production costs	14,563	14,104	13,950	16,684	14,014	13,665	10,337	11,122
Production costs ($/boe)	17.89	16.99	16.71	19.63	17.80	18.31	17.36	17.61
Net income (loss)	(4,277)	530	218	3,574	15,504	(51)	2,996	462
Per share, basic and diluted ($)	(0.01)	0.00	0.00	0.01	0.05	0.00	0.01	0.00
Capital expenditures	34,635	28,991	32,453	43,469	56,974	40,499	57,040	38,121
Cash flow from operations (1)	17,684	20,781	19,765	24,365	27,791	19,137	18,867	11,922
Per share, basic ($)	0.06	0.07	0.07	0.09	0.10	0.07	0.07	0.04
Per share, diluted ($)	0.06	0.07	0.07	0.08	0.09	0.07	0.06	0.04
Total assets (end of period)	620,725	612,083	608,610	608,546	606,521	573,536	576,142	564,175
Weighted average shares outstanding, basic (000s)	288,760	285,344	285,272	285,122	284,389	284,353	283,872	283,272
Weighted average shares outstanding, diluted (000s)	294,525	299,148	299,863	300,796	300,103	284,353	302,242	301,799

(1) Cash flow from operations is a non-GAAP measure. It represents cash flow from operating activities before abandonment costs incurred and changes in non-cash working capital related to operations.

(2) Includes production from the Blackrod SAGD pilot.

Fluctuations in quarterly revenues and net income over the last eight quarters are due primarily to the volatility in crude oil prices and changes in sales volumes due to production growth through successful drilling activity, principally in the Onion Lake and Mooney areas. Decreased production in Q1 and Q2 2011 was primarily a result of asset dispositions. The increased production in the second half of 2011, and the first half of 2012, is a result of new production from Onion Lake wells drilled in the first half of 2011 as well as new drilling at Mooney and John Lake in Q4 2011. Decreased production in Q3 and Q4 2012 was primarily a result of natural declines from some of the highest cumulative production wells at Onion Lake. A significant deferred tax recovery contributed to the increase in net income in Q4 2011.

BUSINESS ENVIRONMENT

Commodity Prices

	Year Ended December 31,		2012				2011			
	2012	2011	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Average Crude Oil Prices										
West Texas Intermediate (WTI) (US$/bbl)	94.25	95.05	88.51	92.17	93.44	102.88	94.03	89.74	102.50	93.95
Western Canadian Select (WCS) (Cdn$/bbl)	73.09	77.19	69.43	70.02	71.29	81.61	85.48	70.98	82.09	70.19
Differential – WCS/WTI (Cdn$/bbl)	21.11	17.03	18.46	21.71	23.08	21.44	10.70	17.27	17.06	22.42
Differential – WCS/WTI (%)	22.3%	17.9%	20.8%	23.6%	24.5%	20.8%	10.9%	19.6%	17.8%	24.5%
Average Natural Gas Prices										
AECO gas (Cdn$/GJ)	2.28	3.49	2.90	2.08	1.74	2.39	3.33	3.44	3.54	3.58
Foreign Exchange (Cdn$ to US$)	1.000	1.011	1.009	1.005	0.990	0.999	0.977	1.020	1.033	1.014

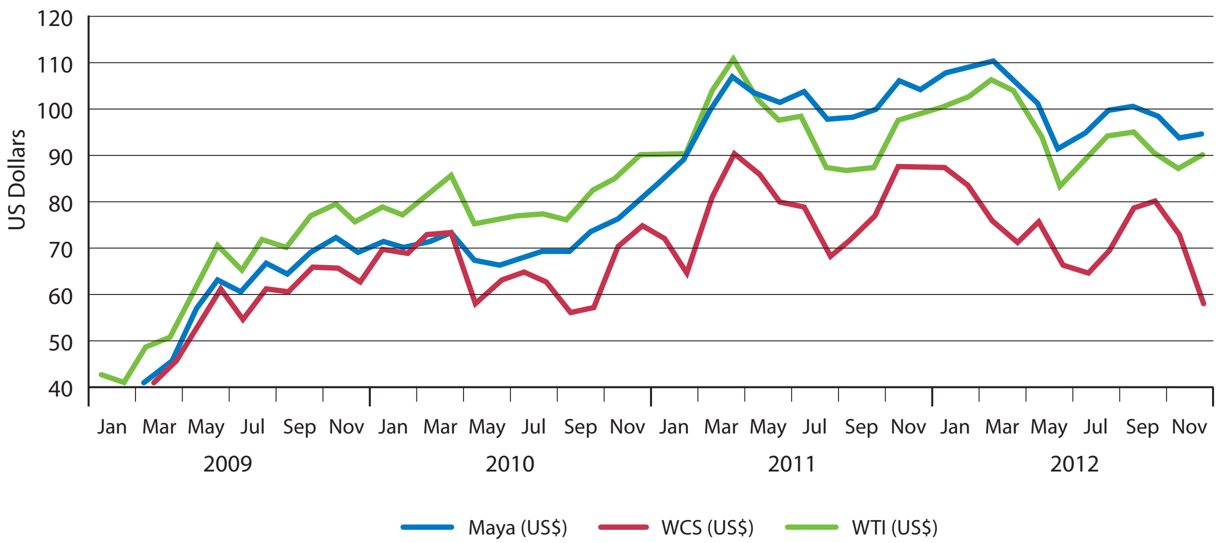
Crude oil prices are based on demand for oil which is generally tied to global economic growth, but is also influenced by other factors such as political instability, market uncertainty, weather conditions, infrastructure constraints and government regulations. Crude oil in North America is commonly 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 has an average gravity of about 20.5 degrees API.

WCS oil prices are lower than WTI oil prices due to the higher cost of refining a barrel 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.

WTI oil prices averaged US$94.25 per barrel, down from US$95.05 per barrel in 2011. WCS oil prices were also down in 2012 averaging $73.09 per barrel in 2012 compared to $77.19 per barrel in 2011. As a result of increasing crude oil production in Canada and the US, in conjunction with pipeline capacity constraints, refinery outages and limited ability to export crude oil, North American crude oil prices in 2012 were discounted compared to global pricing for similar quality crudes. The US mid-continent and the US Gulf Coast are major refining hubs in North America. Increased oil production has resulted in a build-up of inventories in the mid-continent, resulting in discounted crude oil prices. The US Gulf Coast refineries are capable of taking additional crude oil from Canada, especially heavy oil and bitumen, but pipeline infrastructure was not adequate to transport increased production volumes. Various planned and unplanned refinery shutdowns in 2012 also effected demand for crude oil which impacted pricing during the year.

The charts below shows the price comparison between Mexican heavy oil prices ("Mayan") compared to WCS oil prices. Mayan and WCS are similar quality crude oils. As North American oil transportation infrastructure became congested, WCS oil prices were discounted more severely compared to Mayan oil as producers of Mayan crude oil are able to access tide water and can achieve international pricing.

Comparative Crude Oil Prices



To alleviate some of the pipeline congestion an increasing number of producers elected to ship their crude oil by rail to the US Gulf Coast, as well as other regions that are not serviced by pipelines. The cost to transport crude oil by rail is generally higher than by pipeline; however, improved pricing opportunities in conjunction with improved delivery point flexibility has made rail a viable transportation option in the current price environment.

A number of pipeline expansions and debottlenecking currently underway are expected to alleviate some of the pipeline congestion later in 2013 and 2014. In addition, there are a number of other pipeline initiatives proposed, such as the Keystone XL pipeline in the US and the Northern Gateway pipeline in Canada, which could further alleviate current pipeline constraints; however, these proposals have not received government or regulatory approval and therefore the timing of construction or whether they get constructed is uncertain. In addition, there are a number of mid-continent refiners that are in the process of reconfiguring their facilities to handle heavy crudes which could also alleviate some of the pipeline congestion to the Gulf Coast and may have an impact on heavy oil and bitumen pricing in the second half of 2013.

Natural gas prices experienced continued weakness in 2012 averaging $2.28/GJ compared to $3.49/GJ in 2011. BlackPearl produces very little gas and therefore prices do not have a significant impact on our current revenues. However, we do consume gas in our Blackrod pilot operations and as we move toward commercial development of our two thermal projects the cost of gas will have a significant impact on our cost structure.

