BLACKPEARL RESOURCES INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2012

Dated February 26, 2013

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GLOSSARY OF TERMS

In this Annual Information Form, the following words and phrases have the following meanings, unless the context otherwise requires.

"**ABCA**" means the *Business Corporations Act* (Alberta), and the regulations thereunder, as amended from time to time;

"**Annual Information Form**" means this Annual Information Form for the year ended December 31, 2012;

"ASP" means alkali surfactant polymer;

"**BlackCore**" means BlackCore Resources Inc.;

"**BlackPearl Shares**" means the common shares in the capital of BlackPearl;

"Board" or "Board of Directors" means the board of directors of BlackPearl, as constituted from time to time;

"**CBCA**" means the *Canada Business Corporations Act*, and the regulations thereunder, as amended from time to time;

"**CSS**" means cyclic steam stimulation, an in-situ process used to recover bitumen from oil sands;

"**EOR**" means enhanced oil recovery methods that use the injection of fluids such as hydrocarbons, carbon dioxide, nitrogen, steam, chemicals or other approved substances for the recovery of petroleum resources;

"ERCB" means Energy Resources Conservation Board (Alberta);

"IFRS" means International Financial Reporting Standards;

"**IOGC**" means Indian Oil and Gas Canada, a special operating agency within Aboriginal Affairs and Northern Development Canada;

"**NEB**" means the National Energy Board;

"**Newmex**" means Newmex Minerals Inc.;

"**NI 51-101**" means National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* of the Canadian Securities Administrators;

"**NI 51-102**" means National Instrument 51-102 *Continuous Disclosure Obligations* of the Canadian Securities Administrators;

"**NI 52-110**" means National Instrument 52-110 *Audit Committees* of the Canadian Securities Administrators;

"**Pearl E&P**" means the company formed as a result of the amalgamation of Nevarro Energy Ltd., Pan-Global Energy Ltd., Atlas Energy Ltd., Cipher Exploration Ltd., Watch Resources Ltd. and Coda Holdings Corp. under the ABCA;

"**SAGD**" means steam assisted gravity drainage, an in situ process used to recover bitumen from oil sands;

"SDRs" means Swedish Depository Receipts;

"**Serrano**" means Serrano Energy Ltd.;

"SOR" means steam to oil ratio;

"**Sproule**" means Sproule Unconventional Limited, independent petroleum consultants of Calgary, Alberta;

"**Sproule Report**" means, collectively, the report prepared by Sproule dated February 1, 2013 evaluating the oil and gas reserves attributable to BlackPearl's properties as at December 31, 2012 and the contingent resource reports prepared by Sproule dated February 1, 2013 for the Blackrod, Onion Lake and Mooney properties as at December 31, 2012;

"**TLE**" means Treaty Land Entitlement; and

"**TSX**" means the Toronto Stock Exchange.

ABBREVIATIONS

General

AECO	Intra-Alberta Nova Inventory Transfer Price (NIT net price)
API	American Petroleum Institute
API gravity	An indication of the specific gravity of crude oil measured on the API gravity scale, which is a measure of how heavy or light a petroleum liquid is compared to water
Boe	Barrel of oil equivalent on the basis of 6 Mcf to 1 Bbl. Boes 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 does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalency conversion of 6 to 1, utilizing a Boe conversion ratio of 6 Mcf:1 Bbl may be misleading as an indication of value.
Boe/d	Barrel of oil equivalent per day
m^3	Cubic metres
WTI	West Texas Intermediate light sweet crude oil at a reference sales point in Cushing, Oklahoma, a common benchmark for crude oil

Oil and Natural Gas Liquids

Bbl	Barrel
Bbls	Barrels
Bbls/d	barrels of oil per day
Mbbls	thousand barrels
NGLs	natural gas liquids

Natural Gas

Bcf	billion cubic feet
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMcf	million cubic feet
MMcf/d	million cubic feet per day

CONVERSIONS

To Convert From	To	Multiply By
Acres	Hectares	0.405
Bbls	Cubic metres	0.159
Cubic metres	Bbls	6.290
Cubic metres	Cubic feet	35.494
Feet	Metres	0.305
Hectares	Acres	2.471
Kilometres	Miles	0.621
Mcf	Cubic metres	28.174
Metres	Feet	3.281
Miles	Kilometres	1.609

INTRODUCTORY INFORMATION

Except as otherwise indicated or unless the context otherwise require, the terms "BlackPearl", the "Company", "we", "our" and "us" refer to BlackPearl Resources Inc. and its subsidiaries.

Unless otherwise indicated, all financial information included and incorporated by reference in this Annual Information Form is determined using IFRS.

Unless otherwise indicated, all dollar amounts are expressed in Canadian dollars, all references to "dollars" or "$" are to Canadian dollars and all references to "US$" are to United States dollars. "$M" refers to thousands of dollars.

FORWARD-LOOKING STATEMENTS

This Annual Information Form 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", "predict", "targeting", "seek", "intend", "could", "potential", "scheduled", "should", "outlook" or similar words suggesting future outcomes. In particular, and without limitation, this Annual Information Form contains forward-looking statements pertaining to the following:

- business plans and strategies;
- capital expenditure programs, including the drilling of a pilot well pair at Blackrod, and the ASP flood at Mooney;
- the estimated quantity of reserves and contingent resources;
- drilling program for 2013 - 2014
- net present values of future net revenues from reserves and contingent resources;
- anticipated production levels and API gravity of production;
- projections of oil and gas prices;
- projections of future capital and operating costs, including the estimated capital costs for the Blackrod and Onion Lake thermal projects;
- estimated abandonment and reclamation costs;
- expectations regarding the ability to raise capital and continue development of our properties;
- commercial production rates for the Blackrod SAGD pilot well;
- anticipated timing of regulatory applications and approvals, including the Blackrod and Onion Lake thermal projects, and EOR royalty status on the Mooney field;
- anticipated timing of re-pressurization of the Mooney reservoir;
- anticipated timing when the Company will become cash taxable;
- construction and completion of facilities, including the construction of oil processing facilities at Onion Lake and pipeline infrastructure at Mooney; and
- treatment under governmental regulatory and royalty regimes and tax laws.

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

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

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

Undue reliance should not be placed on these forward-looking statements. Readers are cautioned that the actual results achieved will vary from the information provided herein and the variations could be material. Readers are also cautioned that the foregoing list of assumptions, risks and factors is not exhaustive. Consequently, there is no assurance by the Company that actual results achieved will be the same in whole or in part as those set out in the forward-looking statements. Furthermore, the forward-looking statements contained in this Annual Information Form 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.

BLACKPEARL RESOURCES INC.

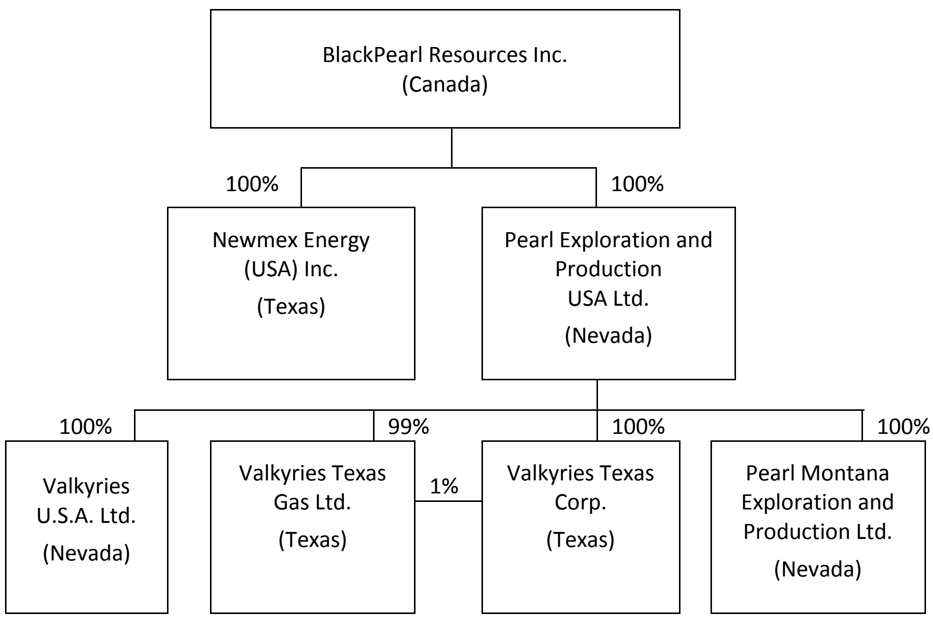
GENERAL

BlackPearl is engaged in the exploration for, and the acquisition, development and production of, oil and natural gas. The Company's properties are located in Canada and the United States. BlackPearl's registered and head office is located at 700, 444 – 7th Avenue S.W., Calgary, Alberta, T2P 0X8.

BlackPearl was incorporated under the ABCA as "Kilo Gold Mines Ltd." on October 15, 1984. On April 22, 1998, Kilo Gold Mines Ltd. changed its name to Newmex Minerals Inc. On July 22, 2002, Newmex Minerals Inc. continued under the CBCA. On February 28, 2006, Newmex Minerals Inc. changed its name to Pearl Exploration and Production Ltd. On May 8, 2009, Pearl Exploration and Production Ltd. changed its name to BlackPearl Resources Inc. On January 1, 2010, BlackPearl Resources Inc. was amalgamated with Pearl E&P Canada Ltd., its wholly-owned Canadian subsidiary, and the amalgamated company was named BlackPearl Resources Inc.

Corporate Structure

The following diagram describes the inter-corporate relationships among the Company and each of its subsidiaries, where each principal subsidiary was incorporated or formed, and the percentage of votes attaching to all voting securities of each subsidiary beneficially owned, or controlled or directed, directly or indirectly, by BlackPearl as at December 31, 2012.



GENERAL DEVELOPMENT OF OUR BUSINESS

Overview

BlackPearl's principal business is the acquisition, development and production of heavy oil and bitumen. Substantially all of BlackPearl's oil and gas interests are located in Canada.

The majority of the Company's current production is from conventional heavy oil projects; however, the Company is actively developing oil projects that utilize SAGD extraction and EOR methods. BlackPearl is not engaged in oil sands mining.

Three Year History

The following describes the development of BlackPearl's business over the last three years.

Year Ended December 31, 2010

On March 29, 2010, the Company acquired the remaining 20% working interest in the Blackrod area, located in the Athabasca oil sands, from Serrano for $21 million. The acquisition resulted in BlackPearl having a 100% working interest in the Blackrod area lands.

On May 11, 2010, the Company issued 10,350,000 BlackPearl Shares at a price of $2.90 per share, for aggregate gross proceeds of approximately $30 million.

On October 18, 2010, the Company announced it had received approval from the ERCB to proceed with development of the first phase of its ASP flood at Mooney and that the ERCB approved BlackPearl's application for the construction and operation of its SAGD pilot project at Blackrod.

On December 7, 2010, the Company issued 10,000,000 BlackPearl Shares at a price of $5.00 per share, for aggregate gross proceeds of $50 million.

Year Ended December 31, 2011

In 2011, the Company completed construction of the facilities for the SAGD pilot project at Blackrod, in northern Alberta. Steam injection commenced in June, and after a warm-up period, the producing well was put on pump and production commenced.

BlackPearl also initiated the first phase of its ASP flood at Mooney in 2011.

Year Ended December 31, 2012

In May 2012, BlackPearl announced that the Company's banking syndicate had increased the Company's credit facilities from $25 million to $115 million.

In June 2012, the Company announced that it had filed an 80,000 Bbls/d commercial development application with the ERCB and Alberta Environment for its Blackrod SAGD Project in northern Alberta. The first phase of this project is planned for 20,000 Bbls/d. The filing of the commercial development application is the culmination of three years of delineation drilling, source water testing, cap rock integrity testing and a successful SAGD pilot operation that has reached commercial production rates after 10 months of testing. The commercial application included extensive public consultation and numerous environmental studies, including baseline testing for air, sound, water and surface disturbance and a pro-active program to monitor and mitigate environmental impacts. Sproule completed an update to the proved plus probable reserves and contingent resource assessment for the Blackrod project and assigned 180 million Bbls of proved plus probable reserves to the first phase of the commercial project. In addition, Sproule assigned 476 million Bbls of contingent resources (best estimate) to the remainder of the Blackrod SAGD Project.

In July 2012, BlackPearl filed an amendment to its application with Saskatchewan Energy and Resources for a 12,000 Bbls/d SAGD thermal project at Onion Lake.

The Company obtained approval of a secondary listing of its SDRs on NASDAQ OMX Stockholm ("Main Market"), and the SDRs commenced trading on the Main Market on November 6, 2012.

DESCRIPTION OF OUR BUSINESS

Heavy Oil and Bitumen Industry

Heavy oil is generally classified as oil with an API gravity of 25° or less and which can be produced commercially by natural flow. This is sometimes referred to as "CHOPS" – Cold Heavy Oil Production with Sand. CHOPS produces large quantities of oily sand and other wastes. The cost to remove these wastes and well work-overs are major cost components in operating a CHOPS well. Bitumen and some heavy oil are highly viscous and they will not flow to a well bore on their own accord in commercial quantities. This is typical in the oil sands region in northern Alberta. This highly viscous bitumen and heavy oil can be categorized as being either a surface-mineable or an in situ extractable deposit. With respect to the former process, the heavy oil or bitumen is recovered through mining and ultimately upgraded to synthetic oil. Generally, if the oil sands deposit is less than 100 metres deep, it is usually extracted using a mining operation. If the deposit is greater than 100 metres, the heavy oil or bitumen is usually extracted using an in situ recovery method. The heavy oil or bitumen is encouraged to flow to well bores through the application of external energy, such as heat. The two most common in situ recovery methods in the Canadian oil sands include SAGD and CSS. SAGD technology involves drilling steam injection and oil production wells (generally horizontal wells). Steam is injected in the upper well at low pressure where it significantly reduces the viscosity of the heavy oil or bitumen which allows it to flow downward to the second well where it is collected and pumped to the surface. CSS technology involves injecting steam and producing heavy oil or bitumen from the same well bore. Steam is injected at high pressure for a period of time, allowed to soak and then the well is converted to production. This cycle is repeated a number of times. Historically, recovery rates have been higher using SAGD technology. Most in situ recovery methods use natural gas to produce steam that is injected into the reservoir. As a result, one of the largest input costs in a SAGD or CSS operation is often the cost of natural gas.

Light Oil / Heavy Oil Price Differentials

Processing heavy oil and bitumen is more expensive than processing conventional light oil and it yields less high value products compared to refining light oil. Accordingly, producers of heavy oil and bitumen receive lower wellhead prices. The difference between prices for heavy oil and light oil (such as WTI oil with an API gravity of 40°) is commonly referred to as the "light/heavy price differential". In order to calculate "light/heavy price differentials", the heavy oil prices are often derived from the Western Canada Select at Hardisty, Alberta or Lloyd Blend at Hardisty, Alberta published prices. Western Canada Select is comprised of Canadian bitumen and heavy oils blended with sweet synthetic and condensate diluents and Lloyd Blend is a heavy, sour crude oil.

Volatility in the light/heavy price differential is a result of availability of supply, seasonal demand, pipeline constraints and heavy oil conversion capacity of refineries. See "Risk Factors – Volatility of Oil and Natural Gas Prices".

Diluent

Heavy oil or bitumen is usually blended with a lighter hydrocarbon stream referred to as "diluent" to improve its pipeline flow characteristics by reducing the viscosity. The volatility in diluent prices can have a significant effect on the wellhead price of heavy oil and bitumen. The most commonly used diluent for the production of heavy oil and bitumen in western Canada is condensate, but synthetic crude oil is also used.

Accessibility to Transport

Canada produces more heavy oil and bitumen than it can refine, therefore, Canadian heavy oil is dependent on demand and refining capacity from the U.S. Midwest, Rocky Mountain and Gulf Coast regions. Pipeline constraints to these markets can lead to wide fluctuations in the light/heavy price differential and ultimately the netback received by heavy oil producers. Currently, North American pipeline capacity is tight which has impacted oil prices received by producers. Increasing volumes of crude oil are being transferred by rail to alleviate some of the congestion in pipeline systems. There are currently proposals submitted to the regulatory authorities in Canada and the U.S. to build heavy oil pipeline capacity from Alberta to the U.S. Gulf Coast, a major heavy oil refining hub, and to the west coast of British Columbia for export.

Seasonality of Markets

Generally, demand for heavy oil and bitumen is greater in the summer months due to higher asphalt demand for road construction programs. As a result, the light/heavy price differential will typically narrow in the summer months and widen during the winter, resulting in higher heavy oil and bitumen prices during those summer periods.

Description of Our Properties

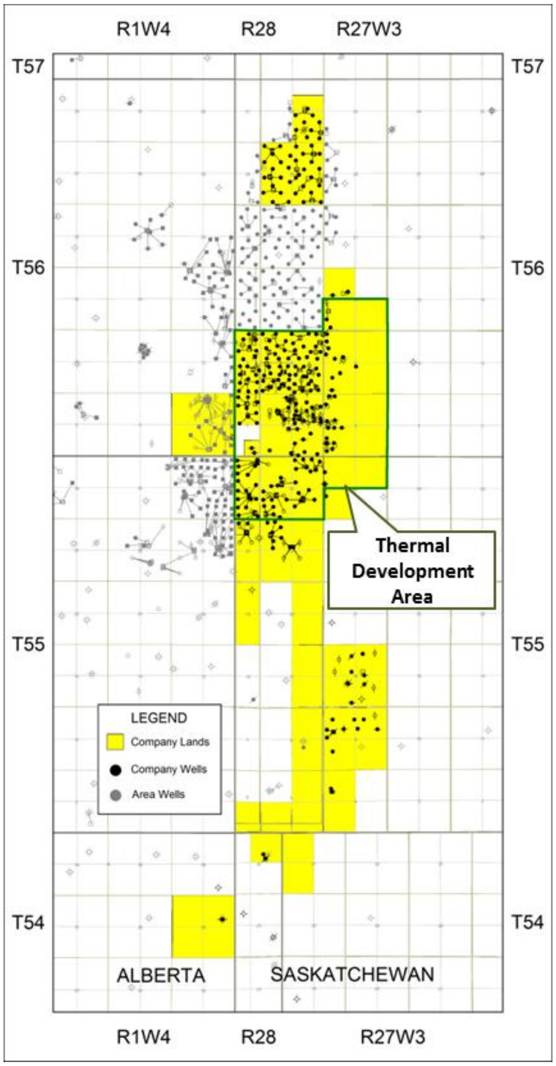
The following map outlines the location of our major assets as at December 31, 2012.

Core Area Properties – Canada

Onion Lake Heavy Oil Project – Saskatchewan

Onion Lake is a conventional heavy oil property that also has the potential for thermal development on a portion of the lands. BlackPearl originally acquired its interest in Onion Lake when it acquired Pan-Global Energy Ltd. in 2006. BlackPearl holds working interests, ranging from 50% to 100%, in approximately 19 net sections of land (12,231 net acres) located in the Onion Lake area of Saskatchewan. BlackPearl is the operator of the field which is located on the Onion Lake First Nation reserve, along the Saskatchewan/Alberta border near Lloydminster. The geological formations of interest are the Cretaceous Lower Cummings and Upper Cummings at a depth of approximately 650 metres.

