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SUNSHINE OILSANDS LTD.

陽光油砂有限公司*

(a corporation incorporated under the Business Corporations Act of the Province of Alberta, Canada with limited liability)

(Stock Code: 2012)

OVERSEAS REGULATORY ANNOUNCEMENT

Sunshine Oilsands Ltd. ("Company") has filed a revised Annual Information Form ("Revised AIF") for the year ended December 31, 2011 on SEDAR (www.sedar.com).

In connection with the Company's listing application to the Toronto Stock Exchange ("TSX"), the TSX had requested some revisions to certain disclosures in the original Annual Information Form ("AIF"). The Revised AIF incorporates such revisions in the Company's original AIF for the year ended December 31, 2011, dated and filed on April 30, 2012.

For a description of the changes to the original AIF, please refer to the disclosure under the heading "Notice Regarding Revisions To AIF" in the Revised AIF. The filing of the Revised AIF does not, and does not purport to, update or restate the information in the original AIF or reflect any events that have occurred since the date of the original AIF.

The Company does not consider that the revised disclosure presented in the Revised AIF differs materially from the disclosure presented in the original AIF. However, the Company wishes to correct the public record and, therefore, considers it prudent to file the Revised AIF.

By Order of the Board of Sunshine Oilsands Ltd.
Michael John Hibberd
Co-Chairman
and
Songning Shen
Co-Chairman

Hong Kong, November 9, 2012

As at the date of this announcement, the Board consists of Mr. Michael John Hibberd and Mr. Songning Shen as executive directors, Mr. Hok Ming Tseung, Mr. Tingan Liu, Mr. Haotian Li and Mr. Gregory George Turnbull as non-executive directors and Mr. Raymond Shengti Fong, Mr. Wazir Chand Seth, Mr. Robert John Herdman and Mr. Gerald Franklin Stevenson as independent non-executive directors.

**For identification purposes only*

SUNSHINE OILSANDS LTD.

Annual Information Form

(Revised)

For the Year Ended December 31, 2011

Dated April 30, 2012

Note: This Annual Information Form has been filed with the Alberta Securities Commission by Sunshine Oilsands Ltd. with respect to its application to become a reporting issuer in Alberta pursuant to Section 145 of the Securities Act (Alberta), RSA 2000, c S-4. For the purposes of disclosure, this Annual Information Form conforms with the requirements of Form 51-102F2 – Annual Information Form and Form 41-101F1 – Information Required in a Prospectus.

(Re-filed on November 8, 2012 to make certain revisions to the Annual Information Form filed on April 30, 2012 (the "Original AIF"). See "Notice Regarding Revisions to Original AIF" herein for a description of the revisions to the "Original AIF").

NOTICE REGARDING REVISIONS TO ORIGINAL AIF

This revised Annual Information Form (the "**Revised AIF**") of Sunshine Oilsands Ltd. for the year ended December 31, 2011 revises certain information contained in the Original AIF that was filed with the Alberta Securities Commission on April 30, 2012, which is available at www.sedar.com. For ease of reference, set forth below is a brief description of the revisions that have been made to the Original AIF. Sunshine does not consider that the information contained in the Revised AIF differs materially for the information contained in the Original AIF.

Reference	Revisions
Page Nos. – 20 and 42	The reservoir characteristics of our properties vary among the different properties and in comparison to other producing projects in McMurray or other formations. The reservoir we are proposing to produce has had little thermally stimulated production to date, although there are several commercial projects announced or in early stage of development. There is no guarantee that our steam oil ratio will be equivalent to those ratios in the McMurray or other formations which are currently producing. There is a risk that the recovery of bitumen will be lower in our projects than in projects in other reservoirs that have been used as analogues to produce the contingent resources in our technical report, because the reservoir characteristics are different although management believes that these differences have been taken into account.
Page No. - 111	Only positive PV10% values and the associated resource barrels are reported in this AIF for each region and classification category. In some scenarios, the low case estimate indicates a 0 value indicating that there are uneconomic results (negative PV10%) and the company would not proceed with development. This is consistent with reporting in the company's independent resource reports and COGEH guidelines that specify that contingent resources must be economic under current pricing.

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SELECTED ABBREVIATIONS

In this Annual Information Form, the abbreviations set forth below have the following meanings:

Oil and Natural Gas Liquids

bbl	barrel
bbls	barrels
bbl/d	bbls per day
Mbbl	thousand bbls
Mbbl/d	thousand bbls per day
MMbbl	million barrels
MMbbl/d	millions bbls per day
NGLs	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMBTU	million British Thermal Units
Bcf	billion cubic feet
GJ	Gigajoule

Other

boe	barrel of oil equivalent of natural gas and crude oil on the basis of 1 boe for 6 (unless otherwise stated) Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
boe/d	barrel of oil equivalent per day
m^3	cubic metres
m^3/d	cubic metres per day
Mboe	thousand barrels of oil equivalent
MMboe	Million barrels of oil equivalent
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

SPECIAL NOTE REGARDING SHARE SPLIT

All share information in this AIF is provided after giving effect to the Share Split (as defined below) that was approved by the Shareholders of the Corporation at the annual and special meeting of the Shareholders on January 26, 2012. The Share Split became effective upon the filing of the Articles of Amendment on February 10, 2012.

FORWARD-LOOKING STATEMENTS

Certain statements in this Annual Information Form are forward-looking statements that are, by their nature, subject to significant risks and uncertainties and readers are hereby cautioned about important factors that could cause Sunshine's actual results to differ materially from those projected in a forward-looking statement included in this Annual Information Form. Any statements that express, or involve discussions as to expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will" "expect", "anticipate", "estimate", "believe", "going forward", "ought to", "may", "seek", "should", "intend", "plan", "projection", "could", "vision", "goals", "objective", "target", "schedules" and "outlook") are not historical facts, are forward-looking and may involve estimates and assumptions and are subject to risks (including the risk factors detailed in this Annual Information Form), uncertainties and other factors some of which are beyond our control and which are difficult to predict. Accordingly, these factors could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements.

Our forward-looking statements have been based on assumptions and factors concerning future events that may prove to be inaccurate. Those assumptions and factors are based on information currently available to us about our businesses and industry. No assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this Annual Information Form should not be unduly relied upon. In addition, this Annual Information Form may contain forward-looking statements attributed to third party industry sources. Accordingly, any such statements are qualified in their entirety by reference to, and are accompanied by, the information and factors discussed throughout this Annual Information Form. The risks, uncertainties and other factors, many of which are beyond our control, that could influence actual results include, but are not limited to:

- the performance and characteristics of our oil sands properties and the size of our oil sands resources and reserves;
- the bitumen production and production capacity of our assets;
- our growth strategy and opportunities;
- our capital expenditure programmes and future capital requirements;
- our estimates of future interest and foreign exchange rates;
- our environmental considerations, including water usage, GHG emissions and the cost of compliance with environmental legislation;
- the timing and size of certain of our operations and phases, including our planned bitumen development projects, and the levels of anticipated production;
- supply and demand fundamentals for crude oil, bitumen blend, condensate and other diluents and fluctuations in market prices and costs;
- supply and demand for oil and volatility in market price;
- our future general and administrative expenses;
- our status and stage of development;
- the majority of our total reserves and contingent resources are non-producing and/or undeveloped;
- uncertainties associated with estimating reserves and resources volumes;

- sale, farming in, farming out or development of certain oil sands properties using third party resources;
- operational hazards;
- competition for, among other things, capital, the acquisition of reserves and resources, pipeline capacity and skilled personnel;
- risks inherent in our operations, including those related to exploration, development and production of oil sands reserves and resources, including the production of oil sands reserves and resources using SAGD, CSS or other *in-situ* technologies;
- our treatment under governmental regulatory and royalty regimes and tax laws;
- our ability to meet specific requirements in respect of our Oil Sands Leases;
- First Nations' claims and our relationships with local and regional stakeholders;
- unforeseen title defects;
- risks arising from future acquisition and / or disposal activities;
- failure to accurately estimate abandonment and reclamation costs;
- the need to obtain regulatory approvals and maintain compliance with regulatory requirements and the extent of, and cost of compliance with, laws and regulations and the effect of changes in such laws and regulations from time to time;
- the cost and availability of capital, including access to capital markets at acceptable rates; and
- all other risks and uncertainties described in the section in this Annual Information Form entitled *"Risk Factors"*. **Readers are cautioned that the risks and uncertainties described in the section entitled *"Risk Factors"* are not exhaustive.**

Since actual results or outcomes could differ materially from those expressed in any forward-looking statements, we strongly caution readers against placing undue reliance on any such forward-looking statements. Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future. Further, any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by law, we undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events.

All forward-looking statements in this Annual Information Form are expressly qualified by reference to this cautionary statement. We do not undertake any obligation to publicly update or revise any forward-looking statement except as required by law.

CURRENCY OF INFORMATION

The information set out in this Annual Information Form is stated as at December 31, 2011, unless otherwise indicated. Capitalized terms used but not defined in the text are defined in the *"Glossary of Technical Terms"* and the *"Glossary of Terms"*.

GLOSSARY OF TECHNICAL TERMS

This glossary contains definitions of certain technical terms used in this Annual Information Form in connection with the Corporation's business. These terms and their given meanings may not correspond to industry standard definitions or usage of these terms.

Technical Terms

"**1P**" Proved Reserves;

"**2P**" Proved plus Probable Reserves;

"**3P**" Proved plus Probable plus Possible Reserves;

"**2D**" Two-dimensional seismic data, being an interpretive data that allows a view of a vertical cross-section of subsurface strata beneath a prospective area;

"**3D**" Three-dimensional seismic data, being geophysical data that depicts the subsurface strata in three dimensions. 3D seismic data typically provides a more detailed and accurate interpretation of the subsurface strata than 2D seismic data;

"**AOSTRA**" Alberta Oil Sands Technology Research Authority;

"**apex**" The thickest point of a formation;

"**API**" American Petroleum Institute, a trade association for the oil and natural gas industry in the United States, of which the Corporation is not a member;

"**API gravity**" or "**API°**" American Petroleum Institute gravity, which is a measure of how heavy or light a petroleum liquid is compared to water. If a petroleum liquid's API gravity is greater than 10 degrees, it is lighter and floats on water; if less than 10 degrees, it is heavier than water. API gravity is thus a measure of the relative density of a petroleum liquid and the density of water, but it is used to compare the relative densities of petroleum liquids. A higher API gravity indicates a lighter and less dense liquid;

"**Assets**" A resource controlled by an enterprise as a result of past events and from which future economic benefits are expected to flow to the enterprise;

"**barrel**" A unit of volume equal to 42 US gallons;

"**best estimate**" At least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate;

"**bioturbation**" The displacement and mixing of sediment particles (i.e. sediment reworking) and solutes (i.e. bio-irrigation) by fauna (animals) or flora (plants);

"**bitumen**" A naturally occurring heavy viscous form of crude oil measured at 10 API° or less and with viscosity greater than 10,000 milliPascal seconds;

"**bottom water**" A reservoir interval that is primarily saturated with water and is immediately below and in communication with the bitumen zone;

"**Bow River Blend**" Bow River Blend, a conventional heavy sour crude oil blend that contains crude oil that has been blended with lighter hydro carbon diluents, such as condensate, to meet the required density and sulphur content;

"**brachipods**" A phylum of marine animals that have hard "valves" (shells) on the upper and lower surfaces. They are hinged at the rear end, while the front can be opened for feeding or closed for protection;

"**cap rock**" A relatively impermeable rock, commonly shale, that forms a barrier or seal above reservoir rock so that injected or *in-situ* fluids cannot migrate beyond the reservoir;

"**CAPP**" Canadian Association of Petroleum Producers, an association representing Canada's upstream oil, oil sands and natural gas industry, of which the Corporation is not a member;

"**casing**" Large diameter pipe that is assembled and inserted into a recently drilled section of a well and typically held in place with cement. Casing prevents contamination, provides strong foundations for the well, seals off high pressure zones from the surface and provides a smooth internal well for installing production equipment;

"**carbonate**" A class of sedimentary rock whose chief mineral constituents (95% or more) are calcite, aragonite and dolomite. Limestone, dolostone (or dolomite) and chalk are carbonate rocks. Carbonate rocks are common hydrocarbon reservoir rocks;

"**CERI**" The Canadian Energy Research Institute, an independent, non-profit research institute founded in 1975 that is committed to the analysis of energy economics and related environmental policy issues in the production, transportation, and consumer sectors;

"**condensate**" A low density mixture of hydrocarbon liquids that is commonly used as a diluent;

"**CHOPS**" Cold Heavy Oil Production with Sand, a technique used for the extraction of conventional heavy oil in which sand is pumped out of the well bore with oil, leading to improved recovery;

"**clastic**" Sediment consisting of weathered fragments derived from pre-existing rocks and transported elsewhere and redeposited before forming another rock. Examples of common clastic sedimentary rocks include siliciclastic rocks such as conglomerate, sandstone, siltstone and shale;

"**clinoforming**" The forming of an underwater land formation;

"**CO_2**" Carbon dioxide;

"**cogeneration of power**" Generating steam and electric power at the same time from the same energy source;

"**Cold Lake Blend**" Cold Lake Blend, a bitumen blend heavy sour crude oil that contains crude oil and bitumen that have been blended with lighter hydrocarbons diluents, such as condensate, to meet the required density and sulphur content;

"**cold production**" A non-thermal production process for heavy oil. During the cold production process, heavy oil and sand are produced simultaneously through the use of a pump, which causes reservoir pressure to decrease;

"**completion**" The process of making a well ready for production;

"**contingent resources**" Quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies;

"**conventional heavy oil**" A heavy crude oil produced through conventional means without thermal stimulation that is measured at 20 API° or less. Our conventional heavy oil development at Muskwa utilises CHOPS for primary production without any thermal stimulation, but due to the nature of the oil produced at Muskwa it falls under the 'Bitumen' classification (quantified as crude oil with API gravities lower than 10 degrees and viscosities greater than 10,000 milliPascal seconds);

"**Cretaceous**" A geological period and system of the Mesozoic era spanning from approximately 145.5 to 65.5 million years ago;

"**crude oil**" A combustible hydrocarbon usually processable into a variety of petrochemicals;

"**CSOR**" Cumulative steam to oil ratio;

"**CSS**" or "**Cyclic Steam Stimulation**" Cyclic steam stimulation, an *in-situ* process used to recover bitumen from oil sands. In this method, the well is put through cycles of steam injection, soak and oil production. First, steam is injected into a well for a period of weeks to months; then, the well is allowed to sit for days to weeks to allow heat to soak into the formation and, later, the hot oil is pumped out of the well for a period of weeks or months. Once the production rate falls off, the well is put through another cycle of injection, soak and production;

"**CSUG**" Canadian Society for Unconventional Gas, a formal not-for-profit society, registered in Alberta in 2002, of which the Corporation is not a member;

"**delineation**" Determination of the physical boundary of something;

"**delineation well**" A well that is so closely located to another well penetrating an accumulation of petroleum that there is a reasonable expectation that another portion of the accumulation will be penetrated by the first mentioned well. The drilling of the first-mentioned well is necessary in order to determine the physical extent, reserves and commercial value of the accumulation;

"**deltaic**" The adjective form of delta. A delta is an area of deposition or the deposit formed by a flowing sediment-laden current as it enters an open or standing body of water, such as a river spilling into a gulf;

"**Devonian**" The Devonian period is a geologic period and system of the Palaeozoic era spanning from 416 to 359.2 million years ago;

"**dilbit**" A blend of diluents and bitumen;

"**diluent**" Lighter viscosity petroleum products that are used to dilute bitumen for transportation in pipelines;

"**dolomite**" A rhomboidal calcium-magnesium carbonate mineral with the chemical formula CaMg(CO3)2;

"**Dry Well**" A well found to be incapable of producing oil or gas in sufficient quantities to justify completion as a producing oil or gas well;

"**Edmonton Par**" Edmonton Par, a light sweet crude oil;

"**EOR**" or "**enhanced oil recovery**" Enhanced oil recovery involves the recovery of oil through the injection of water, solvents and gas to displace oil *in-situ* "estuarine". The adjective form of estuary. An estuary is a semi-enclosed coastal environment of deposition in which a river mouth permits freshwater to contact and mix with seawater;

"**exsolution**" A process through which gas separates from bitumen;

"**extra heavy crude oil**" Crude oil normally measured at 10 API° or less;

"**first steam**" When steam is first injected into a well or well pair;

"**floatstone dolomite**" A dolomitic floatstone is a carbonate rock containing a few bioclasts or other fragments more than 2 mm in diameter, widely spaced, and embedded in sand- or mud-size carbonate sediment that forms over 90% of a rock. They are later recrystallised to dolomite;

"**fracing**" The abbreviation for hydraulic fracture stimulation, a process whereby fluid and sand particles (suspended in the fluid), are pumped into the well causing the geological formation to crack open (fracture), which creates a better conduit for the reservoir fluids to flow into the well bore;

"**free water knockouts**" Vertical or horizontal vessels used upstream of a treater to remove excess free water from the oil-water emulsion;

"**GOB**" Gas over bitumen;

"**heavy crude oil**" Crude oil normally measured at 20 API° or less;

"**heterolithic stratification**" A closely interbedded deposit of sand and mud, generated under considerably variable current flow. Sediments of unlike type contained in a single strata. Inclined hererolithic stratification (or defined as "IHS") involves an inclination of such strata;

"**high estimate**" At least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate;

"**horizontal drilling**" Drilling horizontally rather than vertically through a reservoir, thereby exposing more of the well to the reservoir and increasing production;

"***in-situ***" "**In place**" and, when referring to oil sands, means a process for recovering bitumen from oil sands by means other than surface mining, such as SAGD or CSS;

"**LACT**" Lease automatic custody transfer, which is a measuring device used for the measurement of fluids in transit from a production lease to a truck, other lease, pipeline or other tankage and operates automatically to provide an accurate disclosure of volumes for the negotiated transfer of custody of those volumes between two parties;

"**lenticular**" A formation with a lens-shaped cross section;

"**light crude oil**" Crude oil normally measured at 30 API° or lighter;

"**LLB**" or "**Lloyd Blend**" Lloydminster Blend, a conventional heavy sour crude oil blend that contains crude oil that has been blended with lighter hydrocarbon diluents, such as condensate, to meet the required density and sulphur content;

"**low estimate**" At least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate;

"**makeup water**" Water needed to replace that which is lost by the facility evaporation or reservoir leakage during the SAGD process;

"**medium crude oil**" Crude oil normally measured between 20 API°and 30 API;

"**NCG**" Non-condensable gas;

"**net pay**" A reservoir or portion of a reservoir that contains economically producible hydrocarbons and which meet local criteria (such as minimum porosity, permeability and hydrocarbon saturation) is net pay;

"**Oil Plays**" A deposit of oil in a reservoir under development or being pursued;

"**Overriding royalty**" A percentage share of production, or the value derived from production free from all production costs paid by the lessee or working interest owner;

"**Payout**" The point at which all costs of leasing, exploring, drilling and operating have been recovered from production;

“**permeability**” Measure of the ability of a rock to conduct a fluid through its interconnected pores (pore throat) when that fluid is at 100% saturation. A rock may be highly porous and yet impermeable if it has no pore throat. Permeability is measured in millidarcies;

“**petroleum**” A naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid or solid phase, as defined by PRMS;

“**PIIP**” Quantity of petroleum initially in place that is estimated, as of a given date, to exist in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered. It is a measure that derived from an aggregation of the total reserves, contingent resources and prospective resources held by a person whether they are recoverable or unrecoverable;

“**PNG Licence**” A petroleum and natural gas lease pursuant to which the Crown grants the holder the right to develop and use oil sands resources existing under the *Oil Sands Tenure Regulation* on a primary or a continued basis;

“**porosity**” The ratio of void space to the bulk volume of rock containing that void space. Porosity can be expressed as a fraction or percentage of pore volume in a volume of rock;

“**possible reserves**” Those quantities of petroleum which by analysis of geosciences and engineering data are less likely to be recoverable than probable reserves;

“**Primary Recovery Scheme**” A plan using only the natural energy of the reservoir to recover oil. The main drive mechanisms for primary recovery are typically solution gas drive, gas cap drive and water (aquifer) drive;

“**probable reserves**” Those quantities of petroleum which by analysis of geosciences and engineering data are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves;

“**production pad**” An area of land that has been cleared and made suitable for drilling and production activities;

“**prospective resources**” Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoir and under defined economic conditions, operating methods and government regulations;

“**proved reserves**” Those quantities of petroleum, which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations;

“**PRMS**” The Petroleum Resources Management System published by the Society of Petroleum Engineers, American Association of Petroleum Geologists, World Petroleum Council, and Society of Petroleum Evaluation Engineers in March 2007, as amended from time to time;

“**PV10%**” Means the present value of estimated future net revenues to be generated from the production of proved reserves and discounted using an annual discount rate of 10%;

“**recovery factor**” The percentage of PIIP in a reservoir that ultimately can be recovered at a specific point in time;

“**reserves**” Those quantities of petroleum anticipated to be commercially recoverable by the application of development projects to known accumulations from a given date forward under defined conditions. Reserves are classified according to the degree of certainty associated with the estimates;

“**SAGD**” or “**steam assisted gravity drainage**” An *in-situ* recovery process used to produce heavy crude oil and bitumen. two parallel horizontal wells, which are generally 5 metres apart, are drilled for the SAGD process. Steam is injected to the upper steam injector and a steam chamber is developed above the injector. With the growth of the steam chamber, mobilised bitumen drains to the producer below the injector and is lifted to the surface through an artificial lift system;

"**saturation**" The fraction or percentage of the pore volume occupied by a specific fluid (e.g. oil, gas, water, etc.);

"**SCO**" or "**synthetic crude oil**" Crude oil produced by upgrading bitumen to a mixture of hydrocarbons similar to light crude oil, produced either by the removal of carbon (coking) or the addition of hydrogen through hydrotreating. It is considered synthetic because its original composition mark has been altered in the upgrading process;

"**seismic**" A method by which the physical attributes in the outer rock shell of the earth are determined by measuring, with a seismograph, the rate of transmission of shock waves through the various rock formations;

"**seismic data**" Detailed information obtained by carrying out seismic work;

"**seismic work**" An exploration method in which strong low-frequency sound waves are generated on the surface to find subsurface structures that may contain reserves;

"**shoreline complex**" A stratified sedimentary package composed largely of clastic material located parallel to and adjoining the edge of a standing water body that may contain depositional environments ranging from wave base through to beach and back barrier marsh;

"**shut-in hearing**" Hearing of the ERCB to determine whether a well or a group of wells should be suspended;

"**So**" Oil saturation;

"**SOR**" Steam to oil ratio;

"**Total PIIP**" The sum of discovered and undiscovered PIIP components;

"**treaters**" A vessel operated under pressure to separate liquids and natural gas from oil;

"**unconventional oil**" Heavy oil (excluding extra heavy oil sourced from Venezuela) and natural bitumen derived from oil sands, chemical additives, gas-to-liquids and coal-to-liquids (and excluding biofuels);

"**VRU**" Vapour Recovery Unit;

"**working interest**" A proportional interest in a lease granting its owner the right to explore, develop and produce resources from a property and to receive revenues in proportion to the working interest over the property and incur costs in proportion to the working interest over the property;

"**WCS**" or "**Western Canadian Select**" Western Canadian Select, a conventional heavy sour crude oil blend that contains crude oil that has been blended with lighter hydrocarbon diluents, such as condensate, to meet the required density and sulphur content; and

"**WTI**" West Texas Intermediate, a light sweet crude oil.

GLOSSARY OF TERMS

Wherever used in this Annual Information Form, unless the context otherwise requires, the following words and phrases shall have the meanings set forth below:

"**ABCA**" means the *Business Corporations Act*, RSA 2000, c B-9, together with any amendments thereto and all regulations promulgated thereunder;

"**Advisory Agreement**" means the advisory agreement entered into between the Corporation and Orient Financials dated January 20, 2010, together with any amendments thereto;

"**Advisory Fee**" means the amount payable by the Corporation to Orient Financial pursuant to the Advisory Agreement equal to the product of multiplying 0.75% of the number of issued and outstanding Shares at the time of pricing of the Global Offering by the Offer Price per Share. the Corporation decided to satisfy 95% of the Advisory Fee through the issuance of Shares and 5% through cash payment. Upon the completion of the Global Offering, the Corporation satisfied its obligation for the advisory fee by issuing 13,566,395 Share and by paying a cash fee of $440,933;

"**AEMP**" means the Alberta Environmental Monitoring Plan;

"**AEW**" means the Ministry of Environment and Water, a department of the Government of Alberta;

"**AIF**" means this annual information form;

"**ALSA**" means *Alberta Land Stewardship Act* SA 2009, c A-26.8, together with any amendments thereto and all regulations promulgated thereunder;

"**ALUF**" means Alberta Land-use Framework, a land use policy for surface land in Alberta published by the Government of Alberta in December 2008;

"**AMEC BDR**" means AMEC BDR Limited, a technical and engineering business and a subsidiary of Amec Plc.;

"**Annual and Special Meeting**" means the annual and special meeting of the shareholders of the Corporation held on January 26, 2012;

"**AOSC**" means Athabasca Oilsands Corp., a corporation incorporated under the ABCA on August 23, 2006 and listed on the Toronto Stock Exchange and an independent third party of the Corporation;

"**APEGGA**" means the Association of Professional Engineers, Geologists and Geophysicists of Alberta, an official body that regulates and licences the disciplines of engineering, geology and geophysics in Alberta through practice standards and a code of ethics;

"**ASC**" means the Alberta Securities Commission, the regulatory agency responsible for administering the securities laws of Alberta;

"**AUC**" means the Alberta Utilities Commission, an independent, quasi-judicial agency of the Government of Alberta;

"**Audited Financial Statements**" means the audited consolidated financial statements of the Corporation and notes thereto as at December 31, 2011 and 2010 and for the years ended December 31, 2011, 2010 and 2009, which is attached hereto as Schedule "A";

"**Bank of China**" means Bank of China Limited;

"**Base Case Clastic Assets**" means our West Ells, Thickwood and Legend Lake sites;

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

"**BOCGI**" means Bank of China Group Investment Limited, a wholly owned subsidiary of Bank of China, incorporated in Hong Kong and an indirect shareholder of the Corporation;

"**Canadian Auditing Standards**" means **t**he Canadian Generally Accepted Auditing Standards;

"**Canadian Environmental Assessment Act**" **or** "**CEAA**" means *Canadian Environmental Assessment Act* (Canada), SC 1992, c 37, together with any amendments thereto and all regulations promulgated thereunder;

"**Cenovus**" means Cenovus Energy Inc., a corporation incorporated under the ABCA in 2009 and listed on the Toronto Stock Exchange and the New York Stock Exchange and an independent third party of the Corporation;

"**Class** "**B**" **Shares**" means the Class "B" Common Voting Shares in the capital of the Corporation, and prior to the amendment of the Corporation's Articles on February 28, 2012, the Class "B" Common Shares;

"**Class** "**G**" **Shares**" means the Class "G" Preferred Non-Voting Shares in the capital of the Corporation, and prior to the amendment of the Corporation's Articles on February 28, 2012, the Class "G" Preferred Shares;

"**Class** "**H**" **Shares**" means the Class "H" Preferred Non-Voting Shares in the capital of the Corporation, and prior to the amendment of the Corporation's Articles on February 28, 2012, the Class "H" Preferred Shares;

"**Climate Change and Emissions Management Act**" means *Climate Change and Emissions Management Act* (Alberta), SA 2003, c C-16.7, together with any amendments thereto and all regulations promulgated thereunder;

"**Climate Change and Emissions Management Fund**" **or** "**Fund**" means a provincial fund established pursuant to the *Climate Change and Emissions Management Act*;

"**CNRL**" **or** "**Canadian Natural Resources Limited**" means Canadian Natural Resources Limited, a corporation incorporated under the ABCA in 1973 and listed on the Toronto Stock Exchange and the New York Stock Exchange and an independent third party of the Corporation;