Oil and Natural Gas Production, Pricing and Revenue

	Three months ended December 31		Year Ended December 31	
	2012	2011	2012	2011
Daily production/sales volumes (1)				
Oil (bbls/d)	8,773	8,504	9,032	7,403
Natural gas (Mcf/d)	440	317	374	960
Combined (boe/d)	8,846	8,577	9,094	7,563
Bitumen – Blackrod (bbls/d)	221	178	272	57
Total production (boe/d)	9,067	8,735	9,366	7,620
Product pricing				
Oil ($/bbl)	58.77	74.13	61.76	65.64
Natural gas ($/Mcf)	3.18	3.05	2.45	3.84
Combined ($/boe)	58.45	73.88	61.45	65.00
Sales *($000s)*				
Oil and gas sales – gross	47,569	58,160	204,525	179,443
Royalties	(10,814)	(14,275)	(45,525)	(45,531)
Oil and gas sales – net	36,755	43,885	159,000	133,912

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

Oil and natural gas revenue increased 14% in 2012 to $204.5 million from $179.4 million in 2011. The increase in revenue is attributable to a 23% increase in production (on a boe basis), partially offset by a 5% decrease in average sales prices received in 2012 compared to 2011. Revenues decreased in the fourth quarter of 2012 compared to the same quarter in 2011 mainly due to a significant drop in the average wellhead prices received.

The increase in 2012 oil production is primarily a result of new production from 43 wells drilled in 2012 at Onion Lake, 16 wells drilled in 2012 at Mooney and an initial re-pressurization response from the first phase of the ASP flood at Mooney. The ASP flood at Mooney was initiated in August 2011. As a result of re-pressurization of the reservoir, production increased to 992 boe/d in 2012 compared to 316 boe/d in 2011. We expect future positive response from the ASP flood with peak production rates over 3,000 boe/d in the next 12 months.

BlackPearl sold an average of 9,067 boe/d during the fourth quarter of 2012, an increase of 4% over the same quarter of 2011 and a 3% decrease from third quarter production. The decrease in production in the fourth quarter was due to higher than anticipated production declines from some of our highest cumulative production wells in the Onion Lake area. The Onion Lake field is a maturing area with over 300 wells drilled into portions of the field over the last seven years and some of these wells are nearing the end of their productive life. We fell short of our 2012 average and year-end exit production guidance of 9,500 and 10,000 boe/d respectively as a result of these production declines. It is our intention to continue to drill conventional wells at Onion Lake to further delineate and develop the field in new areas until we transition to thermal development.

On a boe basis, 99% of the Company's oil and natural gas production in 2012 was heavy oil. The Onion Lake area accounted for 63% and the Mooney area accounted for 27% of total production in 2012.

	Three months ended December 31		Year Ended December 31	
Production by area (boe/d)	2012	2011	2012	2011
Onion Lake	4,857	6,805	5,947	6,272
Mooney	3,329	1,102	2,537	788
John Lake	649	413	573	343
Other	11	237	37	160
Blackrod	221	178	272	57
Total production	9,067	8,735	9,366	7,620

Our average wellhead oil price received in 2012 decreased to $61.76 per barrel compared to $65.64 per barrel in 2011. The lower wellhead prices in 2012 reflect the general decrease in prices in the crude oil markets and wider heavy oil differentials.

BlackPearl did not enter into any oil price hedging arrangements during 2012. In the future, as we enter the next phase of development with our thermal projects at Blackrod and Onion Lake we may consider hedging some of our existing production to protect cash flows during the construction period of these projects.

In 2011, BlackPearl commenced operations of 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 revenues 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. During 2012, the net revenues capitalized were a loss of $3.3 million.

Royalties

	Three months ended December 31		Year Ended December 31	
	2012	2011	2012	2011
Royalties *($000s)*	10,814	14,275	45,525	45,531
Per boe ($)	13.29	18.13	13.68	16.49
As a percentage of revenue	23%	25%	22%	25%

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 First Nation. Royalties as a percentage of revenue decreased to 22% of revenues in 2012 from 25% of revenues in 2011 and to 23% of revenues in the fourth quarter of 2012 from 25% of revenues in the same quarter in 2011. The decrease in the royalty as a percentage of revenue and royalty per boe in 2012 compared to 2011 is mainly attributable to the increased production from the Mooney field.

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 barrels 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 the changes would be neutral to slightly positive to BlackPearl.

Transportation Costs

	Three months ended December 31		Year Ended December 31	
	2012	2011	2012	2011
Transportation costs *($000s)*	2,496	469	9,203	1,430
Per boe ($)	3.07	0.60	2.76	0.52

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 expenses rather than transportation costs.

Transportation costs increased by 543% from $1.4 million in 2011 to $9.2 million in 2012. Increased production volumes from the Mooney area is the main contributor to the increase in transportation costs. Due to infrastructure constraints, we are able to achieve better sale prices for our Mooney oil volumes by trucking some of our oil to markets out of the area. In addition, at Onion Lake, we have expanded our tank treating operations which has allowed us to ship more clean oil volumes. This increases our transportation costs but is offset by lower emulsion trucking costs included in production expenses.

As with a number of oil producers, BlackPearl has started to ship some of its Onion Lake and Mooney volumes by rail to the Gulf Coast and West Coast to avoid pipeline bottlenecks, particularly in the US mid-continent, and improve our sales prices for our oil. Although shipping by rail is more expensive than shipping by pipeline, the improved sales price for our oil more than offsets the increase in transportation costs. Currently, BlackPearl is railing between 2,000 and 2,500 bbls/d.

Production Costs

	Three months ended December 31		Year Ended December 31	
	2012	2011	2012	2011
Production costs *($000s)*	14,563	14,014	59,301	49,138
Per boe ($)	17.89	17.80	17.82	17.80

Production expenses increased 21% from $49.1 million in 2011 to $59.3 million in 2012. On a per boe basis, operating costs increased marginally from $17.80 per boe in 2011 to $17.82 per boe in 2012.

Operating expenses tend to fluctuate due to the amount of workovers and well servicing costs required to maintain production levels. As our fields mature, these costs will likely increase. Operating costs associated with the ASP injection at Mooney have been capitalized while the reservoir was being re-pressurized. We will begin expensing these costs in 2013 due to the pressure response seen. Chemical costs associated with the ASP response will continue to be capitalized until we see a response from those chemicals, likely later in 2013. Total costs capitalized in 2012 were $19.1 million of which $10.0 million related to chemicals.

Operating Netback (1)

	Three months ended December 31		Year Ended December 31	
($/boe)	2012	2011	2012	2011
Revenues	58.45	73.88	61.45	65.00
Royalties	13.29	18.13	13.68	16.49
Transportation costs	3.07	0.60	2.76	0.52
Production costs	17.89	17.80	17.82	17.80
Netback per boe	24.20	37.35	27.19	30.19

(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 barrel of oil equivalent sold. Operating netback decreased by 10% from $30.19 per boe in 2011 to $27.19 per boe in 2012. Operating netback for the fourth quarter of 2012 decreased by 35% from $37.35 per boe during the same quarter in 2011 to $24.20 per boe in 2012. The change is primarily attributable to the decrease in realized crude oil prices and higher transportation costs in 2012.

General and Administrative Expenses (G&A)

	Three months ended December 31		Year Ended December 31	
($000s, except per boe)	2012	2011	2012	2011
Gross G&A expense	2,625	2,441	9,819	9,719
Operator recoveries	(641)	(673)	(2,338)	(2,853)
Net G&A expense	1,984	1,768	7,481	6,866
Per boe ($)	2.44	2.25	2.25	2.49

General and administrative expenses consist primarily of salaries and wages of employees, office rent, computer services, legal, accounting and consulting fees. Net general and administrative expense increased by 9% from $6.9 million in 2011 to $7.5 million in 2012. Gross general and administrative expenses were comparable in 2012 and 2011. The increase of net G&A is attributable to reduced overhead recoveries as a result of lower capital expenditures in 2012. On a per barrel basis, general and administrative costs dropped as a result of increased production levels.

General and administrative costs increased in Q4 2012 compared to 2011 due primarily to costs related to applying to have the Company's Swedish Depository Receipts listed on the main market exchange in Sweden.

Finance Costs

	Three months ended December 31		Year Ended December 31	
($000s)	2012	2011	2012	2011
Interest and bank charges	156	10	827	132
Accretion of decommissioning liabilities	153	180	741	862
Total finance costs	309	190	1,568	994

The increase in interest and bank charges in 2012 compared to 2011 is a result of increased stand-by fees from the expansion of our bank credit facilities from $25 million to $115 million in May this year.

Stock-Based Compensation

	Three months ended December 31		Year Ended December 31	
	2012	2011	2012	2011
Stock based compensation *($000s)*	1,016	1,628	6,016	6,353
Per boe ($)	1.25	2.07	1.81	2.30

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 2012 reflects a lower option value assigned to each grant of options. On a per barrel basis, stock-based compensation has been dropping as a result of production levels increasing at a higher rate than the increase in expenses. In 2012, 3,079,500 options were granted and 1,318,601 options were exercised.