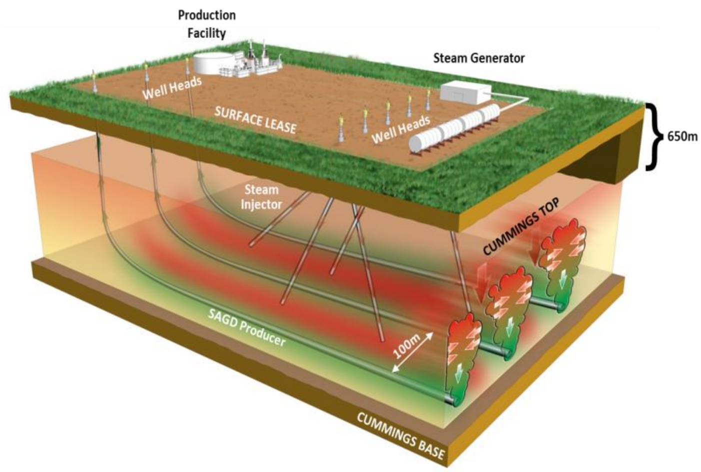
ONION LAKE AREA MAP



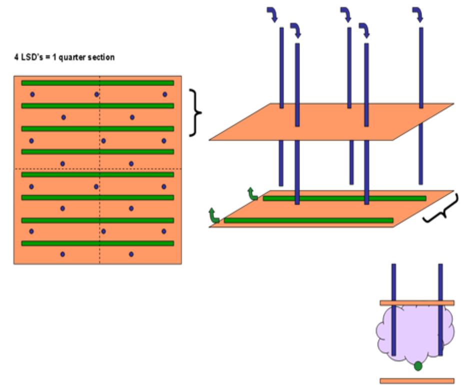
During 2012, BlackPearl produced an average of 5,947 Boe/d at Onion Lake (BlackPearl's working interest, before royalties), primarily heavy oil with an API gravity between 10° and 11°. This represented approximately 63% of BlackPearl's total oil and gas production in 2012. As at December 31, 2012, there were 118 heavy oil producing wells on the property.

Since 2006, BlackPearl has drilled over 300 conventional wells on the Onion Lake property, 43 of which were drilled in 2012. In addition to conventional drilling, due to reservoir thickness, a portion of the lands at Onion Lake are amenable to thermal development in the Lower Cummings formation. In 2009, BlackPearl undertook a two well thermal pilot on the property. The reservoir in this area of the Onion Lake lands ranges between 10 and 25 metres thick, which makes it suitable for SAGD development. In 2011, BlackPearl filed a 12,000 Bbls/d SAGD commercial development application with the Saskatchewan government and Indian Oil and Gas. The application was amended in 2012 to include additional lands for development. Approval of the thermal application is anticipated in the first half of 2013. For SAGD development at Onion Lake the vertical wells used for primary development are expected to be converted to steam injectors. Horizontal wells would then be drilled for oil production. Steam, water and oil handling facilities would also have to be constructed. The thermal project is expected to produce 9° to 11° API oil. BlackPearl has not determined when it would initiate SAGD development at Onion Lake.

PLANNED SAGD PROCESS



INJECTOR-PRODUCER DESIGN

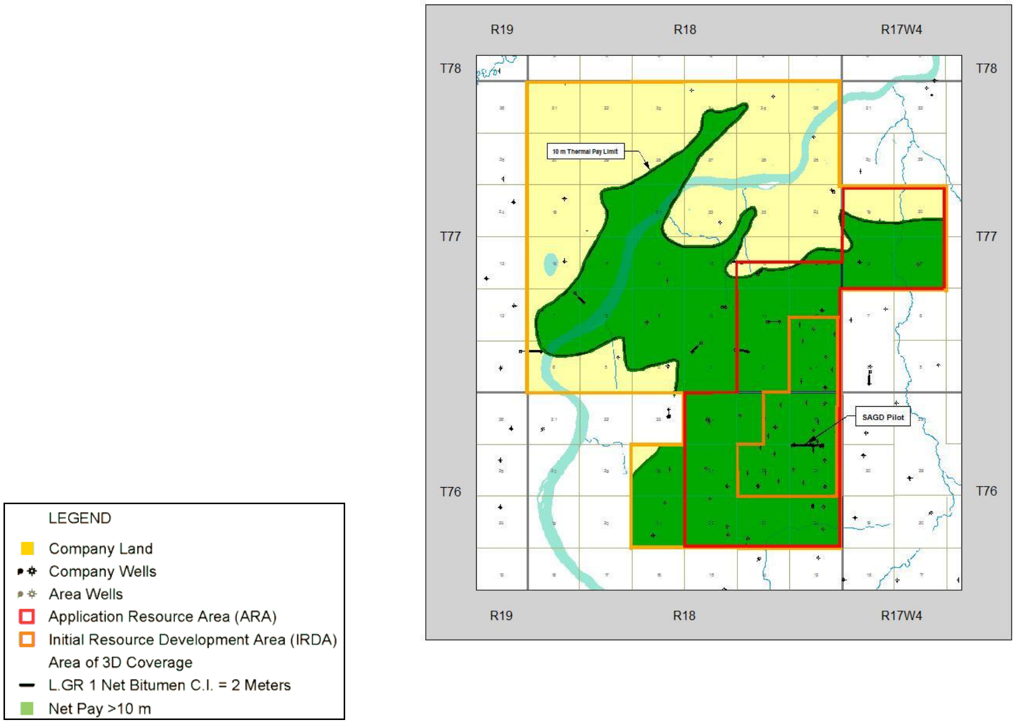


BlackPearl does not have any existing oil processing facilities at Onion Lake, and therefore production from the area is currently trucked to third party facilities or pipeline terminals. Construction of these facilities is expected to occur when we transition to SAGD thermal development.

At December 31, 2012, Sproule assigned proved plus probable reserves of 12.5 million Boe to the Onion Lake area (BlackPearl's working interest, before royalties). All of the reserves recognized by Sproule relate to conventional operations. In addition to the proved and probable reserves, at December 31, 2012, Sproule assigned 70 million Bbls of contingent resource (best estimate) to the Onion Lake area (BlackPearl's working interest, before royalties), of which 67 million Bbls are related to thermal development. See "Statement of Reserves and Contingent Resources Data and Other Oil and Gas Information".

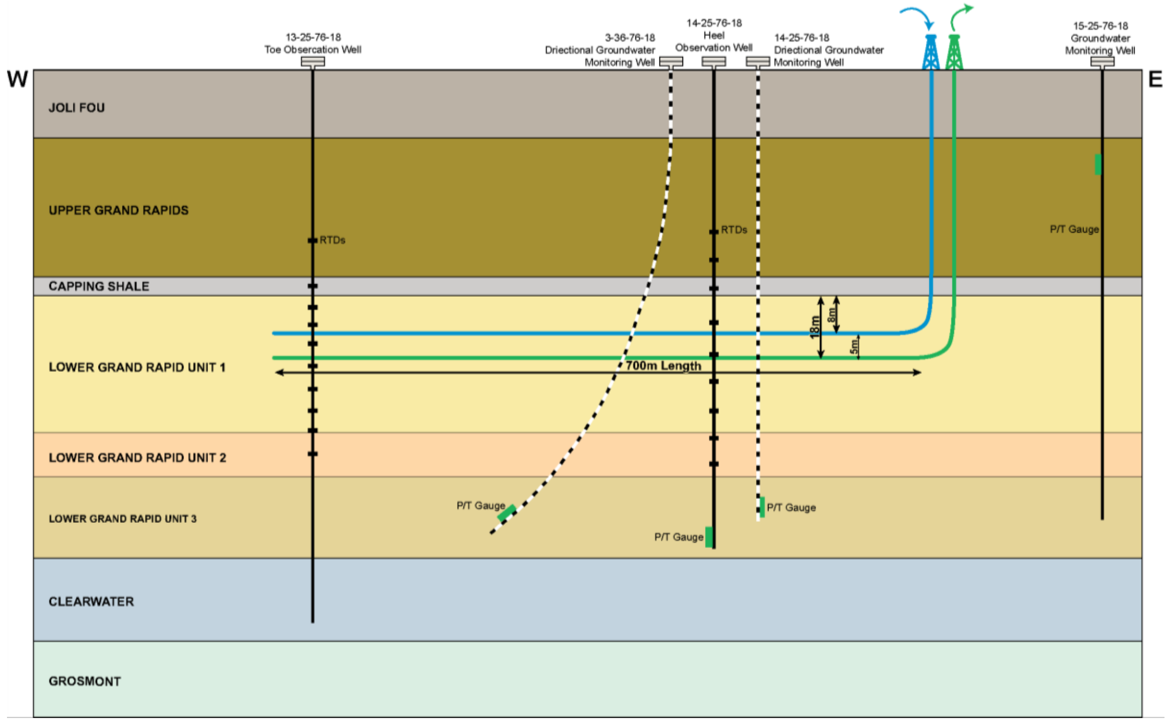
Blackrod SAGD Project – Alberta

Blackrod is an in situ (SAGD) oil sands project located south of Fort McMurray, in the Athabasca oil sands region of northern Alberta. BlackPearl initially acquired, through Crown land sales, a 35% working interest in the Blackrod lands in 2007. In 2008 and 2009, the Company increased its working interest to 80% as a result of acquiring interests from its arms-length partners. In 2010, BlackPearl acquired the remaining 20% interest in the Blackrod lands for $21 million and became the operator of the project. BlackPearl holds oil sands leases on approximately 54 sections (36,480 acres) of land in the Blackrod area.



The geological formation of interest is the Cretaceous Lower Grand Rapids at a depth of approximately 300 metres. The Lower Grand Rapids formation is a shoreface sand which was deposited in a broad coastline setting. This depositional setting allowed for a large, regionally consistent reservoir. The Lower Grand Rapids reservoir sand ranges in thickness from 8 to 28 metres. Bitumen saturation is between 50% and 75%. The Lower Grand Rapids is stratigraphically equivalent to known producing reservoirs in the Sparky, General Petroleum and Rex intervals within the Manville Group.

In 2009, the Company filed an application with regulatory authorities to undertake a single well pair SAGD pilot on the property. The purpose of the pilot was to demonstrate the use of SAGD technology to produce bitumen from the Lower Grand Rapids on the Blackrod lands. The pilot data was used to better understand the reservoir deliverability and optimum operating methods. The Company's SAGD recovery scheme was approved by the ERCB in late 2010. The horizontal well pair was drilled in the fourth quarter of 2010 and construction of facilities commenced shortly thereafter and was completed in the spring of 2011. Steam injection was initiated in June 2011 and following a warm-up period, the well was put on pump in September 2011. The pilot consists of a single SAGD horizontal well pair, water source and disposal wells, observation wells, water monitoring wells and a central facility consisting of water treatment and steam generation equipment and other associated facilities. In order to access the lands, BlackPearl acquired an existing logging road in the area and upgraded the road to facilitate oil and gas operations. The road is approximately 31 kilometres and runs from Highway 63 to the central facility site. Non-potable water to generate steam comes from the Grosmont formation. Emulsion (raw crude bitumen and water) produced from the pilot is trucked from the central facility location to third party oil processing facilities and pipeline terminals.



In 2012, production from the 700 metre long pilot well reached 400 Bbls/d with a steam oil ratio (SOR) of just under 3. The pilot was taken down in May 2012 for facility inspection and well-servicing. When the well was brought back on production in June 2012 we began testing alternate operating strategies in an effort to better understand the optimal way to operate these wells and to potentially incorporate these strategies in the final commercial development design.

In 2013, we plan to drill a second pilot well pair at Blackrod. The second well pair will be drilled slightly deeper in the reservoir and will be longer than the original pilot well pair, approximately 950 metres, to access more of the resource. It is expected that this well pair will be similar to what we expect to drill for the commercial development of the property.

In May 2012, BlackPearl filed an 80,000 Bbls/d commercial development application with the ERCB and Alberta Environment for its Blackrod SAGD Project in northern Alberta. The project will likely be developed in phases. The first phase of this project is planned for 20,000 Bbls/d. Regulatory approval for similar types of projects by other companies has typically taken 18 to 24 months.

The bitumen quality at Blackrod ranges from 8° to 10° API. The viscosity of the bitumen ranges from approximately 150,000 centipoise at the top of the reservoir, increasing with depth to greater than 1,000,000 centipoise. Two major sales oil and diluent pipeline systems are in close proximity to the Blackrod lands.

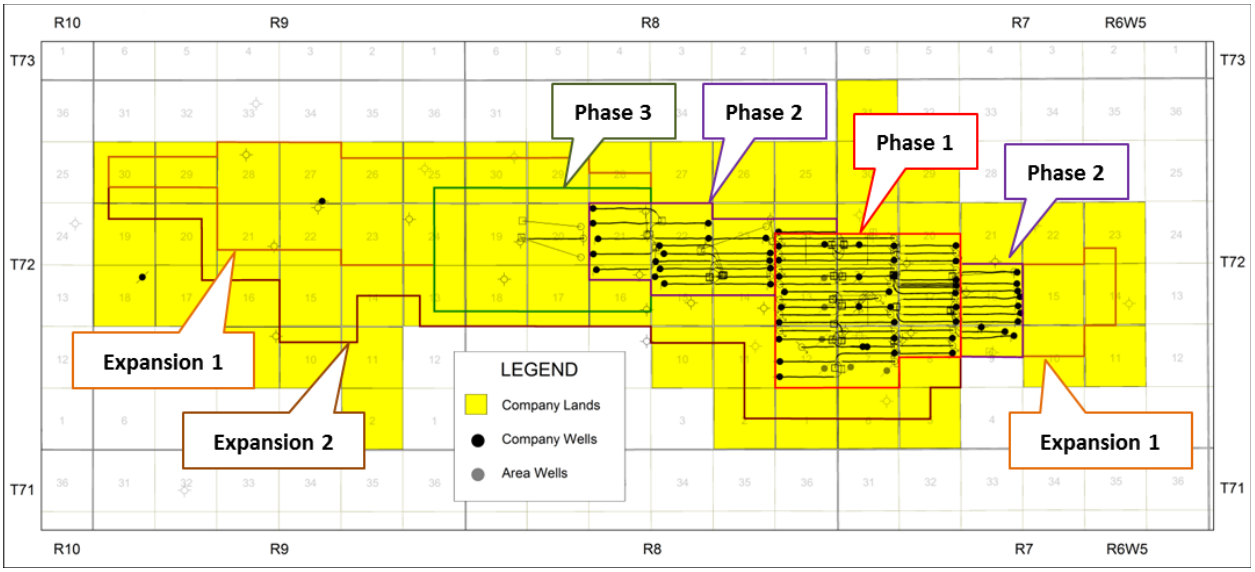
Blackrod is located in a designated oil sands region and BlackPearl has received approval for oil sands royalty treatment for the Blackrod pilot. Royalties on the project are expected to be between 1% and 9% of gross revenues until the project recovers all costs. After payout of project costs, the royalties are expected to be between 25% to 40% of net revenues. Additional regulatory approvals will be required when we initiate commercial development of Blackrod.

As at December 31, 2012, Sproule assigned 182 million Bbls of proved plus probable reserves (BlackPearl's working interest, before royalties) to the pilot operations and the first phase of commercial development of the project. In addition, Sproule has assigned 476 million Bbls of contingent resource (best estimate) to the remainder of the Blackrod SAGD Project. See "Statement of Reserves and Contingent Resources Data and Other Oil and Gas Information".

Mooney Heavy Oil Project – Alberta

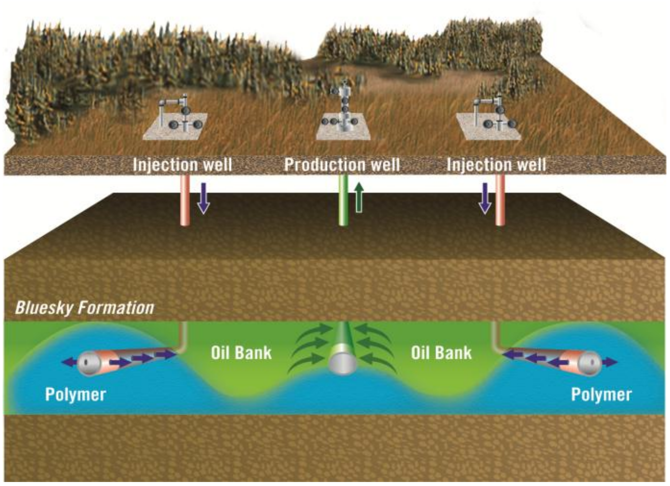
Mooney is a conventional heavy oil property located in north-central Alberta. BlackPearl has a 100% working interest in approximately 90 sections (57,920 acres) in the Mooney field. The Mooney field produces mainly from the Cretaceous Bluesky sand formation, which is at a depth of approximately 900 metres.

MOONEY AREA MAP



BlackPearl acquired its interest at Mooney when it acquired Atlas Energy Ltd. in 2006. The field was initially developed for conventional production using horizontal wells. A waterflood was attempted in 2006; however, it only recovered an additional 2% to 3% of the oil in place. The Company believed the performance of the Mooney field could be further enhanced through ASP flooding. ASP flooding involves adding a polymer chemical to the water to thicken it. The addition of alkali and surfactant chemicals reacts with the natural acidity of the oil to create an in situ "soap" to mobilize additional reservoir oil. This water and chemical mix is then injected to initially re-pressurize the reservoir and then sweep additional oil to the producing wells. A three well polymer pilot, initiated in 2008 and operated for approximately 14 months, taking recoveries to approximately 18% of the oil in place. Conventional recovery rates without ASP flooding would likely be 3% to 5%. As a result of the success of the polymer pilot, in late 2009, the Company filed a development application with the ERCB to commence a commercial ASP flood at Mooney. ERCB approval to proceed with phase one of our commercial ASP flood was received in late 2010 and field construction of the chemical and water handling facilities commenced immediately thereafter. During the implementation of phase one, twenty-five of the existing wells were shut-in and converted to ASP injectors. ASP injection commenced in the third quarter of 2011. Initial re-pressurization of the reservoir was expected to take 18 to 24 months.

ASP FLOOD SCHEMATIC



In 2012, we began to see production response from the initial re-pressurization of the reservoir. Production from the ASP flooded area increased from approximately 316 Boe/d in 2011 to approximately 992 Boe/d in 2012.

In 2012, a new heavy oil processing facility was constructed to handle the increased fluid volumes from the area. The ASP injection facility and heavy oil processing facility that has been constructed at Mooney are expected to accommodate all phases of development at Mooney.

We have also begun development of the phase two and phase three lands at Mooney, with a total of 16 horizontal wells drilled as at December 31, 2012. In early 2013, we applied for regulatory approval to expand the existing ASP flood to the phase two lands. There is further expansion potential on our Mooney lands which we plan to test in the future. The oil on these expansion lands is likely heavier than other areas of the pool and we have not established whether ASP flooding is suitable in these areas.

The oil quality at Mooney ranges from 12° API to 19° API, with an average of approximately 16° API. The viscosity of the oil ranges from 150 centipoise to 2,500 centipoise.