"**Commissioner**" means the Commissioner of Competition, pursuant to the *Competition Act,* RSC 1985, c C-34;

"**Common Shares**" means the Common Shares in the capital of the Corporation, being the Shares, the Class "B" Shares, the Class "C" Non-Voting Common Shares, the Class "D" Non-Voting Common Shares, the Class "E" Non-Voting Common Shares, and the Class "F" Non-Voting Common Shares;

"**Companies Act**" means *Companies Act* (Alberta), RSA 2000, c C-21, together with any amendments thereto and all regulations promulgated thereunder;

"**Companies Ordinance**" means the *Companies Ordinance* (Chapter 32 of the Laws of Hong Kong), as amended, supplemented or otherwise modified from time to time;

"**Corporation**", "**our Corporation**"**, Sunshine**", "**we**"**,** "**our**"**, or** "**us**" means Sunshine Oilsands Ltd., a corporation incorporated under the ABCA in 2007;

"**Competition Act**" means the *Competition Act,* RSC 1985, c C-34, together with any amendments thereto and all regulations promulgated thereunder;

"**Connacher**" means Connacher Oil and Gas Limited, a corporation incorporated under the ABCA in 1997 and listed on the Toronto Stock Exchange and an independent third party of the Corporation;

"**CRA**" means the Canada Revenue Agency;

"**Cross-Strait**" means Cross-Strait Common Development Fund Co. Limited, a limited liability company incorporated under the laws of Hong Kong and a shareholder of the Corporation;

"**Crown**" means Her Majesty in the right of Alberta;

"**Crown Land Sales**" means the competitive process whereby the Government of Alberta awards leases of public land in Alberta;

"**D&M**" means DeGolyer and MacNaughton Canada Limited, formed under the laws of Alberta, and a wholly owned subsidiary of DeGolyer and MacNaughton Corporation, and one of the independent qualified reserves evaluators (such term as defined under NI 51-101) of the Corporation;

"**D&M Report**" means the report prepared by one of the Corporation's independent qualified reserves evaluators (such term as defined under NI 51-101) effective as of November 30, 2011;

"**Department of Energy**" means the Alberta Department of Energy, a department of the Government of Alberta;

"**Directive 23**" means Directive 023: Guidelines Respecting an Application for a Commercial Crude Bitumen Recovery and Upgrading Project, issued by the Alberta Energy and Utilities Board in September 1991;

"**Director(s)**" means the director(s) of the Corporation;

"**E&E**" means Exploration and Evaluation assets;

"**EIA**" means United States Energy Information Administration, an agency within the department of Energy of the Government of the United States;

"**EIG Funds**" means EIG Gateway Direct Investments, LP, TCW Energy Fund XIV, LP, TCW Energy Fund XIV-A, LP, TCW Energy Fund XIV-B, LP and TCW Energy Fund XIV (Cayman), LP;

"**EPEA**" means the *Environmental Protection and Enhancement Act* (Alberta), RSA 2000, c E-12, together with any amendments thereto and all regulations promulgated thereunder;

"**ERCB**" means the Energy Resources Conservation Board;

"**Excluded Share**s" means any Shares which may be issued (i) pursuant to the exercise of any of the Share options granted under our Share Options Schemes; or (ii) pursuant to the conversion of any of the Preferred Shares as at the Listing Date;

"**Farmin and Option Agreement**" means the farmin and option agreement entered into between Petro Energy Corp and the Corporation on March 1, 2008;

"**Fee Warrants**" means 12,499,920 fee warrants issued by the Corporation in 2010 with an exercise price of $0.30 and 21,694,220 fee warrants issued by the Corporation in 2011 with an exercise price of $0.48;

"**First Nations**" means the indigenous peoples of Canada;

"**Fisheries Act**" means the *Fisheries (Alberta) Act,* RSA 2000, c F-16, together with any amendments thereto and all regulations promulgated thereunder;

"**GAAP**" means Generally Accepted Accounting Principles;

"**GHG**" means Greenhouse gas;

"**GLJ**" means GLJ Petroleum Consultants Limited, a limited liability company incorporated under the laws of Alberta and one of the independent qualified reserves evaluators (such term as defined under NI 51-101) of the Corporation;

"**GLJ Report**" means the report prepared by one of the Corporation's independent qualified reserves evaluators (such term as defined under NI 51-101) effective as of November 30, 2011;

"**Global Offering**" means the initial public offering on the SEHK of 923,299,500 Shares in the capital of the Corporation at HK$4.86 per Share for gross proceeds of approximately US$580 million (HK$4,487 million);

"**Global Offering Prospectus**" means the Corporation's long form prospectus dated February 20, 2012 filed with the SEHK as part of the Global Offering;

"**Harper Pilot**" means our Harper Carbonate CSS project launched in 2010;

"**Hong Kong Share Register**" means the branch register of the Shareholders of the Corporation maintained by the Hong Kong Share Registrar in Hong Kong;

"**Hong Kong Share Registrar**" means Computershare Hong Kong Investor Services Limited;

"**ICA**" **or** "**Investment Canada Act**" means the *Investment Canada Act* (Canada), RSC 1985, c 28 (1st Supp), together with any amendments thereto and all regulations promulgated thereunder;

"**IEA**" means International Energy Agency;

"**IFRS**" means International Financial Reporting Standards, as issued by the International Accounting Standards Board;

"**Independent Qualified Reserves Evaluators**" means both D&M and GLJ;

"**Independent Qualified Reserves Evaluators' Report**" means both D&M Report and GLJ Report;

"**Interim Guidance**" means the Interim Guidance on Pre-IPO Investments Pending Consultation On Possible Listing Rule Amendments issued by the Listing Committee on October 13, 2010 (reproduced as HKEx Guidance Letter HKEx-GL29-12 on January 16, 2012);

"**IPO**" means the Initial Public Offering;

"**ITA**" or "**Tax Act**" means *Income Tax Act* (Canada), RSC 1985, c 1 (5th Supp), together with any amendments thereto and all regulations promulgated thereunder;

"**Joint Global Coordinators**" means Morgan Stanley Asia Limited, BOCI Asia Limited and Deutsche Bank AG, Hong Kong Branch;

"**Laricina**" means Laricina Energy Ltd., a corporation formed under the ABCA on November 11, 2005 and an independent third party of the Corporation;

"**LARP**" means the draft Lower Athabasca Regional Plan;

"**Legacy**" means Legacy Oil + Gas Inc., a corporation incorporated under the ABCA on October 15, 2009;

"**Listing**" means the listing of the Shares on the Main Board of the SEHK;

"**Listing Committee**" means the Listing Committee of the SEHK;

"**Listing Date**" means March 1, 2012;

"**Listing Rules**" means the Rules Governing the Listing of Securities on the SEHK, as amended, supplemented or modified from time to time;

"**MEG**" means MEG Energy Corp., a corporation incorporated under the ABCA in 1999 and listed on the Toronto Stock Exchange and an independent third party of the Corporation;

"**Mines and Minerals Act**" means the *Mines and Minerals Act* (Alberta), RSA 2000, c M-17, together with any amendments thereto and all regulations promulgated thereunder;

"**Minister of Energy**" means the Minister of Energy for the Government of Alberta;

"**NEB**" means the National Energy Board of Canada, an independent economic regulatory agency of the Government of Canada;

"**NI 51-101**" means National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities*, as amended from time to time;

"**OECD**" means the Organisation for Economic Co-operation and Development;

"**Offer Price**" means HK$4.86 per Offer Share;

"**Offer Shares**" means 923,299,500 Shares issued in the capital of the Corporation as part of the Global Offering;

"**Oil Sands Conservation Act**" **or** "**OGCA**" means the *Oil and Gas Conservation Act* (Alberta), RSA 2000, c O-6, together with any amendments thereto and all regulations promulgated thereunder;

"**Oil & Gas Leases**" means the Oil Sands Leases and PNG Licences, as applicable;

"**Oil and Gas Asset Purchase Agreement**" means the oil and gas asset purchase agreement entered into between Petro Energy Corp and the Corporation dated September 29, 2008;

"**Oil Sands**" **or** "**oil sands**" means sands and other clastic rock materials which contain bitumen and include all other mineral substances in association therewith;

"**Oil Sands Lease**" means an oil sands lease pursuant to which the Crown grants the holder the right to develop and use oil sands resources existing under the *Oil Sands Tenure Regulation* on a primary or a continued basis;

"**Oil Sands Permit**" means an oil sands lease pursuant to which the Crown grants the holder the right to develop and use oil sands resources existing under the Oil Sands Tenure Regulation for a five year term;

"**Oil Sands Tenure Regulation**" means *Oil Sands Tenure Regulation* (Alberta), 2010, Alta Reg 196/2010, as amended, supplemented or otherwise modified from time to time;

"**Orient**" means Orient International Resources Group Limited, a company incorporated under the laws of the British Virgin Islands on April 7, 2010;

"**Orient Credit Facility**" means the two-year credit facility entered into between Orient and the Corporation on October 18, 2011;

"**Orient Financial**" means Orient Financial Holdings Limited, a company incorporated under the laws of Hong Kong on July 2, 2002;

"**Orient P&C**" means Orient International Petroleum & Chemical Limited, a company incorporated under the laws of Hong Kong on December 6, 2004;

"**Orient Shares**" means the 13,566,395 Shares issued to Orient Financial pursuant to the Advisory Agreement;

"**PADD**" means Petroleum Administration for Defence District;

"**Pelican Lake Farmout**" means a 100% working interest held by Petro-Energy Corp. in the Wabiskaw Formation in seven sections of undeveloped land at Pelican Lake equal to 1,792 hectares in total;

"**Perpetual**" means Perpetual Energy Operating Corp., a corporation incorporated under the ABCA on June 28, 2002;

"**Petro Energy Corp**" means Petro Energy Corp., a corporation formed under the ABCA on July 28, 2006;

"**PIPA**" means the *Personal Information Protection Act* (Alberta), SA 2003, c P-6.5, together with any amendments thereto and all regulations promulgated thereunder;

"**PNG License**" means an oil sands lease pursuant to which the Crown grants the holder the right to develop and use oil sands resources existing under the *Oil Sands Tenure Regulation*, Alta Reg 196/2010, on a primary or a continued basis;

"**Post-IPO Share Option Scheme**" means the stock option plan approved and adopted by the Corporation on January 26, 2012 for the grant of stock options to eligible participants following the completion of the Global Offering;

"**PRC**" means the People's Republic of China;

"**Preferred Shares**" means the preferred shares in the capital of the Corporation, being the Class "G" Shares, and the Class "H" Shares;

"**Pre-IPO Share Option Schemes**" means the stock option plan approved and adopted by the Corporation on May 9, 2007 and amended on April 30, 2008 (the "**2007 Share Option Plan**") and the stock option plan approved and adopted by the Corporation on May 7, 2009 and amended on June 13, 2010 (the "**2009 Share Option Plan**");

"**Principal Share Register**" means the Corporation's register of Shareholders in Alberta, Canada maintained by the Principal Share Registrar;

"**Principal Share Registrar**" means Alliance Trust Company, a trust company incorporated under the laws of Alberta and the principal share registrar of the Corporation;

"**PRS**" means the primary recovery scheme for Muskwa approved on January 18, 2010 (PRS#11382);

"**Public Lands Act**" means *Public Lands Act* (Alberta), RSA 2000, c P-40, together with any amendments thereto and all regulations promulgated thereunder;

"**Purchase Warrants**" means the 139,132,060 purchase warrants issued by the Corporation in 2010 with an exercise price of $0.40;

"**SAGD**" or "**steam assisted gravity drainage**" means the *in-situ* recovery process used to produce heavy crude oil and bitumen. two parallel horizontal wells, which are generally 5 metres apart, are drilled for the SAGD process. Steam is injected to the upper steam injector and a steam chamber is developed above the injector. With the growth of the steam chamber, mobilised bitumen drains to the producer below the injector and is lifted to the surface through an artificial lift system;

"**SEDAR**" means the system for electronic document analysis and retrieval maintained by CDS Inc. under the website address http://www.sedar.com/;

"**SEHK**" means the Stock Exchange of Hong Kong Limited;

"**SFC**" means the Securities and Futures Commission of Hong Kong;

"**SFO**" means the *Securities and Futures Ordinance* (Chapter 571 of the Laws of Hong Kong), as amended, supplemented or otherwise modified from time to time;

“**SGER**” means the *Specified Gas Emitters Regulation* (Alberta), Alta Reg 139/2007, as amended, supplemented or otherwise modified from time to time;

“**Shares**” means the Class “A” Common Voting Shares in the capital of the Corporation as listed on the SEHK, and prior to the amendment of the Corporation’s Articles on February 28, 2012, the Class “A” Common Shares;

“**Shareholders**” means the holder of the Shares and, until their exchange for Shares on a one-for-one basis immediately prior to Listing the Class “B” Shares and the holders of the Preferred Shares;

“**Share Option Schemes**” means the Pre-IPO Share Option Schemes and the Post-IPO Share Option Schemes;

“**Shared Formations**” mean the Pelican Lake Farmout and the Thickwood Farmout;

“**SIPC**” means Sinopec International Petroleum Exploration & Production Corporation, a company incorporated and existing under the laws of the People’s Republic of China, and a wholly owned subsidiary of Sinopec;

“**Sinopec**” means China Petroleum & Chemical Corporation, a joint stock limited company incorporated and existing under the laws of the People’s Republic of China and controlled by Sinopec Group;

“**Sinopec Group**” means China Petrochemical Corporation, a state-owned petroleum and petrochemical enterprise that was incorporated in July 1988;

“**SRD**” means Sustainable Resource Development, a Ministry of the Government of Alberta;

“**Subscription Agreements**” means the three subscription agreements entered into between Sunshine and each of China Life, Charter Globe and Cross-Strait in February 2011, under which China Life subscribed for Class “B” Shares and Charter Globe and Cross-Strait subscribed for Shares;

“**Suncor**” **or** “**Suncor Energy**” means Suncor Energy Inc., a corporation incorporated under the laws of Canada and listed on the Toronto Stock Exchange and the New York Stock Exchange and an independent third party of the Corporation;

“**Surface Rights Act**” means *Surface Rights Act* (Alberta), RSA 2000, c S-24, together with any amendments thereto and all regulations promulgated thereunder;

“**Surface Rights Board**” means the Surface Rights Board established and continued under the *Surface Rights Act;*

“**Thickwood Farmout**” means the 50% working interest held by Petro Energy Corp in the Wabiskaw Formation in six sections of land in the Thickwood region equal to 1,536 hectares in total;

“**Track Record Period**” means the three financial years ended December 31, 2009, 2010 and 2011;

“**UPPVP Act**” means *Unclaimed Personal Property and Vested Property Act* (Alberta), SA 2007, c U-1.5, together with any amendments thereto and all regulations promulgated thereunder;

“**Warrants**” means the Fee Warrants and the Purchase Warrants;

“**Warrant holders**” means the holders of the Warrants; and

“**Water Act**” means the *Water Act* (Alberta), RSA 2000, c W-3, together with any amendments thereto and all regulations promulgated thereunder.

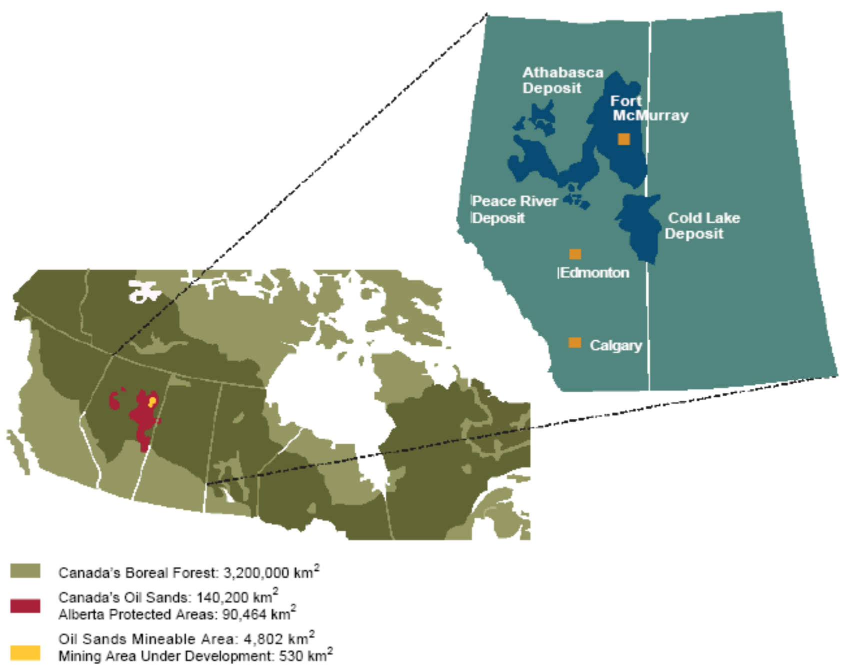
SUMMARY

The following is a summary that is aimed to give an overview of the information contained in this AIF and is qualified by, and should be read in conjunction with, the contents of the complete AIF . See "Glossary of Technical Terms" and "Glossary of Terms" for the meanings given to certain capitalized terms used in this Summary section.

The Corporation has included in this AIF a summary of its oil and gas reserves and resources that is based on the Independent Qualified Reserves Evaluators' Reports prepared by the Corporation's Independent Qualified Reserves Evaluators with an effective date as of November 30, 2011. There are no material differences between the information contained in the summary oil and gas information, which is based on the Independent Qualified Reserves Evaluators' Reports with an effective date as at November 30, 2011 and the information that would be contained in the summary oil and gas information in the AIF, had such summary been prepared based on the Independent Qualified Reserves Evaluators' Reports with an effective date of December 31, 2011.

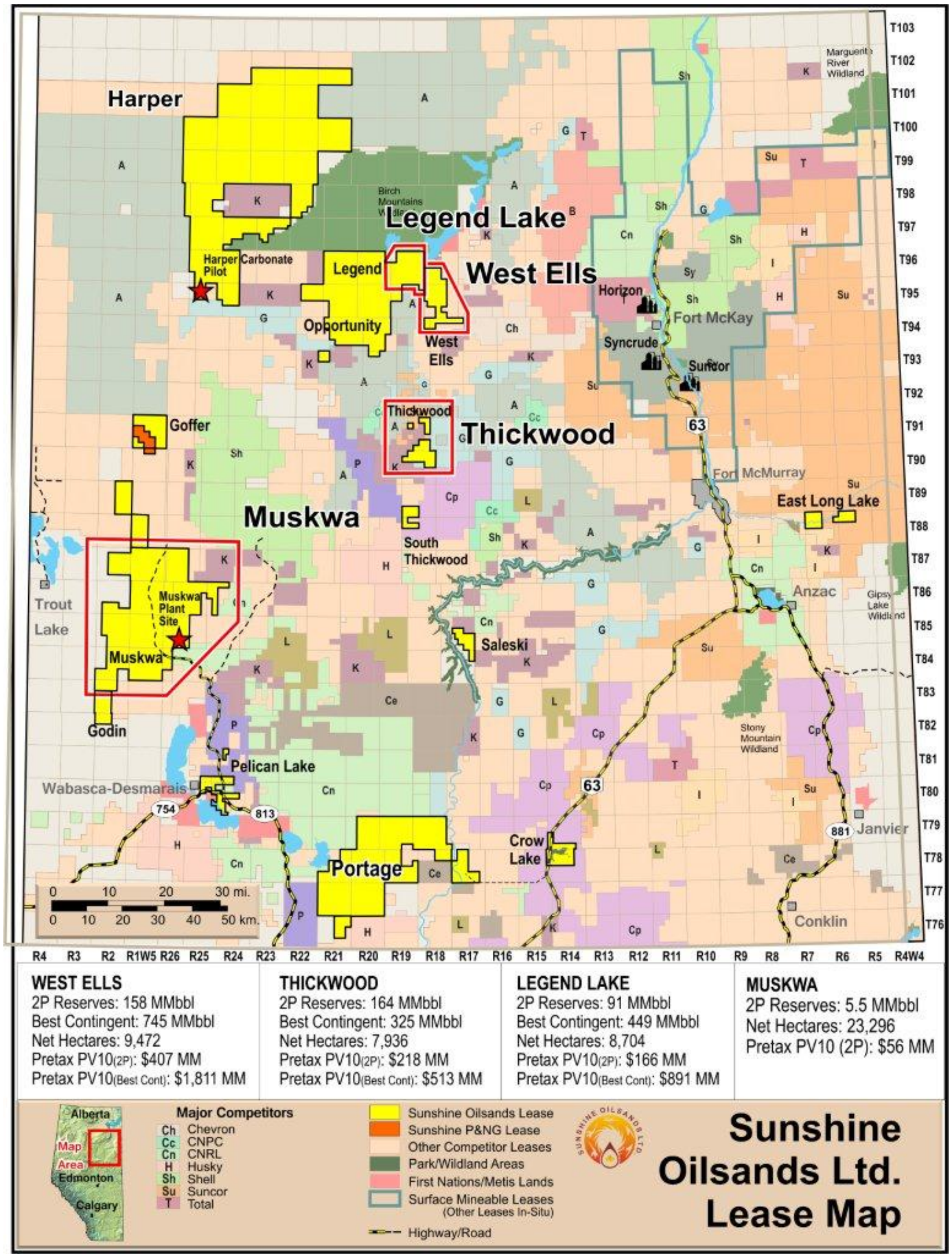
Overview

Sunshine is a corporation incorporated under the ABCA and is engaged in the exploration and development of oil sands leases in Alberta's Athabasca region. Since its incorporation on February 22, 2007, Sunshine has secured over 464,897 hectares of Oil Sands Leases. Athabasca is the most prolific oil sands region in Alberta, Canada. Canada's oil sands represent the largest oil resource found in a stable political environment located in the western hemisphere and the third largest oil resource in terms of oil reserves in the world, with 169 billion bbls of estimated reserves (according to the ERCB and Oil and Gas Journal). Moreover, the Canadian oil sands represent the largest single source of supply of oil to the United States.



Sunshine is headquartered in Calgary, Alberta and its principal operations are the exploration, development and production of a diverse portfolio of Oil Sands Leases. Sunshine's seven principal operating regions in the Athabasca area are at West Ells, Thickwood, Legend Lake, Harper, Muskwa, Goffer and Portage. In addition, Sunshine has certain non-principal areas with no immediate development plans located at Pelican Lake, East Long Lake, Crow Lake, Godin, Saleski and South Thickwood.

The map below highlights the Oil Sands Leases that the Corporation owns. The summary information below the map outlines the statistics related to the Corporation's core lease areas and highlights metrics from evaluations undertaken by our Independent Qualified Reserves Evaluators.



Notes:

(1) Net hectares are based on management's estimates.

Since its incorporation, Sunshine has accumulated Oil Sands Leases in the western Athabasca region. Upon accumulating a meaningful land position, the Corporation commenced an active drilling programme and commissioned its first Independent Qualified Reserves Evaluator's report in 2008. Having identified significant resources, Sunshine has focused on establishing its base of reserves and, in parallel, it initiated a CSS pilot programme at its Harper property that effectively demonstrated oil mobility in the Corporation's carbonate assets. The test was not designed to establish the Grosmont C as a commercial reservoir but it did achieve its stated objective of mobilising bitumen through thermal stimulation, which we believe is an important initial step to understanding this deposit. We are currently attributed with 419 million bbls of 2P reserves and 3.1 billion bbls of best estimate contingent resources. We received regulatory approval from the ERCB for our first 10,000 bbl/d clastic SAGD project at our West Ells property on January 26, 2012.

Sunshine holds 467,969 hectares of leases (including all Oil Sands Leases and PNG Licences) in the Athabasca oil sands region of north-eastern Alberta. We have 100% ownership of our Oil Sands Leases, with the exception of the Shared Formations, and we expect to incur only minimal rental costs to retain our leases. All of our Oil Sands Leases provide mineral extraction rights and are issued for an initial 15-year term. Our first acquired leases expire in approximately 10 years. During the initial term of the lease, an annual rental expense equal to $3.50 per hectare is payable. These leases can be held indefinitely after the initial term, upon determination by the Minister of Energy, provided certain minimum levels of exploration or production have been achieved and all lease rentals have been paid in a timely manner. For the lease areas which the Corporation plans to develop, the Corporation needs to apply for regulatory approvals from the ERCB and the AEW for the construction and operation of oil sands extraction facilities. It typically takes approximately 18 months for SAGD commercial facility approvals to be received. Approvals are granted based on planned SAGD production rates and can be subsequently expanded for additional phases and periods. Having consulted with Canadian regulatory counsel, we do not currently anticipate any legal impediments to obtaining all applicable licences, permits and approvals that are necessary to commence commercial production of all of our asset categories. Please refer to the section entitled *"Laws and Regulations in the Industry"* in this AIF for details of the approval process to be complied with in order to commence production on our Oil Sands Leases and the section entitled *"Business"* in this AIF for details of the predicted time frames for the development of our assets.

Our Oil Sands Leases are grouped into three main asset categories:

- *Clastics* - oil-saturated sands deposited during the Cretaceous period which contain bitumen extracted through thermal production (developed primarily using the SAGD *in-situ* method);

- *Carbonates* - oil-saturated carbonate based sedimentary rock deposited during the Devonian period, with potential to be commercially produced with thermal extraction techniques and developing technologies; and

- *Conventional Heavy Oil* - oil-saturated sands deposited during the Cretaceous period that can be recovered using CHOPS or other conventional heavy oil recovery technologies.

Under all three main asset categories, current and future production of bitumen of varying viscosities and API° gravities will be sold without upgrading. Our bitumen can be upgraded by others into a variety of oil products, such as petroleum, diesel fuel, jet fuel, kerosene, asphalt and tar.

Development of Our Assets

Our clastic, carbonate and conventional heavy oil assets are currently at different stages of development:

- *Clastics* - Our clastic assets are currently in the development stage and are expected to enter the initial steaming stage in the second quarter of 2013 following the approval by the ERCB of the West Ells 10,000 bbl/d commercial application on January 26, 2012. Construction activities at West Ells have commenced, with first steam estimated to take place in the second quarter of 2013. The Thickwood 10,000 bbl/d commercial application was submitted on October 31, 2011. The Legend Lake 10,000 bbl/d commercial application was submitted on November 25, 2011.

- *Carbonates* - Our carbonate assets are currently in the exploration stage. Further delineation drilling and pilot work is required to fully understand the carbonate assets and to identify the best development areas and extraction technologies to maximise their production potential and economic value. The pilot project results will allow us to enhance our ability to define detailed commercial development plans for our carbonate properties.

- *Conventional heavy oil* - Our conventional heavy oil project at Muskwa is in its pre-commercial stage with additional pads being drilled to progress the development plan and increase production capacity to expected rates of between 1,600-1,800 bbl/d by the end of 2012.

The tables below highlight our management's estimates of the project life and average yearly production rates for each of our projects for the period 2011 to 2015.

			Production Capacity				
Property	**Development Capacity**	**Project Life**	**2011**	**2012**	**2013**	**2014**	**2015**
	bbl/d	**Years**			**bbl/d**		
West Ells	100,000	55	-	-	5,000	10,000	10,000
Thickwood	50,000	47	-	-	-	-	10,000
Legend Lake	50,000	-	-	-	-	-	-

		Production[(2)]							
		Actual			Forecast				
Property	**Project Life**	**Oct 2011**	**Nov 2011**	**Dec 2011**	**2011**	**2012[(3)]**	**2013**	**2014**	**2015**
	Years				**bbl/d**				
Muskwa[(1)]	10	407	411	606	354	1,210	1,670	1,565	1,357

Notes:

(1) Muskwa development capacities and project life will be defined through exploration drilling and fairway definition for future development. Current development plan/forecast considers 2012 pad development only for a total of seven pads and 57 wells.