Depletion and Depreciation

	Three months ended December 31		Year Ended December 31	
	2012	2011	2012	2011
Depletion and depreciation *($000s)*	16,753	16,490	69,576	61,318
Per boe ($)	20.58	20.95	20.90	22.21

The Company's properties are depleted on a unit of production basis based on estimated proven plus probable reserves. Depletion and depreciation expense increased by 14% from $61.3 million in 2011 to $69.6 million in 2012. The increase in depletion is a result of increased production volumes in 2012.

On a boe basis, depletion and depreciation expense decreased to $20.90 per boe in 2012 as compared to $22.21 per boe in 2011. This decrease in depletion on a boe basis is primarily attributable to increased oil and gas reserves recognized in our third party reserves evaluation.

Cash-generating units ("CGUs") are petroleum and natural gas properties, exploration evaluation assets and other corporate assets that are aggregated based on their ability to generate largely independent cash flows and are used for impairment testing. At December 31, 2012, the recoverable amounts of the Company's CGUs were estimated at their fair values less costs to sell based on the net present value of the after tax cash flows from oil and gas proved plus probable reserves and contingent resources as estimated by the Company's third party reserve evaluators discounted at a rate of 10%. As a result of lower heavy oil prices and well operating performance, it was determined that the net book value of two of the Company's minor CGUs (Long Coulee in Alberta and Salt Lake in Saskatchewan) exceeded the recoverable amount and the Company recognized a $5.0 million (2011 – $Nil) impairment charge.

Interest Income

	Three months ended December 31		Year Ended December 31	
($000s)	2012	2011	2012	2011
Interest income	21	225	315	1,430

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 2012 as compared to 2011.

Income Taxes

	Three months ended December 31		Year Ended December 31	
($000s)	2012	2011	2012	2011
Current income and other tax recoveries	(41)	–	(76)	–
Deferred income tax (recovery)	(1,042)	(5,347)	1,932	(5,347)
Total income tax (recovery)	(1,083)	(5,347)	1,856	(5,347)

BlackPearl did not pay cash income taxes in 2012 and does not expect to pay income taxes in 2013 as we have sufficient tax pools to shelter expected income. The current income tax recovery for 2012 is a result of a tax refund assessed on a prior period.

Deferred income tax expense was $1.9 million for 2012, for an effective tax rate of 98%. 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 %	Year Ended Dec 31, 2012	Year Ended Dec 31, 2011
Canadian exploration expenses	100	33,862	28,255
Canadian development expenses	30	134,527	139,897
Canadian oil and gas property expenses	10	16,234	14,726
Undepreciated capital costs	10–30	159,323	156,328
Non-capital losses (various expiry dates)	100	247,489	191,766
Share issuance costs	5 years	1,785	2,824
		593,220	533,796

Approximately $28 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)	2012	2011	2012	2011
Gain on disposition of petroleum and natural gas properties	–	(170)	–	3,375

We did not sell any oil and gas properties in 2012. During 2011, BlackPearl recorded gains and losses on the disposition of certain petroleum and natural gas properties in southern Alberta, Saskatchewan and the polymer pilot facilities in the Mooney area. We expect to sell additional non-core assets over the next 12 to 24 months as part of our financing plan to fund development of our SAGD thermal assets.

Gain on Disposition and Revaluation of MAV II Notes

	Three months ended December 31		Year Ended December 31	
($000s)	2012	2011	2012	2011
Gain on disposition of MAV II Notes	–	–	792	–
Revaluation of MAV II Notes	–	956	–	956
Total effect on income	–	956	792	956

During the first quarter 2012, BlackPearl disposed of its investment in MAV II Notes for proceeds of $3.6 million, which resulted in a gain on disposition of $0.8 million.

RESULTS OF OPERATIONS

	Three months ended December 31		Year Ended December 31	
($000s, except where noted)	2012	2011	2012	2011
Net income (loss)	(4,277)	15,504	45	18,911
Per share, basic ($)	(0.01)	0.05	0.00	0.07
Per share, diluted ($)	(0.01)	0.05	0.00	0.06

For the year ended December 31, 2012, the Company generated net income of $45,000 compared to net income of $18.9 million in 2011. For the quarter ended December 31, 2012, the Company incurred a loss of $4.3 million compared to net income of $15.5 million for the same quarter in 2011. The decrease in income in 2012 and the fourth quarter is primarily a result of a decrease in heavy oil prices, an impairment charge to non-core CGUs of $5.0 million, a gain recognized in 2011 on the disposition of various oil and gas properties and the recognition of certain deferred tax benefits in 2011.

	Three months ended December 31		Year Ended December 31	
($000s, except where noted)	2012	2011	2012	2011
Cash flow from operations [(1)]	17,684	27,791	82,595	77,717
Per share, basic ($)	0.06	0.10	0.29	0.27
Per share, diluted ($)	0.06	0.09	0.28	0.26

(1) Cash flow from operations is a non-GAAP measure. It represents cash flow from operating activities before abandonments costs incurred and changes in non-cash working capital related to operations.

Cash flow from operations increased by 6% from $77.7 million in 2011 to $82.6 million in 2012. The increase is cash flow in 2012 reflects higher production volumes offset by lower wellhead sales prices in 2012.

Cash flow from operations in the fourth quarter of 2012 was $17.7 million compared to $27.8 million in the fourth quarter of 2011. Lower cash flow from operations was primarily due to the decrease in heavy oil prices and higher transportation charges.

NON-GAAP MEASURES

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

	Three months ended December 31		Year Ended December 31	
($000s)	2012	2011	2012	2011
Cash flows from operating activities	33,973	39,270	79,862	75,397
Add (deduct):				
Abandonment costs incurred	105	626	989	1,036
Changes in non-cash working capital related to operations	(16,394)	(12,105)	1,744	1,284
Cash flow from operations	17,684	27,791	82,595	77,717

LIQUIDITY AND CAPITAL RESOURCES

As at December 31, 2012, the Company had a working capital deficiency of $7.8 million and no bank indebtedness. The working capital deficiency will be funded from cash flows from operating activities or the credit facilities.

The Company expanded its revolving credit facilities in 2012. At December 31, 2012, the Company had $115 million in credit facilities. The only amount drawn on these facilities at the end of 2012 was a $20,000 letter of credit. 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 next scheduled Borrowing Base redetermination is to occur by May 31, 2013. In the event the lenders elected not to renew the credit facility during this borrowing base review any amounts outstanding on the facilities would be due and payable in full by May 30, 2014.

Pursuant to the terms of the credit agreement, the only financial covenant in the credit facility 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 as compared to current liabilities from the Company's consolidated balance sheet. BlackPearl was in compliance with this covenant throughout 2012. The credit facilities are secured by a floating charge debenture and a general securities agreement.

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 operations and amounts available under the credit facility. We are also able to scale back our capital expenditure program on these projects relatively easily if circumstances warrant it.

During the last four years we have maintained a conservative capital structure with little or no debt, which has allowed us to maximize our financial flexibility without impeding the development and growth of the business. During this period our capital spending was funded by cash flow generated from operations, supplemented by three equity issues which provided net proceeds to the Company of over $123 million. The next significant phase of growth of our business is the development of our two thermal SAGD projects at Blackrod and Onion Lake, which will require additional capital as cash flow and amounts available from the existing credit facility will not be sufficient to fully fund development of these projects. We have not completed detailed third party engineering cost estimates for these projects but our internal estimates suggest the first 20,000 bbl/d phase at Blackrod will likely cost $750 to $800 million, and the 12,000 bbl/d phase at Onion Lake will cost between $300 and $350 million. Timing of development of these thermal projects is dependent on additional financings. It is unlikely that both thermal projects would be developed concurrently due to the amount of additional capital required. We are actively evaluating financing options which include issuance of debt and equity, non-core asset sales, joint venture arrangements or potentially selling one of our three core properties. Our objective is to minimize dilution to our shareholders on a net asset value basis without taking on excessive financial risk. We hope to complete our evaluation of these alternatives and have our financing strategy in place during the first half of 2013.

CAPITAL EXPENDITURES

During the year ended December 31, 2012, capital spending was $139.5 million, a decrease from $192.6 million in 2011. The main components of the 2012 capital program was the construction of the heavy oil battery and ASP flood injection costs at Mooney, costs associated with the SAGD commercial development application and preliminary engineering design at Blackrod, as well as drilling 43 conventional heavy oil wells at Onion Lake, 16 wells at Mooney, 5 wells at John Lake and 10 delineation wells at Blackrod.

Capital expenditures in the fourth quarter of 2012 were $34.6 million, a decrease of 40 percent than in the fourth quarter of 2011. Capital expenditures during Q4 2012 include drilling 11 wells at Onion, 10 wells at Mooney, 1 well at John Lake, continued capitalization of the costs of ASP flooding at Mooney and the Blackrod SAGD operations.