The Mooney field lies outside the designated Peace River oil sands region and is therefore not eligible for oil sands royalty treatment. However, the Alberta government has programs that encourage EOR developments by reducing royalties on fields with tertiary recovery programs. The Company has received EOR royalty status for phase one of the Mooney ASP flood and the Company has applied for EOR royalty status on the phase two lands.

At December 31, 2012, Sproule assigned proved plus probable reserves of 15.6 million Boe to the Mooney area (BlackPearl's working interest, before royalties). In addition, as at December 31, 2012 Sproule has assigned 37 million Boe of contingent resource (best estimate) to the Mooney area. See "Statement of Reserves and Contingent Resources Data and Other Oil and Gas Information". Total production from the Mooney area was 2,537 Boe/d, or 27% of BlackPearl's total production for the year.

Other Properties – Canada

The Company holds interests and has ongoing operations and production in several other areas of Saskatchewan and Alberta. These include John Lake, Fishing Lake, Salt Lake and Druid.

Properties - U.S.A.

San Miguel Heavy Oil Project – Maverick Basin, South Texas

BlackPearl, through its wholly owned subsidiary, Newmex Energy (USA) Inc. is a 50% participant in a large, shallow depth, heavy oil deposit located in the Maverick Basin in southern Texas. The San Miguel heavy oil project focuses on the San Miguel sandstone which is a large, well defined heavy oil deposit.

There is currently no production at San Miguel. The Company did not have any active operations at San Miguel in 2012 and no activities are planned for 2013.

Other Properties – U.S.A.

The Company holds interests in several other areas in the U.S.A., including Promised Land in Montana. There is no production from these areas and there is no evaluation plans contemplated for these lands in 2013. BlackPearl also holds a non-operated financial interest in several wells in California. The properties in the U.S. are not material to the Company's current operations.

Employees

The Company had 44 employees and eight consultants as at December 31, 2012. The Company has also entered into arrangements with 42 contract operators to help manage and operate the Company's oil and gas properties.

INDUSTRY CONDITIONS

Government Regulation

The oil and natural gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government, and our oil and gas operations are subject to various Canadian federal, provincial, territorial, and local laws and regulations. These laws and regulations may be changed in response to economic or political conditions, and regulate, among other things, land tenure and the exploration, development, production, handling, storage, transportation, and disposal of oil and gas, oil and gas by-products, and other substances and materials produced or used in connection with oil and gas operations.

More particularly, matters subject to current governmental regulation and/or pending legislative or regulatory changes include the licensing for drilling of wells, the method and ability to produce wells, surface usage, transportation of production from wells, conservation matters, the discharge or other release into the environment of wastes and other substances in connection with drilling and production activities (including fracture stimulation operations), bonds or other financial responsibility requirements to cover drilling contingencies and well plugging and abandonment costs, reports concerning our operations, the spacing of wells, unitization and pooling of properties, and royalties and taxation. Failure to comply with the laws and regulations in effect from time to time may result in the assessment of administrative, civil, and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions that could delay, limit, or prohibit certain of our operations. We cannot predict the ultimate cost of compliance with these requirements or their effect on our operations.

Federal authorities do not regulate the price of oil and gas in export trade. Legislation exists, however, that regulates the quantities of oil and natural gas which may be removed from the provinces and exported from Canada in certain circumstances. At various times, regulatory agencies have imposed price controls and limitations on oil and gas production. In order to conserve supplies of oil and gas, these agencies may also restrict the rates of flow of oil and gas wells below actual production capacity.

Although BlackPearl does not expect that these controls and regulations will affect the operations of BlackPearl in a manner materially different than they would affect other oil and gas companies of similar size, the controls and regulations should be considered carefully by investors in the oil and gas industry. All current legislation is a matter of public record and BlackPearl is unable to predict what additional legislation or amendments may be enacted.

Pricing and Marketing

Crude Oil, Bitumen and Bitumen Blend

Producers of crude oil, bitumen, and bitumen blend negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of such commodities. The price depends, in part, on product quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance, other contractual terms, and the world price of oil. Oil may be exported from Canada pursuant to export contracts with terms not exceeding one year in the case of light crude, and not exceeding two years in the case of heavy crude, provided that an order approving such export has been obtained from the NEB. Any oil exported under a contract of longer duration (to a maximum of 25 years) requires the exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

Natural Gas

In Canada, the price of natural gas sold in intraprovincial, interprovincial and international trade is determined by negotiations between buyers and sellers. Such price depends, in part, on natural gas quality, prices of competing natural gas and other fuels, distance to market, access to downstream transportation, length of contract term, weather conditions, the supply/demand balance and other contractual terms. Natural gas exported from Canada is subject to regulation by the NEB and the government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the NEB and the government of Canada. Natural gas exports for a term of less than two years or for a term of two to 20 years (in quantities not exceeding 30,000 m^3/day) are subject to an NEB order. Any natural gas exported under a contract of longer duration (to a maximum of 25 years) or in larger quantities requires the exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

The government of Alberta also regulates the volume of natural gas that may be removed from the province for consumption elsewhere, based on such factors as reserve availability, transportation arrangements and other market considerations.

Natural Gas Liquids

The price of condensate and other natural gas liquids ("**NGLs**") sold in intraprovincial, interprovincial and international trade is determined by negotiations between buyers and sellers. Such price depends, in part, on the quality of the NGLs, prices of competing chemical stock, distance to market, access to downstream transportation, length of contract term, the supply/demand balance and other contractual terms. NGLs exported from Canada are subject to regulation by the NEB and the government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain criteria prescribed by the NEB and the government of Canada. NGLs may be exported for a term of not more than one year in respect of propane and butane and not more than two years in respect of ethane – with all exports requiring an order of the NEB.

The North American Free Trade Agreement ("**NAFTA**") among the Canadian, United States and Mexican governments came into effect on January 1, 1994. Under NAFTA, the Canadian government is free to determine whether exports of energy resources to the United States or Mexico should be allowed, provided that export restrictions do not: (1) reduce the proportion of energy resources exported relative to energy resources consumed domestically (with the most recent 36 month period proportion used as the basis for comparison); (2) impose a higher export price than domestic price (subject to an exception relating to certain voluntary measures that restrict the volume of exports); and (3) disrupt normal channels of supply.

NAFTA prohibits discriminatory border restrictions and export taxes and also prohibits the imposition of minimum or maximum export or import price requirements except with respect to the enforcement of countervailing and anti-dumping orders and undertakings. Discipline on regulators is addressed as the signatories to NAFTA agree to ensure that their regulatory bodies provide equitable implementation of regulatory measures and minimize the disruption of contractual arrangements.

Pipeline Capacity

Despite some recent oil pipeline capacity expansions, the overall pipeline capacity in Canada is tight. The space deficit is not likely to be resolved quickly given that heavy oil and bitumen production is set to rise further, while no additional pipeline space is expected until the end of March, 2013.

The capacity issues are resulting in a loss of profits garnered for natural resources in Canada's oil industry. Current oil sands production is approximately 1.7 million barrels per day and the production rate is expected to double by 2020. Accordingly, finding additional export capacity to deal with the increase in Canada's crude oil production is a primary concern.

Currently, there are several pipeline proposals in the works that could help to alleviate access problems from Western Canada's Sedimentary Basin to the international markets: the Keystone XL Pipeline, the Northern Gateway Pipeline and the Kinder Morgan's Trans Mountain Express Pipeline.

Land Tenure

Rights are granted to energy companies to explore for and produce oil and natural gas pursuant to leases, licenses, and permits and regulations as legislated by the respective Provincial and Federal governments. Lease terms vary in length, usually from two to five years. Other terms and conditions to maintain a mineral lease are set forth in the relevant legislation or are negotiated.

Jurisdictions in western Canada, including the provinces of Alberta, and Saskatchewan have legislation in place for mineral rights reversion to the Crown where formations cannot be shown to be capable of production at the end of their primary lease term. Such legislation may also include mechanisms available to energy companies to "continue" lease terms for non-productive lands, having met certain criteria as laid out in the relevant legislation.

Oil and natural gas can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Royalties

General

For crude oil, natural gas and related production from Federal or Provincial government lands, the royalty regime is a significant factor in the profitability of our production. Crown royalties payable in respect of crown lands are determined by governmental regulation and are typically calculated as a percentage of the value of gross production. The value of the production and the rate of royalties payable generally depend on prescribed reference prices, well productivity, geographical location, the field discovery rate and the type of product produced.

Royalties payable on production from privately owned lands are determined by negotiations between the mineral owner and the resource owner, although production from such lands is subject to certain provincial taxes and royalties. Any such royalties (or royalty-like interests) are carved out of the working interest owner’s interest through non-public transactions and are often referred to as overriding royalties, gross overriding royalties, net profit interests or net carried interests.

From time to time, provincial governments have established incentive programs for exploration and development. Such programs often provide for royalty reductions, credits and holidays, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry.

Alberta

The Alberta government implemented its New Royalty Framework, or NRF, effective January 2009 which included significant changes to the oil and gas royalty system. The framework established new royalties for conventional oil, natural gas and bitumen that are linked to price and production levels and apply to both new and existing conventional oil and gas activities and oil sands projects. On March 11, 2010, the government of Alberta announced further adjustments to the royalty framework including a reduction in the maximum royalty rates, making certain temporary incentive programs permanent effective January 1, 2011, and re-naming the NRF the Alberta Royalty Framework, or ARF. Under the NRF (now ARF), the royalties payable for conventional oil and natural gas are derived using sliding rate formulae, which incorporate a market price component and a production volume component.

In November 2008, in connection with the implementation and phase-in of the NRF, the Alberta government announced a five-year program of ''transitional'' royalty rates providing for lower royalties at certain price points in the initial years of a qualifying well's life. Under the transitional royalty program, companies drilling new natural gas and conventional oil deep wells at depths between 1,000 meters and 3,500 meters (3,281 feet and 11,483 feet) spud after November 19, 2008 had a one-time option, on a well-by-well basis, to elect for the production from such wells to be subject to the transitional royalty rates or those provided for under the NRF. The option for producers to elect transitional royalties in respect of qualifying deep wells ended on December 31, 2010 and any wells spudded on or after January 1, 2011 are subject to the royalty rates under the ARF. Wells that are subject to transitional royalty rates will automatically revert to ARF rates on January 1, 2014.

Under the ARF, royalty rates for conventional oil currently range from 0% to 40%; and royalty rates for natural gas (methane and ethane) currently range from 5% to 36%. ARF rates for propane and butane are fixed at 30% and the rate for pentane is fixed at 40%. Condensate royalties under the ARF are calculated on a basis similar to royalties for conventional oil and currently range from 0% to 40%.

The royalty payable on Alberta oil sands production is based on price-sensitive royalty rates. The royalty range applicable to price sensitivities changes depending on whether the project's status is pre-payout or post-payout. ''Payout' generally defined as the point in time when a project has generated enough net revenue to recover its costs and provide a designated return allowance. When a project reaches payout, its cumulative revenue equals or exceeds its cumulative costs. Costs include specified allowed capital and operating costs pursuant to the *Oil Sands Allowed Costs (Ministerial) Regulation*. The royalty payable for pre-payout projects is the gross revenue royalty based on the gross revenue royalty rate. The gross revenue rate starts at 1% and increases for every dollar that the world oil price, as reflected by the WTI crude oil price in Canadian dollars, is priced above $55 per barrel, to a maximum of 9% when the WTI crude oil price is $120 per barrel or higher. The royalty payable for post-payout projects is the greater of the gross revenue royalty based on the gross revenue royalty rate or the net revenue royalty based on the net revenue royalty rate. The net royalty rate starts at 25% and increases for every dollar the WTI crude oil price is above $55 per barrel to a maximum of 40% when the WTI crude oil price $120 per barrel or higher.

As the resource owner, the government of Alberta is entitled to take its royalty share of bitumen production in kind, as it does currently for conventional oil production. The government of Alberta has committed to have a portion of its bitumen royalty in-kind volumes commercially upgraded to higher value products in the province.

The government of Alberta has also introduced a number of royalty reduction and incentive programs to encourage oil and gas exploration and development in Alberta, which include the following programs, among others, currently in effect:

- The Deep Oil Exploration Program (the "**DOEP**") and the Natural Gas Deep Drilling Program (the "**NGDDP**") are two programs that became effective on January 1, 2009. These programs provide upfront royalty adjustments to new wells. To qualify for such royalty adjustments under the DOEP, exploration wells must have a vertical depth greater than 2,000 metres with a Crown interest and must be spudded after January 1, 2009. These oil wells qualify for a royalty exemption on either the first $1,000,000 of royalty or the first 12 months of production. The NGDDP applies to wells producing at a true vertical depth greater than 2,500 metres. The NGDDP has an escalating royalty credit in line with progressively deeper wells from $625 per meter to a maximum of $3,750 per meter and there are additional benefits for the deepest wells. Both the DOEP and the NGDDP were originally announced as five year programs with any wells spudded after December 31, 2013, or any wells selecting the transition option not able to qualify. No royalty adjustments will be granted under the DOEP after December 31, 2018. On May 27, 2010 the NGDDP was made a permanent feature of the royalty regime and was amended, retroactive to May 1, 2010, by reducing the minimum qualifying depth to 2,000 metres, among other changes.

- The new well royalty program that provides a maximum 5% royalty rate for the first 12 months of production from new wells that begin producing oil or natural gas between April 1, 2009 and March 31, 2010 to a maximum of 50,000 Bbls or 500 MMcf of natural gas. As of March 11, 2010, the Alberta government made the new well front-end royalty rate a permanent feature of the royalty system.

In conjunction with the release of the new royalty curves for the ARF the Alberta government also announced its Emerging Resources and Technology Initiative intended to accelerate new technologies and encourage the development of unconventional resources. Among other initiatives, it was announced that horizontal oil wells and horizontal non-project oil sands wells would receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well, retroactive to wells that commenced drilling on or after May 1, 2010. The Emerging Resources and Technology Initiative will be reviewed in 2014 and the Alberta government has committed to provide industry three years notice if it intends to discontinue the program.

Saskatchewan

Crown royalty rates are sensitive to the individual productivity of each natural gas well. The rates are applied to the respective portions of each classification of gas ("fourth tier gas", "third tier gas", "new gas" and "old gas") produced from a well.

Each month, the royalty rates are adjusted based on the level of the Provincial Average Gas Price ("**PGP**") established by the Province monthly. The PGP represents the weighted average fieldgate price (expressed in \$/1000 m^3) received by producers during the month for the sale of all gas subject to royalty. Crown royalty on the production volume is calculated on each individual well using the applicable royalty rate to the volume of gas produced by each well on a monthly basis.

Historically, operators must elect to use either the PGP or the Operator Average Gas Price ("**OGP**") for purposes of valuing the Crown's royalty share of the production volume from each well. The OGP is determined each month by the operator and represents the weighted average fieldgate price (\$/1000 m^3) received by the operator for sales of gas during the month. The Crown royalty share is calculated by multiplying the Crown royalty volume determined for each well by the wellhead value of the gas for the month. On June 14, 2010 the Province of Saskatchewan announced that it will eliminate the option of using the OGP for purposes of valuing the Crown's royalty share of the production volume from each well, and will require use of the PGP. The proposed changes may require further consultation and there may be modifications introduced prior to the implementation of such changes.

In Saskatchewan, the amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of the oil determined monthly by the provincial government. Each month, royalty rates are adjusted based on the level of the reference price established by the Province for each type of oil. For Crown royalty purposes, crude oil is classified as "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". There are separate reference prices established for each type of oil which represent the average wellhead price (in \$/m^3) received by producers during the month for sales of that oil type in Saskatchewan.

The Crown royalty share of production volume is calculated on each individual well using the applicable royalty rate to the volume of oil produced from the well each month. The Crown royalty share is calculated by multiplying the Crown royalty volume determined for each well by the wellhead value of the oil for the month.

A separate cost sensitive royalty structure applies to incremental production from enhanced oil recovery projects, which incorporates lower royalty and freehold production tax rates before the project reaches payout of investment and operating expenditures.

The government of Saskatchewan has introduced a number of oil and natural gas royalty reduction and credit incentive programs to encourage oil and gas exploration and development in Saskatchewan. Such programs include:

- A cost sensitive royalty structure that applies to incremental production from enhanced oil recovery projects that are not Waterflood projects. There are different royalty structures for projects that commenced operation prior to April 1, 2005 and for those that commence operation on or after April 1, 2005. There is also another royalty structure that applies to incremental oil produced from new or expanded Waterflood projects that are implemented on or after October 1, 2002. Each of these royalty structures incorporates lower royalty and freehold production tax rates before the project reaches payout of investment and operating expenditures.

- Different incentive volumes for Deep Development Vertical Oil Well, Exploratory Vertical Oil Well, Horizontal Oil Well and Deep Horizontal Oil Well drilled after October 1, 2002. A lower royalty rate applies to oil produced from such wells up to and including the incentive volumes specified for each such well.

- Individual oil wells or a group of them that are either producing conventional oil at an average water-cut of 95% or greater in the twelve calendar months preceding an application under the program or have been shut-in or suspended for twelve or more consecutive calendar months prior to making investments under the program and produced at an average water-cut of 95% or greater during the three producing months immediately preceding the shut-in or suspension qualify for a royalty incentive that is designed to extend the producing lives and improve the recovery rate of high water-cut oil wells. Oil produced from a well that has an average water-cut of 50% or greater that is part of a group of oil wells that produce at an average water-cut of 95% or greater and benefit from the same qualifying investment also qualifies under this incentive program.

The Government of Saskatchewan has introduced the Oil and Gas Orphan Fund, funded by oil and gas companies to cover the cost of cleaning up abandoned wells and facilities where the owner cannot be located or has gone out of business. The program is composed of a security deposit, based upon a formula considering assets of the well and the facility licensee against the estimated cost of decommissioning the well and facility once it is no longer producing, and an annual levy assessed to each licensee.

Environmental Regulation

As an operator of oil and natural gas properties in Canada, we are subject to stringent federal, provincial, territorial, and local laws and regulations relating to environmental protection as well as controlling the manner in which various substances, including wastes generated in connection with oil and gas exploration, production, and transportation operations, are released into the environment. Compliance with these laws and regulations can affect the location or size of wells and facilities, prohibit or limit the extent to which exploration and development may be allowed, and require proper abandonment of wells and restoration of properties when production ceases. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, or criminal penalties, imposition of remedial obligations, incurrence of capital or increased operating costs to comply with governmental standards, and even injunctions that limit or prohibit exploration and production activities or that constrain the disposal of substances generated by oil field operations.

We currently operate or lease, and have in the past operated or leased, a number of properties that have been used for the exploration and production of oil and gas. Although we utilize and have utilized standard industry operating and disposal practices, hydrocarbons or other wastes may have been disposed of or released on or under the properties operated or leased by us or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and the wastes disposed thereon may be subject to laws and regulations imposing joint and several, strict liability without regard to fault or the legality of the original conduct that could require us to remove previously disposed wastes or remediate property contamination, or to perform well plugging or pit closure or other actions of a remedial nature to prevent future contamination.