(2) All production numbers in the table are based on actual or forecast average production volumes for the periods specified.

(3) We have forecasted exit rates of between 1,600-1,800 bbl/d on the basis of management estimates.

This AIF includes the estimates of our reserves and resources made by our Independent Qualified Reserves Evaluators. In accordance with Canadian market practice, the Corporation has disclosed estimates of both the volumes and values of our possible reserves, contingent resources and PIIP in addition to proved reserves and probable reserves throughout this AIF. However, none of the volumes or values of our resources have been risked for chance of development. Our best estimate contingent resources have a pre-tax PV10% of \$4.8 billion compared to a pre-tax PV10% of \$829 million for our 2P reserves. Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations but the applicable projects are not yet considered mature enough for commercial development due to one or more contingencies. The Corporation does not give any assurance that it will be commercially viable to produce any portion of the contingent resources until the projects are more mature and contingencies are eliminated through detailed designs and regulatory submissions. For more information please refer to the sections entitled *"Risk Factors - Risks Relating to Our Business - There are risks associated with reserves and resource definitions"* in this AIF.

Clastics

The initial development of our clastic assets will involve the exploration, appraisal, development and production of our West Ells, Thickwood and Legend Lake sites (the "**Base Case Clastic Assets**"). On the basis of our management assumptions, we have forecasted that our Base Case Clastic Assets will have a total productive life of over 50 years and a peak production of approximately 200,000 bbl/d for over 18 years. Our management's development plan anticipates execution of these developments in staged and scalable phases in order to carefully manage project timing and funding requirements, as well as to exploit existing established technologies and new technologies as they are developed. Our management has assumed the following summary development timetable for each site:

- *West Ells* - We received regulatory approval from the ERCB on January 26, 2012 for the 10,000 bbl/d West Ells clastics project following the issuance of a final permanent shut-in order by the ERCB in relation to a dispute on December 15, 2011. As the final shut-in order has been granted, production at West Ells will not be affected by this dispute. First steam for the first phase is estimated to take place in the second quarter of 2013. The project has an initial anticipated production rate of 5,000 bbl/d, which will be followed by an expansion of an additional 5,000 bbl/d to reach a planned production capacity of 10,000 bbl/d. Following approval of subsequent regulatory applications, a total planned production capacity of 100,000 bbl/d is anticipated from the area, with first steam of the last expansion expected by 2024. Capital expenditure at West Ells in 2012 is expected to be $272.2 million, which will be funded through our internal cash resources. No production is expected in 2012.

- *Thickwood* - We filed a regulatory application with the ERCB for a 10,000 bbl/d commercial facility in the Thickwood project area on October 31, 2011. First steam is planned for the first quarter of 2015. Total planned production capacity for this area is 50,000 bbl/d by 2021. Capital expenditure at Thickwood in 2012 is expected to be $13.0 million, which will be funded through our internal cash resources. No production is expected in 2012.

- *Legend Lake* - We filed a regulatory application with the ERCB for a 10,000 bbl/d commercial development in the Legend Lake clastics project area on November 25, 2011. First steam is planned for the first quarter of 2016. Total planned production capacity for this area is 50,000 bbl/d by 2022. Capital expenditure at Legend Lake in 2012 is expected to be $16.3 million, which will be funded through our internal cash resources. No production is expected in 2012.

In addition to our Base Case Clastic Assets, we have identified clastic exploration opportunities through our 2010/2011 winter drilling programme in the Harper and Opportunity regions and the Muskwa regions. These areas provide potential for material growth in our clastics contingent resources and with the progression of regulatory applications for these areas, additional reserves over time.

The corporate development plans for each area, including the expected development timelines, are based on our management assumptions and are set out in the section entitled *"Business"* in this AIF. The time gap between "first steam" and commercial production is due to an approximately four month steam circulation period to prepare the steam chamber and link it to the SAGD well pairs.

The reservoir characteristics of our properties vary among the different properties and in comparison to other producing projects in McMurray or other formations. The reservoir we are proposing to produce has had little thermally stimulated production to date, although there are several commercial projects announced or in early stage of development. There is no guarantee that our steam oil ratio will be equivalent to those ratios in the McMurray or other formations which are currently producing. There is a risk that the recovery of bitumen will be lower in our projects than in projects in other reservoirs that have been used as analogues to produce the contingent resources in our technical report, because the reservoir characteristics are different although management believes that these differences have been taken into account.

Carbonates

We do not currently have a corporate development plan for our carbonates assets as our main focus remains the development of our Base Case Clastic Assets. Pilot work is expected to prove extraction technologies which we expect will enable us to further define our development plans for these assets.

However, beyond our currently defined corporate development plan, we believe that in the long term our carbonate assets have the potential to materially increase our contingent resource base and ultimately our production capacity. Unlike clastics, where technologies for commercial operations are well established, there are currently no established successful commercial scale projects in Canada that use CSS or SAGD in carbonate reservoirs; although thermal recovery has been conducted on a commercial scale in other parts of the world in different reservoir conditions, such as in Egypt. We are continuing to investigate the feasibility of thermal recovery processes based on pilot projects for our carbonate resources, and once commerciality of a given technology is proven, we will assess its applicability to our carbonate resources. In the long term, as recovery technologies continue to evolve, we plan to develop our carbonate resources, predominantly at our Harper, Muskwa, Ells-Leduc, Goffer and Portage sites. In 2010, our Harper Carbonate CSS pilot project was one of only two approved and active carbonate pilot projects in Canada and we executed the first cycle of our project during the 2010/2011 winter season. Currently, there are eight approved Carbonate pilots in Canada, of which, according to the

ERCB, only three are currently operational. Our Harper Pilot has been reactivated for operation in the winters of 2011/2012 and 2012/2013 following receipt of project approval from the ERCB. The first cycle of our Harper Pilot successfully demonstrated the thermal mobility of Grosmont C bitumen in the winter of 2010/2011. The test was not designed to demonstrate reservoir conformance to a predictive model and has not established the Grosmont C as a commercial reservoir. The test did achieve the stated objective of mobilising bitumen through thermal stimulation which we believe is an important initial step to dealing with this deposit.

Conventional Heavy Oil

We have identified conventional heavy oil opportunities across several areas within our land base, including Muskwa, Harper, Godin and Portage. The development of conventional oil reservoirs, which do not require thermal stimulation benefit from the Alberta oil sands royalty structure. This provides an economic advantage over non-oil sands heavy oil, as described in the section entitled *"Business"* in this AIF. The most advanced of these projects is in the Muskwa area, where we have executed several stages of preliminary exploration and development spending. Development of our Muskwa project is proceeding according to our development plan. We have demonstrated oil mobility without enhanced recovery techniques as well as sustained production from several well types, including horizontal, slant and vertical wells.

Our Muskwa property began producing conventional heavy oil in September 2010. As at the date of this AIF, we have not recognised any revenue from this property. Once the Muskwa property has been determined to meet the appropriate criteria for technical feasibility and commercial viability, which is expected to occur in 2012, revenues from the production and sales of crude oil will be recognised. We do not anticipate any major obstacles to commencement of commercial production.

Current forecasted development at Muskwa includes adding two multi-well production pads to the site, with up to nine wells per pad, which is anticipated by management to achieve a stabilised production rate ranging between 1,600-1,800 bbl/d by the end of 2012. Capital expenditure at Muskwa is anticipated to be $17.1 million in 2012. In conjunction with this activity, we intend to undertake further confirmation of oil mobility by extending the reservoir through selective production testing. This low cost verification process will provide low risk development fairways. Our 2011/2012 winter drilling programme includes mobility testing in the Harper and Godin areas, which may provide further options for conventional heavy oil development. On the basis of our management assumptions, we have forecast that the productive life of Muskwa for conventional heavy oil will conclude in 2021.

The following table presents a summary of the reserves and resources attributable to our main asset groups as at November 30, 2011. **Some volumes in this table are an arithmetic sum of multiple estimates from various properties of probable and possible reserve and low and high case resources, which statistical principles indicate may be misleading as to volumes that may actually be recovered in the aggregate. Readers should give attention to the estimates of individual classes of resources and appreciate the differing probabilities of recovery associated with each class as explained in the Glossary of Technical Terms.**

			Total PIIP(6)			Reserves			Contingent Resources(4)			Pre-Tax PV10%					
Property	**Region**	**Number of Oil & Gas Leases**	**Low Estimate**	**Best Estimate(3)**	**High Estimate**	**1P**	**2P**	**3P**	**Low Estimate**	**Best Estimate(3)**	**High Estimate**	**1P**	**2P**	**3P**	**Low Estimate Contingent Resources**	**Best Estimate Contingent Resources(3)**	**High Estimate Contingent Resources**
Conventional Heavy Oil																	
Muskwa	Muskwa	21(8)	47	86	120	2.4	5.5	8.8	0	0	0	38	56	61	0	0	0
Total Conventional Heavy Oil			**47**	**86**	**120**	**2.4**	**5.5**	**8.8**	**0**	**0**	**0**	**38**	**56**	**61**	**0**	**0**	**0**
												0					
Clastics(7) (18)																	
West Ells	West Ells(17)	26(9)	1,918	1,918	1,918	0	158	209	401	745	1,011	0	407	706	1,082	1,811	2,548
Thickwood	Thickwood(16)	4(14)	1,403	1,403	1,403	0	164	219	258	325	419	0	218	399	65	513	890
Legend Lake	Legend Lake	27(10)	1,730	1,844	1,844	0	91	124	255	449	673	0	166	271	477	891	1,801
Pelican Lake	Pelican Lake	2(15)	375	375	384	0	0	0	77	118	185	0	0	0	100	270	596
Opportunity	Legend Lake	27(10)	949	2,235	2,235	0	0	0	0	37	131	0	0	0	0	(4)	128
East Long Lake	East Long Lake	5	113	162	162	0	0	0	15	33	74	0	0	0	64	160	353
Crow Lake	Crow Lake	2	225	332	332	0	0	0	0	0	14	0	0	0	0	0	24
Portage Grand Rapids	Portage	14(11)	232	232	367	0	0	0	0	0	4	0	0	0	0	0	4
Harper	Harper	38(12)	5,581	5,581	7,512	0	0	0	0	326	780	0	0	0	0	491	2,068
Muskwa/Godin	Muskwa	21(18)	1,163	1,482	1,870	0	0	0	270	418	643	0	0	0	136	231	437
Portage Wabiskaw	Portage	14(11)	381	445	592	0	0	0	0	0	0	0	0	0	0	0	0
Total Clastics			**14,070**	**16,009**	**18,619**	**0**	**413**	**552**	**1,276**	**2,450**	**3,934**	**0**	**790**	**1,376**	**1,924**	**4,363**	**8,849**
Carbonates(5) (19)																	
Harper	Harper	38(12)	8,780	10,555	11,819				0	393	1,405	0	0	0	0	243	2,668

			Total PIIP[6]			Reserves			Contingent Resources[4]			Pre-Tax PV10%					
Property	**Region**	**Number of Oil & Gas Leases**	**Low Estimate**	**Best Estimate[3]**	**High Estimate**	**1P**	**2P**	**3P**	**Low Estimate**	**Best Estimate[3]**	**High Estimate**	**1P**	**2P**	**3P**	**Low Estimate Contingent Resources**	**Best Estimate Contingent Resources[3]**	**High Estimate Contingent Resources**
Ells Leduc	West Ells	26[9]	856	997	997	0	0	0	0	159	271	0	0	0	0	448	904
Goffer	Goffer	2[13]	1,289	1,732	2,158	0	0	0	0	0	521	0	0	0	0	0	71
Muskwa	Muskwa	21[18]	8,209	10,841	14,583	0	0	0	0	0	1,810	0	0	0	0	0	1,308
Saleski	Saleski	1	538	596	762	0	0	0	0	0	123	0	0	0	0	0	243
South Thickwood	South Thickwood	9[16]	243	287	402	0	0	0	0	0	56	0	0	0	0	0	63
Portage Nisku	Portage	14[11]	3,597	4,265	4,853	0	0	0	0	64	961	0	0	0	0	8	2,771
Goffer Keg River	Goffer	2[13]	0	0	22	0	0	0	0	0	0	0	0	0	0	0	0
Total Carbonates			**23,512**	**29,273**	**35,596**	**0**	**0**	**0**	**0**	**616**	**5,147**	**0**	**0**	**0**	**0**	**699**	**8,028**
Combined Total		**151**	**37,629**	**45,368**	**54,335**	**2**	**419**	**561**	**1,276**	**3,066**	**9,081**	**38**	**846**	**1,437**	**1,924**	**5,062**	**16,877**
Pre-tax PV10%[2]												**30**	**829**	**1,410**	**1,866**	**4,837**	**16,520**
Post-tax PV10%[2]												**21**	**482**	**895**	**869**	**2,555**	**9,723**

Source: GLJ Report and D&M Report dated November 30, 2011.

Notes:

(1) MMbbl unless otherwise noted. Figures are rounded to the nearest MMbbl or $ million (where applicable).

(2) Both GLJ's and D&M's Pre-Tax PV10% and Post-Tax PV10% in this table incorporate GLJ's October 1, 2011 price forecasts for oil, bitumen and natural gas and are denominated in $ millions. PV10% is not a measure of financial or operating performance, nor is it intended to represent the current value of our reserves and resources. For further details, please refer to the section entitled *"Risk Factors – The reserves and resources data and present value calculations presented in this AIF are estimates based on a number of assumptions which may deviate from the actual figures over time"*.

(3) If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate. For further details, please refer to the section entitled *"Risk Factors – Risks Relating to Our Business – There are risks associated with reserves and resource definitions"*.

(4) A significant part of our resources base is comprised of contingent resources, which are estimated to be potentially recoverable but not currently considered to be commercially recoverable due to one or more contingencies. However, none of the volumes or values of our resources have been risked for chance of development. The Corporation does not provide any assurance that it will be commercially viable to produce any portion of the contingent resources until contingencies are eliminated through detailed designs and regulatory submissions. For further details, please refer to the sections entitled *"Risk Factors – Risks Relating to Our Business – There are risks associated with reserves and resource definitions"*, *"Risk Factors – The reserves and resources data and present value calculations presented in this AIF are estimates based on a number of assumptions which may deviate from the actual figures over time"*.

(5) The development of our carbonate assets is based on technology under development. For further details, please refer to the section entitled *"Risk Factors – Risks Relating to Our Business – Carbonate resources may not be successfully developed"*.

(6) Total PIIP is a sum of discovered and undiscovered PIIP components as defined in GLJ and D&M Reports.

(7) We plan to pursue our own development plan and use our own assumptions for our Base Case Clastic Assets, which reflect certain principal differences from the plan and assumptions used by GLJ, one of our Independent Qualified Reserves Evaluators. For further details, please refer to the section entitled *"Business – Reserves and Resources Evaluations – Management commentary on key assumptions"*.

(8) The 21 Oil Sands Leases in the Muskwa region consist of conventional heavy oil, clastics and carbonates. The clastics are at Godin in the Muskwa region.

(9) The 26 Oil Sands Leases in the West Ells region consist of clastic and carbonates. The carbonates are at Ells Leduc in the West Ells region.

(10) The 27 Oil Sands Leases in the Legend Lake region consist of clastics at Legend Lake and Opportunity.

(11) The 14 Oil Sands Leases in the Portage region consist of carbonates at Portage Nisku and clastics at Grand Rapids and Wabiskaw.

(12) The 38 Oil Sands Leases in the Harper region consist of clastics and carbonates.

(13) The one PNG Licence and one Oil Sands Lease in the Goffer region consist of carbonates at Goffer and Keg River.

(14) We have 23 sections or 5,888 hectares at Thickwood that were acquired in 2007.

(15) We have 21.8 sections or 5,614 hectares at Pelican Lake that were acquired in 2007, 2008 and 2011. We acquired 13.3 sections or 3,438 hectares of land at Pelican Lake on December 14, 2011 for approximately $2.7 million, which is not covered by GLJ and D&M Reports. Petro Energy Corp has a 100% working interest in the Wabiskaw Formation in seven sections at Pelican Lake, the area of which is equal to 82.4% of our Pelican Lake holding. Please refer to the section entitled *"Business – Our Assets and Operations"* for more details.

(16) Petro Energy Corp has a 50% participating interest in the Wabiskaw Formation in six sections in the Thickwood region; the area of which equates to 9.1% of our Thickwood holdings (including the 33 sections comprising Thickwood and South Thickwood). Please refer to the section entitled "Business – Our Assets and Operations" for more details.

(17) We received regulatory approval from the ERCB for our first 10,000 bbl/d clastic SAGD project at our West Ells property on January 26, 2012. Please refer to the section entitled *"Summary – Recent Developments"* below for further information.

(18) Clastic Resource Contingencies: Non technical – Regulatory submissions and approvals required. West Ells, Legend Lake and Thickwood properties are proceeding with development guided by the corporate development plan, regulatory submissions and project expansions scheduled. Remaining clastic properties additionally require definition of corporate plans and board of directors approvals.

(19) Carbonate Resource Contingencies: Technical – Technology under development. Carbonate development is contingent upon successful application of SAGD and CSS technology in carbonate reservoirs, which is currently under active development in the industry. Pilot data will help to define company's projects in the carbonates. Non technical – Corporate development plans to be defined, board of directors approvals, regulatory submissions.

2011/2012 Winter Drilling Programme

With the exception of the Muskwa conventional heavy oil project, our assets are only accessible for exploration and delineation drilling in the frozen conditions prevalent in the Athabasca region during winter. As at the date of this AIF, the Corporation was completing the 2011/2012 winter drilling programme, which includes exploration, delineation drilling and seismic acquisitions. As part of its 2011/2012 winter drilling program, the Corporation completed the drilling of a total of 67 wells, including 59 clastic exploration wells, 1 disposal and 7 water wells. Two wells were also drilled through Sunshine's Clearwater Formation by PetroEnergy and logs and cores were provided to Sunshine at no cost. The Corporation also drilled and completed 39 Muskwa development wells. In addition, Sunshine also completed seismic activities at Opportunity, Legend Lake and Thickwood. These locations are designed to advance the recognition of new reserves and new contingent resources additions.

As at the date of this AIF, the 2011/2012 winter drilling programme was completing. This program included exploration drilling, coring operations, production testing and progression of the West Ells project, including observation and SAGD well drilling. Further operations at Harper have been approved for the 2011/2012 and 2012/2013 winter seasons and initial work has been initiated on the existing Harper Pilot well prior to the next CSS steam cycle.

Memorandum of Understanding for Strategic Cooperation with SIPC

In February 2012, Sunshine entered into a non-binding memorandum of understanding for strategic cooperation with SIPC (the "**MOU**"), a wholly owned subsidiary of Sinopec, with a view to forming a strategic alliance with Sinopec for the development of some of our resources. Sinopec is one of the major state-owned petroleum and petrochemical groups in China. The parties intend to examine opportunities for joint participation in the development, exploration and production of Oil Sands Leases, as well as other mutually agreed investments and projects in Canada and globally. A strategic cooperation steering committee is expected to examine and pursue any appropriate opportunities on a joint basis. The MOU is non-binding and terminates on December 31, 2013, unless such term is extended by the parties' mutual agreement in writing. So far, no specific details in relation to joint cooperation projects, the form and funding of any joint investments or their timing have been agreed between Sunshine and SIPC, nor have any such projects arisen. Please refer to the section entitled *"Business - Memorandum of Understanding for Strategic Cooperation with SIPC"* in this AIF for more details. Sinopec Century Bright Capital Investment, a wholly-owned subsidiary of Sinopec Group, is a Cornerstone Investor. Please refer to the section entitled *"Cornerstone Investor"* in this AIF for more details.

Historical Financing

As at December 31, 2011, we had invested $74.7 million in acquisitions of Oil Sands Leases and a further $307.6 million in drilling operations, project planning and regulatory application processing. We completed our last significant private capital raise in February 2011 with gross proceeds of $225.9 million. As at December 31, 2011, we had approximately $85.0 million in cash and cash equivalents (term deposits). In order to fund our exploration and development activities, we have raised approximately $1.0 billion in equity proceeds since our incorporation to the date of this AIF, including funds from prominent Chinese investors such as China Life, BOCGI, Orient and Cross Strait and the Global Offering which was completed on March 1, 2012 for gross proceeds of approximately US$580 million (HK$4,487 million).

On October 18, 2011, Sunshine entered into the Orient Credit Facility in the principal amount of $100 million, for general corporate purposes. The Orient Credit Facility is unsecured and may be subordinated if another lender requires it to be subordinated, with no penalty chargeable upon early repayment or cancellation of the Orient Credit Facility. The Orient Credit Facility is interest-free until May 31, 2012, and commencing on June 1, 2012 an annual interest rate charged at 5% per annum on the outstanding principal will be payable on a semi-annual basis to Orient International Resources Group Limited. The annual interest rate was determined upon commercial negotiations between Orient International Resources Group Limited and Sunshine. The Corporation understands that current market rates for oil sands companies in the developmental stages are approximately 400 basis points plus bankers' acceptances (1.25% as of October 25, 2011) equating to an interest rate of 5.25%. As of the date hereof, Sunshine has $Nil drawn of the Orient Credit Facility.

We are currently in discussions with the Bank of China in relation to a possible credit facility in the amount of US$200 million pursuant to a non-binding letter of intent dated February 3, 2012. Entry into any binding credit facility arrangement will be subject to further negotiations between the parties regarding the terms and conditions of the credit facility and the Bank of China's approval. The letter of intent is valid for one year and will expire in February 2013. As at the date of this AIF, we had not entered into any binding credit facility agreement with the Bank of China.

Key Terms of Our Oil Sands Leases and PNG Licences

As at the date of this AIF, Sunshine had 152 Oil Sands Leases and one PNG Licence in Alberta, Canada. Oil Sands Leases in the Athabasca oil sands area generally have an initial term of 15 years, after which time the leases may be continued if certain activity and/or production levels and conditions are satisfied.

Key common terms of Oil & Gas Leases in Alberta include the following:

- the licensee has an exclusive right to recover the leased substances within the location (in the case of an Oil Sands Lease, the leased substances are the sands and other rock materials containing crude bitumen, the crude bitumen contained in those sands and other rock materials, and any other mineral substances, other than natural gas, in association with that crude bitumen or the sands and other rock materials. In the case of a PNG Licence, the leased substance is petroleum and natural gas);

- the licensee has the right over the leased area for an initial term of 15 years, however, the licensee's rights may continue beyond such initial term, subject to the specific terms of each Oil Sands Lease and the provisions of the *Mines and Minerals Act*;

- the licensee is obligated to pay yearly rentals and royalties as prescribed by the *Mines and Minerals Act*;

- the licensee is obligated to comply with the *Mines and Minerals Act* and other applicable laws and regulations, such as the *Oil Sands Conservation Act*; and

- the licensee is required to indemnify the Crown against all claims brought against the Crown by reason of any acts or omissions of the licensee in respect of its rights or duties.

Summary of Historical Financial Information

The following is a summary of our Audited Financial Statements as at December 31, 2011 and 2010 and for the years ended December 31, 2011, 2010 and 2009.

During the three years ended December 31, 2011, our business has progressed through three winter delineation programmes and has progressed to early stage development and production of our diverse portfolio of Oil Sands Leases. We have not generated net profits and have recorded operating cash outflows up until the year ended December 31, 2011.

The results for the three years ended December 31, 2011 were prepared on the basis of presentation as set out in our Audited Financial Statements. The summary of our consolidated financial information should be read in conjunction with the Audited Financial Statements which is attached hereto as Schedule "A".

Consolidated Statements of Comprehensive Income

	Year Ended December 31,		
	2009	**2010**	**2011**
	$	**$**	**$**
Interest income from bank deposits	3,060	257,067	1,624,507
Other income	3,835	7,602	-
Interest and other income	6,895	264,669	1,624,507
General and administrative expenses	(2,829,716)	(5,789,076)	(12,809,423)

	Year Ended December 31,		
	2009	2010	2011
	$	$	$
Depreciation	(105,589)	(111,551)	(185,729)
Share-based payments	(555,871)	(3,946,638)	(8,075,446)
Allocation of IPO expenses	-	-	(3,547,085)
Fair value loss on warrants	-	-	(20,297,567)
Finance costs	(140,745)	(93,030)	(25,469,650)
Total expenses	**(3,631,921)**	**(9,940,295)**	**(70,384,900)**
Loss before tax	(3,625,026)	(9,675,626)	(68,760,393)
Income tax expense (recovery) credit	777,009	(181,315)	1,367,853
Loss for the year/ period and comprehensive loss attributable to equity holders of the Corporation	**(2,848,017)**	**(9,856,941)**	**(67,392,540)**
Loss per share(1)			
Basic(2)	(0.00)	(0.01)	(0.05)
Diluted(2)	(0.00)	(0.01)	(0.05)

Notes:

(1) During the Track Record Period, redeemable shares were not included in the denominator in the calculation of basic and dilutive loss per share because redeemable shares do not meet the definition of ordinary shares or potential ordinary shares under International Accounting Standard 33 "Earnings Per Share" issued by the International Accounting Standards Board.

(2) The weighted average number of Common Shares for the purpose of calculating basic/diluted loss per share has been adjusted for the effect of the 20 for 1 share split.

We recorded fair value loss on Warrants of $20.3 million for the year ended December 31, 2011. Fair value loss on Warrants represents mark to market adjustment of the fair value of our Warrants arising from certain amendments we entered into with the holders of Purchase Warrants and Fee Warrants, pursuant to which we could elect to make a cash payment instead of issuing a Common Share upon the exercise by a holder of a Purchase Warrant or a Fee Warrant. Please refer to the section entitled "*Financial Information - Period to Period Comparison of Results of Operations - Year ended December 31, 2011 compared to year ended December 31, 2010 - Expenses - Fair value loss on Warrants"* in this AIF.

Our finance costs increased by $25.3 million in the year ended December 31, 2011 as compared to December 31, 2010, primarily due to a $32.1 million cost associated with the equity financing undertaken by us which was completed in February 2011, in which, $6.8 million of this cost was capitalized. Please refer to the section entitled "*Financial Information - Period to Period Comparison of Results of Operations - Year ended December 31, 2011 as compared to December 31, 2010 – Expenses - Finance costs*" in this AIF.

Consolidated Statements of Financial Position

	As at December 31,		
	2009	2010	2011
	$	$	$
Non-current assets			
Property and equipment	301,847	474,051	718,785
Deferred initial public offering expenses	-	-	3,379,627
Exploration and evaluation assets	134,622,825	197,836,345	382,277,258
	134,924,672	198,310,396	386,375,670
Current assets			
Trade and other receivables	80,565	1,273,558	3,582,953
Prepaid expenses and deposits	234,152	1,910,487	797,718
Cash and cash equivalents	575,769	41,540,387	84,957,414
	890,486	44,724,432	89,338,085
Current liabilities			
Trade and other payables	1,292,426	17,521,798	33,365,438
Bank borrowings	5,328,200	-	-
Provision for decommissioning obligations	-	116,734	68,365

	As at December 31,		
	2009	2010	2011
	$	$	$
Provision for flow-through share obligations	250,075	19,914	-
Warrants	-	-	63,000,304
	6,870,701	17,658,446	96,434,107
Net current (liabilities) assets	(5,980,215)	(27,065,986)	(7,096,022)
Total assets less current liabilities	**128,944,457**	**225,376,382**	**379,279,648**
Non-current liabilities			
Redeemable shares	-	-	224,362,115
Provision for decommissioning obligations	354,833	2,052,330	6,331,883
Deferred tax liabilities	624,906	891,262	-
	979,739	2,943,592	230,693,998
	127,964,718	**222,432,790**	**148,585,650**
Capital and reserves			
Issued capital	130,745,650	224,526,472	219,173,885
Reserves	(2,780,932)	(2,093,682)	(70,588,235)
	127,964,718	**222,432,790**	**148,585,650**

Summary of Consolidated Statements of Cash Flow

	Year ended December 31,		
	2009	2010	2011
	$	$	$
Net cash used in operating activities	(2,598,410)	(5,961,534)	(13,779,243)
Net cash used in investing activities	(8,361,315)	(43,493,460)	(154,366,815)
Net cash generated from financing activities	10,994,482	90,419,612	211,563,085
Net (decrease) increase in cash and cash equivalents	34,757	40,964,618	43,417,027
Cash and cash equivalents at beginning of year	541,012	575,769	41,540,387
Cash and cash equivalents at end of year	**575,769**	**41,540,387**	**84,957,414**

Capital Expenditure

	Year ended December 31		
	2009	2010	2011
	$	$	$
Exploration activities			
Exploration Land (land and leasehold payments)	2,217,982	7,052,050	6,435,308
Drilling delineation programme	630,392	21,648,004	67,885,103
Geological Study (including seismic)	319,468	2,771,931	5,029,288
Carbonate pilot programmes	-	620,739	4,328,730
Other (Engineering studies and environmental studies)	1,741,444	1,098,009	4,295,883
Directly Attributable Capitalised Expenses	2,191,204	4,704,970	7,834,753
Total	**7,100,490**	**37,895,703**	**95,809,065**

	Year ended December 31		
	2009	2010	2011
	$	$	$
Development activities			
West Ells	-	-	17,899,576
Muskwa production pads	-	2,487,334	34,761,636
Other Muskwa (including road, capitalised costs, seismic)	-	2,780,707	7,233,515
	-	5,268,041	59,894,727
Total	**7,100,490**	**43,163,744**	**155,560,859**

Use of Proceeds

We received gross proceeds of approximately US$580 million (HK$4,487 million) from the Global Offering.