	Three months ended December 31		Year Ended December 31	
($000s)	2012	2011	2012	2011
Land	44	7,433	591	9,109
Seismic	40	23	671	2,160
Drilling and completion	24,445	36,212	83,454	105,939
Equipment	10,084	13,287	51,780	75,293
Other	22	19	52	133
Total	34,635	56,974	136,548	192,634
Property acquisitions	–	–	3,000	–
Total capital expenditures	34,635	56,974	139,548	192,634
Property dispositions	–	(3,500)	–	(6,100)
Net capital expenditures	34,635	53,474	139,548	186,534

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The Company has a number of financial obligations in the ordinary course of business. The following table summarizes the outstanding contractual obligations and commitments of the Company as at December 31, 2012. These obligations are expected to be funded from operating cash flow.

($000s)	2013	2014	2015	2016	2017	Thereafter
Operating leases (1)	$ 1,511	$ 1,760	$ 1,682	$ 1,336	$ –	$ –
Electrical service agreement (2)	119	119	119	119	119	2,345
Drilling rig commitment (3)	2,688	–	–	–	–	–
Decommissioning liabilities (4)	175	311	826	1,709	301	36,334
	$ 4,493	$ 2,190	$ 2,627	$ 3,164	$ 420	$ 38,679

(1) The Company has 45 months remaining on an operating lease for office space as at December 31, 2012. 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 or any of the subtenants of a portion of the space are unable to fulfill their lease obligation, BlackPearl would be required to pay a maximum additional $14.2 million (including an estimate for operating costs) over the next 45 months.

(2) The Company entered into a long-term agreement to have electricity supplied to one of our processing facilities.

(3) The Company has contracted drilling rig services over the next year. In the event that the Company does not utilize the minimum contracted days, the Company would be obligated to pay the rig operator a variable rate based on days not utilized under the contracts. The payments included herein assumes no additional drilling days used.

(4) The Company also has ongoing obligations related to the abandonment and reclamation 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 $39.7 million as at December 31, 2012. Remediation 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, MAV II notes and accounts payable. The Company manages its risk through its policies and processes, but generally has not used derivative financial instruments to manage these risks.

The carrying value of cash, trade and other receivables and accounts payable approximates their fair value due to the short-term nature of these instruments. The fair value of the investment in MAV II notes has been determined by quoted prices that were determined outside of what would be considered an active market.

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, 2012, the Company held US$706,000 in cash and short-term deposits.

As at December 31, 2012, 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 $25,000 lower, due to a decreased 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, 2012, the Company held $17.0 million in cash at various major financial institutions throughout Canada and the United States. At December 31, 2012, two Canadian financial institutions held approximately 98% 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 $3.1 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.

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 the revolving credit facility, which remained undrawn throughout 2012.

Cash is held in highly liquid, short-term investments and therefore the risk to changes in interest rates is low. At December 31, 2012, 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 $82,000 higher.

At December 31, 2012, the Company had not drawn on its credit facility and therefore the interest rate risk at that time was NIL.

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, 2012, the Company had a working capital deficiency of $7.8 million and an undrawn $115.0 million revolving credit facility. 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, costs 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 exposed to risk of 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 expenditure program.

For more detailed information, see note 16 to the consolidated financial statements.

OFF-BALANCE-SHEET ARRANGEMENTS

The Company has no off-balance-sheet arrangements in 2012 or 2011. We do utilize operating leases in our normal course of business as disclosed under contractual obligations and commitments.

RELATED-PARTY TRANSACTIONS

There were no related-party transactions during 2012.

OUTSTANDING SHARE DATA

As at February 26, 2013, the Company had 296,108,308 common shares outstanding and 16,970,500 stock options outstanding under its stock-based compensation program.

OUTSTANDING CREDIT FACILITY DATA

As at February 26, 2013, the Company had advances of $11,000,000 drawn under the credit facilities and had issued letters of credit in the amount of $20,000; leaving $103,980,000 available under the credit facilities.

PROPOSED TRANSACTIONS

As of February 26, 2013, the Company does not have any significant pending transactions.

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 4 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 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 too 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 $1.5 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 has sanctioned the development. At December 31, 2012, $134.7 million has been excluded from depletion and has been shown separately on the Company's balance sheet.

(iii) *Impairment testing* – BlackPearl is required to review the carrying value of all property, plant, and equipment (PPE) for potential impairment. Throughout the year, the Company analyzes the carrying value of its 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 2012 and 2011 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, production rate, 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, 2012, 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 lower heavy oil prices and well operating performance, our two minor CGUs (Long Coulee in Alberta and Salt Lake in Saskatchewan) were impaired and the Company wrote-down the carrying value of these CGUs by $5.0 million in 2012 (2011 – $Nil).

(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 includes, 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:

	2012	2011
Undiscounted abandonment costs *($000s)*	$ 39,656	$ 32,714
Risk-free rate	2.25%	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 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) *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.

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 below.

IFRS 10: Consolidated Financial Statements – In 2011, the IASB issued IFRS 10 which provides additional guidance to determine whether an investee should be consolidated. The guidance applies to all investees, including special purpose entities. The standard is required to be adopted for periods beginning January 1, 2013. IFRS 10 will have minimal impact on the Company's financial statements on adoption as the current consolidation method adheres to this standard.

IFRS 11: Joint Arrangements – In 2011, the IASB issued IFRS 11 which presents a new model for determining whether an entity should account for joint arrangements using proportionate consolidation or the equity method. An entity will have to follow the substance rather than legal form of a joint arrangement and will no longer have a choice of accounting method. The standard is required to be adopted for periods beginning January 1, 2013. IFRS 11 will have minimal impact on the Company's financial statements on adoption as all the joint arrangements the Company has were determined to be joint operations and therefore use the proportionate consolidation method which is already currently in use.

IFRS 12: Disclosure of Interests in Other Entities – In 2011, the IASB issued IFRS 12 which aggregates and amends disclosure requirements included within other standards. The standard requires a company to provide disclosures about subsidiaries, joint arrangements, associates and unconsolidated structured entities. The standard is required to be adopted for periods beginning January 1, 2013. IFRS 12 will require minimal disclosure changes in the Company's financial statements.

IFRS 13: Fair Value Measurement – In 2011, the IASB issued IFRS 13 to provide comprehensive guidance for instances where IFRS requires fair value to be used. The standard provides guidance on determining fair value and requires disclosures about those measurements. The standard is required to be adopted for periods beginning January 1, 2013. IFRS 13 will require minimal disclosure changes in the Company's financial statements.

IAS 27: Separate Financial Statements – In 2011, the IASB issued amendments to IFRS 27 to conform to the changes made in IFRS 10 *Consolidated Financial Statements*, but the standard retains the current guidance for separate financial statements. These amendments are required to be adopted for periods beginning January 1, 2013. These amendments will require minimal disclosure changes in the Company's financial statements.

IAS 28: Investments in Associates and Joint Ventures – as a consequences of the new IFRS 11 *Joint Arrangements*, and IFRS 12 *Disclosure of Interest in Other Entities*, IAS 28 *Investments in Associates*, has been renamed IAS 28 *Investments in Associates and Joint Ventures*, and describes the application of the equity method to investments in joint ventures in addition to associates. The revised standard is required to be adopted for periods beginning January 1, 2013. IFRS 28 will have minimal impact on the Company's financial statements on adoption as the Company has no associates or joint ventures that will be accounted for under the equity method.

IFRS 9: Financial Instruments: Classification and Measurement – In 2011, the IASB issued an amended version of IFRS 9 which provides additional guidance to classification and measurement of the Company's financial assets, but will not have an impact on classification and measurements of financial liabilities. Due to the amendment in 2011, this standard is now required to be adopted for periods beginning January 1, 2015. The Company is currently analyzing the impact, if any, that the adoption of this standard will have on its financial statements.

IFRS 7: Financial Instruments: Disclosures – In 2011, the IASB issued amendments to IFRS 7 Financial Instruments: Disclosures relating to disclosure requirements for the offsetting of financial assets and liabilities when offsetting is permitted under IFRS. The disclosure amendments are required to be adopted retrospectively for periods beginning January 1, 2013. These amendments will require minimal disclosure changes in the Company's financial statements.

IAS 19: Employee Benefits – the IASB has issued numerous amendments to IAS 19. These range from fundamental changes such as removing the corridor mechanism and the concept of expected returns on plan assets to simple clarifications and re-wording. These amendments are required to be adopted for periods beginning January 1, 2013. These amendments will require minimal disclosure changes in the Company's financial statements.