The Company may be affected by the Lower Athabasca Region Plan ("**LARP**") under the *Alberta Land Stewardship Act*, which came into effect on September 1, 2012 and is currently being implemented. LARP is a legislative instrument equivalent to regulations and will be binding on the government of Alberta and provincial regulators, including those governing the oil and gas industry. LARP is the first of an anticipated seven regional land-use plans in the province and applies to over two million hectares of land and, among other things, implements management frameworks for air emissions, water use, and land disturbance to control cumulative environmental effects of industrial development.

On September 1, 2012, framework for air quality, surface water quality and groundwater came into force, subjecting future and existing operations in the region to more onerous environmental constraints and stringent operating parameter. As part of these frameworks, parties may be required to participate in regional monitoring and report on the progress of implementation. Further, conversation areas established under LARP may impact some oil sands license holders in the region, as there is the potential for specific oil sands leases to be cancelled by the government. Should such a situation occur, the Alberta government would be responsible for compensation to the affected license holders.

On February 3, 2012 the Government of Alberta and the Government of Canada released the Joint Canada-Alberta Implementation Plan for Oil Sands Monitoring (the "**Monitoring Plan**"). The Monitoring Plan is designed to provide an improved understanding of the potential cumulative environmental effects of oil sands development and will increase air, water, land and biodiversity monitoring in the oil sands region. The Monitoring Plan is expected to be phased in over a three-year period and funding will be provided by industry. To support the Monitoring Plan industry has agreed to provide aggregate funding of up to $50 million a year. On October 17, 2012, the Government of Alberta announced that it will establish an independent arm's-length environmental monitoring agency in the province. The independent agency is expected to begin work in the oil sands region with a focus on integrated and coordinated monitoring of land, air, water and biodiversity.

We believe that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. A recent example of this trend is the high-level of regulatory attention that the practice of hydraulic fracturing continues to receive in various jurisdictions. The Province of Alberta has recently announced its intention to adopt mandatory disclosure requirements and an online registry for hydraulic fracturing activities. While we believe that we are in substantial compliance with applicable environmental laws and regulations in effect at the present time and that continued compliance with existing requirements will not have a material adverse impact on us, we cannot give any assurance that we will not be adversely affected in the future. We have established internal guidelines to be followed in order to comply with environmental laws and regulations in the jurisdictions in which we operate. We employ an environmental, health, and safety department whose responsibilities include providing assurance that our operations are carried out in accordance with applicable environmental guidelines and safety precautions. Although we maintain pollution insurance against the costs of cleanup operations, public liability, and physical damage, there is no assurance that such insurance will be adequate to cover all such costs or that such insurance will continue to be available in the future.

Greenhouse Gases and Industrial Air Pollutants

Climate Change Regulation

Federal (Canada)

Internationally, Canada is a signatory to the United Nations Framework Convention on Climate Change and previously ratified the Kyoto Protocol established thereunder, which set legally binding targets to reduce nation-wide emissions of carbon dioxide, methane, nitrous oxide, and other GHGs. The first commitment period under the Kyoto Protocol is the five year period from 2008-2012. In December 2011, the Canadian federal government announced that it would not agree to a second commitment period under the Kyoto Protocol after 2012. The federal government instead endorsed the Durban Platform, a broad agreement reached among the 194 countries that are party to the United Nations Framework Convention on Climate Change, during a conference held in Durban, South Africa in December 2011. The Durban Platform sets forth a process for negotiating a new climate change treaty that would create binding commitments for all major GHG emitters. The Canadian government expressed cautious optimism that agreement on a new treaty can be reached by 2015. The Durban Platform followed the Copenhagen Accord reached in December 2009 as government representatives met in Copenhagen, Denmark to negotiate a successor to the Kyoto Protocol. The Copenhagen Accord represents a broad political consensus and reinforces commitments to reducing GHG emissions but is not a binding international treaty. Although Canada had committed under the Copenhagen Accord to reduce its GHG emissions by 17% from 2005 levels by 2020, the target is not legally binding. The impact of Canada's withdrawal from the Kyoto Protocol on prior GHG emission reduction initiatives is uncertain.

Domestically, the Canadian federal government released in 2007 its Regulatory Framework for Air Emissions, which was updated in March 2008 in a document entitled "Turning the Corner: Regulatory Framework for Industrial Greenhouse Emissions." Canada's previous GHG emission reduction target was 20% from 2006 levels by 2020, but on January 30, 2010 the Canadian federal government announced a new GHG emission reduction target consistent with its commitment under the Copenhagen Accord to reduce GHG emissions to 17% below 2005 levels by 2020. Canada's framework proposes mandatory emissions intensity reduction obligations on a sector-by-sector basis. To date, regulations for Canada's transportation and coal-fired electricity sectors have been developed with the regulations for the electricity sector not expected to take effect until 2015. In 2009, the Canadian federal government announced its commitment to work with the provincial governments to implement a North America-wide cap and trade system for GHG emissions, in cooperation with the United States, under which Canada would have its own cap-and-trade market for Canadian-specific industrial sectors that could be integrated into a North American market for carbon permits. The government of Canada currently proposes to enter into equivalency agreements with provinces to establish a consistent regulatory regime for GHGs, but the success of any such plan is uncertain, possibly leaving overlapping levels of regulation. It is uncertain whether or when either Canadian federal GHG regulations for the oil and gas industry or an integrated North American cap-and-trade system will be implemented, or what obligations might be imposed under any such systems. As the details of the implementation of any federal legislation for GHGs that is applicable to the oil and gas industry have not been announced, the effect on BlackPearl's operations cannot be determined at this time.

Alberta

Alberta introduced the *Climate Change and Emissions Management Act*, which provides a framework for managing GHG emissions by reducing specified gas emissions, relative to gross domestic product, to an amount that is equal to or less than

50% of 1990 levels by December 31, 2020. The accompanying regulations include the Specified Gas Emitters Regulation (the "**SGER**"), which imposes GHG emissions limits, and the Specified Gas Reporting Regulation (the "**SGRR**"), which imposes GHG emissions reporting requirements.

The SGER, effective July 1, 2007, applies to facilities in Alberta that have produced 100,000 or more tonnes of GHG emissions in 2003 or any subsequent year, and requires reductions in GHG emissions intensity (i.e. the quantity of GHG emissions per unit of production) from emissions intensity baselines that are established in accordance with the SGER. The SGER distinguishes between "established" facilities that completed their first year of commercial operation before January 1, 2000 or have completed eight years of commercial operation, and "new" facilities that have completed their first year of commercial operation on December 31, 2000 or a subsequent year and have completed less than eight years of commercial operation. Generally, the baseline for an established facility reflects the average of emissions intensity in 2003, 2004, and 2005, and for a new facility emissions intensity in the third year of commercial operation. For an established facility, the required reduction in GHG emissions is 12% per year from its baseline, and such reduction must be maintained over time. For a new facility, the required reduction from its baseline is phased in by annual 2% increments beginning in the fourth year of commercial operation until the annual 12% reduction requirement is reached, and once reached such 12% reduction must be maintained over time.

There are three methods for operators of facilities that are subject to the SGER to comply with the annual emission intensity reduction requirements: (i) improve emissions intensity at the facility; (ii) purchase emission performance or emission offset credits in the open market, which are generated from Alberta based projects; and/or (iii) purchase "fund credits" by contributing to the Alberta Climate Change and Emissions Management Fund ("**Fund**") run by the Alberta government. Historically the contribution costs to the Fund have been set at $15/tonne of Co_{2e} although that has recently changed and the contribution costs are now set by order of the government of Alberta. Compliance reports for facilities subject to the SGER are due to Alberta Environment on March 31 annually.

The SGRR imposes GHG emissions reporting requirements on facilities that have GHG emissions of 50,000 tonnes or more in a year. In addition, Alberta facilities must currently report emissions of industrial air pollutants and comply with obligations imposed in permits and under other environmental regulations.

Saskatchewan

The Management and Reduction of Greenhouse Gases Act received Royal Assent in the Province of Saskatchewan on May 20, 2010. However, this Act is still awaiting proclamation. The new legislation will establish a provincial plan for reducing GHG emissions to meet provincial targets and promote investments in low-carbon technologies. The Province has indicated that it intends to enter into an equivalency agreement with the federal government to achieve equivalent environmental outcomes under provincial regulation. A draft of the proposed regulations to accompany the Act calls for a reduction of emissions by 20% below 2006 levels by 2020.

RISK FACTORS

The Company is exposed to a number of risks inherent in exploring for, developing and producing heavy oil, bitumen and natural gas. The following list describes some of the risks that could have a material impact on the business, operations and financial condition of BlackPearl. Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Company's other public filings before making an investment decision.

Volatility of Oil and Natural Gas Prices

The Company's revenues, cash flow, results of operations and financial condition are dependent upon, among other things, the price it receives for the heavy oil, bitumen, and bitumen blend that it sells, and the price that it receives for these products is closely correlated to the price of crude oil. Historically, crude oil markets have been volatile and are likely to continue to be volatile in the future. These fluctuations in price are in response to factors including, but not limited to, supply and demand for crude oil and natural gas, market uncertainty, world economic conditions, government regulation, political instability, availability of refining capacity and transportation infrastructure, weather conditions and the prices of alternative forms of energy, all of which are generally beyond the control of the Company.

Any extended decline in the price of crude oil could result in the delay or cancellation of future drilling programs or construction projects. Any such actions could have a material adverse effect on BlackPearl's business, financial condition, results of operations and cash flows.

Over 95% of BlackPearl's production is from heavy oil and bitumen. The market prices for heavy oil and bitumen are lower than the established market indices for light or medium grades of oil, due principally to diluent prices and the higher transportation and refining costs associated with heavy oil and bitumen. Also, the market for heavy oil and bitumen is more limited than for light and medium grades of oil, making it more susceptible to supply and demand fundamentals. Future price differentials are uncertain and any increase in heavy oil differentials could have an adverse effect on the Company's business, financial condition, results of operations and cash flows.

The Company regularly assesses the carrying value of its assets in accordance with IFRS. If oil and natural gas prices decline, the carrying value of the Company's assets could be subject to downward revisions, and net earnings could be adversely affected.

Volatility of Commodity Inputs

Natural gas production is not a significant component of the Company's total current production, therefore changes in gas prices do not currently materially affect the Company. However, as the thermal projects at Blackrod and Onion Lake reach the production stage, natural gas is expected to be used to generate steam and changes in natural gas prices will affect the Company's cost structure, and could have a material adverse effect on BlackPearl's business, financial condition, results of operations and cash flows.

In order to meet pipeline specifications, heavy oil and bitumen is usually blended with a lighter hydrocarbon (commonly referred to as diluent) to increase its flow characteristics. The cost of diluent is highly correlated to crude oil prices. As a result, the Company expects to be able to offset a portion or all of the increase in its costs associated with an increase in diluent prices with an increase in revenue that results from higher oil prices. However, in the event this correlation changes, the Company's results of operations and financial condition could be adversely affected.

Access to Capital

BlackPearl has a small working capital deficiency and no long term debt as of December 31, 2012; however, the Company will have to incur substantial capital expenditures in the future in order to carry out its oil and natural gas, exploration and development activities. In particular, the development of our two thermal SAGD projects at Blackrod and Onion Lake will require a substantial amount of 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 initial capital costs for the first 20,000 barrel per day phase at Blackrod may cost between $750 and $800 million, and the initial capital costs of the 12,000 barrel per day phase at Onion Lake may cost between $300 and $350 million. Timing of development of these projects is dependent on additional financings. While there are various financing options available to the Company, including the issuance of new equity or debt, asset sales, joint ventures, sales of working interests or other alternatives, the Company's ability to arrange such financing or other satisfactory arrangements in the future may depend in part upon the prevailing capital market conditions, as well as the Company's business performance. In addition, uncertain levels of near term industry activity coupled with the ongoing global credit uncertainty exposes the Company to additional access to capital risk. The ongoing global credit uncertainty has resulted in considerable disruption that has affected the financial and banking system, resulting in a tightening of credit markets, higher costs of borrowing, lower returns on invested cash, and increased volatility in the equity markets. These factors could negatively impact the Company in terms of its ability to raise additional capital as well as increased volatility in oil and gas prices which could affect revenues and cash flows and Company valuations. There can be no assurance that the Company will be successful in its efforts to arrange additional financing or to make other satisfactory arrangements on terms satisfactory to the Company or at all. If the Company obtains additional financing by the issuance of shares from treasury, control of the Company may be affected and, depending on the issue price of such shares, existing shareholders may suffer dilution. The inability of BlackPearl to access sufficient capital or to make other satisfactory arrangements could have a material adverse effect on the expected growth and development of the Company's business, including the development of the thermal projects at Blackrod and Onion Lake and the Company's financial condition, results of operation and prospects.

BlackPearl's actual costs and revenues may vary from expected amounts, possibly to a material degree, and such variations are likely to affect BlackPearl's future capital requirements. Accordingly, BlackPearl may be required to raise substantial additional capital in the future and BlackPearl's current projections may not prove to be accurate. In addition, BlackPearl's may accelerate the expansion and development of its projects. If BlackPearl decides to do so, its funding needs will increase, possibly to a significant degree.

The Company's ability to make payments on, and to refinance, its future indebtedness, and to fund planned capital expenditures will depend upon, amongst other matters, the Company's ability to generate cash in the future which, in turn, is subject to general economic, financial, competitive, legislative, regulatory and other factors, many of which are beyond the Company's control.

Uncertainty of Reserve and Contingent Resource Estimates

There are numerous uncertainties inherent in estimating quantities of proved and probable reserves and quantities of contingent resources and future net revenues to be derived therefrom, including many factors beyond the control of the Company. The reserves, contingent resources and future net cash flow information set forth in this Annual Information Form represent estimates only. While the reserves, contingent resources and future net cash flow information from the Company's properties have been independently evaluated by Sproule in the Sproule Report, these evaluations include a number of assumptions, including, without limitation, such factors as initial production rates, production decline rates, ultimate recovery of reserves and contingent resources, timing and amount of capital expenditures, marketability of production, future prices of oil, bitumen and natural gas, operating costs, well abandonment and salvage values, royalties and other government levies that may be imposed over the producing life of the reserves and resources. These assumptions were based on prices in use at the date the relevant evaluations were prepared, and many of these assumptions are subject to change and are beyond the control of the Company. Actual production and cash flow derived therefrom will vary from these evaluations, and such variations could be material.

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

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

Reserves and contingent resource estimates may require revision based on actual production experience. Such figures have been determined based upon assumed commodity prices and operating costs. Market price fluctuations of heavy oil, bitumen and natural gas prices may render the recovery of the reserves or contingent resources uneconomic

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

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

Government Regulation

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

In general, the operations of BlackPearl require licenses and permits from various governmental authorities. The construction and operation of the thermal projects at Blackrod and Onion Lake will require various environmental and other regulatory approvals. Necessary approvals have not been obtained for commercial development of either of these projects and there is no assurance that BlackPearl will be able to obtain all necessary licenses and permits that may be required to conduct operations that it may wish to undertake. In addition, once permits are issued there is no assurance that the approvals will not be repealed, or renewed, or that they will contain terms and conditions which make the Company's projects and operations uneconomic or cause the Company to significantly alter its projects and operations.

Income tax laws or other laws or government incentive programs relating to the oil and gas industry may, in the future, be changed or interpreted differently from the position taken by BlackPearl which may be detrimental to the Company and its shareholders.

Environmental Regulation

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. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material.

The direct and indirect costs of the various GHG regulations, existing and proposed, may adversely affect our business, operations and financial results. Equipment that meets future emission standards may not be available on an economic basis and other compliance methods to reduce our emissions or emissions intensity to future required levels may significantly increase operating costs or reduce the output of the projects. Offset, performance or fund credits may not be available for acquisition or may not be available on an economic basis. Any failure to meet emission reduction compliance obligations may materially adversely affect BlackPearl's business and result in fines, penalties and the suspension of operations. There is also a risk that one or more levels of government could impose additional emissions or emissions intensity reduction requirements or taxes on emissions created by BlackPearl or by consumers of BlackPearl's products. The imposition of such measures might negatively affect BlackPearl's costs and prices for BlackPearl's products and have an adverse effect on earnings and results of operations.

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

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to resources and various properties in western Canada. Such claims, in relation to any of BlackPearl's lands, if successful, could have an adverse effect on its operations.

BlackPearl's interests in the Onion Lake property is situated on Treaty Land Entitlement Reserves and traditional reserve lands and are subject to the federal rules and regulations of Indian Oil and Gas Canada as well as the Onion Lake First Nation of Saskatchewan/Alberta ("**OLFN"**). There are risks associated with the Company's relationship with OLFN and the management of BlackPearl's interests on these lands. Specifically, a dispute could arise between BlackPearl and OLFN regarding issues such as employment, lease terms and project success. The result of such a dispute could be that OLFN denies BlackPearl, among others, access to Onion Lake lands for the exploration and production of oil and gas. In addition, the government of Canada through the governing body, Indian Oil and Gas Canada, could change the rules, leases and dispositions by which BlackPearl is able to explore and operate on Onion Lake treaty lands which may have a material adverse effect on the Company's business, financial condition, results of operations and cash flows.

Operational Risks

The Company's oil and natural gas operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, mechanical or pipe failure, sour gas releases, cratering and oil spills, acts of vandalism, or other unexpected or dangerous conditions, each of which could result in substantial damage to oil and natural gas wells, producing facilities, other property and the environment or in personal injury. The Company attempts to mitigate some of these risks by maintaining an insurance program in amounts it considers adequate; however, BlackPearl will not be insured against all of these risks, as well, the nature of these risks is such that liabilities could exceed policy limits, in which event the Company could incur significant costs that could have a materially adverse effect upon its financial condition. Further, a significant spill from one of our facilities could have a material adverse effect on our results of operations, competitive position, or financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including drilling into unexpected formations or unexpected pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Company's business, financial condition, results of operations and cash flows.

Capital Cost Over-runs

Oil sands projects require a substantial amount of capital to construct and place on production. Due to the number of projects built and planned to be built, the Athabasca oil sands region has seen inflationary pressure on labour rates as well as costs for goods and services on these large projects. The planned Blackrod project is in the Athabasca oil sands region and therefore the project could be negatively impacted by higher capital costs. The Onion Lake thermal project, while not in the Athabasca oil sands region, may also be impacted by increased oil sands activity in western Canada. Higher capital costs could result in project delays or postponement which could materially adversely affect BlackPearl's business, financial condition, results of operations and cash flows.

Foreign Exchange Risk

Most of BlackPearl's revenues are based on the U.S. dollar, since revenues from the sale of heavy oil and bitumen is generally referenced to a price denominated in U.S. dollars, and BlackPearl incurs most of its operating and other costs in Canadian dollars. As a result, BlackPearl is impacted by exchange rate fluctuations between the U.S. dollar and the Canadian dollar and any strengthening of the Canadian dollar relative to the U.S. dollar could negatively impact revenues and cash flow.

Diluent Supply

Heavy oil and bitumen are characterized by high specific gravity or weight and high viscosity or resistance to flow. Diluent is required to facilitate the transportation of heavy oil and bitumen. A shortfall in the supply of diluent may cause its price to increase thereby increasing the cost to transport heavy oil and bitumen to market and correspondingly increasing BlackPearl's operating cost, decreasing its net revenues and negatively impacting the overall profitability of its heavy oil and bitumen projects.