We intend to use the net proceeds we receive from the Global Offering for the following purposes:

- approximately 93% of the net proceeds from the Global Offering is expected to be used for funding the development of oil sands and heavy/light oil projects, out of which we intend to allocate as follows:

West Ells	64%
Delineation Drilling	12%
Muskwa	5%
Thickwood	3%
Other Projects	9%
Total	**93%**

  and

- approximately 7% of the net proceeds is expected to be used as general working capital for corporate and other purposes.

To the extent that the net proceeds of the Global Offering are not immediately used for the purposes described above they will be placed in short term demand deposits and/or money market instruments.

Capital Structure

In addition to our Shares, we also have Class "G" Shares and Class "H" Shares issued and outstanding.

The Class "G" Shares and Class "H" Shares were issued to certain directors, officers, employees, consultants and advisers of Sunshine in order to incentivise them to remain in our employment during the period from August 2010 to the earlier of December 31, 2013 or completion of approximately a two year period after the date of the Global Offering. They amount to, and have been accounted for as, a form of compensation scheme for the holders thereof, as opposed to investments. The total number of Class "G" Shares authorised for issuance is unlimited. However, our Board, in accordance with the terms of the Class "G" Shares set out in the Articles, has set a limit of 65,000,000 Class "G" Shares for issuance. As of the present date, Sunshine has 64,140,000 Class "G" Shares issued and outstanding. The total number of Class "H" Shares authorised for issuance is unlimited. However, the Board, in accordance with the terms of the Class "H" Shares set out in the Articles, has set a limit of 25,000,000 Class "H" Shares for issuance. As of the present date, Sunshine has 22,200,000 Class "H" Shares were issued and outstanding. We will not issue any further Class "G" Shares or Class "H" Shares after the closing of the Global Offering.

The Class "G" Shares and the Class "H" Shares are preferred shares and take priority with regard to dividends, return of capital and the distribution of assets on a dissolution of Sunshine. They are convertible at the option of the holder or redeemable by us at any time prior to their expiry date. They are convertible into the number of Shares such holder is entitled to at the exercise date pursuant to a vesting schedule, or they are retractable at the option of the holder from 21 months following the Global Offering for the number of Shares that the holder is entitled to on the date of retraction. The holders of the Class "G" Shares and Class "H" Shares are entitled to an annual non-cumulative cash dividend equal to the dividend declared by the Board in that year, if any, on the Shares based on the number of Shares the Class "G" Shares and Class "H" Shares are convertible into on the record date for such a dividend. No dividend shall be declared and paid on, or set apart for payment, on the Shares or any other shares that rank junior to the Class "G" Shares and Class "H" Shares in any fiscal year unless the dividends on all the Class "G" Shares and Class "H" Shares which are issued and outstanding at that time have been declared, paid or set apart for payment, except with the written consent of all of the holders of Class "G" Shares and Class "H" Shares. In the event that a holder of Class "G" Shares and/or Class "H" Shares ceases to be a director, officer, employee, consultant or adviser of the Corporation, those Class "G" Shares and Class "H" Shares held by such holder shall terminate on the date that is 30 days after such holder ceases to retain such role and shall only be convertible, redeemable or retractable for the number of Shares such holder is then entitled to, pursuant to a vesting schedule. The Class "G" Shares and Class "H" Shares are non-voting shares and are non-transferable.

The Class “G” Shares and Class “H” Shares are equity-settled share-based payments. For those granted to directors, officers and employees, these are measured at the fair value of the Class “G” Shares and Class “H” Shares at the grant date using the Black-Scholes option pricing model less the fair value of proceeds received on granting the Class “G” Shares and Class “H” Shares at the grant date. The fair value received determined at the grant date is expensed on the statement of comprehensive income based on the Corporation’s estimate of when the Class “G” Shares and Class “H” Shares will eventually vest, unless the services are directly attributable to exploration and evaluation activities, in which case the expenses will be capitalised in exploration and evaluation assets on the statement of financial position, with a corresponding increase in equity (share-based payments reserve). For those granted to parties other than employees, these are measured at the fair value received, except where that fair value cannot be estimated reliably, in which case they are measured at the fair value of the Class “G” Shares and Class “H” Shares granted, measured at the grant date. The fair value received is recognised as expenses on the statement of comprehensive income, unless it qualifies for recognition as assets or are directly attributable to exploration and evaluation assets, with a corresponding increase in equity (share-based payments reserve).

During the Track Record Period, the following amounts were recorded in the statement of comprehensive income, and the statement of financial position for the Class “G” Shares and Class “H” Shares:

	For the year ended December 31,		
	2009	**2010**	**2011**
	$	**$**	**$**
Expensed on the statement of comprehensive income	-	786,444	4,650,795
Capitalised in exploration and evaluation assets	-	912,170	3,604,742
Amount recorded under share-based payment reserve	**-**	**1,698,614**	**8,255,537**

Dividend and Dividend Policy

We have not declared or paid any dividends since our date of incorporation, nor do we have any present intention of paying any dividends in the near term. We do not have a fixed dividend policy.

Risk Factors

An investment in the securities of the Corporation is subject to certain risks. These can be categorized into (i) risks relating to the business of the Sunshine; (ii) risks relating to the oil sands industry; (iii) risks relating to Alberta and Canada; and (iv) risks relating to our Shares. Investors should carefully consider the various risk factors associated with the business and operations of the Corporation. Please see section entitled *“Risk Factors”*.

CORPORATE STRUCTURE

Sunshine was incorporated pursuant to the provisions of the ABCA on February 22, 2007. The registered office of Sunshine is located at Suite 3300, 421 – 7th Avenue SW, Calgary, Alberta, T2P 4K9, Canada, and its corporate head office and principal place of business is located at Suite 1020, 903 – 8th Avenue SW, Calgary, Alberta, T2P 0P7, Canada.

On May 4, 2007, Sunshine amended its articles of association (the "**Articles**") to add restrictions on the transfer of its shares, removed restrictions on the number of shareholders allowable by the Corporation, removed the prohibition on the Corporation from making an invitation to the public to subscribe for its securities and included a provision with respect to appointment of additional directors between annual general meetings.

On January 26, 2012, Sunshine held its annual general and special shareholders meeting whereby the Shareholders approved, among others, the amendment of the Articles to allow for a share split of the Common Shares and the Preferred Shares on an up to 25 for 1 basis. On February 10, 2012, the Corporation amended its Articles to give effect to a 20 for 1 share split of all of its issued and outstanding shares of the Corporation (the "**Share Split**"). On February 28, 2012, the Corporation amended its Articles to increase the maximum number of directors of the Corporation from ten to fifteen, amended the retraction rights available to the holders of the Class "G" Shares and the Class "H" Shares, removed the voting rights available to the holders of the Class "G" Shares, removed the provision with respect to liens the Corporation had against the issued and outstanding shares of its registered Shareholders to the extent of their indebtedness to the Corporation, included a provision in the Articles that any future amendments or repeals of the Corporation's by-law would only be effective if passed by a special resolution of Shareholders, re-designated each class of shares of the Corporation such that each class of shares are expressly indicated as being either "voting" or "non-voting" shares of the Corporation and removed its private company restrictions with respect to restrictions on the transfer of shares of the Corporation.

Fern Energy Ltd., ("**Fern**") is a wholly-owned subsidiary of the Corporation. Fern was incorporated pursuant to the provisions of the ABCA on February 3, 2006. The registered of Fern is located at Suite 3300, 421 - 7th Avenue SW, Calgary, Alberta, T2P 4K9, Canada, and its corporate head office and principal place of business is located at Suite 1020, 903 - 8th Avenue SW, Calgary, Alberta, T2P 0P7, Canada.

Key Milestones

Our key milestones are set out below:

2007

- incorporated on February 22, 2007 under the ABCA;
- acquired Fern for $60,000;
- raised $69.8 million through private equity issuances. The sale of Common Shares amounted to $58.8 million, the issuance of flow-through shares amounted to $7.2 million with the balance of $3.8 million raised from the exercise of warrants. Of the $58.8 million raised, approximately $13.7 million was brokered and approximately $45.1 million was unbrokered. Of the investors who participated in the funding, approximately 44.6% were institutions and approximately 55.4% were individual investors. The timing of these multiple fund raisings allowed us to acquire land at a number of Crown Land Sales and to fund the delineation of those lands; and
- acquired 38 Oil Sands Leases through Crown Land Sales. This consisted of five Oil Sands Leases (16 sections or 4,096 hectares) at East Long Lake, three Oil Sands Leases (29 sections or 7,424 hectares) at Harper, four Oil Sands Leases (32 sections or 8,192 hectares) at Opportunity, one Oil Sands Lease (seven sections or 1,792 hectares) at Pelican Lake, one Oil Sands Lease (20 sections or 5,120 hectares) at Portage, one Oil Sands Lease (12.5 sections or 3,200 hectares) at Saleski, eight Oil Sands Leases (eight

sections or 2,048 hectares) at South Thickwood, four Oil Sands Leases (23 sections or 5,888 hectares) at Thickwood and 11 Oil Sands Leases (21 sections or 5,376 hectares) at West Ells.

2008

- acquired 89 Oil Sands Leases through Crown Land Sales;
- this consisted of two Oil Sands Leases (22 sections or 5,632 hectares) at Crow Lake, one Oil Sands Lease (36 sections or 9,216 hectares) at Goffer, 35 Oil Sands Leases (664.75 sections or 170,176 hectares) at Harper, two Oil Sands Leases (34 sections or 8,704 hectares) at Legend Lake, nine Oil Sands Leases (183.6 sections or 47,021 hectares) at Muskwa, 20 Oil Sands Leases (184 sections or 47,104 hectares) at Opportunity, one Oil Sands Lease (1.5 sections or 384 hectares) at Pelican Lake, nine Oil Sands Leases (254 sections or 65,024 hectares) at Portage, one Oil Sands Lease (two sections or 512 hectares) at South Thickwood and nine Oil Sands Leases (13 sections or 3,328 hectares) at West Ells;
- raised $24.5 million through equity issuances. The sale of Common Shares amounted to $18.0 million, the issuance of flow-through shares amounted to $3.9 million with the balance of $2.6 million raised from the exercise of warrants and $0.1 million from the exercise of options. All issuances were unbrokered. Of the investors who participated in the funding, approximately 5.9% were institutions and approximately 94.1% were individual investors. The timing of these multiple fund raisings allowed us to acquire land at a number of Crown Land Sales;
- completed the winter drilling programme encompassing the drilling, coring and logging of 58 well locations;
- Petro Energy Corp acquired a 50% operating working interest in the Wabiskaw Formation in six sections of the Thickwood area for $3.9 million;
- commissioned a resource report from GLJ, resulting in an assignment of 4.9 billion bbls best estimate Total PIIP, 1.2 billion bbls best estimate contingent resources and best estimate contingent resources pre-tax PV10% of $1.9 billion;
- submitted a regulatory application for a carbonate pilot at Harper; and
- entered into a $35 million committed syndicated revolving credit facility with Royal Bank of Canada, Canadian Imperial Bank of Commerce, Bank of Montreal and Alberta Treasury Branch.

2009

- raised $31.0 million through a sale of equity. The sale of Common Shares amounted to approximately $29.0 million, the issuance of flow-through shares amounted to $2.0 million with the balance of $0.03 million raised from the exercise of options. All issuances were unbrokered. The timing of these multiple fund raisings allowed us to fund the delineation of our existing lands;
- submitted a regulatory application for the PRS at Muskwa; and
- received approval from the ERCB for the Harper carbonate pilot application.

2010

- acquired eleven Oil Sands Leases and one PNG Licence through Crown Land Sales. This consisted of one Oil Sands Lease (18 sections or 4,608 hectares) at Godin, five Oil Sands Leases (102.65 sections or 26,277.6 hectares) at Muskwa, one Oil Sands Lease (four sections or 1,024 hectares) at Opportunity, one

Oil Sands Lease (seven sections or 1,792 hectares) at Portage, three Oil Sands Leases (1.5 sections or 384 hectares) at West Ells and one PNG Licence (36 sections or 3.072 hectares);

- raised $99.7 million through a sale of equity securities. The sale of Common Shares and units, where each unit consisted of one common share and half a warrant in which one whole warrant entitled the holder to purchase one common share for $8.00 within three years of the purchase of the unit, accounted for $95.1 million. The issuance of flow-through shares amounted to $3.8 million and the balance of $0.8 million was raised from the exercise of options. All issuances were unbrokered. Of the investors who participated in the funding, approximately 94.5% were institutions and approximately 5.5% were individual investors. The timing of these multiple fund raisings allowed us to acquire land at a number of Crown Land Sales and to fund the delineation of our existing lands;

- received approval for the PRS at Muskwa from the ERCB;

- completed a winter drilling programme encompassing the drilling, coring and logging of 17 well locations, in addition to three vertical wells;

- credit facility repaid in full;

- submitted a regulatory application to develop a 10,000 bbl/d SAGD project at West Ells;

- commissioned a resource report from GLJ, resulting in an assignment of 38.8 billion bbls best estimate total PIIP, 2.2 billion bbls best estimate contingent resources with Pre-tax PV10% of $3.1 billion and 54.4 million 2P reserves with Pre-tax PV10% of $79 million; and

- commenced drilling at Harper Carbonate Pilot.

2011

- acquired fourteen Oil Sands Leases through Crown Land Sales. This consisted of one Oil Sands Lease (16 sections or 4,096 hectares) at Godin, five Oil Sands Leases (77 sections or 19,712 hectares) at Muskwa, three Oil Sands Leases (10 sections or 2,560 hectares) at Portage, three Oil Sands Leases (three sections or 768 hectares) at West Ells and two Oil Sands Leases (13.3 sections or 3,437.67 hectares) at Pelican lake;

- raised gross proceeds of $225.9 million through a private placement. The sale of Common Shares amounted to $147.5 million and the sale of Class "B" Shares amounted to $70.0 million. The issuance of flow-through shares amounted to $7.1 million with the balance was raised from the exercise of options ($1.3 million). All issuances were brokered, with the exception of $5.9 million of the funds raised. Of the investors who participated in the funding, approximately 91.0% were institutions and approximately 9.0% were individual investors, $100.0 million was raised from Charter Globe Limited, $70.0 million from China Life Insurance and $40 million from Cross-Strait. The timing of these multiple fund raisings allowed us to fund the delineation of our existing lands and continue with the development of our Muskwa heavy oil project;

- successfully completed mobility testing at our Harper Pilot and demonstrated thermal mobility. The test achieved its stated objective of mobilising bitumen through thermal stimulation which we believe is an important initial step to understanding this deposit;

- completed major operations for a winter drilling programme; drilling, coring and logging 118 well locations;

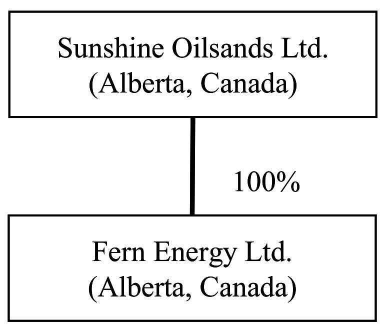
- commissioned resource reports from GLJ and D&M, resulting in an assignment of 45.4 billion bbls best estimate Total PIIP, 3.1 billion bbls best estimate contingent resources with Pre-tax PV10% of $5.1 billion and 418.9 million 2P reserves with Pre-tax PV10% of $846 million;
- submitted a regulatory application to develop a 10,000 bbl/d SAGD project at Thickwood; and
- submitted a regulatory application to develop a 10,000 bbl/d SAGD project at Legend Lake.

2012

- received regulatory approval from the ERCB to develop a 10,000 bbl/d SAGD project at West Ells.
- executed a Memorandum of Understanding for Strategic Cooperation with SIPC; and
- raised gross proceeds of approximately US$580 million (HK$4,487 million) from the completion of the Global Offering and Listing on the SEHK;

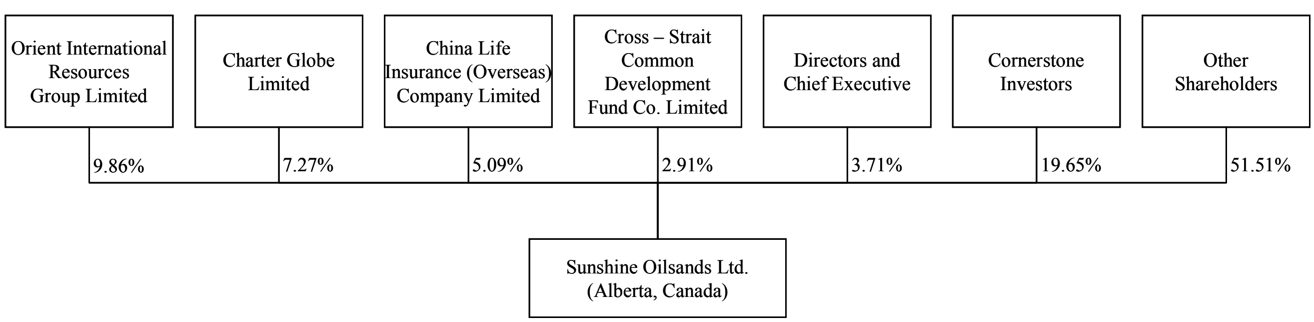
INTERCORPORATE RELATIONSHIP

The corporate structure of the Corporation as at the date of this AIF is as follows:



SHAREHOLDERS OF SUNSHINE

The below chart shows the outstanding Common Share ownership of the Corporation immediately following completion of the Global Offering:



Notes:

(1) 923,299,500 Shares were issued by the Corporation pursuant to the Global Offering. This chart does not include any Preferred Shares which, together accounts for 2.95% of our issued share capital upon completion of the Global Offering. In addition, it does not include Shares issuable on the exercise of options.

(2) This chart is based post-issuance of Orient Shares to Orient Financial and prior to the issuance of any Excluded Shares.

Our Substantial Shareholder

Orient International Resources Group Limited

Our largest shareholder is Orient International Resources Group Limited. Orient was incorporated in the British Virgin Islands on April 7, 2010 as a wholly owned subsidiary of Orient International Petroleum & Chemical Limited and became a shareholder of Sunshine on June 22, 2011 pursuant to an internal reorganisation of the shareholdings of certain of the Orient group of companies controlled by Mr. Hok Ming Tseung, a non-executive director of the Corporation, namely China Energy Group (Overseas) Investment Limited ("**China Energy**"), Pioneer Resources Industrial Holdings Limited ("**Pioneer**") and Orient P&C (together, the "**Orient Group**"). The sole director of Orient is Mr. Tseung. Orient P&C was incorporated in Hong Kong on December 6, 2004 and its shareholders are Far East International Investment Limited ("**Far East International**") (shareholding of 60%) and Mr. Tseung (shareholding of 40%). Far East International was incorporated in Samoa on September 29, 2003 and its shareholders are Mr. Tseung (who holds a 70% interest) and Concord Ocean Limited, a BVI Company ultimately solely held by Mr. Jin Chun Gen, a business associate of Mr. Tseung (which holds a 30% interest). Accordingly, Mr. Tseung directly and indirectly holds 82% of Orient and is the controlling shareholder of Orient P&C and Orient. Mr. Tseung is a beneficial owner and his ownership does not involve a trust or nominee arrangement. Far East International owns a cement company and toll road management rights in the PRC. Orient is an investment holding company. The largest asset owned by Orient, and Orient P&C, is their interest in Sunshine.

Pursuant to the internal reorganisation of the shareholdings of the Orient Group on June 7, 2011, China Energy, Pioneer and Orient P&C transferred their interests in Sunshine to Orient. The internal reorganisation did not affect the proportional holdings of Mr. Tseung and Mr. Jin Chun Gen in Sunshine, which remained the same before and after the transfer.

The Orient Group first became a shareholder of Sunshine on September 15, 2009, through a private placement made by Orient P&C. Mr. Tseung was first introduced to Sunshine in June 2009 by Mr. Xie Jin Tai of Far East Enterprise Investment Foundation Limited, a mutual friend of both Mr. Songning Shen, one of the two Co-Chairmen of the Corporation, and Mr. Tseung. At that time, Far East Enterprise Investment Foundation Limited had no shareholding or any other interest in the Corporation. During the course of 2009, the Corporation sought overseas investment to fund our corporate development and following our introduction and subsequent discussions with Mr. Tseung, the Orient Group decided to invest in the Corporation later in that year.

Since September 2009, the Orient Group has invested approximately $75.0 million in Sunshine. The stake originally held by the Orient Group has increased steadily to an approximate 9.86% interest in the Corporation immediately after the completion of the Global Offering. The Orient Group's funding into Sunshine was from its cash resources derived from its infrastructure and construction business in the PRC. Neither Mr. Tseung nor the Orient Group compete with Sunshine, or hold any interests in any business that competes with Sunshine.

Our Strategic Investors

Overview

We are supported by prominent Strategic Investors (defined below), each of whom have strong connections and broad experience in Asia. In February 2011, China Life, BOCGI and Cross-Strait, (each individually, the "**Strategic Investor**" and, collectively, the "**Strategic Investors**") made significant investments into Sunshine.

The investments made by each of China Life, BOCGI and Cross-Strait into Sunshine are investments with the primary goal of enhancing the Corporation's shareholder profile and growth prospects in Asia. China Life, BOCGI and Cross-Strait are prominent investors in the Asian markets, particularly in the PRC. Our Directors believe that, in addition to the financial resources brought to Sunshine by China Life, BOCGI and Cross-Strait, their introduction as investors in Sunshine may enhance the Corporation's shareholder profile. Further, our Directors believe that their relationships and contacts can help us build relationships and provide introductions to suppliers and customers not only in China, but Asia as a whole. Our Strategic Investors are able to provide access to significant additional resources and experience, although it is at the discretion of our management and Directors to decide how best to take advantage of such resources.

China Life

China Life is a wholly owned subsidiary of China Life Insurance (Group) Company. China Life Insurance (Group) Company is one of the largest life insurance companies in China and is also one of the largest insurance asset management and institutional investors in China. China Life's products and services include individual life insurance, group life insurance, accident and health insurance. China Life is a leading provider of annuity products and life insurance for both individuals and groups, and a leading provider of accident and health insurance.

China Life entered into a subscription agreement to subscribe for 7,231,405 Class "B" Shares (prior to the 20 for 1 share split) at an issue price of $9.68 on January 31, 2011 as part of their strategic investment into the Corporation. Immediately prior to the completion of the Global Offering, China Life held 144,628,100 Class "B" Shares, equal to 7.60% of our issued Common Shares. Under the applicable terms of the subscription agreement entered into between China Life and the Corporation, the Class "B" Shares held by China Life were exchangeable for Shares on a one-for-one basis.

Immediately prior to Listing, China Life exchanged their Class "B" Shares for Shares on a one-for-one basis. Following the exchange by China Life of its Class "B" Shares and upon the completion of the Global Offering, China Life holds 144,628,100 Shares in the capital of the Corporation (which would be equal to approximately 5.09% of our issued Shares at completion of the Global Offering, assuming that Excluded Shares have not been issued). At the present time, the Corporation has no issued and outstanding Class "B" Shares.

BOCGI

BOCGI is a company incorporated in Hong Kong and a wholly owned subsidiary of Bank of China Limited. It is principally engaged in investment holding activities and has invested in a large number of large infrastructure and other major projects in Hong Kong, Macau, the PRC and overseas locations, covering such sectors as real estate, industry, energy, transportation, media, hotel and finance.

Charter Globe, a wholly owned subsidiary of BOCGI, entered into a subscription agreement to acquire 10,330,578 Common Shares (prior to the 20 for 1 share split) at an issue price of $9.68 on February 1, 2011 as part of their strategic investment into Sunshine. Immediately prior to the completion of the Global Offering, BOCGI held 206,611,560 Shares, equal to approximately 10.85% of our issued Shares.

Upon the completion of the Global Offering, BOCGI holds 206,611,560 Shares in the capital of the Corporation (which would be equal to approximately 7.27% of our issued Shares at completion of the Global Offering, assuming that Excluded Shares have not been issued).

Cross-Strait

Cross-Strait is a Hong Kong based investment fund. Cross-Strait entered into a subscription agreement to acquire 4,132,232 Common Shares (prior to the 20 for 1 share split) at an issue price of $9.68 on January 26, 2011 as part of their strategic investment into Sunshine. Immediately prior to the completion of the Global Offering, Cross-Strait held 82,644,640 Shares, equal to 4.34% of our issued Shares.

Upon the completion of the Global Offering, Cross-Strait holds 82,644,640 Shares in the capital of the Corporation (which would be equal to approximately 2.91% of our issued Shares at completion of the Global Offering, assuming that Excluded Shares have not been issued).

Cornerstone Investors

As part of the Global Offering, the Corporation along with the Joint Global Coordinators entered into cornerstone placing arrangements with each of the investors described below (the "**Cornerstone Investors**" and each a "**Cornerstone**

Investor"), pursuant to which the Cornerstone Investors purchased such number of Offer Shares for an aggregate amount of US$350,000,000 (the "**Cornerstone Placing**"). Set out below is a breakdown of the aggregate holding of Shares of each of our Cornerstone Investors.

Cornerstone Investor	Maximum Investment Amount (US$)	Number of Shares	Percentage of Total number of Offer Shares	Percentage of our issued Shares immediately following the Global Offering	Percentage of our full diluted share capital immediately following the Global Offering[(1)]
Premium Investment Corporation	150,000,000	239,197,500	25.9	8.42	7.3
Sinopec Century Bright Capital Investment Limited	150,000,000	239,197,500	25.9	8.42	7.3
EIG Management Company, LLC	50,000,000	79,732,500	8.6	2.81	2.4
Total:	**350,000,000**	**558,127,500**	**60.4**	**19.65**	**17.0**

Notes:
(1) Based on the fully diluted share capital of the Corporation at completion of the Global Offering, including all Common Shares, Preferred Shares, Share options, the exercise in full of the over-allotment option and the issue of the Orient Shares on the Listing Date.

Provided below is some information about our Cornerstone Investors:

Premium Investment Corporation

Premium Investment Corporation purchased 239,197,500 Shares for an aggregate amount of US$150,000,000, representing approximately 8.42% of our issued Shares immediately after the completion of the Global Offering (assuming the issue of the Orient Shares and excluding any Excluded Shares).