IAS 32: Offsetting Financial Assets and Financial Liabilities – 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. The Company is currently analyzing the impact, if any, that the adoption of this standard will have on its 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:

- Risk of fluctuating oil, natural gas prices and the cost of diluent;
- Operational risk of finding and producing reserves economically;
- Uncertainties associated with estimating the quantity of reserves and resources;
- Risk associated with securing the needed capital to carry out the Company's operations;
- Changes in global economic conditions, particularly in Canada and the U.S.;
- Risk from aboriginal claims;
- 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;
- Competition for, among other things, capital, undeveloped land, skilled labor and equipment;
- Reliance on third parties for pipeline and other infrastructure;
- Risk of fluctuating foreign currency exchange rates;
- Credit or counterparty risk with respect to non-performance by counterparties to financial instruments;
- Risk of changes to interest rates;
- Marketing oil production at acceptable prices;
- Uncertainty associated with obtaining drilling licenses and other regulatory consents and approvals; and
- Uncertainties of the SAGD bitumen and ASP flood recovery processes.

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. The Company does not currently utilize derivative instruments to hedge its commodity price, foreign currency exchange or interest rate risks.

BlackPearl strives to minimize and manage these risks in a number of ways, including:

- Employing qualified professional and technical staff;
- Maintaining a healthy balance sheet that minimizes the use of debt;
- Carrying insurance to provide a reasonable amount of protection from risk of loss;
- Concentrating in areas with long-life reserves to reduce the risk associated with commodity price cycles;
- Monitoring price trends and establishing relationships with creditworthy counterparties;
- Utilizing the latest technology for finding and developing reserves;
- Constructing high-quality, environmentally sensitive and safe production facilities; and
- Maximizing operational control of drilling and producing operations.

ENVIRONMENTAL RISKS

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Compliance with such legislation can require significant expenditures and a breach could result in the imposition of fines and penalties, some of which could be material. The Company continually assesses new and existing regulatory requirements and environmental risks and determines the impact these risks might have on the Company, as well as the appropriate actions necessary to manage those risks. These assessments and the resulting policy decisions are discussed quarterly with the Board of Directors which evaluates the performance and effectiveness of the Company's environmental policies and programs.

The Company's environmental responsibilities includes removing property, plant and equipment as well as reclaiming land and property to its original state, subsequent to the completion of oil and natural gas extraction activities. This requirement results in a decommissioning liability that provides current recognition of estimated expenditures that will be incurred in the future. The Company's decommissioning liabilities are discussed in further detail under "Critical Accounting Estimates" above, as well as in note 11 to the Company's consolidated financial statements.

CONTROL CERTIFICATION

Disclosure Controls and Procedures

Disclosure controls and procedures have been designed to ensure that information required to be disclosed by the Company is accumulated and communicated to management to allow for timely decisions regarding required disclosures. The Company carried out an evaluation of the effectiveness of the Company's disclosure controls and procedures as at December 31, 2012. The evaluation was carried out under the supervision and with the participation of the Chief Executive Officer and the Chief Financial Officer. The Company's Chief Executive Officer and Chief Financial Officer, together with other members of management, have concluded, based on their evaluation of the effectiveness of the Company's disclosure controls and procedures as at year-end, that the Company's disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company is (i) recorded, processed, summarized and reported within the time periods specified in Canadian securities law and (ii) accumulated and communicated to the Company's management, including its Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure.

It should be noted that while the Company's Chief Executive Officer and Chief Financial Officer believe that the Company's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the disclosure controls and procedures 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

The Company's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, a system of internal control over financial reporting to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's internal control over financial reporting at the financial year-end of the Company and concluded that the Company's internal control over financial reporting is effective, at the financial year-end of the Company, for the foregoing purpose.

The Company is required to disclose herein any change in its internal control over financial reporting during the period that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting. No material change in the Company's internal control over financial reporting was identified during such period that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, 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 disclosure and internal controls and procedures will prevent all errors or fraud.

OUTLOOK

2013 Guidance	Initial Guidance	February Update
Production (boe/d)		
Annual average	10,500 – 11,000	9,000 – 10,000
Exit	11,000 – 12,000	10,000 – 10,500
Cashflow from operations ($millions)	75 – 85	50 – 60
Capital expenditures ($millions)	140 – 160	125 – 140
Year-end debt ($millions)	80 – 90	80 – 90
Year-end working capital ($millions)	0 – 5	0 – 5
Pricing Assumptions (annual average)		
Crude oil – WTI	US $88	US $95
Light/heavy differential	US $18	US $27
Foreign Exchange (Cdn$ to US$)	1.00	1.00

Our initial guidance for 2013 anticipated a capital spending program of $140 to $160 million. As a result of a significant decrease in heavy oil prices during the first quarter of 2013 we elected to defer some of our first quarter capital spending. As a result, we have decreased our estimated 2013 capital spending to between $125 and $140 million. The Blackrod project continues to dominate our 2013 capital expenditure program, accounting for over 45% of our revised budget. Our plans in 2013 for the Blackrod area remain unchanged. We plan to expand the existing pilot with a second well pair, continue with detailed engineering design for the first phase of development and order long lead equipment items for the central processing facility. At Mooney we will continue development of the phase two lands with 15 to 20 horizontal wells planned; a small decrease from our original plan of drilling 20 to 25 wells. At Onion Lake we will continue primary development with 20 vertical wells planned. We have also reduced spending on some of our minor non-core assets.

Cash flow from operations is expected to be between $50 and $60 million. The decrease in our estimated cash flow from operations from our initial guidance reflects lower forecast oil prices in the first quarter of 2013 and reduced capital spending which impacts our production guidance.

It is expected that this capital program will be funded from anticipated cash flow from operations and the Company's credit facilities. We have a lot of flexibility in our capital program and can adjust capital spending if required.

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 2013 performance:

($000s)	Cash Flow	Net Income
Price change		
US$5 per barrel change in the price of WTI oil	10,871	8,044
CDN$1 per barrel change in operating costs	3,189	2,360
Exchange rate		
$0.02 change in US/CDN rate	2,998	995
Production rate		
500 barrel per day change	1,711	1,610

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", "believe", "plan", "target", "continuous", "estimate", "expect", "may", "will", "project", "should", "scheduled", "outlook" or similar words suggesting future outcomes. In particular, but without limiting the foregoing, this report contains forward-looking statements pertaining to our business plans and strategies; capital expenditure and drilling programs, including the estimated capital costs for the first phase of thermal development at Blackrod and the thermal project at Onion Lake; methods, sources and timing to finance capital expenditure programs, particularly for the SAGD thermal projects at Blackrod and Onion Lake; anticipated oil and gas production levels; anticipated timing of a production response from the Mooney ASP flood and expected peak production volumes from the flood; future oil and gas prices and their impact on BlackPearl; potential oil price hedging arrangements; future costs including operating and administrative costs and royalty rates; future cash flows and net income; anticipated future asset dispositions, impact from pipeline expansion and debottlenecking, expected cash taxes to be paid in 2013, estimated capital costs for the development of the Blackrod and Onion Lake SAGD projects and corporate guidance for 2013 included in the "Outlook" section of this report.

In addition, statements relating to "reserves" or "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 described exist in the quantities predicted or estimated and can be profitably produced in the future.

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

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

Undue reliance should not be placed on these forward-looking statements. Readers are cautioned that the actual results achieved will vary from the information provided herein and the variations could be material. Readers are also cautioned that the foregoing list of assumptions, risks and factors is not exhaustive. There can be no assurance by the Company that actual results achieved will be the same in whole or in part as those set out in the forward-looking 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 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. 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 option on the Corporation's financial statements as at and for the year ended December 31, 2012. 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, 2013 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, 2013

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, 2012 and December 31, 2011, 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, 2012 and December 31, 2011, 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, 2013

Calgary, Alberta

CONSOLIDATED BALANCE SHEETS

(audited)

(Cdn$ in thousands)	Note	December 31, 2012	December 31, 2011
Assets			
Current assets			
Cash and cash equivalents	5	$ 16,977	$ 59,672
Trade and other receivables	6	16,708	23,315
Prepaid expenses and deposits		878	817
		34,563	83,804
MAV II Notes (formerly asset backed commercial paper)		–	2,795
Deferred tax assets	13	4,142	6,074
Exploration and evaluation assets	7	134,721	106,450
Property, plant and equipment	8	447,299	407,398
		$ 620,725	$ 606,521
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	9	$ 42,351	$ 45,979
Decommissioning liabilities	11	33,372	30,420
		75,723	76,399
Shareholders' equity			
Share capital	12	876,400	864,633
Contributed surplus		26,762	23,694
Deficit		(358,160)	(358,205)
		545,002	530,122
		$ 620,725	$ 606,521

Commitments and contingencies (note 15)

See accompanying notes to consolidated financial statements

Signed on behalf of the Board:

(signed)

John H. Craig
Chairman and Director

(signed)