Competition

The Canadian and international petroleum industry is highly competitive in all respects, including, without limitation, the exploration for, and the development of, new sources of supply, the acquisition of crude oil, natural gas and oil sands leases, licenses and concessions and the distribution and marketing of petroleum products. The Company competes with other producers of heavy oil, bitumen, synthetic crude oil blends and conventional crude oil. Some of these producers have lower operating costs than BlackPearl and many of them have greater resources to source, attract and retain the personnel, materials and services that the Company requires to conduct its operations. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers.

A number of other companies have announced plans to enter the heavy oil or oil sands business or expand existing operations. Expansion of existing operations and development of new projects could significantly increase the supply of heavy oil and bitumen in the marketplace. Depending on the levels of future demand, increased supplies could have a negative impact on prices of heavy oil and bitumen and accordingly, the Company's results of operations, financial condition and prospects. In addition, expansion of existing operations and development of new projects could materially increase the costs of inputs such as natural gas, diluent, labour, equipment, materials or services, which, in turn, may have a material adverse effect on the Company's business, financial condition, results of operations and cash flows.

SAGD Bitumen Recovery Process

The recovery of heavy oil and bitumen using SAGD processes is subject to uncertainty. Current SAGD technologies for in situ extraction of heavy oil and bitumen are energy intensive, requiring significant consumption of natural gas or other fuels to produce steam for use in the recovery process. There can be no assurance that the Company's operations will produce heavy oil and bitumen at the expected levels or on schedule. The amount of steam required in the production process can vary and impact costs significantly. The quality and performance of the heavy oil and bitumen reservoirs can also impact the Company's steam-oil ratio and the timing and levels of production using this technology. Should the Company encounter adverse reservoir conditions, heavy oil and bitumen recovery levels achieved by the Company using SAGD processes may be negatively impacted.

Alkali Sufactant Polymer (ASP) Recovery Process

The recovery of heavy oil using an ASP flood is subject to uncertainty. Alkali surfactant is added to a polymer flood and is intended to dislodge oil trapped in pore spaces of the reservoir. The polymer increases the viscosity of the water to enhance the sweep of the reservoir. The process is subject to risks that include premature water breakthrough, poor reservoir sweep efficiency and adverse chemical reactions in the reservoir. These risks could result in production levels and recovery rates less than expected. In addition, if more chemicals are required to be injected than was anticipated, it could render the project uneconomic.

Credit Risk

In the ordinary course of business, the Company enters into contractual relationships with various parties, including joint venture partners, marketers of the Company's oil and natural gas production and others. In the event these parties fail to meet their contractual obligations the failure may have a material adverse effect on the Company's business, financial condition, results of operation and prospects. As a result of the downturn in economic conditions, the likelihood of a third party failing to meet its obligations has increased.

Expiration of Leases, Licenses or Permits

The Company's properties are held in the form of leases, licenses and permits. If the Company or the holder of the lease, license or permit fails to meet the specific requirement of a lease, license or permit, it may terminate or expire. There can be no assurance that any of the obligations required to maintain each lease, license or permit will be met. The termination of a lease, license or permit may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Reliance on Third Parties

The Company's core projects at Onion Lake, Blackrod and Mooney as well as the non-core assets of the Company will depend on certain infrastructure owned and operated by third parties, including, without limitation processing facilities, capacity on gathering systems and pipelines for the transportation of heavy oil and bitumen to market, natural gas, disposal pipelines and electrical grid transmission lines for the sale of electricity to the Company.

A decline in our ability to market our oil production could have a material adverse effect on production lands or on the prices that we receive for our production.

Currently, all of BlackPearl's heavy oil and bitumen production is trucked from the lease to a sales point. The ability to deliver oil to market is dependent on, among other things, access to trucks and drivers, accidents, weather delay and general road conditions. The Company is also dependent on third parties to provide other services such as drilling and servicing wells.

The failure of any of these third parties to supply goods and services on a timely basis and on acceptable commercial terms will adversely effect the Company's business, financial condition, results of operations and cash flows.

Royalty Regimes

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

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

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

Abandonment and Reclamation Costs

Estimates of the Company's abandonment and reclamation costs will be a function of regulatory requirements existing at the time that the estimates are made, which are subject to change in the future. In addition, the value of the salvaged equipment may be more or less than the abandonment and reclamation costs. Consequently, the estimates may or may not reflect these future costs. The Company has not established a specific fund to provide for the payment of future abandonment and reclamation costs.

Management Estimates and Assumptions

In preparing consolidated financial statements estimates and assumptions are used by management in determining the reported amounts of assets and liabilities, revenues and expenses recognized during the periods presented and disclosures of contingent assets and liabilities known to exist as of the date of the financial statements. These estimates and assumptions must be made because certain information that is used in the preparation of such financial statements is dependent on future events, cannot be calculated with a high degree of precision from data available, or is not capable of being readily calculated based on generally accepted methodologies. In some cases, these estimates are particularly difficult to determine and the Company must exercise significant judgment. Estimates may be used in management's assessment of items such as depreciation and accretion, fair values, useful life of assets, income taxes, stock based compensation and asset retirement obligations. Actual results for all estimates could differ materially from the estimates and assumptions used by the Company, which could have a material adverse effect on the financial condition, results of operations and cash flows of the Company.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Company and may delay exploration and development activities.

Reliance on Key Personnel

BlackPearl's success depends, in part, on the performance of certain key personnel. The loss of services of such key personnel could have a material adverse effect on the Company. In addition, competition for qualified personnel in the oil and gas industry can be intense and there can be no assurance that the Company will be able to continue to attract and retain personnel necessary for the development and operation of its business.

It is likely that other oil sands projects will proceed at the same time as the Blackrod and Onion Lake thermal projects and the Company will compete with these other projects for experienced employees, which may result in increased compensation costs or the inability to hire qualified personnel.

Title to Properties

Although title reviews may be conducted in accordance with industry practice prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells as determined appropriate by management, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat BlackPearl's ownership claim which could result in a reduction of revenues and reserves received by the Company. Any uncertainty with respect to one or more of BlackPearl's interests could have a material adverse effect on BlackPearl's business, prospects and results of operations.

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by the Company is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle East, and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore could have a material adverse effect on the Company's results of operations, financial condition and prospects.

In addition, the long-term impact of previous terrorist attacks and the threat of future terrorist attacks on the oil and gas industry in general, and on facilities for the transportation and refinement of oil and gas in particular, is not known at this time. The possibility that infrastructure and other facilities, such as pipelines, terminals and refineries, may be direct targets of, or indirect casualties of, an act of terror and the implementation of security measures which may be taken as a precaution against possible terrorist attacks have resulted in, and are expected to continue to result in, increased costs to the Company's business. Furthermore, any interruption in the services provided by infrastructure on which the Company relies as a result of terrorist attack would have a material adverse effect on the Company's results of operations, financial condition and prospects.

Insurance Risks

The Company’s property and liability insurance is subject to deductibles, limits and exclusions, and may not provide sufficient coverage for these or other insurable risks. There can be no assurance that such insurance will continue to be offered on an economically feasible basis, that all events that could give rise to a loss or liability are insurable, or that the amounts of insurance (net of applicable deductibles) will at all times be sufficient to cover each and every loss or claim that may occur involving the assets or operations of the Company.

Litigation Risk

In the normal course of the Company’s operations, it may become involved in, named as a party to or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, relating to personal injuries, property damage, property taxes, land rights, the environment and contract disputes. The outcome with respect to future proceedings cannot be predicted with certainty and may be determined adversely to the Company and as a result, could have a material adverse effect on the Company’s business, financial condition, results of operations and cash flows. Even if the Company prevails in any such legal proceeding, the proceedings could be costly and time-consuming and would divert the attention of management and key personnel from the Company’s business operations, which could adversely affect its financial condition.

Tax Reassessments

The Company has filed tax returns and issued "flow-through shares" whereby certain tax benefits generated from the Company’s capital expenditure program have been renounced to investors. Should the Company’s tax returns or renouncements of capital expenditures be audited, there exists a risk that the Company could become liable for incremental income taxes and penalties and could be required to indemnify investors as a result of any reduction in benefits received.

Conflicts of Interest

Some of the directors and officers of the Company are engaged and will continue to be engaged in the search of oil and gas interests on their own behalf and on behalf of other corporations, and situations may arise where the directors and officers will be in direct competition with the Company. Such conflicts must be disclosed in accordance with, and are subject to such other procedures and remedies as apply under the CBCA.

Possible Failure to Realize Anticipated Benefits of Acquisitions

BlackPearl may seek to acquire additional companies or assets in the oil and natural gas industry. The acquisition of companies or assets is subject to substantial risks, including the failure to identify material problems during due diligence, the risk of over-paying for assets, and the inability to arrange financing for an acquisition as may be required or desired. Furthermore, the benefits of any future acquisitions depends, in part, on successfully consolidating functions and integrating operations, procedures and personnel in a timely and efficient manner, as well as BlackPearl's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with its own. The integration of acquired businesses requires the dedication of substantial management effort, time and resources which may divert management’s focus and resources from other strategic opportunities and from operational matters during this process. There can be no assurances that any future acquisitions will perform as expected or that the returns from such acquisitions will support the indebtedness incurred to acquire them or the capital expenditures needed to develop them.

STATEMENT OF RESERVES AND CONTINGENT RESOURCES DATA AND OTHER OIL AND GAS INFORMATION

Sproule has evaluated the proved plus probable heavy oil, bitumen, natural gas and NGLs reserves and contingent resources of the Company as at December 31, 2012 (the "Sproule Report"). Sproule did not evaluate possible reserves. Sproule only evaluated contingent resources for the Company's three core properties: Blackrod, Onion Lake and Mooney.

The reserves and contingent resource data set forth below is based upon the evaluation by Sproule and has been prepared in accordance with NI 51-101.

The reserves and contingent resource data and other oil and gas information set forth below has an effective date of December 31, 2012 and a preparation date of February 1, 2013.

All evaluations of future net revenue are based on forecast prices and costs and are after the deduction of royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. It should not be assumed that the estimated future net revenues presented in the tables below represent the fair market value of the reserves and contingent resources. There is no assurance that the assumptions used in the forecast prices and costs tables will be attained and variances could be material. The recovery and reserve and contingent resource estimates of the Company's heavy oil, bitumen, oil, natural gas and NGLs reserves and contingent resources provided herein are estimates only and there is no guarantee that the estimated reserves and contingent resources will be recovered. Actual heavy oil, bitumen, oil, natural gas and NGLs reserves and contingent resources may be greater than or less than the estimates provided therein (see "Risk Factors ").

The Sproule Report does not take into account taxes or other amounts that may be payable in the future by the Company pursuant to new or existing provincial and federal laws and regulations that restrict or otherwise regulate GHG emissions. See "Regulatory Matters – Greenhouse Gases and Industrial Air Pollutants" and "Risk Factors – Environmental Regulation".

All of BlackPearl's proved plus probable heavy oil, bitumen, oil, natural gas and NGLs reserves and contingent resources are located within Canada, specifically Alberta and Saskatchewan.

Sproule's "Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor" in Form 51-102F2 and "Report on Resources Data by Independent Qualified Reserves Evaluator or Auditor" are attached as Schedule A to this Annual Information Form. The Company's "Report of Management and Directors on Oil and Gas Disclosure" in Form 51-101F3 is attached as Schedule B to this Annual Information Form.

The information set forth below relating to the Company's reserves and contingent resources constitutes forward looking information which is subject to certain risks and uncertainties. See "Forward Looking Statements" and "Risk Factors".

SUMMARY OF OIL AND GAS RESERVES
AS AT DECEMBER 31, 2012
FORECAST PRICES AND COSTS

	Light and Medium Oil and Natural Gas Liquids[(1)]		Heavy Oil		Bitumen		Natural Gas (non-associated & associated)	
Reserve Category	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MMcf)**	**Net (MMcf)**
Proved								
Developed Producing	0.0	0.0	6,779.4	5,097.7	321.6	304.0	223	206
Developed Non-Producing	0.4	0.3	1,859.6	1,329.3	429.1	402.4	11	9
Undeveloped	0.0	0.0	5,565.9	4,338.9	890.0	840.2	0	0
Total Proved	**0.4**	**0.3**	**14,204.8**	**10,766.0**	**1,640.7**	**1,546.5**	**234**	**215**
Probable	0.5	0.3	17,300.4	11,328.8	180,137.3	145,895.5	2	-9
Total Proved Plus Probable	**0.9**	**0.7**	**31,505.3**	**22,094.8**	**181,777.9**	**147,442.0**	**236**	**207**

Notes:
(1) Natural Gas Liquids have been merged with Light and Medium Oil volumes due to the immaterial amounts.

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE OF OIL AND GAS RESERVES
AS AT DECEMBER 31, 2012
FORECAST PRICES AND COSTS

	Before Income Taxes Discounted at (%/Year)							Before Tax Unit Value[(1)]
Reserves Category	**0 (M$)**	**5 (M$)**	**8 (M$)**	**10 (M$)**	**12 (M$)**	**15 (M$)**	**20 (M$)**	**10%/yr ($/Boe)**
Proved								
Developed Producing	175,025	163,722	157,760	154,078	150,608	145,761	138,518	28.34
Developed Non-Producing	62,287	51,291	45,936	42,783	39,920	36,097	30,768	24.68
Undeveloped	86,247	65,459	55,459	49,616	44,341	37,350	27,718	9.58
Total Proved	**323,558**	**280,472**	**259,155**	**246,478**	**234,868**	**219,207**	**197,004**	**19.96**
Probable	4,247,696	1,885,997	1,211,397	911,737	688,921	451,061	208,179	5.80
Total Proved Plus Probable	**4,571,254**	**2,166,469**	**1,470,522**	**1,158,214**	**923,789**	**670,268**	**405,183**	**6.83**

	After Income Taxes Discounted at (%/Year)						
Reserves Category	**0 (M$)**	**5 (M$)**	**8 (M$)**	**10 (M$)**	**12 (M$)**	**15 (M$)**	**20 (M$)**
Proved							
Developed Producing	175,025	163,722	157,760	154,078	150,608	145,761	138,518
Developed Non-Producing	62,287	51,291	45,936	42,783	39,920	36,097	30,768
Undeveloped	86,247	65,459	55,459	49,616	44,341	37,350	27,718
Total Proved	**323,558**	**280,472**	**259,155**	**246,478**	**234,868**	**219,207**	**197,004**
Probable	3,236,977	1,409,681	887,927	656,029	483,487	299,155	110,840
Total Proved Plus Probable	**3,560,535**	**1,690,153**	**1,147,082**	**902,506**	**718,355**	**518,362**	**307,844**

Notes:
(1) Unit values are based on net reserve volumes.

TOTAL FUTURE NET REVENUE (undiscounted)
AS AT DECEMBER 31, 2012
FORECAST PRICES AND COSTS

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Abandonment (1)	Future Net Revenue Before Income Taxes	Future Income Taxes	Future Net Revenue After Income Taxes
	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)
Proved	1,061,242	227,968	369,914	127,275	12,527	323,558	0	323,558
Proved Plus Probable	15,374,630	3,150,092	5,243,523	2,365,865	43,893	4,571,254	1,010,718	3,560,535

Note:

(1) The abandonment costs only include downhole abandonment costs for the wells considered in Sproule's evaluation of reserves. Abandonment of other wells, surface reclamation and facility site reclamation are not included. See "Reclamation and Abandonment Costs."

NET PRESENT VALUE OF FUTURE NET REVENUE BY PRODUCTION GROUP
AS AT DECEMBER 31, 2012
FORECAST PRICES AND COSTS

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (M$)	Unit Value(2) Before Income Taxes (Discounted at 10%/Year) ($/Boe)
Proved	Light and Medium Crude Oil (including solution gas and associated by-products)	0	0
	Heavy Oil (including solution gas and associated by-products)	228,017	21.11
	Bitumen (including solution gas and associated by-products)	18,464	11.94
	Natural Gas (including associated by-products)(1)	-4	-2.05
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and associated by-products)	0	0
	Heavy Oil (including solution gas and associated by-products)	449,923	20.33
	Bitumen (including solution gas and associated by-products)	708,292	4.80
	Natural Gas (including associated by-products)(1)	0	-0.08

Notes:

(1) Includes Corporate GCA, if applicable.

(2) Unit values are based on net reserve volumes.

Definitions and Notes to Reserves Data Tables

In the tables set forth under the heading "Statement of Reserves and Contingent Resources Data and Other Oil and Gas Information" and elsewhere in this Annual Information Form the following definitions and notes are applicable:

1) Columns and rows may not add due to rounding.

2) **"COGE Handbook"** means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum, (Petroleum Society), as amended from time to time.

3) **"Development costs"** means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

   (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;
   (b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;
   (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and
   (d) provide improved recovery systems.

4) **"Development well"** means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

5) **"Exploration costs"** means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

   (a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;
   (b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;
   (c) dry hole contributions and bottom hole contributions;
   (d) costs of drilling and equipping exploratory well; and
   (e) costs of drilling exploratory type stratigraphic test wells.

6) **"Gross"** means:

   (a) In relation to the Company's interest in production or reserves, the Company's working interest (operating and non-operating) share before deduction of royalties;
   (b) In relation to wells, the total number of wells in which the Company has an interest; and
   (c) In relation to properties, the total area of properties in which the Company has an interest.

7) **"Net"** means:

   (a) In relation to the Company's interest in production or reserves, BlackPearl's working interest (operating and non-operating) share after deduction of royalty obligations, plus the Company's royalty interest in production or reserves;
   (b) In relation to the Company's interest in wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and
   (c) In relation to the Company's interest in a property, the total area in which BlackPearl has an interest multiplied by the Company's working interest.

8) **"Reserves"** are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on:

   (a) analysis of drilling, geological, geophysical and engineering data;
   (b) the use of established technology; and
   (c) specified economic conditions (The key economic assumptions include, but are not limited to, the prices and costs used in the estimate, namely the forecast prices and cost).

Reserves are classified according to the degree of certainty associated with the estimates.

(a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
(b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved and probable reserves.
(c) **Possible reserves** are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

Each of the reserve categories (proved, probable and possible) may be divided into developed and undeveloped categories:

(a) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.
(b) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
(c) **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption is unknown.
(d) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation is based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserve estimates are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
(b) at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and
(c) at least a 10% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates are prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

9) **"Service well"** means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

Pricing Assumptions

The price forecasts that formed the basis for the revenue projections and net present value estimates in the Sproule Report were based on Sproule's December 31, 2012 pricing models. A summary of selected price forecasts used by Sproule is set forth below.