Premium Investment Corporation is a fully-owned subsidiary of China Investment Corporation ("**CIC**"). Headquartered in Beijing, CIC was founded on September 29, 2007 as a wholly state-owned company incorporated in accordance with the Company Law of the People's Republic of China. CIC is operated on a commercial basis, seeking long-term, risk-adjusted financial returns.

Sinopec Century Bright Capital Investment Limited

Sinopec Century Bright Capital Investment Limited purchased 239,197,500 Shares for an aggregate amount of US$150,000,000, representing approximately 8.42% of our issued Shares immediately after the completion of the Global Offering (assuming the issue of the Orient Shares and excluding any Excluded Shares).

China Petrochemical Corporation ("**Sinopec Group**") is a state-owned petroleum and petrochemical enterprise that was incorporated in July 1998. Sinopec Group was ranked 5th among Fortune magazine's Global 500 in 2011. Sinopec Century Bright Capital Investment Limited is a wholly-owned subsidiary of Sinopec Group, engaging in financial activities of the Sinopec Group.

EIG Management Company, LLC

EIG Management Company, LLC ("**EIG MC**") entered into a cornerstone placing agreement on behalf of TCW Energy Fund XIV, L.P., TCW Energy Fund XIV-A, L.P., TCW Energy Fund XIV-B, L.P. and TCW Energy Fund XIV (Cayman), L.P. (the "**EIG Funds**"), pursuant to which the EIG Funds purchased 79,732,500 Shares for an aggregate amount of US$50,000,000, representing approximately 2.81% of our issued and outstanding Shares immediately after the completion of the Global Offering (assuming the issue of the Orient Shares and excluding any Excluded Shares).

EIG Global Energy Partners (which includes as a group company EIG MC) ("**EIG**") is a leading institutional investor in the global energy sector, with US$9.6 billion under management as of December 31, 2011. EIG specialises in private investments in energy, resources and related infrastructure and was formerly the Energy & Infrastructure Group of Trust Company of the West. During its 30 year history, EIG has invested in more than 280 projects or companies in 33 countries on 6 continents. EIG's clients include many of the leading pension plans, insurance companies, endowments, foundations and sovereign wealth funds in the United States, Asia and Europe. EIG is headquartered in Washington DC, with offices in Houston, London, Sydney and Hong Kong. Each of the EIG Funds is commingled investment funds focused on investments in the global energy sector and are controlled and solely managed by EIG.

Restrictions on Disposals by the Cornerstone Investors

Each of the Cornerstone Investors has agreed that, without our prior written consent and that of the Joint Global Coordinators, it will not, whether directly or indirectly, at any time during the period of six months following the Listing Date, dispose of any Shares subscribed for pursuant to the Global Offering (or interest in any company or entity holding any of the Shares so subscribed), other than transfers to another company that is wholly owned by the Cornerstone Investor (in the case of EIG MC, any investment fund controlled and solely managed by EIG MC) and that undertakes to abide by the restrictions on disposals imposed on the Cornerstone Investor.

Cancellation of the Warrants

On October 28, 2011, we reached agreement with all of the Warrant holders to cancel the Warrants. We agreed to terminate the Warrants for an aggregate sum of $68.9 million which was paid in full to the Warrant holders on January 4, 2012 in cash, upon which the Warrants were cancelled and extinguished in full. Since all Warrant holders are Shareholders of Sunshine, the difference between the fair value of the Warrants at the repurchase date and the repurchase consideration is adjusted to equity. We undertook to cancel the Warrants in order to clean up our capital structure in advance of Listing and in order to comply with the HKSE Listing Rules - *Interim Guidance on Pre-IPO Investments Pending Consultation On Possible Listing Rule Amendments* issued by the Listing Committee on October 13, 2010 (reproduced as HKEx Guidance Letter HKEx-GL29-12 on January 16, 2012).

During 2010 and 2011, we issued 173,326,200 Warrants to our Warrant holders. We issued 12,499,920 Fee Warrants exercisable at $0.30 between February and May 2010 and 21,694,220 Fee Warrants exercisable at $0.48 in February 2011 as compensation for the solicitation of investors in respect of certain fund raisings that we undertook. We also issued 139,132,060 Purchase Warrants exercisable at $0.40 between February and May 2010 in conjunction with a unit private placement that we undertook.

A table summarising the Warrants that were outstanding prior to their cancellation date, being January 4, 2012, is set out below:

Warrants	Purpose of Issue	Date of Issue	No. of Holders(2)	No. of Warrants	Percentage of the Issued Shares of the Corporation as at December 31, 2011(1)	Percentage of the Issued Shares of the Corporation Following Completion of the Global Offering(3)
Fee Warrants Exercisable at $0.30	Finder's Fee Commission	Feb– May 2010	2	12,499,920	0.57%	0.40%
Purchase Warrants Exercisable at $0.40	Part of a Private Placement of Units	Feb-May 2010	43	139,132,060	6.39%	4.49%
Fee Warrants Exercisable at $0.48	Finder's Fee Commission	Feb 2011	1	21,694,220	1.00%	0.70%
Total	-	-	**46**	**173,326,200**	**7.96%**	**5.59%**

Notes:

(1) This represents a percentage of our Warrants plus our Shares, Class "B" Shares, Class "G" Shares and Class "H" Shares in issue as at December 31, 2011 (being a total of 2,177,243,900 which is 1,989,565,540 Shares and 187,678,360 Warrants) and assumes that the exercise of the Warrants would be satisfied by the issuance of Shares.

(2) Represents the total number of different holders of Warrants.

(3) This represents a percentage of our Warrants, Shares, Class "G" Shares and Class "H" Shares issued and outstanding as at the date of completion of the Global Offering (which is a total of 3,100,543,400 Shares and Warrants, assuming that the Warrants were subject to the 20 for 1 share split), and assuming that the Orient Shares are issued on the Listing Date and excluding the Excluded Shares.

We had previously applied to the SEHK for an exemption from the HKSE Listing Rules - *Interim Guidance on Pre-IPO Investments Pending Consultation On Possible Listing Rule Amendments* issued by the Listing Committee on October 13, 2010 (reproduced as HKEx Guidance Letter HKEx-GL29-12 on January 16, 2012) but our exemption application was rejected by the SEHK. Therefore, to ensure compliance with the Listing Rules and the Interim Guidance, our Board concluded that it was necessary and in the best interests of the Corporation to cancel the Warrants to facilitate our Listing. Our Board consulted with the Warrant holders and sought their agreement to cancel the Warrants in exchange for cash compensation. The compensation sum was arrived at after arms length negotiations between the parties and was confirmed by an independent committee consisting of Mr. Robert John Herdman and Mr. Gerald Franklin Stevenson that was established in August 2011 to assess the compensation value to be paid for the Warrants and to provide a recommendation to the Board on this sum. The independent committee considered the matter and referred to market information in making its evaluation.

We reached an agreement with all Warrant holders on October 28, 2011 and executed agreements for the cancellation of all Warrants with each of the Warrant holders. All of the Warrants were cancelled for an aggregate cash payment to them of $68.9 million on January 4, 2012.

GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History

The following is a summary of significant events in the development of the Corporation's business over the past three years:

2009

Between September 2009 and January 2010, Sunshine completed a non-brokered private placement of a total of 133,333,320 Shares at a price of $0.26 per Share for aggregate gross proceeds of $34,999,997. Gross proceeds from the above financing were used to fund the delineation of the Corporation's existing lands.

On December 31, 2009, Sunshine completed a non-brokered private placement of a total of 6,668,660 Shares, issued on a "flow-through" basis at a price of $0.30 per Share for aggregate gross proceeds of $2,000,598. Gross proceeds from the above financing were used to fund the delineation of the Corporation's existing lands.

2010

In 2010, the Corporation acquired eleven Oil Sands Leases and one PNG Licence through Crown Land Sales. The acquired Oil Sands Leases consisted of one Oil Sands Lease (18 sections or 4,608 hectares) at Godin, five Oil Sands Leases (102.65 sections or 26,277.6 hectares) at Muskwa, one Oil Sands Lease (four sections or 1,024 hectares) at Opportunity, one Oil Sands Lease (seven sections or 1,792 hectares) at Portage, three Oil Sands Leases (1.5 sections or 384 hectares) at West Ells and one PNG Licence (36 sections or 3.072 hectares).

Between January 29, 2010 and May 31, 2010, Sunshine completed a non-brokered private placement of a total of 278,264,360 units at a price of $0.30 per unit, where each unit consisted of one Share and one-half a purchase warrant for aggregate gross proceeds of $83,479,308. Each purchase warrant had an exercise price of $0.40 and is exercisable until February 28, 2013. Sunshine granted 12,499,920 fee warrants to two finders in connection with the above financing. Each fee warrant had an exercise price of $0.30 and is exercisable from February 28, 2013 to May 26, 2013. Gross proceeds from the above financings were used to acquire land at a number of Crown Land Sales fund the delineation of the Corporation's existing lands.

On March 2, 2010, Sunshine announced the appointment of Mr. Hok Ming Tseung to the Corporation's Board of Directors.

Between April 1, 2010 and May 17, 2010, Sunshine completed a non-brokered private placement of a total of 11,780,080 Shares, issued on a "flow-through" basis at a price of $0.33 per Share for aggregate gross proceeds of $3,828,526.

On December 31, 2010, Sunshine completed a non-brokered private placement of 11,215,000 special warrants, issued on a "flow-through" basis at a price of $0.50 per special warrant, where each special warrant entitled the holder to acquire one Share for no additional consideration until January 20, 2011 for aggregate gross proceeds of $5,607,500.

2011

On February 1, 2011, Sunshine announced the appointment of Mr. Tingan Liu to the Corporation's Board of Directors.

On February 14, 2011, Sunshine announced the appointment of Mr. Haotian Li to the Corporation's Board of Directors.

In 2011, the Corporation acquired fourteen Oil Sands Leases through Crown Land Sales. The acquired Oil Sands Leases consisted of one Oil Sands Lease (16 sections or 4,096 hectares) at Godin, five Oil Sands Leases (77 sections or 19,712 hectares) at Muskwa, three Oil Sands Leases (10 sections or 2,560 hectares) at Portage, three Oil Sands Leases (three sections or 768 hectares) at West Ells and two Oil Sands Leases (13.3 sections or 3,437.67 hectares) at Pelican lake.

Between January 31, 2011 and February 15, 2011, Sunshine completed a non-brokered private placement of a total of 289,256,200 Shares at a price of $0.48 per Share and 144,628,100 Class "B" Share at a price of $0.48 per Class "B" Shares for aggregate gross proceeds of $210,000,001. The Corporation granted 21,694,220 fee warrants to Far East Enterprise Investment Foundation Limited in connection with the above financing. Each such fee warrant has an exercise price of $0.48 and is exercisable until February 2014.

Between February 17, 2011 and February 22, 2011, Sunshine completed a non-brokered private placement of a total of 15,432,780 Shares at a price of $0.48 per Share for aggregate gross proceeds of $7,469,466, and a non-brokered private placement of a total of 13,370,820 Shares, issued on a "flow-through" basis, at a price of $0.53 per Share for aggregate gross proceeds of $7,119,962.

On July 15, 2011 and July 18, 2011, Sunshine announced the appointment of Mr. Gerald Stevenson and Mr. Robert Herdman, respectively, to the Corporation's Board of Directors.

2012

As part of its 2011/2012 winter drilling program, the Corporation completed the drilling of a total of 67 wells, including 59 clastic exploration wells, 1 disposal and 7 water wells. Two wells were also drilled through Sunshine's Grand Rapids Formation by PetroEnergy and logs and cores were provided to Sunshine at no cost. The Corporation also drilled and completed 39 Muskwa development wells. In addition, Sunshine completed seismic activities at Opportunity, Legend Lake and Thickwood.

On March 1, 2012, the Corporation completed its Global Offering. The Corporation became the first Canadian oil sands company to list on the SEHK. No Shares were issued in Canada pursuant to the Global Offering.

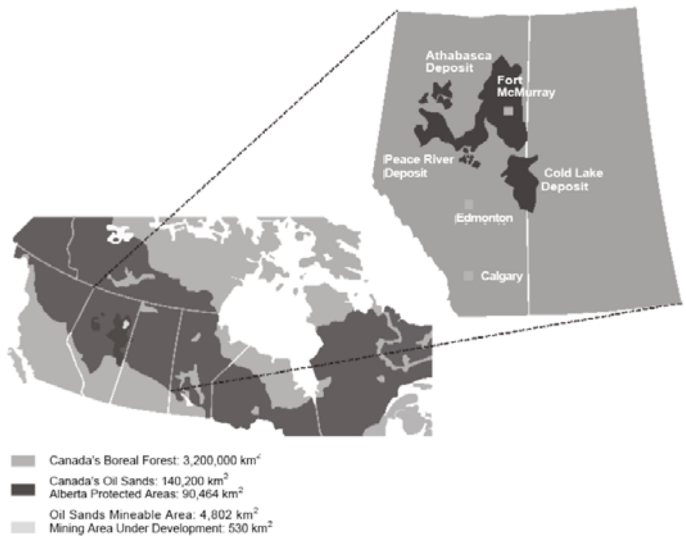
Significant Acquisitions

The Corporation did not complete any significant acquisitions during the financial year ended December 31, 2011.

DESCRIPTION OF THE BUSINESS

Overview

Sunshine is headquartered in Calgary, Alberta and the Corporation's principal operations are the exploration, development and production of its diverse portfolio of Oil Sands Leases. The Corporation's seven principal operating regions in the Athabasca area are at West Ells, Thickwood, Legend Lake, Harper, Muskwa, Goffer and Portage. In addition, the Corporation has non-principal areas with no immediate development plans located at Pelican Lake, East Long Lake, Crow Lake, Godin, Saleski and South Thickwood.



Holdings

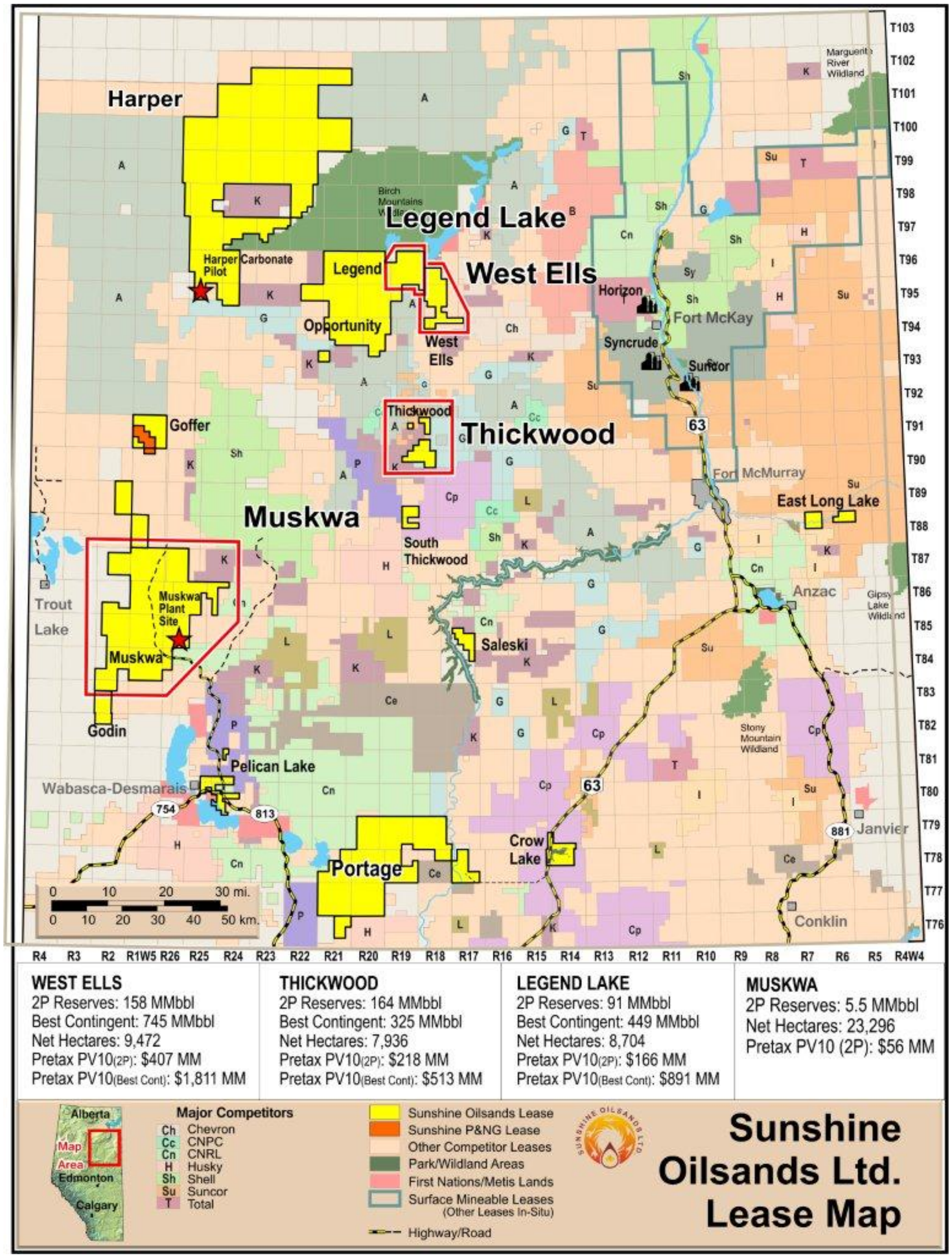
Since its incorporation on February 22, 2007, the Corporation has secured over 464,897 hectares of Oil Sands Leases. The Corporation has 100% ownership of its Oil Sands Leases, with the exception of the Shared Formations, and the Corporation expects to incur only minimal rental costs to retain the Oil Sands Leases.

The Corporation's Our Oil Sands Leases can be grouped into three main asset categories:

- *Clastics* - oil-saturated sands deposited during the Cretaceous period which contain bitumen extracted through thermal production (developed primarily using the SAGD *in-situ* method);
- *Carbonates* - oil-saturated carbonate based sedimentary rock deposited during the Devonian period, with potential to be commercially produced with thermal extraction techniques and developing technologies; and
- *Conventional Heavy Oil* - oil-saturated sands deposited during the Cretaceous period that can be recovered using CHOPS or other conventional heavy oil recovery technologies.

The map below highlights the Oil Sands Leases that we own. The summary information below the map outlines the areas and highlights metrics from evaluations undertaken by our Independent Qualified Reserves Evaluators.

Figure 1: Sunshine Oilsands Ltd. Lease Map



Notes:
(1) Net hectares are based on management's estimates.

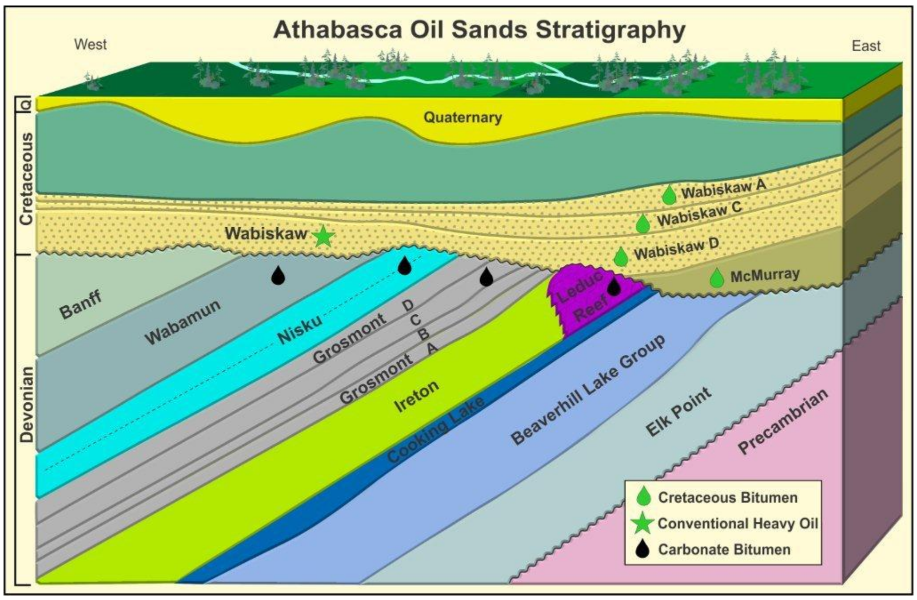
Under all three main asset categories, current and future production of bitumen of varying viscosities and API° gravities will be sold without upgrading. Our bitumen can be upgraded into a variety of oil products, such as petroleum, diesel fuel, jet fuel, kerosene, asphalt and tar.

This AIF includes estimates of our reserves and resources made by GLJ and D&M. In accordance with standard market practice, we have disclosed estimates of both the volumes and values of our possible reserves, contingent resources and PIIP in addition to proved reserves and probable reserves throughout this AIF. However, none of the volumes or values of our resources have been risked for chance of development. Our best estimate contingent resources have a pre-tax PV10%

of $4.8 billion compared to a pre-tax PV10% of $829 million for our 2P reserves. Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations but the applicable projects are not yet considered mature enough for commercial development due to one or more contingencies. The Corporation does not provide any assurance that it will be commercially viable to produce any portion of the contingent resources until the projects are more mature and contingencies are eliminated through detailed designs and regulatory submissions. For more information please refer to the sections entitled *"Risk Factors — Risks Relating to Our Business — There are risks associated with reserves and resource definitions"* in this AIF.

The Figure below illustrates the stratigraphy of the Athabasca oil sands region and highlights the formations and depths where our clastics, carbonates and conventional heavy oil assets are found.

Figure 2: Athabasca Oil Sands Stratigraphy



Development of Our Assets

Clastics

The initial development of our clastic assets will involve the exploration, appraisal, development and production of our West Ells, Thickwood and Legend Lake assets (Base Case Clastic Assets). On the basis of our management assumptions, we have forecast that our Base Case Clastic Assets will have a total productive life of over 50 years and a peak production of approximately 200,000 bbl/d for over 18 years. Our management's development plan anticipates execution of these developments in staged and scalable Phases in order to carefully manage project timing and funding requirements, as well as to exploit existing established technologies and new technologies as they are developed. Our management has assumed the following summary development timetable for each site:

- *West Ells* — We received regulatory approval from the ERCB on January 26, 2012 for the 10,000 bbl/d West Ells clastics project following the issuance of a final permanent shut-in order by the ERCB in relation to a dispute on December 15, 2011. As the final shut-in order has been granted, production at West Ells will not be affected by this dispute. First steam for the first Phase is estimated to take place in the second quarter of 2013. The project has an initial anticipated production rate of 5,000 bbl/d, which will be followed by an expansion of an additional 5,000 bbl/d to reach a planned production capacity of 10,000 bbl/d. Following approval of subsequent regulatory applications, a total planned production capacity of 100,000 bbl/d is anticipated from the area, with first steam of the last expansion expected by 2024. Capital expenditure at West Ells in 2012 is expected to be $272.2 million, which will be funded through our internal cash resources. There will be no production in 2012.

- *Thickwood* — We filed a regulatory application with the ERCB for a 10,000 bbl/d commercial facility in the Thickwood project area on October 31, 2011. First steam is planned for the first quarter of 2015. Total planned production capacity for this area is 50,000 bbl/d by 2021. Capital expenditure at Thickwood in 2012 is expected to be $13.0 million, which will be funded through our internal cash resources. There will be no production in 2012.

- *Legend Lake* — We filed the regulatory applications with the ERCB for a 10,000 bbl/d commercial development in the Legend Lake clastics project area on November 25, 2011. First steam is planned for the first quarter of 2016. Total planned production capacity for this area is 50,000 bbl/d by 2022. Capital expenditure at Legend Lake in 2012 is expected to be $16.3 million, which will be funded through our internal cash resources. There will be no production in 2012.

In addition to our Base Case Clastic Assets, we have identified clastic exploration opportunities through our 2010/2011 winter drilling programme in the Harper, Opportunity and the Muskwa regions. These areas provide potential for material growth in our clastics contingent resources and with the progression of regulatory applications for these areas, additional reserves over time.

Each project follows the following stages:

- *Exploration* — Delineation drilling allows for proper and complete resource assessment and evaluation of potential technologies for development.

- *Development* — Once the resource assessments are complete we submit commercial applications and continue our detailed designs and planning. As approvals are received we proceed with construction of facilities, pads and drilling of SAGD wells for the production stage; and

- *Production* — Initial production stage commences when steam is first injected into a well pair, referred to as "first steam". Please refer to the section entitled *"Industry Overview — Overview of Canada's Oil Sands — Oil sands production methods — In-situ recovery (thermal production methods) — Steam assisted gravity drainage"* for an explanation of SAGD.

There is a time gap between "first steam" and commercial production due to an approximately four month steam circulation period to prepare the steam chamber and link it to the SAGD well pairs, after which commercial production may begin. Please also refer to the section entitled *"Financial Information — Revenue and Cost Structure upon Commercial Production"* for an explanation of the concept of commercial production.

The reservoir characteristics of our properties vary among the different properties and in comparison to other producing projects in McMurray or other formations. The reservoir we are proposing to produce has had little thermally stimulated production to date, although there are several commercial projects announced or in early stage of development. There is no guarantee that our steam oil ratio will be equivalent to those ratios in the McMurray or other formations which are currently producing. There is a risk that the recovery of bitumen will be lower in our projects than in projects in other reservoirs that have been used as analogues to produce the contingent resources in our technical report, because the reservoir characteristics are different although management believes that these differences have been taken into account.

Carbonates

We do not currently have a corporate development plan for our carbonates assets as our main focus remains the development of our Base Case Clastic Assets. Current and future pilot work is expected to lead to the development of extraction technologies which we expect will enable us to further define our development plans for these assets.

However, beyond our currently defined corporate development plan, Sunshine believes that its carbonate assets have the potential to materially increase the Corporation's contingent resource base and ultimately its production capacity. Unlike clastics, where technologies for commercial operations are well established, there are currently no established successful commercial scale projects in Canada that use CSS or SAGD in carbonate reservoir; although thermal recovery has been conducted on a commercial scale in other parts of the world in different reservoir conditions, such as Egypt. We are continuing to investigate the feasibility of thermal recovery processes based on pilot projects for our carbonate resources and, once commerciality of a given technology is proven, we will assess its applicability to our carbonate resources. In the long term, as recovery technologies continue to evolve, we plan to develop our carbonate resources, predominantly at our Harper, Muskwa, Ells-Leduc, Goffer and Portage sites. In 2010, our Harper Pilot was one of the only two approved and active carbonate pilot projects in Canada and we executed the first cycle of our project during the 2010/2011 winter season. Currently, there are eight approved carbonate pilots in Canada, of which, according to the ERCB, only three are currently operational. Our Harper Pilot has been reactivated for operation in the winters of 2011/2012 and 2012/2013 following receipt of project approval from the ERCB. The first cycle of our Harper Pilot successfully demonstrated the thermal mobility of Grosmont C bitumen in the winter of 2010/2011. The test was not designed to demonstrate reservoir conformance to a predictive model and has not established the Grosmont C as a commercial reservoir. The test did achieve the stated objective of mobilising bitumen through thermal stimulation which we believe is an important initial step to understanding this deposit.

Conventional Heavy Oil

We have identified conventional heavy oil opportunities across several areas within our land base, including Muskwa, Harper, Godin and Portage. The development of conventional oil reservoirs, which do not require thermal stimulation, benefit from the Alberta oil sands royalty structure. This provides an economic advantage over non-oil sands heavy oil. The most advanced of these projects is in the Muskwa area, where we have executed several stages of preliminary exploration and development spending. The pre-commercial stage involves testing of different development strategies to define and optimise the extraction process and economics. During pre-commercial stage, any revenue and operating expenses generated are capitalised. Once this assessment is complete the project will enter the commercial production phase. Please also refer to the section entitled *"Financial Information — Revenue and Cost Structure upon commercial production"* for an explanation of the concept of commercial production.

Development of our Muskwa project is proceeding according to our development plan. We have demonstrated oil mobility without enhanced recovery techniques as well as sustained production from several well types, including horizontal, slant and vertical wells.