Brian D. Edgar
Director

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(audited)

(Cdn$ in thousands, except for per share amounts)	Note	Year ended December 31, 2012	Year ended December 31, 2011
Revenue			
Oil and gas sales		$ 204,525	$ 179,443
Royalties		(45,525)	(45,531)
		159,000	133,912
Expenses			
Production		59,301	49,138
Transportation		9,203	1,430
General and administrative		7,481	6,866
Depletion and depreciation	8	69,576	61,318
Impairment of property, plant and equipment	8	5,000	–
Finance costs	17	1,568	994
Stock-based compensation	12	6,016	6,353
Foreign currency exchange loss		61	10
		158,206	126,109
Other income			
Interest income		315	1,430
Gain on disposition of petroleum and natural gas properties		–	3,375
Gain on disposition of investment in MAV II Notes		792	–
Revaluation of investment in MAV II Notes		–	956
		1,107	5,761
Income before income taxes		1,901	13,564
Income taxes			
Current income tax (recovery)	13	(76)	–
Deferred income tax (recovery)	13	1,932	(5,347)
		1,856	(5,347)
Net and Comprehensive income for the year		$ 45	$ 18,911
Income per share			
Basic	12	$ 0.00	$ 0.07
Diluted	12	$ 0.00	$ 0.06

See accompanying notes to consolidated financial statements

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(audited)

(Cdn$ in thousands)				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**

				Year ended December 31, 2011
	Share Capital	Contributed Surplus	Deficit	Total Equity
Balance – January 1, 2011	$ 858,610	$ 19,041	$ (377,116)	$ 500,535
Net and comprehensive income for the year	–	–	18,911	18,911
Stock-based compensation	–	6,353	–	6,353
Shares issued on exercise of stock options and warrants	3,596	–	–	3,596
Transfer to share capital on exercise of stock options and warrants	1,700	(1,700)	–	–
Recognition of tax benefits of share issue costs incurred in prior periods	727	–	–	727
Balance – December 31, 2011	$ 864,633	$ 23,694	$ (358,205)	$ 530,122

See accompanying notes to consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

(audited)

(Cdn$ in thousands)	Note	Year ended December 31 2012	Year ended December 31 2011
Operating activities			
Net income for the year		$ 45	$ 18,911
Items not involving cash:			
Depletion and depreciation	8	69,576	61,318
Accretion of decommissioning liabilities	17	741	862
Stock-based compensation	12	6,016	6,353
Foreign exchange loss (gain)		77	(49)
Deferred tax expense (recovery)		1,932	(5,347)
Impairment of property, plant and equipment		5,000	–
Gain on disposal of petroleum and natural gas properties		–	(3,375)
Gain on disposition of investment in MAV II Notes		(792)	–
Revaluation of investment in MAV II Notes		–	(956)
Abandonment costs incurred		(989)	(1,036)
Changes in non-cash working capital related to operations	17	(1,744)	(1,284)
Cash flows from operating activities		79,862	75,397
Financing activities			
Proceeds on issue of common shares, net of costs	12	8,445	3,596
Investing activities			
Capital expenditures - exploration and evaluation assets		(27,483)	(29,079)
Capital expenditures - property, plant and equipment		(111,691)	(160,055)
Proceeds from sale of petroleum and natural gas properties		–	2,600
Proceeds from disposition of investment in MAV II Notes		3,587	–
Changes in non-cash working capital from investing	17	4,601	(2,442)
Cash flows from investing activities		(130,986)	(188,976)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		(16)	59
Decrease in cash and cash equivalents		(42,695)	(109,924)
Cash and cash equivalents, beginning of year		59,672	169,596
Cash and cash equivalents, end of year		$ 16,977	$ 59,672

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 and outstanding as of February 26, 2013, the date they were approved and authorized for issuance by the Board of Directors ("the Board").

3. SIGNIFICANT ACCOUNTING POLICIES

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

Basis of measurement

The consolidated financial statements have been prepared on a historical cost basis, except for the Company's investment in MAV II Notes, which were 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, 2012. All intercompany transactions, balances and unrealized gains and losses from intercompany transactions are eliminated in full on consolidation.

Subsidiaries are those entities which BlackPearl controls by having the power to govern their financial and operating policies. The financial statements of the subsidiaries are prepared for the same reporting period as BlackPearl, using consistent accounting policies.

Joint operations

A portion of the Company's activities are owned and operated jointly with other parties. These consolidated financial statements reflect only the Company's proportionate 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 operation and a share of production in such activities.

Financial instruments

The Company's financial instruments include cash and cash equivalents, trade and other receivables, MAV II Notes, accounts payable and accrued liabilities and credit facilities. 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 per 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. The Company's investment in MAV II notes are classified as held-for-trading.

(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 and trade and other receivables 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 and credit facilities 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.

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. 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 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 CGU's are based on the higher of their fair value less costs to sell and value in use. Unless indicated otherwise, the recoverable amount used in assessing impairment changes is fair value less costs to sell. The Company estimates fair value less cost to sell 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 to sell and its value in use. Fair value less cost to sell 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 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 and warrants granted.

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 below.

IFRS 10: Consolidated Financial Statements – In 2011, the IASB issued IFRS 10 which provides additional guidance to determine whether an investee should be consolidated. The guidance applies to all investees, including special purpose entities. The standard is required to be adopted for periods beginning January 1, 2013. IFRS 10 will have minimal impact on the Company's financial statements on adoption as the current consolidation method adheres to this standard.

IFRS 11: Joint Arrangements – In 2011, the IASB issued IFRS 11 which presents a new model for determining whether an entity should account for joint arrangements using proportionate consolidation or the equity method. An entity will have to follow the substance rather than legal form of a joint arrangement and will no longer have a choice of accounting method. The standard is required to be adopted for periods beginning January 1, 2013. IFRS 11 will have minimal impact on the Company's financial statements on adoption as all the joint arrangements the Company has were determined to be joint operations and; therefore, use the proportionate consolidation method, which is already currently in use.

IFRS 12: Disclosure of Interests in Other Entities – In 2011, the IASB issued IFRS 12 which aggregates and amends disclosure requirements included within other standards. The standard requires a company to provide disclosures about subsidiaries, joint arrangements, associates and unconsolidated structured entities. The standard is required to be adopted for periods beginning January 1, 2013. IFRS 12 will require minimal disclosure changes in the Company's financial statements.

IFRS 13: Fair Value Measurement – In 2011, the IASB issued IFRS 13 to provide comprehensive guidance for instances where IFRS requires fair value to be used. The standard provides guidance on determining fair value and requires disclosures about those measurements. The standard is required to be adopted for periods beginning January 1, 2013. IFRS 13 will require minimal disclosure changes in the Company's financial statements.

IAS 27: Separate Financial Statements – In 2011, the IASB issued amendments to IFRS 27 to conform to the changes made in IFRS 10 *Consolidated Financial Statements*, but the standard retains the current guidance for separate financial statements. These amendments are required to be adopted for periods beginning January 1, 2013. These amendments will require minimal disclosure changes in the Company's financial statements.

IAS 28: Investments in Associates and Joint Ventures – as a consequences of the new IFRS 11 *Joint Arrangements*, and IFRS 12 *Disclosure of Interest in Other Entities*, IAS 28 *Investments in Associates*, has been renamed IAS 28 *Investments in Associates and Joint Ventures*, and describes the application of the equity method to investments in joint ventures in addition to associates. The revised standard is required to be adopted for periods beginning January 1, 2013. IFRS 28 will have minimal impact on the Company's financial statements on adoption as the Company has no associates or joint ventures that will be accounted for under the equity method.

IFRS 9: Financial Instruments: Classification and Measurement – In 2011, the IASB issued an amended version of IFRS 9 which provides additional guidance to classification and measurement of the Company's financial assets, but will not have an impact on classification and measurements of financial liabilities. Due to the amendment in 2011, this standard is now required to be adopted for periods beginning January 1, 2015. The Company is currently analyzing the impact, if any, that the adoption of this standard will have on its financial statements.

IFRS 7: Financial Instruments: Disclosures – In 2011, the IASB issued amendments to IFRS 7 *Financial Instruments: Disclosures* relating to disclosure requirements for the offsetting of financial assets and liabilities when offsetting is permitted under IFRS. The disclosure amendments are required to be adopted retrospectively for periods beginning January 1, 2013. These amendments will require minimal disclosure changes in the Company's financial statements.

IAS 19: Employee Benefits – the IASB has issued numerous amendments to IAS 19. These range from fundamental changes such as removing the corridor mechanism and the concept of expected returns on plan assets to simple clarifications and re-wording. These amendments are required to be adopted for periods beginning January 1, 2013. These amendments will require minimal disclosure changes in the Company's financial statements.