SUMMARY OF PRICING USED IN PREPARATION OF RESERVES AND CONTINGENT RESOURCES DATA AS AT DECEMBER 31, 2012 FORECAST PRICES AND COSTS(1)(4)(5)

Year	WTI Cushing Oklahoma ($US/Bbl)	Edmonton Par Price 40° API ($Cdn/Bbl)	Western Canadian Select 20.5° API ($Cdn/Bbl)	Natural Gas AECO Gas Prices ($Cdn/MMBtu)	Pentanes Plus FOB Edmonton ($Cdn/Bbl)	Butanes FOB Edmonton ($Cdn/Bbl)	Inflation Rate(2) (%/Yr)	Exchange Rate(3) ($US/$Cdn)
Historical								
2008	99.59	102.85	83.62	8.15	104.70	75.09	1.1	0.943
2009	61.63	66.20	58.66	4.19	68.13	49.34	2.0	0.880
2010	79.43	77.80	67.21	4.16	84.21	57.99	1.2	0.971
2011	95.00	95.16	77.09	3.72	104.12	70.93	1.6	1.012
2012	94.19	86.53	73.04	2.43	100.76	64.48	1.3	1.001
Forecast								
2013	89.63	84.55	69.33	3.31	90.53	63.02	1.5	1.001
2014	89.93	89.84	74.57	3.72	96.19	66.96	1.5	1.001
2015	88.29	88.21	73.21	3.91	94.44	65.74	1.5	1.001
2016	95.52	95.43	80.17	4.70	102.18	71.13	1.5	1.001
2017	96.96	96.87	81.37	5.32	103.71	72.20	1.5	1.001
2018	98.41	98.32	82.59	5.40	105.27	73.28	1.5	1.001
2019	99.89	99.79	83.83	5.49	106.85	74.38	1.5	1.001
2020	101.38	101.29	85.08	5.58	108.45	75.50	1.5	1.001
2021	102.91	102.81	86.36	5.67	110.08	76.63	1.5	1.001
2022	104.45	104.35	87.66	5.76	111.73	77.78	1.5	1.001
Thereafter	Escalation Rate of 1.5% per annum thereafter							

Notes:

(1) This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.
(2) Inflation rates used in forecasting prices and costs.
(3) Exchange rates used to generate the benchmark reference prices in this table.
(4) None of the Company's future production is subject to a fixed or contractually committed price.
(5) The Company's weighted average wellhead price in 2012 was $61.76 per Bbl for heavy oil/bitumen/NGLs and $2.45 per Mcf for natural gas.

Reconciliation of Changes in Reserves and Future Net Revenue

The following table summarizes the changes in the Company's gross oil and gas reserves (before the deduction for royalties) from December 31, 2011 to December 31, 2012.

RECONCILIATION OF COMPANY GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
BASED ON FORECAST PRICES AND COSTS

	Light and Medium Oil and Natural Gas Liquids			Heavy Oil			Bitumen			Natural Gas (non-associated & associated)		
	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)
Dec. 31, 2011	1.9	3.0	4.9	13,408	20,113	33,522	1,753	197	1,950	695	1,311	2,007
Extensions & Improved Recovery	0	-0.9	-0.9	5,388	-1,558	3,830	0	179,977	179,977	24	-682	-658
Technical Revisions	-1.1	-1.9	-3.0	-1,445	-1,511	-2,956	4	-36	-33	-149	-571	-720
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0
Acquisitions	0	0	0	199	228	427	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	-0.3	0.3	0	-40	28	-11	0	0	0	-199	-55	-256
Production	-0.1	0	-0.1	-3,306	0	-3,306	-116	0	-116	-137	0	-137
Dec. 31, 2012	0.4	0.5	0.9	14,205	17,301	31,505	1,641	180,137	181,778	234	3	236

Undeveloped Reserves

The following table discloses, for each product type, the volumes of undeveloped reserves that were first attributed in each of the most recent three financial years.

Reserves	Light & Medium Oil and Natural Gas Liquids		Heavy Oil		Bitumen		Natural Gas (non-associated & associated)	
	1st attributed Gross (Mbbl)	Cumulative Gross (Mbbl)	1st attributed Gross (Mbbl)	Cumulative Gross (Mbbl)	1st attributed Gross (Mbbl)	Cumulative Gross (Mbbl)	1st attributed Gross (MMcf)	Cumulative Gross (MMcf)
Proved Undeveloped								
Prior to Dec. 31, 2010 (in aggregate)	6	6	3,819	6,967	0	0	2	240
Dec. 31, 2010	0	1	2,401	6,526	0	0	0	310
Dec. 31, 2011	0	1	2,796	6,530	890	890	103	213
Dec. 31, 2012	0	0	749	5,566	0	890	0	0
Probable Undeveloped								
Prior to Dec. 31, 2010 (in aggregate)	5	5	2,396	8,579	0	0	1	374
Dec. 31, 2010	0	2	1,420	11,718	0	0	159	873
Dec. 31, 2011	1	3	7,980	18,132	197	197	540	1,195
Dec. 31, 2012	0	0	1,530	8,432	179,977	180,052	0	0

Undeveloped reserves are attributed by Sproule in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those additional reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

BlackPearl has a significant level of undeveloped reserves relative to developed reserves. The majority of undeveloped reserves assigned by Sproule were to the Blackrod, Mooney, Onion Lake and John Lake fields.

At Blackrod, Sproule assigned proved and probable undeveloped reserves to the current pilot and its expansion and probable reserves to phase one of the Blackrod SAGD Project. The Blackrod SAGD Project represents the majority of BlackPearl's probable undeveloped reserves. If BlackPearl receives regulatory approval for the Blackrod SAGD Project and commits to spend, within three years, the funds necessary to achieve first bitumen production a portion of these probable undeveloped reserves are expected to become proved undeveloped reserves. Upon initiation of production and ramp up of production to design rates, some of these undeveloped reserves will become developed reserves.

At Mooney, the majority of the proved and probable undeveloped reserves were assigned based upon the continued extension of the field to the west and south and the continued conversion of the field to the EOR scheme. Construction of the commercial ASP flood injection facility was completed and ASP injection commenced in 2011; while a new heavy oil processing facility was constructed and began to handle the increased fluid volumes from the area in 2012. In 2012, we began to see production response from the initial re-pressurization of the reservoir and we expect to see further response in 2013. With this initial response, we are planning to continue development of the phase two and phase three lands with 15 to 20 wells expected to be drilled in 2013. In February 2013, we applied for regulatory approval to expand the existing ASP flood to the phase two lands. We are also planning to construct the pipeline infrastructure necessary to allow further development drilling of the phase three lands which is expected to occur later in 2013. Future follow up phases of the ASP flood, including phase 3, will likely occur over the longer term and will likely be controlled by the throughput constraints of the ASP injection and production facilities. Sproule assigned proved and probable undeveloped reserves to 16 future primary horizontal development locations including the implementation of EOR across 11 future well pairs. The high level of proved and probable undeveloped reserves relative to developed reserves at Mooney reflects the ongoing implementation of the ASP flood and the continued extension of the field; as the Mooney field continues to show increasing production response from the ASP flood, is further delineated and as the ASP flood is implemented across more well pairs, the ratio of undeveloped to developed reserves is expected to decline.

At Onion Lake, Sproule assigned proved and probable undeveloped reserves to 146 future drilling locations. To date, we have drilled 11 of these wells and have budgeted to drill another 9 wells in 2013. We will likely drill an additional 20 to 40 of these locations in 2014. BlackPearl continues to extend the reservoir boundaries at Onion Lake and as a result there continues to be a relatively high level of undeveloped reserves relative to developed reserves. As the field's primary development continues to mature, it is expected that the ratio of undeveloped to developed reserves will continue to fall.

At John Lake, Sproule assigned proved and probable undeveloped reserves to 13 future horizontal drilling locations and 10 vertical drilling locations. In 2013, we may drill up to 5 of these locations. At John Lake exploitation of the Sparky reservoir using horizontal wells is relatively new and delineation of the Cummings reservoir is in its early stages, as a result there continues to be a relatively high level of undeveloped reserves relative to developed reserves. As the field's primary development continues to mature it is expected that the ratio of undeveloped to developed reserves will continue to fall.

The actual number of wells drilled could change as a result of changes in, among other items, economic conditions, technical and operating results, or changing budget priorities. A portion of the Company's capital budget is allocated to new projects or projects that do not have reserves assigned as yet. As a result, all capital required to develop the undeveloped reserves may not be spent in the next two years.

Significant Factors or Uncertainties

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. A number of economic factors can also affect the reserves, including product prices, royalty and tax regimes, and changes in operating and capital costs. The reserves estimates contained herein are based on current production forecasts, prices and economic conditions. See "Risk Factors".

As circumstances change and additional data become 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 restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to estimates can arise from changes in year-end oil and natural gas prices and reservoir performance. Such revisions can be either positive or negative. See "Risk Factors".

Future Development Costs

The following table sets forth development costs (all within Canada) deducted in the estimation of future net revenue attributable to the reserve categories below using forecast costs.

Year	Total Proved ($M)	Total Proved Plus Probable ($M)
2013	45,602	93,474
2014	32,917	278,103
2015	16,469	468,453
2016	23,053	54,862
2017	6,173	69,517
Remainder	3,061	1,401,456
Total for all years undiscounted	127,275	2,365,865

On-going development at Mooney and conventional development at Onion Lake is expected to be funded from cash flow and the Company's existing credit facilities. However, the SAGD projects at Blackrod and Onion Lake will require significant capital investment to develop these properties that will likely necessitate additional external financing. We are currently evaluating funding options for these projects which include making use of the Company's existing credit facilities, additional debt or equity offerings, using proceeds from the disposition of additional non-core properties or potentially selling one of the three core projects. We anticipate putting our financing strategy in place for these projects during 2013.

There can be no guarantee that funds will be available or that the Company's Board of Directors will allocate funding to develop all of the reserves in the reserve reports. Failure to develop those reserves would have a negative impact on future cash flow.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. We do not anticipate that interest or other funding costs would make development of any property uneconomic.

See "Risk Factor – Access to Capital."

CONTINGENT RESOURCES

The following tables summarize certain information contained in the contingent resource evaluations prepared by Sproule as of December 31, 2012. The reports were independently prepared in accordance with definitions, standards and procedures contained in the COGE Handbook, and are based on Sproule's December 31, 2012 pricing models (see "Pricing Assumptions"). The following tables do not include the proved and probable reserves assigned by Sproule as at December 31, 2012.

It should not be assumed that the estimates of recovery, production, and net revenue presented in the tables below represent the fair market value of the Company's contingent resources. There is no assurance that the forecast prices and cost assumptions will be realized and variances could be material. The recovery and production estimates of the Company's contingent resources provided herein are only estimates and there is no guarantee that the estimated contingent resources will be recovered or produced. Actual contingent resources may be greater than or less than the estimates provided herein. The contingencies which currently prevent the classification of these contingent resources as reserves are described in notes 7, 8 and 9 on pages 41 and 42 of this AIF. Once all contingencies are removed, the resources may then be reclassified as reserves. There is no certainty that it will be commercially viable for the Company to produce any portion of the contingent resources on any of its properties.

SUMMARY OF CONTINGENT RESOURCES
AS AT DECEMBER 31, 2012
FORECAST PRICES AND COSTS

	Light and Medium Oil and Natural Gas Liquids		Heavy Oil		Bitumen		Natural Gas (non-associated & associated)	
Project	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)
Blackrod(7)								
Low Estimate(3)	0	0	0	0	424,393	358,562	0	0
Best Estimate(2)	0	0	0	0	475,521	393,582	0	0
High Estimate(4)	0	0	0	0	527,963	428,495	0	0
Onion Lake(8)								
Low Estimate(3)	0	0	62,000	52,136	0	0	0	0
Best Estimate(2)	0	0	70,212	58,380	0	0	0	0
High Estimate(4)	0	0	78,341	64,424	0	0	0	0
Mooney(9)								
Low Estimate(3)	0	0	40,428	24,390	0	0	888	621
Best Estimate(2)	0	0	36,384	21,883	0	0	1,085	761
High Estimate(4)	0	0	43,923	25,964	0	0	1,276	887

SUMMARY OF VOLUMES AND NET PRESENT VALUES OF CONTINGENT RESOURCES
AS AT DECEMBER 31, 2012
FORECAST PRICES AND COSTS

Project	Contingent Resources	Net Present Values of Future Net Revenue Before Income Taxes Discounted at (%/year)						
		0%	5%	8%	10%	12%	15%	20%
	(MMboe)	($million)						
Blackrod(7)								
Low Estimate(3)	424	6,947	2,709	1,525	1,019	657	295	-29
Best Estimate(2)	476	9,037	3,500	2,018	1,393	951	510	112
High Estimate(4)	528	11,276	4,237	2,438	1,695	1,174	660	199
Onion Lake(8)								
Low Estimate(3)	62	2,434	1,308	921	733	585	418	234
Best Estimate(2)	70	2,892	1,514	1,058	840	671	482	277
High Estimate(4)	78	3,424	1,733	1,196	945	753	541	316
Mooney(9)								
Low Estimate(3)	40	777	381	267	215	173	128	77
Best Estimate(2)	37	743	332	220	169	131	89	44
High Estimate(4)	44	1,000	434	291	228	181	129	74

Project	Contingent Resources	Net Present Values of Future Net Revenue After Income Taxes (10) Discounted at (%/year)						
		0%	5%	8%	10%	12%	15%	20%
	(MMboe)	($million)						
Blackrod(7)								
Low Estimate(3)	424	5,196	1,897	990	607	336	69	-161
Best Estimate(2)	476	6,767	2,497	1,368	897	566	240	-45
High Estimate(4)	528	8,447	3,053	1,688	1,129	740	359	25
Onion Lake(8)								
Low Estimate(3)	62	1,777	937	649	509	399	274	137
Best Estimate(2)	70	2,111	1,088	750	588	462	322	170
High Estimate(4)	78	2,500	1,249	851	666	523	366	200
Mooney(9)								
Low Estimate(3)	40	582	281	194	154	123	88	50
Best Estimate(2)	37	556	244	158	120	91	59	25
High Estimate(4)	44	750	321	212	165	129	91	49

Notes:

(1) **Contingent resources** are defined in the COGE Handbook as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as Contingent Resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent Resources are further classified in accordance with the level of certainty associated with the estimates and may be subclassified based on project maturity and/or characterized by their economic status.

(2) **Best estimate** (P50) is a classification of estimated resources described in the COGE Handbook as being considered to be the best estimate of the quantity that will be actually recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate.

(3) **Low estimate** (P90) is a classification of estimated resources described in the COGE Handbook as being considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the Low Estimate. If probabilistic methods are used, there should be a 90% probability that the quantities actually recovered will equal or exceed the Low Estimate.

(4) **High estimate** (P10) is a classification of estimate resources described in the COGE Handbook as being considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the High Estimate. If probabilistic methods are used, there should be a 10% probability that the quantities actually recovered will equal or exceed the High Estimate.

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

(6) The amounts included in these tables do not include the volume and value of BlackPearl's proved and probable reserves previously assigned by Sproule to these properties.

(7) The contingencies in the Sproule Report associated with the Company's Blackrod contingent resources are due to the following:

Technical Contingencies

• The requirement for more evaluation drilling to define the reservoir characteristics of the resource;

We intend to complete delineation drilling required for the future phases of commercial development. The timing of additional delineation drilling required to satisfy ERCB requirements for future commercial phases at Blackrod has not been established.

Non-technical Contingencies

• The absence of submission of commercial SAGD development application;

The application to develop phase one (20,000 Bbls/d of the 80,000 Bbls/d commercial development) was submitted to regulatory authorities in the first half of 2012. Timing for development of future phases of the project has not been established.

• The uncertainty of timing of production and development.

BlackPearl expects to commence the first phase of commercial development at Blackrod within the next five years. Timing is dependent upon, among other things, oil and natural gas prices, anticipated capital and operating costs and the Company's ability to finance the construction of the project. The timing of future phases has not been established.

Economic Contingencies

• The contingent resources disclosed are not contingent due to economic factors.

(8) The contingencies in the Sproule Report associated with the Company's Onion Lake contingent resources are due to the following:

Technical Contingencies

• The requirement for more evaluation drilling to define the reservoir characteristics of the resource;

BlackPearl intends to continue delineation drilling to better define the resource (as part of its on-going primary development program) in 2013. The timing of additional delineation drilling to define the entire thermal resource has not been established.

Non-technical Contingencies

• The uncertainty of company commitment for commercial SAGD development;

BlackPearl has not established a timetable for commercial SAGD development at Onion Lake. Timing is dependent upon, among other things, oil and natural gas prices, anticipated capital and operating costs and the Company's ability to finance the construction of the project.

• The uncertainty of timing of production and development.

BlackPearl has not established a timetable for commercial SAGD development at Onion Lake. Timing is dependent upon, among other things, oil and natural gas prices, anticipated capital and operating costs and the Company's ability to finance the construction of the project.

Economic Contingencies

• The contingent resources disclosed are not contingent due to economic factors.

(9) The contingencies in the Sproule Report associated with the Company's Mooney contingent resources are due to the following:

Technical Contingencies

• The requirement for more evaluation wells to further define reservoir and fluid characteristics.

BlackPearl expects to drill additional evaluation wells over the next several years. The timing of further delineation drilling beyond those wells contemplated in the next several years to further extend the reservoir and better understand its fluid characteristics has not been established.

Non-technical Contingencies

• Further establishment of increased oil production response from the Alkali Surfactant Polymer (ASP) flood in Phase One, which began July 2011.

The first phase of the ASP flood is in operation and initial oil production response from the ASP flood was achieved in 2012. Further ASP response is anticipated in 2013.

• The uncertainty of timing of production and development of the entire field.

BlackPearl expects to commence phase two of the ASP flood within the next 12 to 18 months. Timing of additional phases of the ASP flood have not been determined; however, it is expected that development of future ASP wells will be timed in order to utilize spare capacity as it becomes available at the central ASP injection facility and the central battery.

Economic Contingencies

• The contingent resources disclosed are not contingent due to economic factors.

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

OTHER OIL AND GAS INFORMATION

OIL AND GAS WELLS

The following table sets out BlackPearl's gross and net interests in oil and natural gas wells in which it has a working interest as at December 31, 2012 (all of which are on-shore wells):

	Oil wells				Gas wells			
	Producing		Non-producing		Producing		Non-producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada								
Alberta	64	64	106	104	-	-	8	5
Saskatchewan	114	100	180	159	4	4	69	67
Total Canada	178	164	286	263	4	4	77	72
U.S.	-	-	16	8	-	-	-	-
Total	178	164	302	271	4	4	77	72

LAND HOLDINGS INCLUDING PROPERTIES WITH NO ATTRIBUTED RESERVES

The following table sets out the developed and undeveloped land holdings as at December 31, 2012.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	25,420	22,158	111,060	106,200	136,480	128,358
Saskatchewan	34,124	33,390	26,462	24,794	60,586	58,184
British Columbia						
Total - Canada	59,544	55,548	137,522	130,994	197,066	186,542
Total – USA	520	260	65,673	50,425	66,193	50,685
Total	60,064	55,808	203,195	181,419	263,259	237,227

The Company has commitments to drill two horizontals well in Saskatchewan in the next 12 months. BlackPearl expects its rights to explore, develop and exploit approximately 3,223 net acres of its undeveloped land to expire within the next year.

FORWARD CONTRACTS

As at December 31, 2012, BlackPearl is not bound by any material agreement under which it is precluded from fully realizing, or being protected from, the full effect of future market prices for its production and did not have any fixed price contracts to sell any of its production. The majority of the Company's production is currently sold under short-term contracts.