2011/2012 Winter Drilling Programme

With the exception of the Muskwa conventional heavy oil project, our assets are only accessible for exploration and delineation drilling in the frozen conditions prevalent in the Athabasca region during winter. This is because throughout the western Athabasca region, the land surface is dominated by high water content and soft, thick organic surface materials. This combination creates an environment that severely constrains our ability to deploy the heavy equipment required to conduct drilling, exploration and delineation activities. Additionally, these areas are sensitive to disturbance and the determination of viable resources is best conducted under frozen conditions to prevent unnecessary disruption in the event that resource volumes discovered are sub-commercial. Once commercial resource volumes are identified, the construction of high grade, year round access roads and operating sites which are not materially affected by seasonal factors is commenced in order to allow full, uninterrupted development of the resource. Exploration and delineation activities are conducted from November through to as late as April.

We are currently completing the 2011/2012 winter drilling programme, which includes additional exploration, delineation drilling and seismic acquisitions. We conducted an extensive survey programme during the summer of 2011, where over 215 potential exploration and delineation well locations were confirmed. The identified locations are designed to advance the recognition of new reserves and new contingent resources additions. As part of its 2011/2012 winter drilling program, the Corporation completed the drilling of a total of 67 wells, including 59 clastic exploration wells, 1 disposal and 7 water wells. Two wells were also drilled through Sunshine's Grand Rapids Formation by PetroEnergy and logs and cores were provided to Sunshine at no cost. The Corporation also drilled and completed 39 Muskwa development wells. In addition, Sunshine completed seismic activities at Opportunity, Legend Lake and Thickwood.

As of the date of the AIF, the 2011/2012 winter drilling programme was completing. This program included exploration drilling, coring operations, production testing and progression of the West Ells project, including observation and SAGD well drilling. Further, operations at Harper were approved by the ERCB for the 2011/2012 and 2012/2013 winter seasons and initial work has been initiated on the existing Harper Pilot prior to the next CSS cycle.

As of the date of the filing of this AIF, the Corporation had already completed its 2011/2012 winter drilling program. As part of its 2011/2012 winter drilling program, the Corporation completed the drilling of a total of 67 wells, including 59 clastic exploration wells, 1 disposal and 7 water wells. The Corporation also drilled and completed for production 39 Muskwa development wells. In addition, Sunshine also completed seismic activities at Opportunity, Legend Lake and Thickwood.

OUR ASSETS AND OPERATIONS

Overview

We hold 467,969 hectares of leases (including our Oil Sands Leases and our PNG Licences) in the Athabasca oil sands region of north-eastern Alberta that we have acquired, through Crown Land Sales and purchases from third parties, for approximately $73.6 million. We have a 100% working interest in all of these leases with the exception of the Shared Formations. Our portfolio of Oil Sands Leases consists of three distinct asset categories: clastics, carbonates and conventional heavy oil.

Shared Formations

Thickwood Farmout

The Corporation and Petro Energy Corp entered into the Farmin and Option Agreement on March 1, 2008. Under the terms of the Farmin and Option Agreement, Petro Energy Corp paid us $650,000 for a 50% working interest in the Wabiskaw Formation in one section of land in the Thickwood region, with the option to initially elect to participate (as to a 50% working interest) in the Wabiskaw Formation in three additional sections of land and, in the event that the initial option were taken up, a further option to participate (as to a 50% working interest) in the Wabiskaw Formation in a further four sections, all of which are in the Thickwood region (including Thickwood and South Thickwood). In each case, the consideration for an interest was a cash payment of $650,000 per section. The Wabiskaw Formation is a thin subsurface strata of sandstone with a high bitumen content that sits at the lower end of the cretaceous bed. Under the Farmin and Option Agreement, Petro Energy Corp's interests in the relevant sections are solely in respect of the strata comprising the Wabiskaw Formation.

In April 2008, Petro Energy Corp made its initial election to participate in an additional three sections. We received payment totalling $1,950,000 in April 2008 for these three sections. In May 2008, Petro Energy Corp elected to participate in the final four sections. We received payments totalling $1,300,000 (which earned them a right in two of the final four sections). We did not receive the remaining $1,300,000 for the final two sections and, as such, we elected to retain our 100% interest in these final two sections. Petro Energy Corp's option to acquire a participating interest in these final two sections expired on May 31, 2008.

As such, at the present time, Petro Energy Corp holds a 50% working interest in the Wabiskaw Formation in six sections of land in the Thickwood region equal to 1,536 hectares in total. Under the terms of the Farmin and Option Agreement, we will bear all lease rental costs in respect of the Thickwood Farmout and the parties will share in the costs of exploring and developing the Thickwood Farmout, as well as the right to receive any royalties and production revenues arising from these lands on a 50:50 basis, reflecting the parties' respective working interests. We have a right to shut-in any petroleum substance (including bitumen, gas or other hydrocarbons) that may be detrimental to our operations at our discretion. We have legal title to the six sections in the Thickwood Farmout. As of the date hereof, no development activities have been conducted on the Thickwood Farmout since the date of entry into the Farmin and Option Agreement.

Pelican Lake Farmout

The Corporation and Petro Energy Corp entered into the Oil and Gas Asset Purchase Agreement on September 29, 2008. Under the terms of the Oil and Gas Asset Purchase Agreement, in September 2008, we disposed of a 100% working interest in the Wabiskaw Formation in seven sections of undeveloped land at Pelican Lake equal to 1,792 hectares in total to Petro Energy Corp for $1.00, plus pre-paid leases costs of $5,876.78. As of the date of this AIF, Petro Energy Corp was in retention of its 100% working interest in the Pelican Lake Farmout, which provides it with the sole right to explore for, develop and extract hydrocarbons from the subsurface strata of the Wabiskaw Formation at these lands. Sunshine has retained an overriding royalty in the formations comprising the Pelican Lake Farmout of 3.5% before payout and 7% after payout (as determined independently with respect to each well drilled) on any hydrocarbons produced under the Pelican Lake Farmout, as well, Sunshine has retained a 100% working interest in respect of all other oil sands formations over the land in which the Pelican Lake Farmout exists.

Under the terms of the Oil and Gas Asset Purchase Agreement, Petro Energy Corp must bear all lease rental costs in respect of the Pelican Lake Farmout and all the costs of exploring and developing the land. We have a right to shut-in any petroleum substance (including bitumen, gas or other hydrocarbons) that may have a detriment on our operations. The agreement will terminate on the termination or expiry of the relevant leases. Other than in the Wabiskaw Formation, we have retained ownership of the other formations in the seven sections in the Pelican Lake Farmout. Two exploration wells were drilled on the Pelican Lake Farmout by Petro Energy in its 2011/2012 Winter Program. Logs and core data was provided by Petro Energy to Sunshine at no cost.

The Farmin and Option Agreement and the Oil and Gas Asset Purchase Agreement are the only agreements or arrangements that we have entered into with third parties with respect to rights over different geographical horizons over land for which we own an Oil & Gas Lease.

The following table presents a summary of the reserves and resources attributable to our main asset groups as at November 30, 2011, as contained in our independent reserves evaluators' reports. **Some volumes in this table are an arithmetic sum of multiple estimates from various properties of probable and possible reserve and low and high case resources, which statistical principles indicate may be misleading as to volumes that may actually be recovered in the aggregate. Readers should give attention to the estimates of individual classes of resources and appreciate the differing probabilities of recovery associated with each class as explained in the Glossary of Technical Terms.**

Figure 3: Summary of Independent Qualified Reserves Evaluators' Reports Evaluation

			Total PIIP[6]			Reserves			Contingent Resources						Pre-Tax PV 10%		
Property	**Region**	**Number of Oil & Gas Leases**	**Low Estimate**	**Best Estimate**	**High Estimate**	**1P**	**2P**	**3P**	**Low Estimate**	**Best Estimate**	**High Estimate**	**1P**	**2P**	**3P**	**Low Estimate Contingent Resources**	**Best Estimate Contingent Resources**	**Best Estimate Contingent Resources**
Conventional Heavy Oil																	
Muskwa	Muskwa	21[8]	47	86	120	2.4	5.5	8.8	0	0	0	38	56	611	0	0	0
Total Conventional Heavy Oil			**47**	**86**	**120**	**2.4**	**5.5**	**8.8**	**0**	**0**	**0**	**38**	**56**	**61**	**0**	**0**	**0**
Clastics[7] [18]																	
West Ells	West Ells[17]	26[9]	1,918	1,918	1,918	0	158	209	401	745	1,011	0	407	706	1,082	1,811	2,548
Thickwood	Thickwood[16]	4[14]	1,403	1,403	1,403	0	164	219	258	325	419	0	218	399	65	513	890
Legend Lake	Legend Lake	27[10]	1,730	1,844	1,844	0	91	124	255	449	673	0	166	271	477	891	1,801
Pelican Lake	Pelican Lake	2[15]	375	375	384	0	0	0	77	118	185	0	0	0	100	270	596
Opportunity	Legend Lake	27[10]	949	2,235	2.235	0	0	0	0	37	131	0	0	0	0	(4)	128
East Long Lake	East Long Lake	5	113	162	162	0	0	0	15	33	74	0	0	0	64	160	353
Crow Lake	Crow Lake	2	225	332	332	0	0	0	0	0	14	0	0	0	0	0	24
Portage Grand Rapids	Portage	14[11]	232	232	367	0	0	0	0	0	4	0	0	0	0	0	4
Harper	Harper	38[12]	5,581	5,581	7,512	0	0	0	0	326	78	0	0	0	0	491	2,068
Muskwa/ Godin	Muskwa	21[8]	1,163	1,482	1,870	0	0	0	270	418	64	3	0	0	136	231	437
Portgage Wabiskaw	Portage	14[11]	381	445	592	0	0	0	0	0		0	0	0	0	0	0
Total Clastics			14,070	16,009	18,619	0	413	552	1,276	2,450	3934	0	790	1,376	1,924	4,363	8,849
Carbonates[5] [19]																	
Harper	Harper	38[12]	8,780	10,555	11,819				0	393	1,405	0	0	0	0	243	2,668
Ells Leduc	West Ells	26[9]	856	997	997	0	0	0	0	159	271	0	0	0	0	448	904
Goffer	Goffer	2[13]	1289	1732	2158	0	0	0	0	0	521	0	0	0	0	0	71
Muskwa	Muskwa	21[8]	8,209	10,841	14,583	0	0	0	0	0	1,810	0	0	0	0	0	1,308
Saleski	Saleski	1	538	596	762	0	0	0	0	0	123	0	0	0	0	0	243
South Thickwood	South Thickwood	9[16]	243	287	402	0	0	0	0	0	56	0	0	0	0	0	63
Portgate Nisku	Portage	14[11]	3,97	4,65	4,53	0	0	0	0	64	961	0	0	0	0	8	2,771
Goffer Keg River	Goffer	2[13]	0	0	22	0	0	0	0	0		0	0	0	0	0	0
Total Carbonates			**23,512**	**29,273**	**35,596**	**0**	**0**	**0**	**0**	**616**	**5,147**	**0**	**0**	**0**	**0**	**699**	**8,028**
Combined Total		**151**	**37,629**	**45,368**	**54,335**	**2,419**	**561**	**1,276**		**3,066**	**9,081**	**38**	**846**	**1,437**	**1,924**	**5,062**	**16,877**
Pre-tax PV 10%[2]												**30**	**829**	**1,410**	**1,866**	**4,837**	**16,520**
Post-tax PV 10%[2]												**21**	**482**	**895**	**869**	**2,555**	**9,723**

Source: GLJ and D&M Reports dated November 30, 2011.

Notes:

(1) MMbbl unless otherwise noted. Figures are rounded to the nearest MMbbl or $ million (where it applies).

(2) Both D&M's and GLJ's Pre-Tax PV10% and Post-Tax PV10% in this table incorporate GLJ's October 1, 2011 price forecasts for oil, bitumen and natural gas and are denominated in $ millions. PV10% is not a measure of financial or operating performance, nor is it intended to represent the current value of our reserves and resources. For further details, please refer to the sections entitled *"Risk Factors — The reserves and resources data and present value calculations presented in this AIF are estimates based on a number of assumptions which may deviate from the actual figures over time"*.

(3) If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best. For further details, please refer to the section entitled *"Risk Factors — Risks Relating to Our Business — There are risks associated with reserves and resource definitions"*.

(4) A significant part of our Group's resource base is comprised of contingent resources, which are estimated to be potentially recoverable but not currently considered to be commercially recoverable due to one or more contingencies. None of the volumes or values of our resources have been risked for chance of development. We cannot assure you that it will be commercially viable to produce any portion of the contingent resources until contingencies are eliminated through detailed designs and regulatory submissions. For further details, please refer to the sections entitled *"Risk Factors — Risks Relating to Our Business — There are risks associated with reserves and resource definitions"*, *"Risk Factors — The reserves and resources data and present value calculations presented in this AIF are estimates based on a number of assumptions which may deviate from the actual figures over time"* in this AIF.

(5) The development of the carbonates is based on technology under development. For further details, please refer to the section entitled *"Risk Factors — Risks Relating to Our Business — Carbonate resources may not be successfully developed"*.

(6) Total PIIP is a sum of discovered and undiscovered PIIP components as defined in GLJ and D&M Reports.

(7) Our Group plans to pursue its own development plan and use its own assumptions for its Base Case Clastic Assets, which reflect certain principal differences from the plan and assumptions used by GLJ, one of our Independent Qualified Reserves Evaluators. For further details, please refer to the section entitled *"Reserves and Resources Evaluations — Management Commentary on Key Assumptions"*.

(8) The 21 Oil Sands Leases in the Muskwa region consist of conventional heavy oil, clastics and carbonates. The clastics are at Godin in the Muskwa region.

(9) The 26 Oil Sands Leases in the West Ells region consist of clastic and carbonates. The carbonates are at Ells Leduc in the West Ells region.

(10) The 27 Oil Sands Leases in the Legend Lake region consist of clastics at Legend Lake and Opportunity.

(11) The 14 Oil Sands Leases in the Portage region consist of carbonates at Portage Nisku and Clastics at Grand Rapids and Wabiskaw.

(12) The 38 Oil Sands Leases in the Harper region consist of clastics and carbonates.

(13) The one PNG Licence and one Oil Sands Lease in the Goffer region consist of Carbonates at Goffer and Keg River.

(14) We have 23 sections or 5,888 hectares at Thickwood that were acquired in 2007.

(15) We have 21.8 sections or 5,614 hectares at Pelican Lake that were acquired in 2007, 2008 and 2011. We acquired 13.3 sections or 3,438 hectares of land at Pelican Lake on December 14, 2011 for approximately $2.7 million, which is not covered by our Independent Qualified Reserves Evaluators' Reports. This table and our Independent Qualified Reserves Evaluators' Reports only contain estimates for the 8.5 sections or 2,176 hectares at Pelican Lake that were acquired prior to November 30, 2011. Petro Energy Corp has a 100% working interest in the Wabiskaw Formation in seven sections at Pelican Lake; the area of which is equal to 82.4% of our Pelican Lake holding. Please refer to the section entitled *"Our Assets and Operations"* for more details.

(16) Petro Energy Corp has a 50% participating interest in the Wabiskaw Formation in six sections in the Thickwood region; the area of which equates to 9.1% of our Thickwood holdings (including the 33 sections comprising Thickwood and South Thickwood). Please refer to the section entitled *"Our Assets and Operations"* for more details.

(17) We received regulatory approval from the ERCB for our first 10,000 bbl/d clastic SAGD project at our West Ells property on January 26, 2012. Please refer to the section entitled *"Business — Recent Developments"* above for further information.

(18) Clastic Resource Contingencies: Non technical – Regulatory submissions and approvals required. West Ells, Legend Lake and Thickwood properties are proceeding with development guided by the corporate development plan, regulatory submissions and project expansions scheduled. Remaining clastic properties additionally require definition of corporate plans and board of directors approvals.

(19) Carbonate Resource Contingencies: Technical – Technology under development. Carbonate development is contingent upon successful application of SAGD and CSS technology in carbonate reservoirs, which is currently under active development in the industry. Pilot data will help to define company's projects in the carbonates. Non technical – Corporate development plans to be defined, board of directors approvals, regulatory submissions.

Clastics

Overview

Our primary bitumen deposits are situated in the western Athabasca region of Alberta and are differentiated from those in the eastern Athabasca region in several important ways. The primary depositional environment of wave dominated deltaic sands in western Athabasca created reservoirs with several extraction advantages over the estuarine or channel deposits that dominate the eastern areas. The Wabiskaw member in western Athabasca maintains high lateral continuity and predictability in its oil sands that can be consistent over many kilometres. This contrasts sharply with the estuarine deposits that can be as narrow as 50 m wide.

Vertical homogeneity can be quite high in the western Wabiskaw region with high vertical permeability and few breaks, creating promising SAGD reservoirs. Little or no inclined heterolithic stratification is present, and shales, if present, tend to be thin, providing a higher likelihood of the reservoir conforming to performance predictions and providing attractive conditions for extraction. Bioturbation is also consistently evidenced, which aids the development of vertical permeability.

Our clastic assets are located within the West Ells, Thickwood, Legend Lake, Pelican Lake, East Long Lake, Crow Lake, Harper, Opportunity, Portage, Muskwa and Godin areas in the Athabasca Oil Sands region. The clastic assets encompass 951 sections or approximately 243,456 hectares of land within these areas. We acquired the leases for our clastic assets between February 2007 and October 2010, with some additional sections acquired in 2010 and 2011, including the recent acquisition of 13.3 sections of land at Pelican Lake for approximately $2.7 million on December 14, 2011. Our clastic assets represent approximately 80% of our best estimate contingent resources and 100% of our probable plus possible reserves.

We plan to initially develop our clastic assets at our West Ells, Thickwood and Legend Lake sites in modular and scalable phased commercial SAGD projects. Projects in other areas will be considered at a later date and will be scaled in a similar fashion to our Base Case Clastic Assets. The following table summarises our near-term clastic oil sands development schedule:

Figure 4: Clastic Asset Development Schedule

Asset(1)	**Working Interest**	**Net Area**	**Best Estimate Total PIIP**(2)(4)	**Proven and Probable Reserves**(2)	**Best Estimate Contingent Resources**(2)	**Anticipated First Steam**(1)	**Estimated Gross Peak Production**(1)
	%	**hectares**	**MMbbl**	**MMbbl**	**MMbbl**	**Year**	**Mbbl/d**
West Ells	100	9,472	1,918	158	745	2013	100
Thickwood	100	7,936	1,403	164	325	2015	50
Legend Lake	100	8,704	1,844	91	449	2016	50
Pelican Lake	100	1,792	375	0	118	TBD(3)	TBD(3)
East Long Lake	100	2,304	162	0	33	TBD(3)	TBD(3)
Crow Lake	100	4,096	332	0	0	TBD(3)	TBD(3)
Harper	100	145,920	5,581	0	326	TBD(3)	TBD(3)
Opportunity	100	21,760	2,235	0	37	TBD(3)	TBD(3)
Portage	100	14,336	677	0	0	TBD(3)	TBD(3)
Muskwa	100	23,296	1,134	0	260	TBD(3)	TBD(3)
Godin	100	3,840	348	0	158	TBD(3)	TBD(3)
Total	**100**	**243,456**	**16,009**	**413**	**2,450**	**—**	**200**

Notes:

(1) West Ells, Thickwood and Legend Lake anticipated First Steam and Estimate Gross Peak Production are numbers based on our management assumptions. Net Area hectares are numbers based on geological interpretations and resulting assessments of exploitable bitumen areas for each property.

(2) Figures have been rounded to the nearest MMbbl.

(3) Development schedule to be determined.

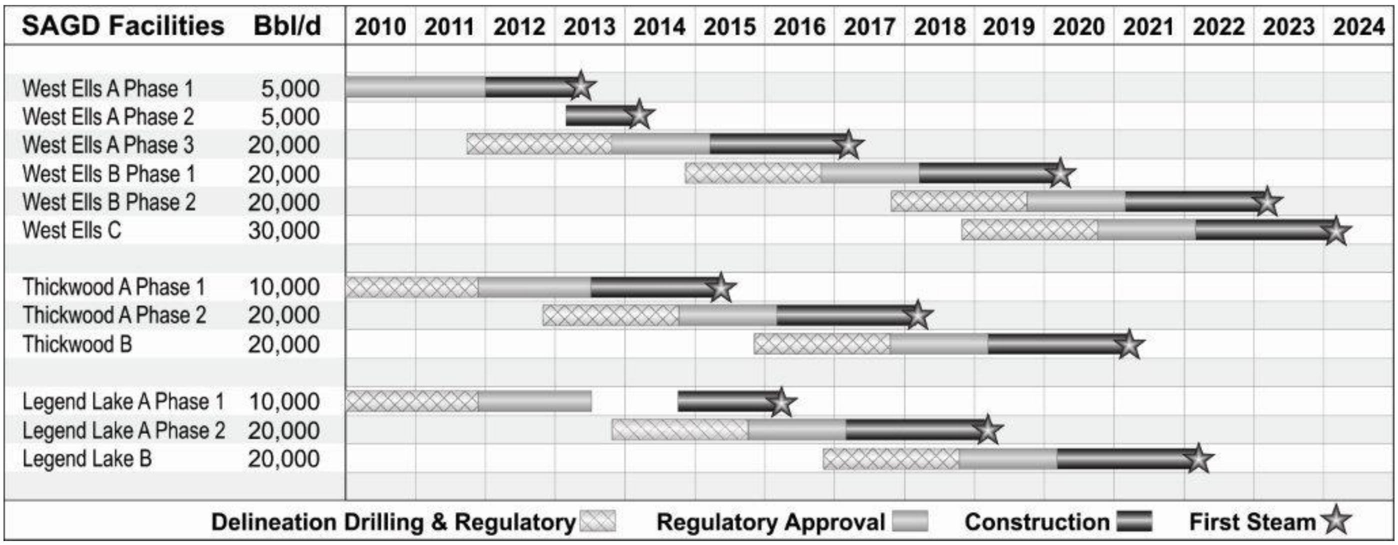
(4) Total PIIP is a sum of discovered and undiscovered PIIP components as defined in GLJ and D&M Reports.

We plan on exploiting our clastic assets with *in-situ* SAGD recovery technology. We do not intend to upgrade our bitumen and we are not currently planning on constructing upgrading or refining facilities as part of our operations, a decision which we believe will reduce our capital costs and mitigate timetable and environmental issues that have challenged other businesses which have integrated these downstream facilities with their oil sands projects. Our clastic assets display similar reservoir characteristics to certain existing SAGD projects that are in production and are located adjacent to oil sands properties held by large international oil & gas companies such as Canadian Natural Resources Limited, Chevron Corporation, Husky Energy Inc., PetroChina, Royal Dutch Shell, Suncor Energy and Total SA.

The incremental development of our West Ells, Thickwood and Legend Lake sites in modular and scalable Phases will assist us in managing project timing and cost pressures, as well as allowing us to take advantage of any improvements in recovery technologies. On the basis of our management assumptions, we expect our Base Case Clastic Assets to have a total productive life of 50 years and to reach a peak production rate of approximately 200,000 bbl/d for 18 years.

On March 31, 2010, we submitted an application for approval to construct a commercial production facility capable of 10,000 bbl/d at our West Ells site. We have designed a plant to support a production base of 10,000 bbl/d on the site of the commercial application for Phases 1 and 2 of the West Ells development. We received regulatory approval from the ERCB on January 26, 2012 and the first steams for Phase 1 and Phase 2 are expected to commence in the second quarter of 2013 and the first quarter of 2014, respectively. The following chart summarises our management development schedule for our Base Case Clastic Assets:

Figure 5: Base Case Clastic Assets Development Schedule

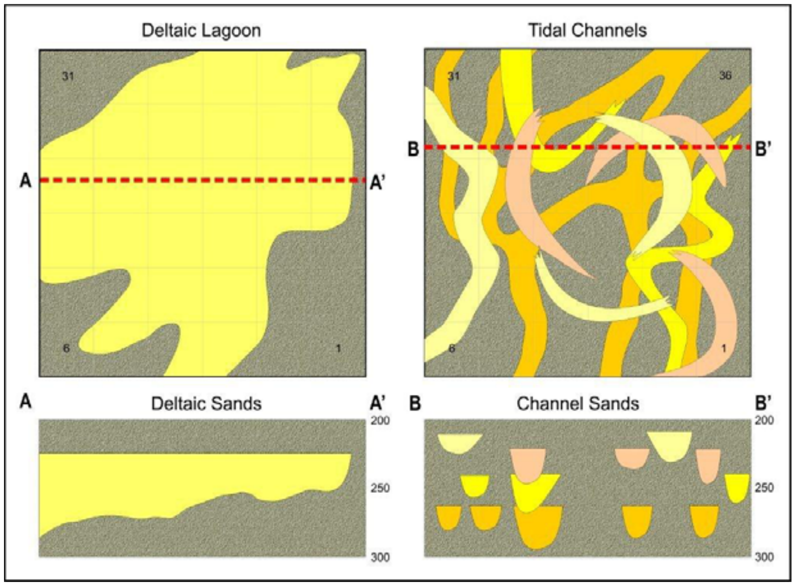


Under the terms of the Memorandum of Understanding for Strategic Cooperation, we anticipate exploring opportunities for the future development and exploration of our clastics assets with SIPC. Please refer to the section entitled "*Memorandum of Understanding for Strategic Cooperation with SIPC*" for more details.

Reservoir Characteristics

The Base Case Clastic Assets are located in the Athabasca oil sands region in north eastern Alberta. The Wabiskaw Formation reservoir is an extensive and laterally continuous marine shelf/shoreline system broken into three sandstone sub-members: the Wabiskaw A, C, and D of the Cretaceous Clearwater Formation. The Wabiskaw reservoir is a fine-grained continuous bitumen-saturated sandstone with minimal mud barriers, consistent thickness and a predictable structural top and base, all of which aids bitumen extraction. The Wabiskaw C and D sands are the main bitumen reservoirs and have few heterogeneities and are therefore predictable and consistent particularly when compared to the estuarine McMurray Formations that are more typically found in the eastern Athabasca region. A diagram illustrating the differences between the deltaic Wabiskaw sands and the estuarine McMurray channel sands is set out below:

Figure 6: Deltaic Versus Channel Depositional Contrast



Though the Wabiskaw retains the characteristics discussed above, which provide advantages for SAGD development, reservoir complexities do exist in both types of deposits and can impact the successful development of bitumen. These complexities are generally broken down into overlying or interbedded gas zones, overlying or interbedded lean zones, interbedded mudstones, bottom water and calcite cementation.

Consistent with the estuarine McMurray channel deposits, the Wabiskaw sequence contains elements of these complexities or heterogeneities both in lithology and in bitumen distribution. However, based on our penetrations in this formation across our lands, we have analysed these heterogeneities and believe our development plan and operating strategy will mitigate these risks.

Commercial development of deltaic sand reservoirs has historically been restricted by infrastructure. Historically the Athabasca region has been developed from the east, owing to the existence of pre-oil sands developments and associated infrastructure. Global demand for oil has made expansion into western Athabasca more attractive due to the size of its deposits and operators have focused their attention on the western region. Recently operators have acquired mineral rights and prepared development plans, including the creation of access routes, into regions where deltaic reservoirs are located.

We are contributing to the development of this infrastructure through the construction of the proposed West Ells access road from Highway 63, 23 km north of Ft. McMurray to our West Ells site.

Operation of these reservoirs is expected to be in line with industry experience, with efficient extraction facilitated by the clean vertical sand columns and uniform lateral characteristics in the Wabiskaw Formation. The deltaic sands have little or no structural variation, providing a consistent base and top for placement of SAGD well pairs and consistent reservoir depths permitting efficient wellbores and predictable directional drilling. Compared to our Wabiskaw deltaic reservoirs, McMurray channel reservoirs generally have higher shale to sand ratios including numerous thick shale lenses. These lenses can impede vertical steam chamber growth and therefore production rate and ultimate recovery as steam is dispersed around rather than through the lenses. Our Wabiskaw reservoirs have low shale to sand ratios, and where shales exist, they are generally bioturbated, allowing the steam chamber to continue growing vertically through the shale instead of around it, which provides a faster and more efficient sweep of the bitumen in the steam chamber.