IAS 32: Offsetting Financial Assets and Financial Liabilities – 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. The Company is currently analyzing the impact, if any, that the adoption of this standard will have on its financial statements.

4. 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 changed 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 7 & note 8)

The recoverable amount of CGUs and individual assets are based on the higher of their value-in-use and fair value less costs to sell. 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 to sell. The Company estimates fair value less costs to sell 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 2012, the Company utilized a 10% discount rate 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 8 to the consolidated financial statements summarize the commodity price forecast used to assess CGU impairment in 2012.

(iv) Exploration and evaluation assets (note 7)

The decision to transfer exploration and evaluation assets to property, plant and equipment is when 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 11)

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 the 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 13)

The Company follows the liability 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 12)

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.

5. CASH AND CASH EQUIVALENTS

	2012	2011
Cash at banks	$ 16,977	$ 4,810
Short-term deposits	–	54,862
	$ 16,977	$ 59,672

Cash at banks earn interest at floating rates based on daily bank deposit rates. As of December 31, 2012, US $0.7 million (2011 – US $3.5 million) is included in cash at banks. The Company only deposits cash with major banks of high quality credit ratings.

6. TRADE AND OTHER RECEIVABLES

	2012	2011
Trade accounts receivable	$ 13,405	$ 22,724
Receivables from joint venturers	866	877
Allowance for doubtful accounts	(815)	(815)
Net accounts receivable	13,456	22,786
Royalty reimbursement from enhanced oil recovery incentive programs	3,082	240
Other receivables	170	289
	$ 16,708	$ 23,315

Aging of trade accounts receivables are as follows:

	2012	2011
Current	$ 13,255	$ 22,687
31 to 60 days	50	21
61 to 90 days	15	16
Over 90 days	85	–
	$ 13,405	$ 22,724

7. EXPLORATION AND EVALUATION ASSETS

At January 1, 2011	$ 74,606
Expenditures	29,079
Change in decommissioning provision	2,765
At December 31, 2011	106,450
Expenditures	27,857
Change in decommissioning provision	414
At December 31, 2012	$ 134,721

The Company's exploration and evaluation assets consist entirely 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 2012, 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 4. During the year ended December 31, 2012, the Company capitalized net operating revenues totaling a loss of $3.3 million (2011 – $0.4 million). The Company capitalized stock-based compensation of $0.4 million to exploration and evaluation assets during the year ended December 31, 2012 (2011 – $Nil). The Company did not capitalize any general and administrative costs in respect to exploration activities during the year ended December 31, 2012 (2011 – $Nil).

8. PROPERTY, PLANT AND EQUIPMENT

	Petroleum and natural gas properties	Corporate	Total
Cost			
At January 1, 2011	$ 573,772	$ 3,168	$ 576,940
Capital expenditures	163,423	132	163,555
Change in decommissioning provision	4,038	–	4,038
Disposals	(7,550)	–	(7,550)
At December 31, 2011	733,683	3,300	736,983
Capital expenditures	111,639	52	111,691
Change in decommissioning provision	2,786	–	2,786
Disposals	–	–	–
At December 31, 2012	$ 848,108	$ 3,352	$ 851,460
Accumulated depletion and depreciation			
At January 1, 2011	$ 271,725	$ 1,363	$ 273,088
Depletion and depreciation	61,028	290	61,318
Disposals	(4,821)	–	(4,821)
At December 31, 2011	327,932	1,653	329,585
Depletion and depreciation	69,324	252	69,576
Impairment	5,000	–	5,000
Disposals	–	–	–
At December 31, 2012	$ 402,256	$ 1,905	$ 404,161
Net book value			
December 31, 2011	$ 405,751	$ 1,647	$ 407,398
December 31, 2012	$ 445,852	$ 1,447	$ 447,299

The calculation of depletion for the year ended December 31, 2012 included estimated future development costs of $164 million (2011 – $209 million) associated with the development of the Company's proved plus probable reserves. The Company did not capitalize any general and administrative costs in respect to development activities during the year ended December 31, 2012 (2011 – $Nil).

The Company performed impairment test calculations at December 31, 2012 to assess whether the carrying value of the petroleum and natural gas properties were recoverable. As a result of lower heavy oil prices and well operating performance, an impairment loss of $5.0 million on certain Company minor CGUs (Long Coulee in Alberta and Salt Lake in Saskatchewan) was recognized in the Consolidated Statement of Comprehensive Income based on the difference between the fair value less costs to sell and the carrying amount of the CGUs. A one percent increase in the assumed discount rate would result in an additional impairment of $0.2 million while a ten percent decrease to the forward commodity price estimated would result in an additional impairment of $1.6 million.

The following represent the prices that were used in the December 31, 2012 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$)
2013	89.63	69.33	3.31	1.001
2014	89.93	74.57	3.72	1.001
2015	88.29	73.21	3.91	1.001
2016	95.52	80.17	4.70	1.001
2017	96.96	81.37	5.32	1.001
2018	98.41	82.59	5.40	1.001
2019	99.89	83.83	5.49	1.001
2020	101.38	85.08	5.58	1.001
2021	102.91	86.36	5.67	1.001
2022	104.45	87.66	5.76	1.001
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 2022 to the end of the reserve life.

9. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	2012	2011
Trade payables and accrued liabilities	$ 41,681	$ 44,571
Payables to joint venturers	483	1,408
Other payables	187	–
	$ 42,351	$ 45,979

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

10. CREDIT FACILITIES

At December 31, 2012 the Company's credit facilities consist of a $105 million syndicated revolving line of credit (2011 – $25 million) and a non-syndicated operating line of credit of $10 million (2011 – $Nil). The facilities are secured by a floating charge debenture and a general securities agreement 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, 2013. The facilities are also subject to annual reviews by the lenders and the next scheduled review is to be completed by May 31, 2013. In the event the lenders elected not to renew the credit facility during this borrowing base review, any amounts outstanding on the facilities would be due and payable in full by May 30, 2014.

The credit facility 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, 2012, no amounts were drawn under these facilities; however, the Company has issued a $20,000 letter of credit, which reduces the amount available for borrowing under the credit facilities.

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 3.5:1 at December 31, 2012 (2011 – 2.3:1) and is in compliance with this covenant at year end.

11. 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 $39.7 million (2011 – $32.7 million). The estimated net present value of the decommissioning liability was calculated using an inflation factor of 2% (2011 – 2%) and discounted using a risk-free rate of 2.25% (2011 – 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:

	2012	2011
Decommissioning liability, beginning of year	$ 30,420	$ 23,794
New liabilities recognized	3,214	9,008
Reduction in liabilities due to asset dispositions	(14)	(5,352)
Remediation costs incurred	(989)	(1,036)
Liabilities settled	–	(4)
Revaluation due to change in discount rate	–	3,148
Accretion expense	741	862
Decommissioning liability, end of year	$ 33,372	$ 30,420

12. SHARE CAPITAL

(a) Authorized

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

(b) Common Shares Issued

	Number of Shares	Attributed Value
Balance as at January 1, 2011	283,215,387	$ 858,610
Shares issued on exercise of warrants	355,124	213
Shares issued on exercise of stock options	1,231,500	3,383
Transferred from contributed surplus on exercise of stock options and warrants	–	1,700
Recognition of tax benefits of share issue costs incurred in prior periods	–	727
Balance as at December 31, 2011	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

(c) Warrants Outstanding

	Number of Warrants	Weighted Average Exercise Price ($)
Outstanding as at January 1, 2011	10,000,320	0.60
Exercised	(355,124)	0.60
Outstanding as at December 31, 2011	9,645,196	0.60
Exercised	(9,645,196)	0.60
Outstanding as at December 31, 2012	–	–

The warrants were issued as a result of the acquisition of BlackCore Resources Inc. in 2009. Each warrant allowed the holder to acquire, on or before January 8, 2013, one common share of the Company at $0.60.

(d) 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 summarizes stock options outstanding:

	Number of Options	Weighted Average Exercise Price ($)
Outstanding at January 1, 2011	14,969,998	2.20
Granted	3,179,500	5.26
Exercised	(1,231,500)	2.75
Forfeited	(112,333)	3.95
Expired	(277,000)	5.15
Outstanding at December 31, 2011	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

Options outstanding and exercisable as at December 31, 2012 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)
0.50 – 1.50	5,797,000	0.73	1.03	5,797,000	0.73	1.03
1.51 – 3.00	3,626,499	2.21	1.83	3,533,166	2.19	1.81
3.01 – 4.50	2,804,500	3.65	4.48	50,000	3.06	2.67
4.51 – 6.00	4,795,000	4.98	3.42	2,271,873	5.03	3.23
6.01 – 7.66	360,000	6.94	3.43	123,336	6.94	3.43
	17,382,999	2.81	2.46	11,775,375	2.07	1.72

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, 2012, 3,079,500 options were granted (2011 – 3,179,500). The fair value of these options was estimated using the following weighted average assumptions:

Assumptions	Year Ended December 31, 2012	Year Ended December 31, 2011
Risk free interest rate (%)	1.2	1.2
Expected life (years)	3.2	3.0
Expected volatility (%)	53.9	66.1
Forfeiture rate (%)	14.6	0.0
Weighted average fair value of options	$ 1.43	$ 2.35

(e) Stock-based Compensation

Stock-based compensation of $6,016,000, net of recoveries of $286,000, has been recorded in the consolidated statements of comprehensive income for the year ended December 31, 2012 (2011 – $6,353,000).