ABANDONMENT AND RECLAMATION COSTS

The following table summarizes the estimate for abandonment and disconnect costs included in the report by Sproule for wells which have reserves assigned. Only well abandonment costs and disconnect costs were deducted by Sproule in estimating future net revenue in the Sproule Report. No allowance for surface lease reclamation or downhole salvage value was included. It does not include costs to abandon pipelines, facilities or wells for which no reserves have been assigned. BlackPearl expects to incur abandonment and reclamation costs on approximately 548 net wells.

Total Abandonment and Reclamation Costs and Timing for Expected Payments

Year	Total Proved (M$)	Total Proved Plus Probable (M$)
2013	122	71
2014	577	484
2015	938	471
2016	2,452	605
2017	2,359	2,173
Remaining	6,079	40,089
Total (Undiscounted)	12,527	43,893
Total (Discounted at 10%)	7,892	11,450

BlackPearl has not established a reclamation fund to pay future asset retirement obligation costs. During 2012, the Company incurred $1.0 million to abandon and reclaim sites.

For purposes of preparation of decommissioning liabilities on the Company's December 31, 2012 consolidated financial statements, the Company estimated an undiscounted amount of $39.7 million ($22.9 million discounted at 10%) to abandon all wells (including wells which have no reserves assigned), pipelines and facilities owned by the Company as at December 31, 2012.

The future asset retirement obligation is reviewed regularly by management based upon current regulations, costs, technologies and industry standards. The discounted obligation is recognized as a liability and is accreted against income until it is settled or the property is sold and is included as a component of net finance expense. Actual restoration expenditures are charged to the accumulated obligation as incurred.

TAX HORIZON

The Company did not pay any current income taxes in the year ended December 31, 2012. As at December 31, 2012, the Company had approximately $592 million of tax pools and loss carry-forwards available to be applied against future income for tax purposes (not all tax pools can be fully utilized in any single year).

On a total proved reserves basis, the Sproule Report estimates that the Company will not be taxable. On a proved and probable reserves basis, the Sproule Report indicates the Company will be taxable in 2018. The Sproule Report does not include capital spending on projects that have not been assigned proved and probable reserves. This additional spending could impact the Company's tax horizon. The Company's internal estimate is that it will not be taxable until 2020.

The Company's tax horizon is dependent on, among other things, anticipated levels of operations, anticipated capital spending, the current tax regime and the current commodity price forecast. Changes in these factors from estimates used by the Company could result in the Company paying income taxes earlier or later than expected.

COSTS INCURRED

The following table summarizes capital expenditures made by BlackPearl on oil and natural gas properties for the year ended December 31, 2012.

($millions)	Canada	U.S.	Total
Property acquisition costs – unproved	0	0	0
Property acquisition costs – proved	3.0	0	3.0
Exploration costs [(1)]	27.9	0	27.9
Development costs	108.6	0	108.6
Total	139.5	0	139.5

Note:

(1) Includes costs of land, geological and geophysical expenses and drilling costs for exploration wells.

EXPLORATION AND DEVELOPMENT ACTIVITIES

The following table summarizes the number of gross and net exploratory and development wells BlackPearl participated in drilling during the year ended December 31, 2012.

	Development wells		Exploratory wells	
	Gross	Net	Gross	Net
Oil Wells	64	59	-	-
Gas Wells	0	0	-	-
Service Wells	-	-	-	-
Stratigraphic Wells	10	10		
Dry	0	0	-	-
Total	74	69	-	-

All of the wells drilled in 2012 were located in Canada, and all of our planned exploration and development activities for 2013 are located in Canada. For a summary of our most important current and likely exploration and development activities, see "Description of Our Business – Description of Our Properties".

PRODUCTION ESTIMATES

The following table sets out our estimated working interest production volumes for the year ended December 31, 2013 which is reflected in the estimate of gross proved and probable reserves disclosed in the tables contained under "Statement of Reserves and Contingent Resources Data and Other Oil and Gas Information".

	Gross Daily Production Total
Total Proved	
Light & Medium Oil (Bbl/d)	0
Heavy Oil (Bbl/d)	9,063
Bitumen (Bbl/d)	581
Natural Gas (Mcf/d)	326
Natural Gas Liquids (Bbl/d)	0
Total (Boe/d)	**9,700**
Total Probable	
Light & Medium Oil (Bbl/d)	0
Heavy Oil (Bbl/d)	2,234
Bitumen (Bbl/d)	92
Natural Gas (Mcf/d)	46
Natural Gas Liquids (Bbl/d)	0
Total (Boe/d)	**2,334**
Total Proved + Probable	
Light & Medium Oil (Bbl/d)	1
Heavy Oil (Bbl/d)	11,298
Bitumen (Bbl/d)	673
Natural Gas (Mcf/d)	371
Natural Gas Liquids (Bbl/d)	0
Total (Boe/d)	**12,033**

All of BlackPearl's forecasted production for 2013 is expected to come from the Company's Canadian properties. The Onion Lake field in Saskatchewan accounts for 43% (5,217 Boe/d) of BlackPearl's total forecasted 2013 production from its Proved plus Probable reserves and the Mooney field in Alberta accounts for 42% (5,061 Boe/d) of BlackPearl's total forecasted 2013 production from its Proved plus Probable reserves.

PRODUCTION HISTORY

The following table indicates the Company's average gross daily oil and gas production in 2011 and 2012:

	2012				2011			
	Heavy Oil[(1)]	Bitumen	Gas	Boe/d	Heavy Oil[(1)]	Bitumen	Gas	Boe/d
	(Bbl/d)	(Bbl/d)	(Mcf/d)		(Bbl/d)	(Bbl/d)	(Mcf/d)	
Onion Lake	5,947	-	-	5,947	6,272	-	-	6,272
Mooney	2,475	-	369	2,537	682	-	638	788
John Lake	573	-	-	573	343	-	-	343
Blackrod	-	272	-	272	-	57	-	57
Other	36	-	5	37	106	-	322	160
	9,031	272	374	9,366	7,403	57	960	7,620

Note:

(1) Light and medium crude oil and natural gas liquids are not material and have been grouped with Heavy Oil for reporting purposes.

NETBACKS

The following table sets forth certain information in respect of production, product prices, royalties, transportation costs, production costs and netbacks received for each quarter of the Company's most recently completed financial year. The table excludes operating results of the pilot project at Blackrod.

	Quarter Ended				Year Ended
	Mar. 31, 2012	June 30, 2012	Sep. 30, 2012	Dec. 31, 2012	2012
Average Daily Production [(1)(2)]					
Heavy Oil (Bbl/d)	9,300	9,117	8,941	8,773	9,032
Natural Gas (mcf/d)	234	334	485	440	374
Products Combined (Boe/d)	9,339	9,173	9,022	8,846	9,094
Average Net Prices Received					
Heavy Oil ($/Bbl)	68.20	59.10	60.76	58.77	61.76
Natural Gas ($/Mcf)	2.24	1.94	2.20	3.18	2.45
Products Combined (Boe/d)	67.98	58.82	60.34	58.45	61.45
Transportation Costs [(3)]					
Heavy Oil ($/Boe)	2.12	2.82	3.07	3.07	2.76
Royalties					
Heavy Oil ($/Boe)	15.60	12.72	13.05	12.30	13.44
Production Costs [(3)]					
Heavy Oil ($/Boe)	19.63	16.71	16.99	17.89	17.82
Netback Received [(4)]					
Heavy Oil ($/Boe)	30.63	26.57	27.23	25.19	27.43

Notes:

(1) Light and Medium Crude Oil and Natural Gas Liquids are not material and have been grouped with Heavy Oil volumes for reporting purposes.

(2) Before deduction of royalties.

(3) Operating expenses are composed of direct costs incurred to operate both oil and gas wells. The majority of our gas volumes are associated gas from oil wells and are not material amounts (1%); therefore, we have reported transportation costs, royalties, production costs and netbacks on a Boe basis only.

(4) Netbacks are calculated by subtracting royalties, transportation costs and production expenses from revenues.

DIVIDENDS

There are no restrictions which prevent BlackPearl from paying dividends. To date, BlackPearl has not paid any dividends on the BlackPearl Shares. The future payment of dividends, if any, will depend on the earnings and financial condition of BlackPearl and such other factors as the Board considers appropriate. The Company does not anticipate paying dividends on BlackPearl Shares in the foreseeable future as it intends to retain future earnings for the development of its oil and gas assets.

DESCRIPTION OF CAPITAL STRUCTURE

The authorized capital of BlackPearl consists of an unlimited number of BlackPearl Shares. As at February 26, 2013, there were 296,108,308 BlackPearl Shares issued and outstanding.

Each BlackPearl Share entitles the holder to receive notice of and to attend all meetings of the shareholders of the Company and to one vote at such meetings. The holders of BlackPearl Shares are, at the discretion of the Board and subject to applicable legal restrictions, entitled to receive any dividends declared by the Board. The holders of BlackPearl Shares are entitled to share equally in any distribution of the assets of the Company upon the liquidation, dissolution, bankruptcy or winding-up of the Company or other distribution of its assets among its shareholders for the purpose of winding-up its affairs. The Company has not adopted a shareholder rights plan.

MARKET FOR SECURITIES

Trading Price and Volume

The BlackPearl Shares are listed and posted for trading on the TSX and trade under the symbol "PXX". The Company's SDRs trade on NASDAQ OMX Stockholm market under the symbol "PXXS". The following sets forth the price range and trading volume of the BlackPearl Shares on the TSX for the periods indicated.

2012	High ($/Share)	Low ($/Share)	Volume
January	5.47	4.26	21,299,051
February	4.91	4.37	28,777,165
March	4.56	3.97	61,385,704
April	4.45	3.67	26,573,880
May	4.51	3.64	33,345,364
June	4.06	2.71	39,841,490
July	3.41	2.82	34,339,673
August	3.50	3.05	27,848,321
September	4.08	3.09	26,406,388
October	3.88	3.37	14,948,250
November	3.51	3.03	18,695,370
December	3.20	2.87	17,827,632

Prior Sales

The Company has issued the following BlackPearl Shares during the 12 month period ended December 31, 2012:

Date	Price per Common Share ($)	Number of Common Shares
January 3, 2012 (1)	0.77	100,000
January 3, 2012 (1)	1.75	10,000
January 5, 2012 (1)	2.53	13,500
January 9, 2012 (1)	0.77	100,000
January 12, 2012 (1)	1.75	2,500
January 12, 2012 (1)	4.65	18,000
January 12, 2012 (1)	0.77	100,000
February 15, 2012 (1)	2.21	6,667
March 20, 2012 (1)	2.21	20,000
April 2, 2012 (1)	2.21	25,000
April 12, 2012 (1)	1.95	73,167
June 6, 2012 (1)	2.42	15,000
June 6, 2012 (1)	0.83	9,000
June 7, 2012 (1)	2.42	18,334

Date	Price per Common Share ($)	Number of Common Shares
June 27, 2012 (1)	1.75	5,000
August 14, 2012 (1)	3.43	9,000
August 16, 2012 (1)	1.19	30,000
September 14, 2012 (1)	2.21	16,667
September 14, 2012 (1)	2.53	13,500
September 19, 2012 (1)	0.40	6,000
September 20, 2012 (1)	0.63	8,000
October 5, 2012 (1)	1.75	10,000
October 19, 2012 (1)	0.63	5,000
November 16, 2012 (1)	2.53	46,500
November 21, 2012 (1)	2.53	115,300
November 22, 2012 (1)	2.53	384,700
November 23, 2012 (1)	2.53	37,500
November 23, 2012 (2)	3.29	5,100
November 27, 2012 (2)	0.60	50,000
November 28, 2012 (2)	0.60	2,361,299
November 29, 2012 (1)	0.60	4,822,598
December 11, 2012 (1)	0.60	2,411,299
December 11, 2012 (1)	2.53	36,000
December 13, 2012 (1)	2.21	16,666
December 13, 2012 (1)	2.53	40,500
December 14, 2012 (1)	2.53	12,000
December 14, 2012 (1)	1.75	10,000

Notes:

(1) Issued pursuant to the exercise of stock options pursuant to and in accordance with the Company's stock option plan.

(2) Issued pursuant to the exercise of warrants.

During the 12 month period ended December 31, 2012, the Company granted options exercisable for 3,079,500 BlackPearl Shares, the particulars of which are set forth in the following table:

Date of Grant	Number of Options Issued (1)	Exercise Price ($)
January 9, 2012	200,000	4.58
May 17, 2012	1,874,500	3.87
June 21,2012	150,000	3.55
July 9, 2012	15,000	3.11
September 17, 2012	100,000	3.78
October 9, 2012	50,000	3.64
November 9, 2012	690,000	3.09

Note:

(1) Each option entitles the holder to acquire one BlackPearl Share, on the terms and conditions set forth in the Company's stock option plan.

DIRECTORS AND EXECUTIVE OFFICERS

The following table sets forth the name, municipality of residence, principal occupation for the prior five years and position of each of the directors and executive officers of BlackPearl:

Name and Residence	Principal Occupation for Past Five Years	Position	Date Appointed
John H. Craig (1)(2)(3) Toronto, Ontario, Canada	Mr. Craig is a lawyer and partner of Cassels Brock & Blackwell LLP since September 1994.	Chairman and Director	May 2009
Brian D. Edgar (1)(2)(3)(4) Vancouver, British Columbia, Canada	Mr. Edgar is Chairman of Silver Bull Resources, Inc. (formerly Metalline Mining Company), an exploration stage mining company since April 2010. From February 2005 to April 2010, Mr. Edgar was President and Chief Executive Officer of Dome Ventures Corporation which was merged with Metalline Mining Company in April 2010.	Director	Feb. 2006
John L. Festival Calgary, Alberta, Canada	Mr. Festival is President and Chief Executive Officer of BlackPearl since January 8, 2009. From October 2007 to January 2009, he was President of BlackCore Resources Inc. From January 2001 to June 2006, Mr. Festival was President and a Director of BlackRock Ventures Inc.	Officer and Director	Jan. 2009
Keith C. Hill (4) West Vancouver, British Columbia, Canada	Mr. Hill is President and Chief Executive Officer of Africa Oil Corp., an oil and gas exploration and production company since January 2009. He was the President and Chief Executive Officer of BlackPearl from February 2007 to January 8, 2009. Mr. Hill was President, CEO and a director of Valkyries Petroleum Corp. from August 2002 to July 2006.	Director	Jan. 2006
Victor Luhowy (1)(2)(3)(4) Priddis, Alberta, Canada	Mr. Luhowy is President, BelAir Petroleum Management Ltd., a private management company since 2009. From February 2004 to June 2009, Mr. Luhowy was President and Chief Executive Officer of Mystique Energy Inc.	Director	Jan. 2009
Don Cook Calgary, Alberta, Canada	Mr. Cook is Chief Financial Officer of BlackPearl since January 8, 2009. From October 2007 to January 2009, he was Vice President, Finance of BlackCore Resources Inc. From 1999 to June 2006 he was Vice President, Finance, Chief Financial Officer and Secretary of BlackRock Ventures Inc.	Officer	Jan. 2009
Edward Sobel Calgary, Alberta, Canada	Mr. Sobel is Vice President Exploration of BlackPearl since January 8, 2009. From October 2007 to January 2009, he was Vice President, Exploration of BlackCore Resources Inc. From August 2007 to January 2009 he was VP Geology of Soho Resources Ltd. From 1999 to June 2006 he was Exploration Manager of BlackRock Ventures Inc.	Officer	Jan. 2009
Chris Hogue Calgary, Alberta, Canada	Mr. Hogue is Vice President Operations of BlackPearl since January 8, 2009. From October 2007 to January 2009, he was Vice President, Operations of BlackCore Resources Inc. From August 2007 to January 2009 he was VP Operations of Soho Resources Ltd. From July 2006 to August 2007, Mr. Hogue was Operations Manager, Heavy Oil at Shell Canada Ltd. From 2002 to June 2006 he was Manager Operations of BlackRock Ventures Inc.	Officer	Jan. 2009
Diane Phillips Calgary, Alberta, Canada	Ms. Phillips has been the Corporate Secretary of BlackPearl since August 2006. From February 2006 to December 2008, Ms. Phillips was the Corporate Secretary of Tanganyika Oil Company Ltd. From 2002 to 2006, she was Assistant Corporate Secretary of Viking Energy Royalty Trust.	Officer	Aug. 2006

Notes:

(1) Member of the Audit Committee.
(2) Member of the Corporate Governance and Nominating Committee.
(3) Member of the Compensation Committee.
(4) Member of the Reserves Committee.

The term of office of each of the directors of BlackPearl will expire at the next annual meeting of shareholders of BlackPearl.

As at December 31, 2012, our directors and executive officers, as a group, beneficially owned, or controlled or directed, directly or indirectly, 28,187,478 BlackPearl Shares or approximately 9.5% of the issued and outstanding BlackPearl Shares. In addition, directors and executive officers held 7,430,000 options resulting in directors and executive officers holding 11% of the BlackPearl Shares on a fully diluted basis. The information as to BlackPearl Shares beneficially owned, not being within the knowledge of the Company, has been furnished by the respective individuals.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Except as discussed below, no director, executive officer or controlling security holder of BlackPearl is, as at the date of this Annual Information Form, or has been, within the past 10 years before the date hereof, a director or executive officer of any other issuer that: (i) while that person was acting in that capacity was the subject of: (a) a cease trade order or similar order; or (b) an order that denied the relevant company access to any exemption under securities legislation, that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**"); (ii) was subject to an Order after the person ceased to be a director or executive officer, which resulted from an event that occurred while that person was acting that capacity; or (iii) within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Mr. Brian Edgar was a director of New West Energy Services Inc. (TSX-V) when, on September 5, 2006, a cease trade order was issued against that company by the British Columbia Securities Commission for failure to file its financial statements within the prescribed time. The default was rectified and the order was rescinded on November 9, 2006. Mr. Edgar resigned as a director of New West Energy Services Inc. on August 24, 2009.

Mr. Victor Luhowy was formerly President and Chief Executive Officer of Mystique Energy Inc., which on April 24, 2007 filed for and obtained protection from its creditors under the *Companies' Creditors Arrangement Act* (Canada).

Personal Bankruptcies

No director, executive officer or controlling security holder of BlackPearl has, within the 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold such person's assets.

Penalties or Sanctions

No director, executive officer or controlling security holder of BlackPearl has: (i) been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, other than penalties for late filing of insider reports; or (ii) been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

AUDIT COMMITTEE INFORMATION

The responsibilities and duties of the Audit Committee are set out in the Audit Committee's charter, which is set forth in Schedule "C" attached to this Annual Information Form.

Composition of the Audit Committee

At December 31, 2012, the Audit Committee was comprised of the following individuals:

	Independent [(1)]	Financially literate [(1)]	Relevant Education and Experience
Brian Edgar	Yes	Yes	Law degree with 16 year practice as a corporate/securities lawyer. Extensive experience with management of public companies.
Victor Luhowy	Yes	Yes	Education includes B.Sc. in Engineering and Masters of Business Administration. Extensive experience with management of public companies.
John Craig	Yes	Yes	Education includes law degree and BA (Economics) and over 30 years experience as a director of public companies. As a securities lawyer, required to review financial statements as part of responsibilities in carrying out legal services.