The steam oil ratio (SOR) is a key indicator of SAGD project economics, with lower SORs indicative of better economics. There are several operational considerations which are normally expected to reduce SOR. These include inserting infill wells between existing wells to capitalise on the heat that is already present in the reservoir and produce oil without any material, additional steam requirements, which reduces the SOR required for the development. Due to the thinner bitumen pay present in deltaic sands, infill wells may be used earlier to improve production in Wabiskaw reservoirs than McMurray reservoirs.

Other factors that have a positive impact on the SOR required for the typical Wabiskaw reservoir, as compared to typical McMurray reservoirs include fewer impermeable shale lenses and heterogeneities.

The table below sets out a comparison of SAGD projects in the Athabasca region and their differing reservoir parameters.

Figure 7: Comparison Table of SAGD Projects and Reservoir Parameters

Projects	Company	Porosity	Bitumen Saturation	Reservoir Depth (m)	SOR[1]	Production per well (bbl/d)	Facies
Our Projects							
West Ells[2]	*Sunshine Oilsands*	31%	76%	255	2.7	808	*Deltaic sands*
Thickwood[2]	*Sunshine Oilsands*	32%	73%	190	3.6	653	*Deltaic sands*
Legend Lake[2]	*Sunshine Oilsands*	32%	69%	430	2.9	604	*Deltaic sands*
Other Projects							
Great Divide[4]	Connacher	32%	85%	400	3.6	414	Channel sands
Christina Lake[4]	Cenovus	35%	81%	400	2.2	945	Channel sands
Hangingstone[4]	JACOS	33%	80%	350	3.5	525	Channel sands
Mackay River[4]	Suncor	34%	74%	137	2.5	657	Channel sands
Christina Lake[4]	MEG	31%	77%	370	2.4	906	Channel sands
Surmont[4]	Conoco	32%	78%	375	2.6	813	Channel sands
Foster Creek[4]	Cenovus	33%	85%	450	2.6	795	Channel sands
Firebag[4]	Suncor	34%	78%	300	3.2	1,689	Channel sands
Dover West[3]	AOSC	33%	77%	220	—	—	Deltaic sands
Mackay River[3]	AOSC	33%	77%	180	—	—	Deltaic sands
Ells River[3]	Chevron	33%	78%	220	—	—	Deltaic sands

Source: All information from IHS Inc. systems data or ERCB published In-situ Progress reports.

Notes:

(1) Production and SOR inputs on other projects based on analysis of public data up to December 2010 (average steady state performance since inception). The SOR for our projects is based on internal development models and assumptions, including plant build SORs and expected well peak production rates. The SOR is lifetime of development area.

(2) Calculated in accordance with our corporate development plans and assumptions, including plant build SORs and expected well peak production rate.

(3) Non-operating projects — no historical performance data.

(4) Production and SOR inputs based on analysis of IHS Inc. public industry data up to December 2010 (average steady state performance since inception). Project data based on ERCB's published *In-situ* Progress reports.

West Ells

Location and Size

The West Ells region includes 26 Oil Sands Leases covering 9,856 contiguous gross hectares and is located within the Athabasca oil sands region between townships 94 to 96 and ranges 17 and 18 west of the fourth meridian, approximately 88 km from Fort McMurray. It is also located west of Chevron's announced, though not yet applied for, Ells River Project and Dover Operating Corp's Dover Commercial Project Area (jointly owned by AOSC and PetroChina). Although the project will proceed in two Phases of 5,000 bbl/d each, approval has been received for an initial planned production capacity of up to 10,000 bbl/d in the first of multiple phases. According to our management assumptions, West Ells is expected to be capable of producing up to 100,000 bbl/d of bitumen from the Wabiskaw zone over a period of 18 years with a productive life of 55 years. Multiple well pairs will be drilled from individual well pads to reduce surface disturbance.

Reserves and Resources

West Ells has been assigned an estimated 1,918 MMbbl of best estimate total PIIP with 158 MMbbl of probable reserves and 745 MMbbl of best estimate contingent resources. Please refer to the sections entitled *"Reserves and Resources Evaluations"* below for more information.

Geology

The bitumen deposits found in the West Ells region are contained in the Wabiskaw C and D sands of the Cretaceous Clearwater Formation. Bitumen reservoirs in the West Ells region consist of wave dominated deltaic deposits that conform to SAGD extraction criteria with relatively thick pays and good reservoir quality. The reservoir is situated at an average depth of 255 metres and has a pay thickness range of 10 metres to 21 metres, bitumen saturation of 76% and average porosity of 31%.

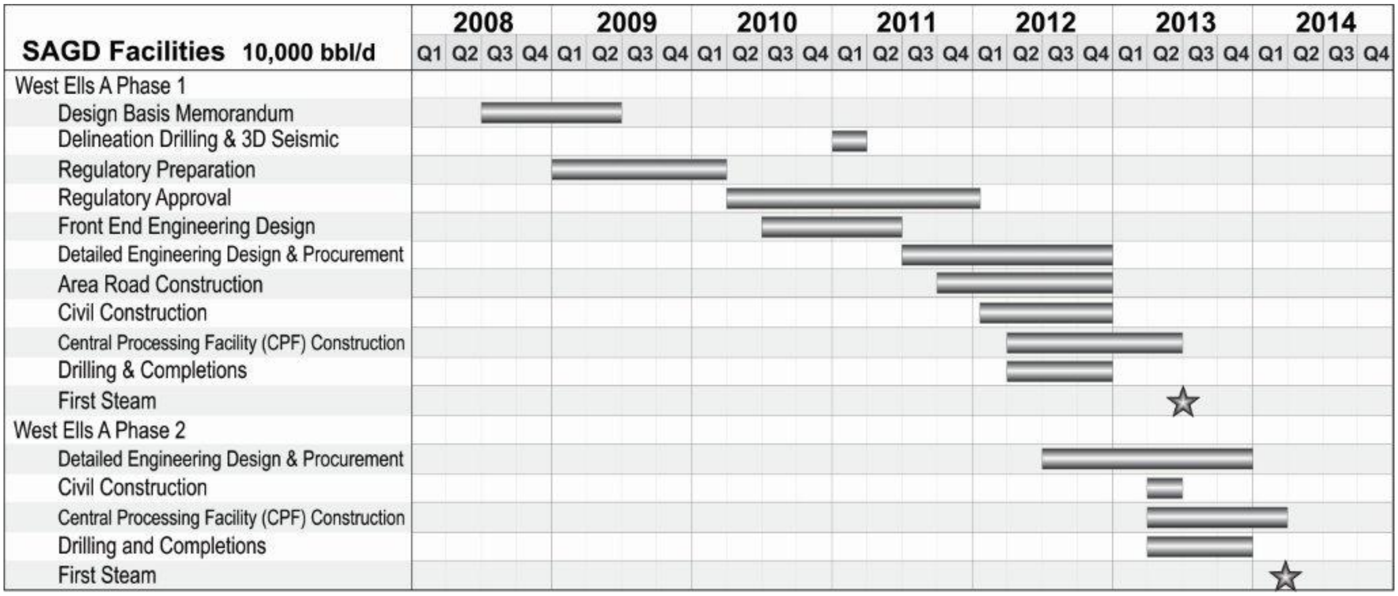
Stage of Development

Since 2007, we have drilled 54 delineation wells in the West Ells region in order to assess the resource potential of the site. In addition, we have drilled 5 water wells to define our water strategy for development of this area. During the fourth quarter of 2009, we initiated a seismic programme at our West Ells and Legend Lake sites. We shot 11 km^2 of 3D and 4 km of 2D seismic data in 2010/2011 in order to accurately geologically map the area. On March 31, 2010 we submitted an application for regulatory approval to produce up to 10,000 bbl/d of bitumen. We have designed a plant to support a production base of 10,000 bbl/d on the site of the commercial application for Phases 1 and 2 of the West Ells development. We received regulatory approval from the ERCB on January 26, 2012 and the first steams of Phase 1 and Phase 2 are expected to commence in the second quarter of 2013 and the first quarter of 2014, respectively. The ERCB approved our request for a permanent shut-in of gas wells order on December 13, 2011.

Development Strategy and Schedule

The West Ells area will be developed in Phases to help control costs, implement improving technologies and capture efficiencies. We expect that each Phase of the West Ells development will be completed in three stages. The first Phase consists of activities completed before steam is first injected into a well pair, referred to as "first stage". This includes the engineering, resource definition, public consultation and environmental work required to support a regulatory application, the filing of regulatory applications, the receipt of the necessary regulatory approvals and the construction of well pairs, steam generation and oil treatment facilities and related infrastructure. The second stage consists of activities required to bring the facilities and well pairs to their designed level of production capacity. The final stage consists of the activities needed to operate the facilities and well pairs at their designed level of production capacity. The following table outlines our management's currently contemplated development plan for West Ells:

Figure 8: West Ells Timeline (Phase 1 and 2)



We propose to develop the initial West Ells facility through a two-Phase construction process, with a 5,000 bbl/d facility followed by a 5,000 bbl/d expansion one year later. Phase 1 of the West Ells development will have one SAGD well pad containing a total of eight well pairs, Phase 2 will also consist of a single SAGD well pad with eight wells. AMEC BDR, an experienced SAGD designer has designed and prepared cost estimates for the site facilities.

The West Ells Access Road will be a 53 km high grade road estimated to cost approximately $55.8 million to construct. We will share this cost with an industry partner and will contribute $29.5 million in construction costs. Our total investment in the road will be $33.8 million, when our additional investment of $4.3 million in the road is added to the construction costs. The final design Phase of the road has been completed and construction has commenced. Further details can be found in the section entitled *"Operations for Clastic Assets — Facility Descriptions"*.

We will recruit the necessary field staff to properly supervise and construct a 10,000 bbl/d plant and will recruit appropriate operations staff to operate and maintain a 10,000 bbl/d SAGD facility. On the basis of our management's assumptions, we anticipate that West Ells will have a total productive life of over 50 years and will produce, at ultimate production rates, approximately 100,000 bbl/d for up to 18 years.

We have initiated the regulatory work required to support expansion of West Ells and our other core SAGD properties to permit full development of the potential of these assets. Regulatory work includes the capture of critical environmental field data over the next two years to establish a complete baseline for compliance with environmental standards. We have undertaken a detailed analysis of comparative facility designs to ensure future Phases of expansion utilise the most suitable technology for our reservoir type.

Thickwood

Location and Size

The Thickwood region consists of four Oil Sands Leases covering 5,888 contiguous gross hectares and is located within the Athabasca oil sands region between townships 90 and 91 and range 18 west of the fourth meridian, approximately 90 km from Fort McMurray and 40 km from West Ells. On the basis of our management's assumptions, we anticipate that Thickwood will be capable of producing up to 50,000 bbl/d of bitumen and to maintain a productive life of 47 years. Multiple well pairs will be drilled from individual well pads to reduce surface disturbance. Field crews gathered the required data sets in the summer of 2011 and the application to construct the 10,000 bbl/d Phase 1 facility at Thickwood was submitted on October 13, 2011.

Reserves and Resources

Thickwood has been assigned an estimated 1,403 MMbbl of best estimate total PIIP with 164 MMbbl of probable reserves and 325 MMbbl of best estimate contingent resources. Please refer to the sections entitled *"Reserves and Resources Evaluations"* below.

Geology

The bitumen deposits found in the Thickwood region are contained in the Wabiskaw A and D units of the Cretaceous Clearwater Formation, which are wave-influenced deltas of the northern sub basin. The reservoir is situated at an average depth of 190 metres and has a pay thickness in the range of 10 metres to 17 metres, bitumen saturation of 73% and average porosity of 32%.

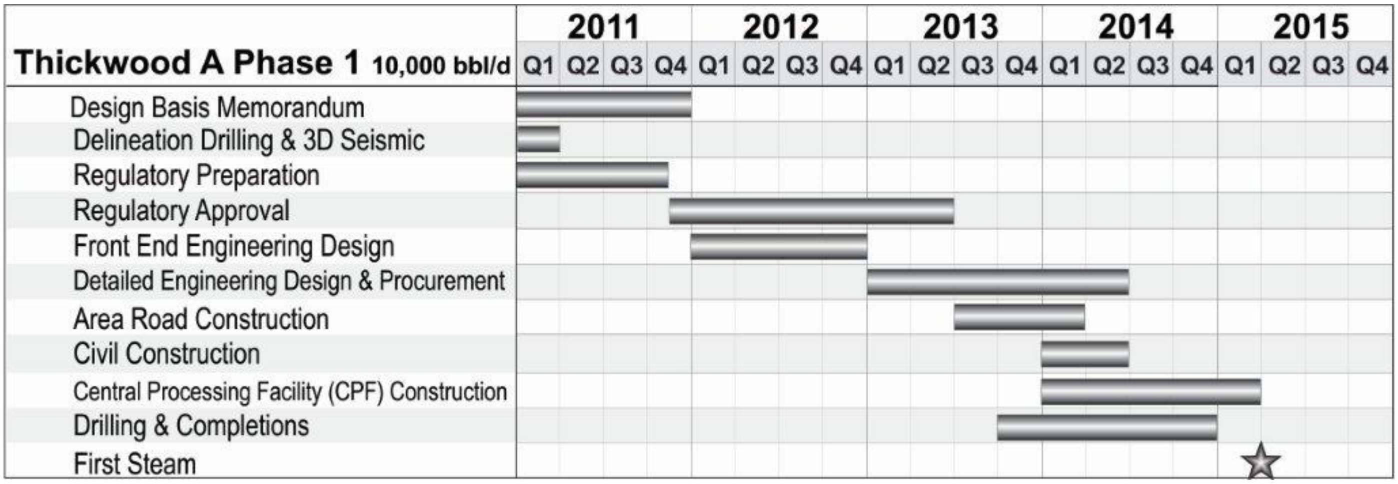
Stage of Development

Since 2007, we have drilled 46 delineation wells in the Thickwood development area in order to assess resource potential. In addition, we have also drilled 2 water wells to define our water strategy for development of this area. In total we have acquired 28 km of 2D seismic data in order to accurately geologically map the area and we executed a 3D seismic program of 15.9 square kilometres. We submitted an application for a 10,000 bbl/d facility in the Thickwood area to the ERCB on October 31, 2011. This submission is the genesis of the extraction strategy developed for this core area. A common access and utility corridor will benefit the Thickwood, Legend Lake and West Ells operating areas. Regulatory approval is expected in the second quarter of 2013 and first steam of the first 10,000 bbl/d facility is expected to commence during 2015.

Development Strategy and Schedule

The Thickwood area will be developed in Phases in order to control costs, implement improvements in recovery technologies and improve efficiency. The following chart outlines our management's currently contemplated development plan for Thickwood:

Figure 9: Thickwood Timeline



Following receipt of regulatory approval, we propose to develop the Phase 1 10,000 bbl/d facility in the Thickwood area. The facility is planned to produce 10,000 bbl/d of bitumen product through the use of SAGD technology. Phase 1 of the Thickwood development will have two SAGD well pads containing a total of 16 well pairs.

The size and scope of the Thickwood project is based on management assumptions. On the basis of our management's assumptions, we anticipate that Thickwood will produce at ultimate production rates of approximately 50,000 bbl/d for over 21 years with a productive life of up to 47 years.

Legend Lake

Location and Size

The Legend Lake region consists of 27 Oil Sands Leases covering 65,024 contiguous gross hectares[1] and is located within the Athabasca oil sands region in townships 93-96 and ranges 18-21 west of the fourth meridian, approximately 103 km from Fort McMurray and 15 km from West Ells. On the basis of our management's assumptions, we anticipate that Legend Lake will be capable of a 44 year productive life, achieving up to 50,000 bbl/d of bitumen for 20 years. Multiple well pairs will be drilled from individual well pads to reduce surface disturbance. Field crews gathered the required data sets during the summer of 2011 and the relevant application for a 10,000 bbl/d development at Legend Lake was submitted to the ERCB on November 25, 2011.

Reserves and Resources

Legend Lake has been assigned an estimated 1,844 MMbbl of best estimate total PIIP with 91 MMbbl of probable reserves and 449 MMbbl of best estimate contingent resources. Please refer to the sections entitled *"Reserves and Resources Evaluations"* below.

Geology

The bitumen deposits found in the Legend Lake region are contained in the Wabiskaw C and D units of the Cretaceous Clearwater Formation and are made up of wave-dominated deltaic deposits that conform well to SAGD extraction technology with good reservoir thickness. The reservoir is situated at an average depth of 430 metres) and has a exploitable pay thickness in the range of 10 metres to 18 metres, bitumen saturation of 69% and average porosity of 32%.

[1] The 27 Oil Sands Leases in the Legend Lake region consist of Clastics at Legend Lake and Opportunity.

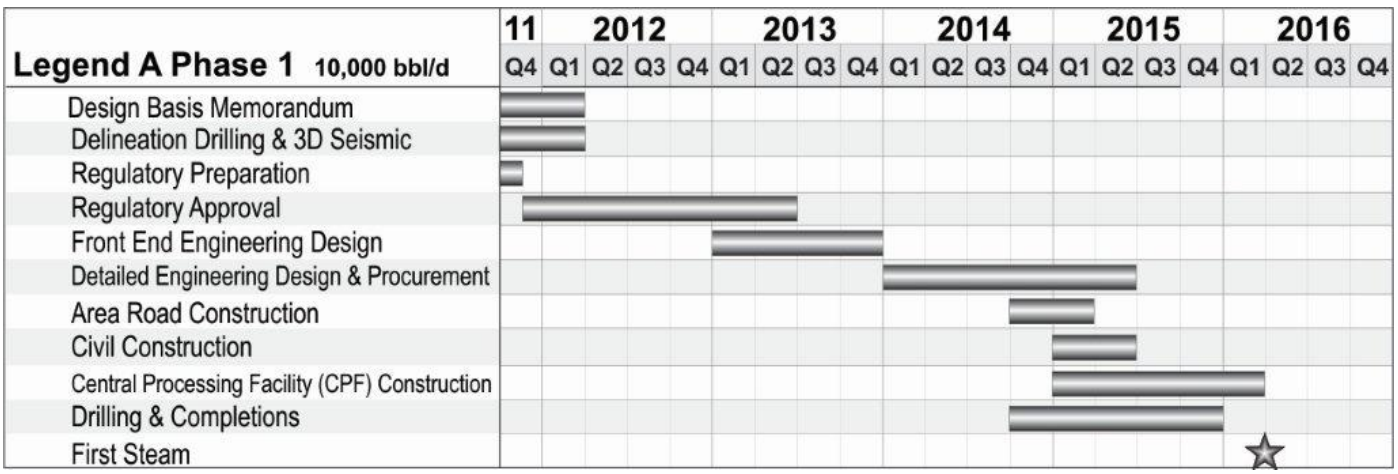
Stage of Development

Since 2007, we have drilled 46 delineation wells in the Legend Lake development area in order to assess resource potential. In addition, we have also drilled one water well to further define our water strategy for the development of this area. In total we have recorded 79 km of 2D seismic data in order to accurately geologically map the area and have executed a 3D seismic program extending over 14.8 square kilometres. We submitted an application for a 10,000 bbl/d facility in the Legend Lake area to the ERCB on November 25, 2011. A common access and utility corridor will benefit the Thickwood, Legend Lake and West Ells operating areas. Regulatory approval is expected in the second quarter of 2013 and first steam of the first 10,000 bbl/d facility is expected to commence during 2016. It is anticipated that the site will have two SAGD well pads containing a total of 16 well pairs.

Development Strategy and Schedule

The Legend Lake area will be developed in Phases to control costs, implement improvements in recovery technologies and capture efficiency. The following chart outlines our management's currently contemplated development plan for Legend Lake:

Figure 10: Legend Lake Timeline



The size and scope of the Legend Lake project is based on management assumptions. On the basis of our management's assumptions, we anticipate that Legend Lake development will produce at ultimate production rates of approximately 50,000 bbl/d for 20 years and will have a productive life of over 44 years.

Harper

Location and Size

The Harper region consists of 38 Oil Sands Leases covering 177,600 contiguous gross hectares and is located within the Athabasca oil sands region between townships 95 to 102 and range 20 and range 24 west of the fourth meridian, approximately 165 km northwest from Fort McMurray. Seven wells have been drilled in the eastern Harper region targeting clastic deposits. We will assess the region in the future as potential opportunities for further development of the area's clastic assets arise.

Reserves and Resources

Harper has been assigned an estimated 5,581 MMbbl of best estimate Total PIIP with 326 MMbbl of best estimate contingent resources. Please refer to the sections entitled *"Reserves and Resources Evaluations"* below.

Geology

The clastics reservoirs found in the Harper region are contained in the Wabiskaw member of the Cretaceous Clearwater Formation and bitumen in the Harper region is suitable for thermal heavy oil recovery. The reservoir is situated at an average depth of 450 metres and has a pay thickness in the range of 10 metres to 12 metres, bitumen saturation of 50% and average porosity of 30%.

Stage of Development

The size and scope of commercial development of the clastic assets in the Harper region is still being evaluated. Currently we only have seven proprietary penetrations that have been evaluated combined with a modest number of legacy penetrations across a vast regional depositional environment and we anticipate additional delineation drilling will continue to confirm the resource expectations for this area. We drilled 8 additional delineation wells and appraisal tests during 2012.

Other Clastic Assets

In addition to the core areas that have been identified to date for commercial development, we are continuing to both evaluate clastic areas as well as execute future delineation programmes to expand these existing commercial areas and potentially identify new commercial areas. We will continue to monitor and assess the results of each winter programme as we weigh our investment decisions in order to maximise the returns.

Carbonates

Overview

We have acquired Oil Sands Leases in the bitumen rich Grosmont, Nisku, Leduc and Wabamun carbonate formations in the following regions: Harper, Ells Leduc, Goffer, Muskwa, Saleski, South Thickwood, Portage Nisku and Godin. Our carbonate assets encompass approximately 216,576 hectares of land in these regions. We own 100% of these assets, which possess an estimated 29 billion bbls of best estimate total PIIP and 616 MMbbl of best estimate contingent resources.

Carbonate bitumen reservoirs are a significant untapped resource, providing a significant commercial extraction opportunity as technology develops for this resource type. It is estimated that the Grossmont, Nisku, Leduc and Wabamum Formation in the Athabasca oil sands region contain over 406 billion bbls of bitumen in place(according to the ERCB new release dated June 5, 2010 titled *"ERCB Report shows 14% Growth in Alberta Oil Sands Production in 2009)*.

We have continued to delineate our carbonate resources since their acquisition and we drilled 22 carbonate wells in the 2010/2011 drilling season. We also acquired 1,205 km of 2D seismic at Harper, Portage Nisku, Muskwa, Goffer and Ells Leduc areas in 2010 and 2011, which identified exploration targets and guided the planning of core holes. GLJ has conducted an assessment of our carbonate assets across all strike areas with carbonate reservoir potential. Several areas have demonstrated adequate characteristics to be assigned contingent best resources, as shown below. The remaining areas have demonstrated the existence of bitumen and have been assigned alternate resource categories. GLJ describes these reservoirs as conforming to developing technology, and will progress their resource classification as appropriate technology is developed. For our assets, this progression will occur with the execution of pilot operations and the associated demonstration of reservoir conformity. A summary of our carbonate assets is set out in the table below:

Figure 11: Carbonate Property Summary

Asset	Working Interest	Net Area[2]	Best Estimate Total PIIP[(1)(3)]	Best Estimate Contingent Resources[1]
	%	hectares	MMbbl	MMbbl
Harper	100	45,568	10,555	393
Ells Leduc	100	12,672	997	159
Goffer	100	9,216	1,732	0
Muskwa	100	92,928	10,841	0
Saleski	100	3,200	596	0
South Thickwood	100	2,560	287	0
Portage Nisku	100	41,728	4,265	64
Godin	100	8,704	0	0
Total		**216,576**	**29,273**	**616**

Notes:

(1) Best estimate PIIP and best estimate contingent resources.

(2) Net area hectares are numbers based on geological interpretations and the resulting assessments of exploitable bitumen areas for each property.

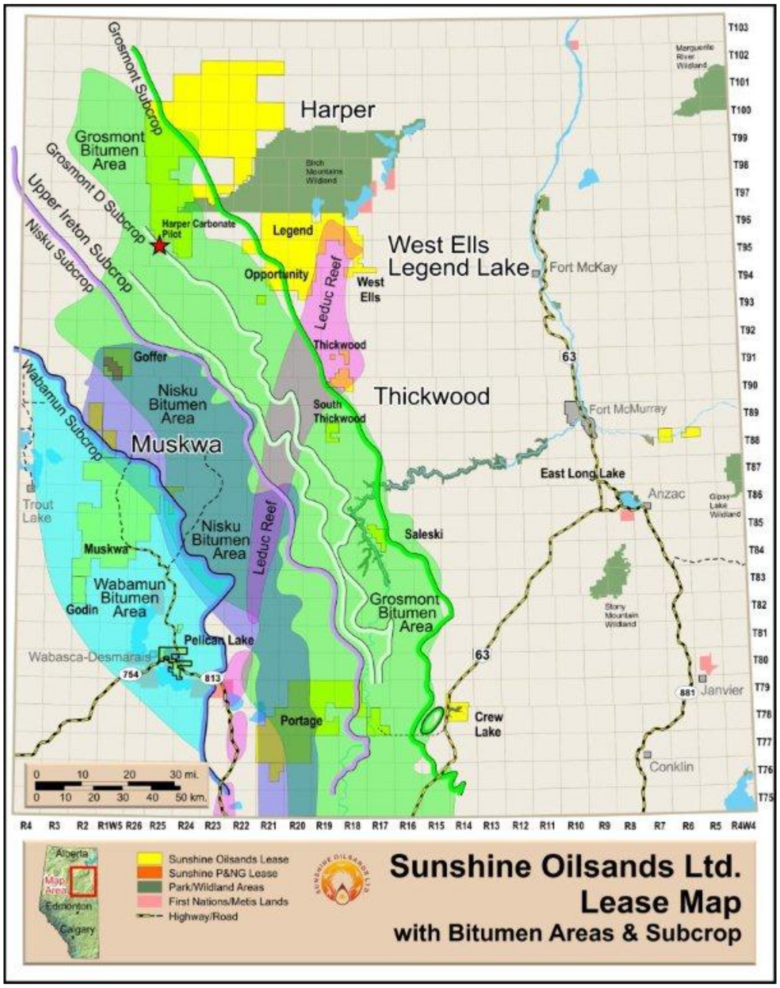
(3) Total PIIP is a sum of discovered and undiscovered PIIP components as defined in GLJ and D&M Reports.

There remain significant technical challenges to extracting bitumen from carbonate rock and there is currently no commercially proven extraction method, although a number of pilot projects have been launched to address this, both by ourselves and by other industry participants. In the winter of 2010 and 2011, our Harper Pilot successfully proved thermally induced bitumen mobility in our Grosmont C carbonate assets. The test was not designed to demonstrate reservoir conformance to a predictive model and has not established the Grosmont C as a commercial reservoir. The test did achieve the stated objective of mobilising bitumen through thermal stimulation which we believe is an important initial step to understanding this deposit. We will continue to investigate technological developments from other industry participants that will enable us to exploit these reservoirs. We do not intend to conduct research and development of carbonate recovery and extraction related technologies. Our management team includes certain key operations and engineering personnel who were responsible for the planning, modelling and the successful execution of the carbonates thermal recovery programme in the Issaran field in Egypt. The applied technologies successfully employed in the Issaran field in Egypt were formulated on lands adjacent to our carbonates assets at Saleski and Muskwa.