(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:

	2012	2011
Net comprehensive income	$ 45	$ 18,911
Weighted average number of common shares – basic	286,130	283,976
Dilutive effect:		
Outstanding options	6,528	8,526
Outstanding warrants	–	8,688
Weighted average number of common shares – diluted	292,658	301,190
Basic income per share	$ 0.00	$ 0.07
Diluted income per share	$ 0.00	$ 0.06

The Company used an average market price of $3.79 (2011 – $5.91) per share to calculate the dilutive effect of stock options. In 2012, 6,531,106 options were anti-dilutive (2011 – 307,562) and were not included in the calculation of diluted net income per share.

13. INCOME TAXES

(a) Deferred 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:

	2012	2011
Income (loss) before income taxes	$ 1,901	$ 13,564
Corporate income tax rate	25.95%	26.13%
Computed income tax expense	$ 493	$ 3,545
Increase (decrease) resulting from:		
Change in unrecognized deferred income tax assets	2,225	–
Recognition of previously unrecognized tax assets	–	(10,479)
Non-deductible stock-based compensation expense	1,561	1,660
Foreign exchange	(7)	(456)
Change in enacted tax rates	(2,340)	383
Current income tax recovery	(76)	–
Income tax expense (recovery)	$ 1,856	$ (5,347)

(b) Deferred tax asset:

At December 31, 2012 a deferred tax asset of $4.1 million (2011 – $6.1 million) has 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:

	2012	2011
Property, plant and equipment	$ (66,737)	$ (52,240)
Decommissioning liability	8,271	7,859
Other	–	561
Share issue costs	448	727
Non-capital losses	62,160	49,167
Net future tax asset	$ 4,142	$ 6,074

Factors that influenced the decision to recognize the deferred tax asset include positive net income in 2012 and a significant increase in proved and probable reserves and the associated forecast cash flows.

(c) Unrecognized deferred tax assets:

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

	2012	2011
Property, plant and equipment	$ 13,961	$ 13,620
Non-capital losses	15,611	13,745
Capital losses	144	126
	$ 29,716	$ 27,491

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 had no current tax payable in 2012 or 2011.

14. SALARY AND OTHER COMPENSATION EXPENSES

(a) Employee compensation expenses

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

	Year Ended December 31, 2012	Year Ended December 31, 2011
Production expense (1)	$ 959	$ 1,273
General and administrative expense	4,841	5,407
Stock-based compensation	6,016	6,353
	$ 11,816	$ 13,033

(1) Excludes compensation paid to contractors and consultants.

(b) Key management compensation

Key management includes the Company's directors and officers. At December 31, 2012, directors and senior management consisted of 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, 2012	Year Ended December 31, 2011
Short-term employee benefits	$ 1,198	$ 1,030
Stock-based compensation	1,375	1,961
	$ 2,573	$ 2,991

15. COMMITMENTS AND CONTINGENCIES

	2013	2014	2015	2016	2017	Thereafter
Operating leases (1)	$ 1,511	$ 1,760	$ 1,682	$ 1,336	$ –	$ –
Electrical service agreement (2)	119	119	119	119	119	2,345
Drilling rig commitment (3)	2,688	–	–	–	–	–
	$ 4,318	$ 1,879	$ 1,801	$ 1,455	$ 119	$ 2,345

(1) The Company has 45 months remaining on an operating lease for office space as at December 31, 2012. 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 or any of the subtenants of a portion of the space are unable to fulfill their lease obligation, BlackPearl would be required to pay a maximum additional amount of $14.2 million (including an estimate for operating costs) over the next 45 months.

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

(3) The Company has contracted drilling rig services over the next year. In the event that the Company does not utilize the minimum contracted days, the Company would be obligated to pay the rig operator a variable rate based on days not utilized under the contracts. The payments included herein assumes no additional drilling days used.

16. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments as at December 31, 2012 include cash and cash equivalents, trade and other receivables and accounts payable and accrued liabilities. The Company manages its risk through its policies and procedures, but the Company generally has not used derivative financial instruments to manage these risks.

(a) Fair value of financial instruments

	As at December 31, 2012		As at December 31, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial Assets				
Held-for-trading:				
MAV II Notes	–	–	$ 2,795	$ 2,795
Loans and receivables:				
Cash and cash equivalents	$ 16,977	$ 16,977	$ 59,672	$ 59,672
Trade and other receivables	$ 16,708	$ 16,708	$ 23,315	$ 23,315
Financial liabilities				
Financial liabilities at amortized cost:				
Accounts payable and accrued liabilities	$ 42,351	$ 42,351	$ 45,979	$ 45,979

The fair values of the Company's financial instruments have been calculated using the following methods:

(i) The carrying value of cash and cash equivalents, trade other receivables and accounts payable and accrued liabilities approximates their fair value amounts due to the short-term nature of the instruments.

(ii) The fair value of the investment in MAV II notes have been 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 hierarchy has the following levels:

a. Level 1: fair value is based on quoted prices (unadjusted) in active markets for identical assets or liabilities;

b. 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 (ie. as prices) or indirectly (ie. derived from prices); and

c. Level 3: fair value is based on inputs for the asset or liability that are not based on observable market data (unobservable inputs).

The investment in MAV II notes has been valued using Level 2 of the hierarchy. The fair value of the investment was determined by quoted prices that were determined outside of what would be considered an active market.

(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 counterpart and entering into relationships with larger purchasers with established credit history. During 2012, the Company did not experience any collection issues with its marketers. At December 31, 2012, over 77 percent of total accounts receivables are for crude oil sales revenue.

At December 31, 2012, the Company had a $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, 2012 the amount receivable from joint venture partners was $866,000 (2011 – $877,000). 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, 2012 and 2011, accounts receivable includes an allowance for doubtful accounts of $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, 2012, the Company held $17.0 million (2011 – $59.7 million) in cash at various major financial institutions throughout Canada and the USA; as well as $Nil (2011 – $2.8 million) in investments in MAV II Notes. At December 31, 2012, two Canadian financial institutions held over 98% of our cash and short-term deposits.

(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, credit facilities and equity offerings to fund its capital requirements.

The Company manages this risk by maintaining a balance sheet with minimal use of long-term debt. As at December 31, 2012 the Company had an undrawn $115 million credit facility (note 10) and a working capital deficiency of $7.8 million (2011 – working capital of $37.8 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	$ 42,351	–	–

(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, 2012, 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 $82,000 (2011 – $542,000) 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, 2012, the Company has not entered into any fixed rate contracts to mitigate its currency risks.

As at December 31, 2012, the Company held $US $702,000 (2011 – $3,490,000) cash and cash equivalents, $US $Nil (2011 – $1,000) trade and other receivables and $US $950,000 (2011 – $15,000) accounts payable and accrued liabilities.

As at December 31, 2012, 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 $25,000 lower (2011 – $348,000 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 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 2012 the Company did not use derivative financial instruments to manage its exposure to this risk.

(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, 2012, the Company's $115 million available credit facilities were undrawn. Additional funding will be required to continue to develop exploration and evaluation assets as the existing credit facilities 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 2.0; 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.

17. SUPPLEMENTARY INFORMATION

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

	Year ended December 31, 2012	Year ended December 31, 2011
Cash interest paid	$ 827	$ 132
Cash taxes paid (refund)	$ (6)	$ –

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

	Year ended December 31, 2012	Year ended December 31, 2011
Accretion of decommissioning liabilities	$ 741	$ 862
Interest and bank charges	827	132
	$ 1,568	$ 994

(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, 2012	Year ended December 31, 2011
Changes in non-cash working capital:		
Trade and other receivables	$ 6,607	$ (3,764)
Prepaid expenses and deposits	(61)	66
Income and other taxes receivable	–	2,083
Accounts payable and accrued liabilities	(3,689)	(2,111)
Change in working capital	$ 2,857	$ (3,726)
Relating to:		
Operating activities	$ (1,744)	$ (1,284)
Investing activities	4,601	(2,442)
Change in non-cash working capital	$ 2,857	$ (3,726)