Note:
(1) As defined by NI-52-110.

Pre-Approval Policies and Procedures

The audit committee has adopted specific policies and procedures for the engagement of non-audit services as described under the heading "Accounting Systems, Internal Control and Procedures" in the Audit Committee's charter which is attached as Schedule "C" to this Annual Information Form.

Audit Fees

The following table summarizes the fees earned by the Company's independent auditors, PricewaterhouseCoopers LLP, for the years ended December 31, 2012 and 2011.

Type of Work	2012 Fees	2011 Fees
Audit Fees	$146,000	$146,943
Audit Related Fees Review of interim financial statements and MD&A	$66,150	$66,150
Tax Fees [(1)]	Nil	Nil
All Other Fees Review of prospectus and IFRS strategy	Nil	$24,150
TOTAL	$212,150	$237,243

Note:
(1) BlackPearl utilizes another third party for its tax services.

CONFLICTS OF INTEREST

The directors and officers of BlackPearl are engaged in and will continue to engage in other activities in the oil and natural gas industry and, as a result of these and other activities, the directors and officers of BlackPearl may become subject to conflicts of interest. The CBCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his or her interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided under the CBCA. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the CBCA.

As at the date hereof, BlackPearl is not aware of any existing or potential material conflicts of interest between BlackPearl and a director or officer of BlackPearl.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Neither BlackPearl nor any of its subsidiaries is or was a party to, or has or had any property subject to, any legal proceedings during the financial year ended December 31, 2012 that are material to the Company, or knows of any such legal proceedings contemplated.

During the year ended December 31, 2012, there have not been any penalties or sanctions imposed against BlackPearl by a court relating to securities legislation or by a securities regulatory authority, nor have there been any other penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decision, and BlackPearl has not entered into any settlement agreements before a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as discussed herein, no director, executive officer of the Company or any person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of the outstanding BlackPearl Shares or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or is reasonably expected to materially affect the Company.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of the Company are PricewaterhouseCoopers LLP, Chartered Accountants, Suite 3100, 111 – 5th Avenue S.W., Calgary, Alberta T2P 5L3.

Computershare Trust Company of Canada, at its principal offices in Calgary, Alberta and Toronto, Ontario, is the transfer agent and registrar of the BlackPearl Shares.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business and not of the type required in any event to be disclosed pursuant to Part 12 of NI 51-102, there are no contracts entered into by BlackPearl or any of its subsidiaries within the last financial year, or entered into before the last financial year but still in effect, which the Company considers to be material as at the date of this Annual Information Form.

INTERESTS OF EXPERTS

The Company's auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have prepared an independent auditors' report dated February 26, 2013 in respect of the Company's financial statements as at December 31, 2012 and December 31, 2011 and for each of the years ended. PricewaterhouseCoopers LLP has advised that they are independent with respect to the Company within the meaning of the rules of professional conduct of the Institute of Chartered Accountants of Alberta. Sproule prepared the Sproule Report, referenced herein. As at the date of the Sproule Report, the principals of Sproule, as a group, owned beneficially, directly or indirectly, less than one percent of the outstanding BlackPearl Shares. Sproule did not receive nor will they receive any interest, direct or indirect, in any securities or other property of the Company or its affiliates in connection with the preparation of its report.

ADDITIONAL INFORMATION

Additional information relating to the Company can be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and securities authorized for issuance under equity compensation plans is contained in the Company's information circular for the Company's annual meeting of shareholders to be held on May 9, 2013. Additional financial information is contained in the Company's consolidated financial statements and the related management's discussion and analysis for the period ended December 31, 2012.

Additional copies of this Annual Information Form and the materials listed in the preceding paragraph and any other document incorporated herein by reference are available on the foregoing basis and upon request by contacting the Corporate Secretary at 700, 444 – 7 Avenue S.W., Calgary, Alberta, T2P 0X8, Canada, by phone at (403) 213-8768 or by fax at (403) 265-8324.

Form 51-101F2

Report on Reserves Data
by Independent Qualified Reserves Evaluator or Auditor

Report on Reserves Data

To the Board of Directors of BlackPearl Resources Inc. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2012. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook"), prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us as of December 31, 2012, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	**Description and Preparation Date of Evaluation Report**	**Location of Reserves (Country)**	**Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)**			
			Audited (M$)	**Evaluated (M$)**	**Reviewed (M$)**	**Total (M$)**
Sproule	Evaluation of the P&NG Reserves of BlackPearl Resources Inc., As of December 31, 2012, prepared September 2012 to January 2013	Canada				
Total			**Nil**	**1,158,214**	**Nil**	**1,158,214**

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are presented in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update the report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Sproule Unconventional Limited
Calgary, Alberta
February 01, 2013

Jason E. Robottom, P.Eng.
Petroleum Engineer and Partner

Victor Verkhogliad, P.Geol.
Senior Petroleum Geologist and Associate

Alec Kovaltchouk, P.Geo.
Manager, Geoscience and Partner

Doug W.C. Ho, P.Eng.
Vice-President, Unconventional, and Director

Report on Contingent Resource Data by Independent Qualified Reserves and Resources Evaluator or Auditor

Report on Contingent Bitumen Resource Data

To the Board of Directors of BlackPearl Resources Inc. (the "Company"):

1. We have evaluated the Company's Contingent Bitumen Resources Data in the Blackrod Area of Alberta as at December 31, 2012. The resources data are low, best, and high estimates of contingent bitumen resources and related future net revenue as at December 31, 2012, estimated using forecast prices and costs.

2. The Resource Data are the responsibility of the Company's management. Our responsibility is to express an opinion on the Resource Data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook"), prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation of contingent bitumen resources to obtain reasonable assurance as to whether the resource data are free of material misstatement. An evaluation also includes assessing whether the resource data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue attributed to low, best and high contingent bitumen resources, estimated using forecast prices and costs on a before tax basis and calculated using a discount rate of 10 percent, included in the resources data of the Company evaluated by us as of December 31, 2012, and reported on to the Company's management and Board of Directors:

Independent Qualified Resources Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Resources (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)		
			Low Estimate (MM$)	**Best Estimate (MM$)**	**High Estimate (MM$)**
Sproule	Evaluation of the Contingent Bitumen Resources in the Blackrod Area of Alberta of BlackPearl Resources Inc., as of December 31, 2012, prepared September 2012 to January 2013	Canada	1,018.8	1,393.4	1,694.7
Total			**1,018.8**	**1,393.4**	**1,694.7**

5. In our opinion, the resource data evaluated by us have, in all material respects, been determined and are presented in accordance with the COGE Handbook.

6. We have no responsibility to update the report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

7. Because the resources data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Sproule Unconventional Limited
Calgary, Alberta
February 1st, 2013

Alec Kovaltchouk, P.Geol.
Manager, Geoscience and Partner

Doug W.C. Ho, P.Eng.
Vice-President, Unconventional and Director

Report on Contingent Resource Data by Independent Qualified Reserves and Resources Evaluator or Auditor

Report on Contingent Heavy Oil Resource Data

To the Board of Directors of BlackPearl Resources Inc. (the "Company"):

1. We have evaluated the Company's Contingent Heavy Oil Resource Data in the Mooney Area of Alberta as at December 31, 2012. The resource data are low, best, and high estimates of contingent resources and related future net revenue as at December 31, 2012, estimated using forecast prices and costs.

2. The resource data are the responsibility of the Company's management. Our responsibility is to express an opinion on the resource data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook"), prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the resource data are free of material misstatement. An evaluation also includes assessing whether the resource data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue attributed to low, best and high contingent heavy oil resources, estimated using forecast prices and costs on a before tax basis and calculated using a discount rate of 10 percent, included in the resource data of the Company evaluated by us as of December 31, 2012, and reported on to the Company's management and Board of Directors:

Independent Qualified Resources Evaluator or Auditor	**Description and Preparation Date of Evaluation Report**	**Location of Resources (Country)**	**Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)**		
			Low Estimate (MM$)	**Best Estimate (MM$)**	**High Estimate (MM$)**
Sproule	Evaluation of the Contingent Heavy Oil Resources in the Mooney Area of Alberta of BlackPearl Resources Inc., as of December 31, 2012, prepared September 2012 to January 2013	Canada			
Total			**215**	**169**	**228**

5. In our opinion, the resource data evaluated by us have, in all material respects, been determined and are presented in accordance with the COGE Handbook.

6. We have no responsibility to update the report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

7. Because the resource data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Sproule Unconventional Limited
Calgary, Alberta
February 01, 2013

Jason Robottom, P.Eng.
Petroleum Engineer and Partner

Chris Galas, Ph.D., P.Eng.
Manager, Reservoir Studies and Partner

Alec Kovaltchouk, P.Geo.
Manager, Geoscience and Partner

Doug W.C. Ho, P.Eng.
Vice-President, Unconventional and Director

Report on Contingent Resource Data by Independent Qualified Reserves and Resources Evaluator or Auditor

Report on Contingent Heavy Oil Resource Data

To the Board of Directors of BlackPearl Resources Inc. (the "Company"):

1. We have evaluated the Company's Contingent Heavy Oil Resources Data in the Onion Lake Area of Alberta and Saskatchewan as at December 31, 2012. The resources data are low, best, and high estimates of contingent heavy oil resources and related future net revenue as at December 31, 2012, estimated using forecast prices and costs.

2. The Resource Data are the responsibility of the Company's management. Our responsibility is to express an opinion on the Resource Data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook"), prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the resource data are free of material misstatement. An evaluation also includes assessing whether the resource data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue attributed to low, best and high contingent heavy oil resources, estimated using forecast prices and costs on a before tax basis and calculated using a discount rate of 10 percent, included in the resources data of the Company evaluated by us as of December 31, 2012, and reported on to the Company's management and Board of Directors:

Independent Qualified Resources Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Resources (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)		
			Low Estimate (MM$)	Best Estimate (MM$)	High Estimate (MM$)
Sproule	Evaluation of the Contingent Heavy Oil Resources in the Onion Lake Area of Alberta and Saskatchewan of BlackPearl Resources Inc., as of December 31, 2012, prepared September 2012 to January 2013	Canada	733.2	840.5	945.2
Total			**733.2**	**840.5**	**945.2**

5. In our opinion, the resource data evaluated by us have, in all material respects, been determined and are presented in accordance with the COGE Handbook.

6. We have no responsibility to update the report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

7. Because the resources data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Sproule Unconventional Limited
Calgary, Alberta
February 1st, 2013

Victor Verkhogliad, P.Geol.
Senior Petroleum Geologist and Associate

Alec Kovaltchouk, P.Geo.
Manager, Geoscience and Partner

Doug W.C. Ho, P.Eng.
Vice-President, Unconventional and Director

FORM 51-101F3

BLACKPEARL RESOURCES INC.

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of BlackPearl Resources Inc. (the "Company") is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data and resource data, which are estimates of proved reserves and probable reserves and contingent resources and related future net revenue as at December 31, 2012, estimated using forecast prices and costs.

Sproule Unconventional Limited, independent qualified reserves evaluators, has evaluated the Company's reserves and resource data. The reports of Sproule Unconventional Limited will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Company has:

(a) reviewed the Company's procedures for providing information to Sproule Unconventional Limited;

(b) met with Sproule Unconventional Limited to determine whether any restrictions affected the ability of Sproule Unconventional Limited to report without reservation; and

(c) reviewed the reserves and resources data with management and Sproule Unconventional Limited.

The board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves and resources data and other oil and gas information;

(b) the filing of Forms 51-101F2 which are the reports of Sproule Unconventional Limited on the reserves and resources data; and

(c) the content and filing of this report.

Because the reserves and resources data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Signed "John Festival"
John Festival
President and Chief Executive Officer

Signed "Don Cook"
Don Cook
Chief Financial Officer

Signed "Vic Luhowy"
Vic Luhowy
Director

Signed "Keith Hill"
Keith Hill
Director

February 26, 2013

BLACKPEARL RESOURCES INC.
(the "Corporation")

Audit Committee of the Board of Directors
(the "Audit Committee")

CHARTER

1. Composition and Process

(a) The Audit Committee shall be composed of a minimum of three members of the Board of Directors, a majority of whom are independent. An independent director, as defined in *Multilateral Instrument 52-110, Audit Committees*, ("MI 52-110") is a director who has no direct or indirect material relationship which could , in the view of the Corporation's board of directors, be reasonably expected to interfere with the exercise of a members independent judgement or as otherwise determined to be independent in accordance with MI 52-110.

(b) Members of the Audit Committee shall serve one-year terms and may serve consecutive terms, which are encouraged to ensure continuity of experience.

(c) The Chairperson of the Audit Committee shall be appointed by the Board of Directors for a one-year term, and may serve any number of consecutive terms.

(d) All members of the Audit Committee shall be financially literate. Financial literacy is the ability to read and understand a balance sheet, income statement and cash flow statement that present a breadth and level of complexity comparable to the Corporation's financial statements.

(e) The Chairperson of the Audit Committee shall, in consultation with management and the external auditor and internal auditor (if any), establish the agenda for the meetings and ensure that properly prepared agenda materials are circulated to the Audit Committee members with sufficient time for study prior to the meeting. The external auditor will also receive notice of all meetings of the Audit Committee. The Audit Committee may employ a list of prepared questions and considerations as a portion of its review and assessment process.

(f) The Audit Committee shall meet at least four times per year and may call special meetings as required. A quorum at meetings of the Audit Committee shall be its Chairperson and one of its other members or the Chairman of the Board of Directors. The Audit Committee may hold its meetings, and members of the Audit Committee may attend meetings, by telephone conference if this is deemed appropriate.

(g) The minutes of the Audit Committee meetings shall accurately record the decisions reached and shall be distributed to Audit Committee members with copies to the Board of Directors, the Chief Executive Officer, the Chief Financial Officer and the external auditor.

(h) The Audit Committee shall review, prior to their presentation to the Board of Directors and their release, all material financial information required by securities legislation and policies.

(i) The Audit Committee shall enquire about potential claims, assessments and other contingent liabilities.

(j) The Audit Committee shall periodically review with management, depreciation and amortization policies, loss provisions and other accounting policies for appropriateness and consistency.

(k) The Charter of the Audit Committee shall be reviewed by the Board of Directors on an annual basis.

2. Authority

(a) The Audit Committee is appointed by the Board of Directors pursuant to provisions of the *Canada Business Corporations Act* and the bylaws of the Corporation.

(b) The Audit Committee's primary responsibility is to ensure that the Corporation's financial reporting, accounting systems and internal controls is vested in senior management and is overseen by the Board of Directors. The Audit Committee is a standing committee of the Board of Directors established to assist it in fulfilling its responsibilities in this regard. The Audit Committee shall have responsibility for overseeing management reporting on internal controls. While it is management's responsibility to design and implement an effective system of internal control, it is the responsibility of the Audit Committee to ensure that management has done so.

(c) In fulfilling its responsibilities, the Audit Committee shall have unrestricted access to the Corporation's personnel and documents and will be provided with the resources necessary to carry out its responsibilities.

(d) The Audit Committee shall have direct communication channels with the internal auditor (if any) and the external auditor to discuss and review specific issues, as appropriate.

(e) The Audit Committee shall have the authority to engage independent counsel and other advisors as it determines necessary to carry out its duties.

(f) The Audit Committee shall establish the compensation to be paid to any advisors employed by the Audit Committee and such compensation shall be paid by the Corporation as directed by the Audit Committee.

3. Relationship with External Auditors

(a) An external auditor must report directly to the Audit Committee.

(b) The Audit Committee is directly responsible for overseeing the work of the external auditor including the resolution of disagreements between management and the external auditor regarding financial reporting.

(c) The Audit Committee shall implement structures and procedures to ensure that it meets with the external auditor at least annually in the absence of management.

4. Accounting Systems, Internal Controls and Procedures

(a) The Audit Committee shall:

(i) obtain reasonable assurance from discussions with and/or reports from management and reports from external auditors that accounting systems are reliable and that the prescribed internal controls are operating effectively for the Corporation and its subsidiaries and affiliates;

(ii) review to ensure to its satisfaction that adequate procedures are in place for the review of the Corporation’s disclosure of financial information extracted or derived from the Corporation’s financial statements and will periodically assess the adequacy of those procedures;

(iii) direct the external auditor’s examinations to particular areas;

(iv) review control weaknesses identified by the external auditor, together with management's response; and

(v) review with the external auditor its view of the qualifications and performance of the key financial and accounting executives.

(b) In order to preserve the independence of the external auditor, the Audit Committee will:

(i) recommend to the Board of Directors the external auditor to be nominated; and

(ii) recommend to the Board of Directors the compensation of the external auditor’s engagement.

(c) The Audit Committee shall:

(i) review and pre-approve any engagements for non-audit services to be provided by the external auditor or its affiliates, together with estimated fees, and consider the impact on the independence of the external auditor;

(ii) review with management and with the external auditor any proposed changes in major accounting policies, the presentation and impact of significant risks and uncertainties and key estimates and judgments of management that may be material to financial reporting;

(iii) review and approve the Corporation’s hiring policies regarding partners, employees and former partners and employees of the present and most recent former external auditor of the Corporation;

(iv) establish procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters and the confidential anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters; and

(v) on an annual basis, prior to public disclosure of its annual financial statements, ensure that the external auditor has entered into a participation agreement and has not had its participant status terminated, or, if its participant status was terminated, has been reinstated in accordance with the Canadian Public Accountability Board ("CPAB") bylaws and is in compliance with any restriction or sanction imposed by the CPAB.

5. <u>Statutory and Regulatory Responsibilities</u>

(a) *Annual Financial Information*. The Audit Committee shall review the annual audited financial statements, including any letter to shareholders and related press releases and recommend their approval to the Board of Directors, after discussing matters such as the selection of accounting policies (and changes thereto), major accounting judgments, accruals and estimates with management and the external auditor.

(b) *Annual Report*. The Audit Committee shall review the management discussion and analysis ("MD&A") section and all other relevant sections of the annual report to ensure consistency of all financial information included in the annual report.

(c) *Interim Financial Statements*. The Audit Committee shall review the quarterly interim financial statements, including any letter to shareholders and related press releases, and recommend their approval to the Board of Directors.

(d) *Earnings Guidance/Forecasts*. The Audit Committee shall review forecasted financial information and forward looking statements.

(e) The Audit Committee shall review the Corporation's financial statements, MD&A and earnings press releases before the Corporation publicly discloses this information.

6. <u>Reporting</u>

The Audit Committee shall:

(a) report, through the Chairperson of the Audit Committee, to the Board of Directors following each meeting on the major discussions and decisions made by the Audit Committee;

(b) report annually to the Board of Directors on the Audit Committee's responsibilities and how it has discharged them; and

(c) review the Audit Committee's Charter annually and recommend the approval of any proposed amendments to the Board of Directors.

7. <u>Other Responsibilities</u>

The Audit Committee shall:

(a) investigate fraud, illegal acts or conflicts of interest; and

(b) discuss selected issues with corporate counsel or the external auditor or management.