Reservoir Characteristics

Our carbonates properties are located in the prolific Carbonate Triangle, which contains bitumen in the Grosmont, Nisku, Leduc, and Wabamun Upper Devonian Formations. The map below sets out the location of the carbonate formations in Alberta and their typical stratigraphy:

Figure 12: Carbonate Bitumen Bearing Formations Forming the Carbonate Triangle



One of the richest bitumen reservoirs is the Grosmont Formation. The Grosmont can be subdivided into the Grosmont A, B, C and D, of which we have bitumen accumulations captured in the A, B and C at Harper, Saleski and Thickwood. The Grosmont A is primarily limestone and can be found at Harper, Saleski and Thickwood. The Grosmont B is composed of a very permeable amphipora floatstone dolomite and can be found at Harper. The Grosmont C, at Harper, is characterised as a high quality fractured dolomite reservoir. The Devonian Leduc Formation is found at our Ells-Leduc property. The Leduc is a classic barrier reef complex and we have acquired a position in potentially the most prolific reservoir on the reef margin. The reef margin is composed of robust corals, and is highly dolomitised, fractured and karsted, making it an excellent candidate for SAGD/CSS recovery. The Devonian Nisku Formation is found at our Muskwa, Goffer and Portage properties. The Nisku was deposited in a carbonates ramp setting. It is dolomitised, and is very predictable in its thickness, saturations and lateral extent.

Overall Development Plan

We intend to create a long term development plan for our carbonate resources once we have compiled sufficient data for determining the extent of our asset base and the feasibility of *In-situ* thermal recovery methods at our properties. We drilled 22 carbonate core holes across our carbonate asset base during the 2010/2011 winter drilling season as well as shooting and/or purchasing 1,205 km of 2D seismic. In addition, with our Harper Pilot we performed a short-term steam-based injection cycle to establish fluid mobility at our Grosmont C assets at Harper. The test was not designed to demonstrate reservoir conformance to a predictive model and has not established the Grosmont C as a commercial reservoir. The test did achieve the stated objective of mobilising bitumen through thermal stimulation which we believe is an important initial step to understanding this deposit.

The creation of a commercial development plan is contingent on the development of applicable commercial scale recovery technology. Variations in porosity and permeability of carbonates can result in technically challenging commercial extraction.

Three key Grosmont carbonates pilots were conducted in the 1980's. One of these tests occurred between 1980 and 1986 at the Buffalo Creek Pilot site owned by AOSTRA, Unocal (Husky Energy Inc.) and Canadian Superior. The scheme recovered 46,000 bbls in five steaming cycles over 18 months with a peak rate of 440 bbl/d. Further, Laricina implemented their Saleski SAGD pilot at the end of 2010 in order to target a production rate of 1,800 bbl/d. Three well pairs were drilled for the project and Laricina submitted a regulatory application for its first 12,500 bbl/d commercial Phase in 2011, with start-up anticipated in 2013. Other companies operating in the area include Osum Oil Sands Corporation, Shell Canada Ltd. and AOSC, some of which have also implemented pilot schemes. We will realise value on our carbonates position by adopting technologies as they become commercial. Further details of commercial advancements in the carbonate field can be found in the section entitled *"Industry Overview"* in this AIF.

Although we maintain a technology committee made up of certain executive, management and technical staff which evaluates emerging and maturing extraction techniques, we are not a technology company and we will continue to observe advancements in new and developing methods in the industry.

Under the terms of the Memorandum of Understanding for Strategic Cooperation, we anticipate exploring opportunities for the future development and exploration of our carbonate assets with SIPC. Please refer to the section entitled *"Memorandum of Understanding for Strategic Cooperation with SIPC"* for more details.

GLJ highlights the Ells Leduc, Harper and Portage Nisku carbonate properties with best case contingent allocation and 616 MMbbls of recoverable resources (please refer to Figure 3 in this section). The detailed individual property reports, as presented in the GLJ evaluation, discusses carbonate resources based on on-going and planned pilot work as well as GLJ's industry knowledge and experience. The Ells Leduc best case evaluation shows that first steam is anticipated in 2018 with peak rates of 20,000 bbl/d by 2020. The Harper best case evaluation for the carbonates shows first steam for the initial pilot is anticipated in 2013. The initial pilot operations at Harper lead to commercial development in 2016 with peak rates of 40,000 bbl/d by 2020. The Portage Nisku best case evaluation shows first steam anticipated in 2013 with peak rates of 5,000 bbl/d by 2017. GLJ's evaluation shows potential for 0, 616 and 5,147 MMbbls of recoverable contingent resources from the carbonates respectively in the low, best and high estimate assessments (please refer to Figure 3 in this section). As efficient extraction technologies are established and proven, we will continue progressing the development of these carbonate assets and focus on improving the best estimate recoverable volumes.

Harper

Location, Size and Geology

The Harper region consists of 693.75 sections of which 178 have been identified to date as having carbonate bitumen potential. The entire area encompasses 177,600 contiguous gross hectares and is located within the Athabasca oil sands region between townships 95 to 102 and range 20 and range 24 west of the fourth meridian, approximately 165 km northwest from Fort McMurray. The carbonates found in the Harper region are contained in the Grosmont A, B and C formations. The Grosmont C carbonate reservoirs in the Harper area are situated at an average depth of 450 – 600 metres, have a pay thickness of up to approximately 25 metres, and average porosity of 19%. Absolute permeability is 100-10,000 millidarcies. The Grosmont B carbonate reservoirs in the Harper area are situated at an average depth of 500-600 metres, a pay thickness in the range of 12 metres to 20 metres, and average porosity of 17%. Permeability is 100-10,000 millidarcies. The Grosmont A carbonate reservoirs in the Harper area are situated at an average depth of 380-600 metres, a pay thickness in the range of 10 to 25 metres, and average porosity of 15%. Permeability is 100-1,000 millidarcies.

Reserves and Resources

Harper has an estimated 10.6 billion bbls of best estimate total PIIP and has been assigned 393 MMbbl of best estimate contingent resources. Please refer to the sections entitled *"Reserves and Resources Evaluations"* below.

Stage of Development

The size and scope of commercial development of the carbonate assets in the Harper region is still being evaluated. In 2011, we drilled six carbonate delineation wells and shot 61.2 km of proprietary 2D seismic data.

We launched a steam injection demonstration pilot at Harper late in 2010. We submitted an application to conduct a steam injection programme in September 2008, which was approved by the ERCB in November 2009. We conducted the steam injection pilot, utilising CSS, at the site between December 2010 and March 2011 in order to confirm oil mobility through thermal stimulation and additionally to establish a preliminary data set to aid determination of the feasibility of *in-situ* thermal recovery methods to the Grosmont Formation. The project was located in our Harper area within township 95 and range 24 west of the fourth meridian, approximately 210 km from Fort McMurray. We drilled into the Grosmont C reservoir, which contains fractured, vuggy, intergranular dolomitised carbonate types with a high bitumen saturation.

The Harper Pilot successfully established thermal mobility of Grosmont C bitumen and confirmed that Grosmont C carbonates have a high steam injectivity due to extensive permeability. Typical cyclic thermal response on first cycle results in limited oil production during the initial flow back period. A total of 365 bbls of oil were produced prior to early shut down of the production Phase due to seasonal restrictions. The pilot has provided us with the opportunity to consider potential design improvements to our single cycle thermal recovery techniques. The test was not designed to demonstrate reservoir conformance to a predictive model and has not established the Grosmont C as a commercial reservoir. The test did achieve the stated objective of mobilising bitumen through thermal stimulation which we believe is an important initial step to understanding this deposit.

Development Strategy

We are currently evaluating the viability of conducting a further steam stimulation oil recovery project, either on the existing site or elsewhere in the Harper area and we have reactivated our Harper Pilot for our 2011/2012 winter operations.

Ells Leduc

Location, Size and Geology

The Ells Leduc region consists of 49.5 sections covering 12,672 net hectares over portions of our West Ells, Opportunity and Legend Lake sites between townships 94 to 96 and range 17 and range 19 west of the fourth meridian, approximately 98 km from Fort McMurray. The carbonates found in the Ells Leduc region are contained in the Leduc Formation. The carbonate reservoirs in the Ells Leduc area are situated at an average depth range of 250 – 500 metres, a pay thickness in the range of 10 to 75 metres, and average porosity of up to 15%. Absolute permeability of the carbonate is 100-10,000 millidarcies.

Reserves and Resources

The Ells Leduc asset has an estimated 997 MMbbl of best estimate total PIIP and has been assigned 159 MMbbl of best estimate contingent resource. Please refer to the sections entitled *"Reserves and Resources Evaluations"* below.

Stage of Development

The size and scope of commercial development of the carbonate assets in the Ells Leduc region is still being evaluated. In 2011, we drilled two delineation wells, shot 11 km of proprietary 2D seismic data. We are evaluating the potential for a future carbonate pilot, once all season road access is built into the area. The Ells Leduc Formation has future pilot potential. Thick accumulations of bitumen have been detected and pilot execution will be facilitated with completion of the West Ells 10,000 bbl/d SAGD access road.

Other Carbonate Assets

Our other carbonate assets are located in the Athabasca oil sands region at Goffer, Muskwa, Portage Nisku, Saleski, Godin and South Thickwood. Together the carbonate assets on these sites encompass 618.5 sections covering 158,336 net hectares and are illustrated in Figure 12 in this section. Approximately 24 wells have been drilled in these areas and they will be assessed in the future as potential opportunities for further development of the carbonate assets. The Wabamun Formation at Muskwa has future pilot potential and is situated in close proximity to an all season access road and our conventional heavy oil production at Muskwa. At Goffer, we have one PNG Licence, in which the wells in the Keg River Formation have shown light oil potential. We will need to conduct further evaluations to understand the development possibilities for the PNG Licence, however it is not part of our immediate development plans.

Conventional Heavy Oil Overview

We own Oil Sands Leases in the Muskwa area, where we currently produce conventional heavy oil. We also hold Oil Sands Leases in the Harper, Godin and Portage areas, all with untested potential for the production of conventional heavy oil. We acquired the Oil Sands Leases for our Muskwa project between May 2008 and January 2011 through Crown auctions and we hold interests at other complementary potential conventional heavy oil sites in the Harper and Portage areas.

All of our Oil Sands Leases are subject to Alberta's bitumen royalty scheme opposed to the Alberta conventional heavy oil royalty scheme applicable to non-oil sands leases. This reduces the impact on our oil sales as bitumen royalties are lower than the conventional oil royalties payable on non-oil sands leases. Conventional heavy oil produced on Oil Sands Leases in Alberta are subject to royalty rates that are price sensitive and are dependent on a project's status. Further information about the royalty structure applicable in Alberta can be found in the section entitled *"Laws and Regulations in the Industry — Laws and Regulations Relating to Taxation and Royalties — Royalty Regime"*.

To date, regulatory approval has been received to develop 4,608 hectares of the Muskwa region. As of the date of this AIF, we have developed five well pads, where a total of 39 production wells have been drilled. The Muskwa area has demonstrated a large reservoir fairway with proven oil mobility under cold flow conditions which provides opportunities for development. At Muskwa, we are proposing to develop two additional pads with up to nine wells per pad once we have confirmed that the currently defined reservoir fairway conforms to our performance expectations. If executed, these additional two pads are expected to enable the site to achieve a production rate ranging between 1,600 – 1,800 bbl/d of conventional heavy oil by the end of 2012. In conjunction with this development, we intend to evaluate low cost options for defining further reservoir fairways for future development.

We also completed several cold flow production tests, to further assess the potential for non-thermal production, at Harper and Godin as part of the 2011/2012 winter drilling programme.

Muskwa

Location and Size

The Muskwa region consists of 21 Oil Sands Leases of 101,715 contiguous gross hectares[2] and is located within the Athabasca oil sands region within townships 83 to 89 and range 2 west of the fifth meridian and range 24 west of the fourth meridian, approximately 47 km from Wabasca and adjacent to the existing Pelican Lake operating areas. We own 100% of the mineral rights in the areas covered by our leases in the Muskwa region without encumbrance. The Muskwa PRS consists of 768 hectares. We received approval from the ERCB to expand the PRS to 4,608 hectares on October 6, 2011.

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[2] The 21 Oil Sands Leases in the Muskwa region include the clastics assets at Godin.

Reserves and Resources

Muskwa has been assigned 2.4 MMbbl of conventional heavy oil proved reserves with a pre-tax value of $38 million, 5.5 MMbbl of conventional heavy oil proved plus probable reserves with a pre-tax value of $56 million, 8.8 MMbbl of conventional heavy oil proved plus probable and possible reserves with a pre-tax value of $61 million. The combined Muskwa, Godin and Portage areas have been assigned a best estimate total PIIP of 2,013 MMbbl. Please refer to the sections entitled *"Reserves and Resources Evaluations"* below.

Geology and Reservoir

The conventional heavy oil deposits found in the Muskwa region are capable of mobility without thermal or other kinds of stimulation and are contained in the sands of the Wabiskaw D Formation of the Cretaceous Clearwater Formation. The Wabiskaw D Formation is a sand-rich, wave-dominated delta deposited on the outskirts of the central sub-basin. The Wabiskaw is deposited as a series of welded, seaward clinoforming lenticular sand bodies that display a consistent coarsening and shallow upward profile. Sands in the Wabiskaw D in the Muskwa region are variably saturated with water, bitumen and natural gas and generally have an API gravity of approximately 10 degrees, which is suitable for conventional recovery. At Muskwa, and at other areas with conventional heavy oil production potential, the reservoir and hydrocarbon systems are significantly different from our clastic reservoirs, though the production benefits from the same royalty structure as thermal clastic oil sands production. Current production is dominated by the CHOPS recovery technique though we have confirmed that we can produce at Muskwa with alternative production techniques, for example, with sand control.

The reservoir at Muskwa is situated at an average depth of 380 metres and has a net pay range of 4 metres to 12 metres, conventional heavy oil saturation of 72% and average porosity of 31%. Absolute permeability of the sand is 4,300-6,300 millidarcies. Reservoir pressure is approximately 2,100k Pa and the temperature of the reservoir is 14ºC. Overlying gas pools are on occasion in contact with the same Wabiskaw Formation sands.

Stage of Development

The table below highlights our management's estimates of the project life and production rates for Muskwa for the period 2011 to 2015.

	Project	Production (bbl/d)(2)							
	Life	Actual					Forecast		
Property	**Years**	**Oct 2011**	**Nov 2011**	**Dec 2011**	**2011**	**2012(3)**	**2013**	**2014**	**2015**
Muskwa(1)	10	407	411	606	354	1,210	1,670	1,565	1,357

Notes:

(1) Muskwa Development Capacities and Project Life will be defined through exploration drilling and fairway definition for future development. Current development plan/forecast considers 2012 pad development only for a total of 7 pads and 57 wells

(2) All production numbers in the table are based on actual or forecast average production volumes for the periods specified

(3) We have forecast exit rates of between 1,600-1,800 bbl/d on the basis of management estimates

Our extraction of conventional heavy oil at Muskwa in 2011 has been at pre-commercial stage and operating costs per barrel have been high. This is as expected and is normal for this type of development at this stage and is not representative of future costs. Costs per barrel will drop as fixed costs are distributed across higher volumes and efficiencies are captured on the variable cost components. Additionally, the reduction of fuel costs is anticipated with the replacement of propane with natural gas. Our average rate of production for the second half of 2011 was 479 bbl/d with an average operating cost of approximately $44.25/bbl, the average rate of production for December 2011 was 606 bbl/d with an average operating cash cost of approximately $34.75/bbl. For 2012 our exit rate of production is estimated to be approximately 1,600-1,800 bbl/d with an average annual cost of approximately $26.30/bbl. Key operating cost reduction opportunities that we are addressing include reducing sand handling/removal costs, reducing fuel costs and reducing completions/ maintenance costs.

Muskwa's development will continue to benefit from a constantly developing infrastructure. Major operators, such as CNRL and Husky Energy Inc. are active in the Muskwa area and regional production and development programmes support the retention of seasoned and skilled labour in the nearby municipality of Wabiskaw. An existing high grade road runs through the western edge of the Muskwa area and into the southern part of our Muskwa leases and provides access to our production area, as well as to oil development projects maintained by CNRL and Shell Canada Limited to the north of the Muskwa area. Our oil is currently trucked to a nearby facility, approximately 64 km away, which is owned and operated by Legacy.

Development Strategy and Schedule

We received the approval from the ERCB on October 6, 2011 to expand the PRS to cover 4,608 hectares. This expansion adds an incremental 15 continuous sections to the current PRS of three sections.

We have also drilled three delineation wells at Godin, a 26 section lease of 6,656 contiguous gross hectares connected to the Muskwa region that is located within townships 82 and 83 and range 2 west of the fifth meridian, approximately 40 km from Wabasca. Initial estimates suggest a bitumen pay of approximately 12 metres in the region to be extracted using thermal methods. We are drilling additional delineation wells to conduct appraisal tests during 2012. A horizontal production test well has been drilled during the 2011/2012 winter season and is being evaluated for the conventional heavy oil production potential in this area.

On the basis of our management assumptions, we have forecast that the productive life of Muskwa for conventional heavy oil will conclude in 2021.

Portage

Location and Size

The Portage region consists of 291 sections of 74,496 contiguous gross hectares and is located within the Athabasca oil sands region between townships 76 and 79 and ranges 17 and 21 west of the fourth meridian. This region offers conventional heavy oil production potential and further carbonate opportunities. To date, no wells have been drilled targeting the Wabiskaw Formation in the Portage region. We have created the option for a cold flow production test in this region in the winter of 2012 or 2013.

The Portage region benefits from some of the same infrastructure advantages as Muskwa, with oil and gas roads, labour and services in the region.

Reserves and Resources

Portage has not been assigned any contingent best resources at this time. Please refer to the sections entitled *"Reserves and Resources Evaluations"* below.

Geology

Oil deposits found in the Portage region are contained in the same Wabiskaw D member of the Cretaceous Clearwater Formation found in the Muskwa region.

The hydrocarbons in our Portage leases are potentially suitable for conventional heavy oil recovery. The reservoir is situated at an average depth of 400 metres, has a bitumen saturation of 53% and average porosity of 25%.

Stage of Development

The size and scope of commercial development of the conventional heavy oil assets in the Portage region is still being evaluated. We propose to drill additional delineation wells, conduct appraisal tests and shoot further seismic tests in the area during 2012.

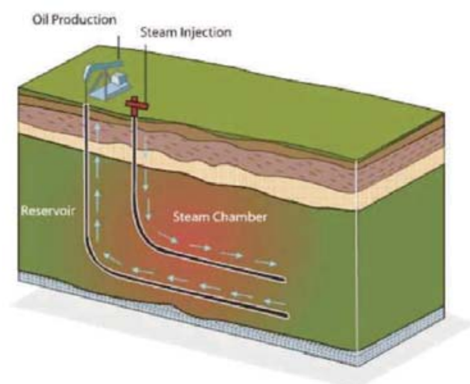
Operations for Clastic Assets

Set out below is a description of the operations and infrastructure to be utilised by our Base Case Clastic Assets, which will be our main development assets in the near-term.

SAGD Process

Production under the SAGD process takes place in a number of stages. Initially, high pressure steam will be delivered to the SAGD well pads via above-ground distribution lines. The well pads will be equipped with the facilities necessary to inject steam into the reservoir and then recover bitumen from the reservoir. The bitumen is brought to the surface through artificial lift from the reservoir. The bitumen emulsion is then delivered to the central processing facility ("**CPF**") via above-ground production lines. The CPF contains the following key systems: the inlet separation system; the gas handling system; the oil removal system; the steam generation and cogeneration system; and the water treatment system. These systems are supported by various storage facilities, utilities and other infrastructure.

Figure 15: SAGD Extraction Process Diagram



Regional Infrastructure

Product Movement

We intend to transport early SAGD production volumes by truck via year round access roads. In early stages of development, below 10,000 bbl/d at any site, the trucks will also be used to transport diluent to site for subsequent use in the extraction process and for blending with the bitumen prior to transportation. In conjunction with developing SAGD facilities, we will also develop related infrastructure such as a main access road, spur roads and natural gas pipelines. As noted, we intend to utilise trucks to transport bitumen until a critical mass of 10,000 bbl/d is reached at any site, at which point, pipeline transportation is expected to be available from third parties to satisfy the need of takeaway capacity for the regional developing projects. According to our current development schedule, we expect the West Ells, Thickwood and Legend Lake 10,000 bbl/d production capacities in place by 2014, 2015 and 2016 respectively.

The West Ells Access Road will be a 53 km high grade road estimated to cost approximately $55.8 million to construct. We will share this cost with an industry partner and will contribute $29.5 million in construction costs. Our total investment in the road will be $33.8 million when our additional investment of $4.3 million in the road is added to the construction costs. The final design Phase of the road, including cost breakdowns has been completed, and construction has commenced. The all season road will have a wide running surface capable of managing heavy loads, construction modules and equipment and will be available for public use without liability to us.

With a number of major companies in the process of developing projects in the area, we anticipate the construction of a pipeline by a third party company in order to satisfy the need of takeaway capacity for the developing projects. In addition, we propose to leverage our contacts in Asia, and in particular China, in order to source cheaper supplies, plant and equipment to support our developments.

Water Source

We require water to generate steam for our SAGD processing. We have explored for and confirmed the presence of a massive water source located in the Viking Formation. This shoreline complex is mapped up to 65m thick at the apex and is spread over three townships, or over 279 km^2. The average porosity for the Viking water sand is generally 35% in the Viking reservoir in the West Ells and Legend Lake areas. This complex contains an estimated 19 billion bbls of water supply underlying our leases. This water is not utilised for any other purposes. We plan to submit a water licence application with the applicable regulatory authority during the spring of 2012 with respect to our proposed water usage from the Viking Formation, which is subject to an application fee of less than $1,000 and an advertising fee to cover giving notice of our application which is also under $1,000. Having consulted with our Canadian legal advisors, we understand that under the *Water Act*, the AEW has the discretion to require that additional security requirements be imposed pursuant to the requirements set out by the regulations. To date, no regulations have been enacted that address additional security requirements for water licences. There is also no royalty or fee owed to the Crown for water usage. Having consulted with our Canadian legal advisers, we anticipate no issues or complications with obtaining the water licence nor any issues with the ongoing utilisation of this water source. Having consulted with our Canadian legal advisors, we also do not currently anticipate any issues relating to native land rights. For further information on water use and the regulatory procedures to be followed in applying for a water licence, please refer to the section entitled *"Laws and Regulations in the Industry — Laws and Regulations relating to Environmental Protection — Water use"* in this AIF.

As we have yet to commence SAGD operations, we currently do not require water for operations. We do not receive any government subsidies for water. In addition to our fresh water source, we are exploring saline water sources for long term operations that we have identified in the Devonian Leduc and Grosmont Formations. We are conducting drilling and water deliverability testing during the 2011/2012 winter season.

Natural Gas Source

We require natural gas to fuel our steam generators and to generate electricity to power our pumps and other prime movers for our SAGD processing. We intend to procure natural gas from Alberta's extensive and sophisticated network of natural gas delivery systems and suppliers. A main natural gas trunk line, operated by TransCanada Corporation, bisects the West Ells leases. We have draft delivery agreements with this supplier and distributor that contemplate delivery of the natural gas required for West Ells' steaming and power generation. As we have yet to commence SAGD operations, we have not yet entered into any long term supply contracts. We will be able to guarantee long term supply following the expansion of the local supply system and our entry into long term purchase contracts. We do not receive any government subsidies for natural gas.

Cogeneration of Power

We have worked with AMEC BDR to estimate facility costs and the feasibility of cogeneration. We plan to integrate cogeneration into all of our SAGD projects throughout their lives. Integrated natural gas driven cogeneration is more economic than purchasing electricity from the grid, and has fewer emissions than coal power generation. The cogeneration unit will also be tied into the system power line to sell surplus power to the grid when it is established in the project area. In addition, the system power line will provide the electricity backup for SAGD operations. As we have yet to commence SAGD operations, such operations are not currently tied into the electricity grid. We do not receive any government subsidies for electricity.

Over time, as commercial projects for bitumen extraction are established in the region, fixed power distribution lines, tied to the provincial power grid, will be constructed in the local area. Critical demand levels are required to trigger the utility company to allocate capital for new distribution regions. Alternatively, oil sands and other industrial operators are able to procure industrial distribution by paying capital charges up front. This alternative is not preferred as cogeneration is efficient for utility purposes and as the industrial grid expands, we will implement a business plan for sales of excess supply strategically.

Diluent Source

We do not intend to upgrade our bitumen, and will utilise condensate as a diluent. Prior to the installation of product and diluent pipelines, trucks will be used for transportation of volumes to and from the site. Trucks returning from the delivery of blended dilbit will be loaded with appropriate amounts of condensate diluent, which will be stored on site for use in the process and for blending of future production volume. The condensate will come from one of the various condensate hubs on Highway 63. Initial condensate will come from the Cheecham Terminal. Diluents for future project Phases will come from potential suppliers including but not limited to venders connected to the Enbridge pipeline, the Corridor pipeline and the Kinder Morgan pipeline as well as local suppliers such as Suncor Energy and CNRL. As we have yet to commence SAGD operations, we do not currently require diluent and we have not entered any long term supply agreements, although if we require diluent, we would be able to access diluent. Please refer to the section entitled *"Industry Overview"* in this AIF for more information.

Production Economics for Clastic Assets

Marketing of Bitumen Blend

We anticipate that our bitumen will be sold as a blend. Currently, the market for blend is strong and production from the Athabasca region is primarily sold to refineries in Canada, the Midwest (PADD II) and Rocky Mountains (PADD IV) in the United States. Our conventional heavy oil is typically priced off the Canadian benchmark crude known as Western Canadian Select, which is priced at Hardisty at a monthly floating differential to WTI. We expect our bitumen will be similarly priced. Our conventional heavy oil is sold in Hardisty, Alberta (the location of the terminal for the Athabasca pipeline owned and managed by Enbridge Inc., which transports bitumen derived from oil sands from Fort McMurray to Hardisty, and the hub for Enbridge Inc.'s main pipeline to Eastern Canada and the United States), which is a marketing node for the industry.

Revenue

The revenue that a producer ultimately receives for one barrel of bitumen production is derived from the price of bitumen blend, less transportation and diluent costs. The price for bitumen blend is benchmarked to conventional heavy oil at various locations, which in turn typically trades at a discount to light oil benchmarks such as WTI at Cushing, Oklahoma or Edmonton Par in Alberta owing to the increased processing associated with the refining of bitumen blends.

Bitumen revenue will be dependent on the cost of diluent and the blending ratio required to create bitumen blend. We are currently planning to use condensate as diluent at a ratio of 0.3 per barrel of condensate per barrel of bitumen for trucked volumes and a ratio 0.43 for pipeline volumes. The price per barrel of condensate varies depending on its quality attributes, although it typically trades at a price that is similar to WTI or Edmonton Par. The supply of condensate is currently adequate in the oil sands region and management expects to be able to source sufficient quantities to satisfy blending requirements for its planned bitumen production projects.

The table below illustrates how bitumen per barrel is calculated using GLJ's price estimates as at October 2011.

Estimated Long-Term Bitumen Pricing at West Ells (2011 Dollars)

(All amounts are expressed in \$/bbl, unless otherwise noted)	**Sensitivity Cases**		**Base Case**
U.S. Dollar WTI Price (US\$/bbl)	\$ 50.00	\$ 70.00	\$ 90.00
U.S. Dollar per Canadian Dollar Exchange Rate (US\$/\$)	0.98	0.98	0.98
Canadian Dollar WTI Price	51.02	71.43	91.84
Edmonton Par(1)	50.16	70.57	90.98
Heavy Oil Discount to Edmonton Par(2)	(9.78)	(13.76)	(17.74)
Bitumen Blend Quality Discount(3)	(1.16)	(1.16)	(1.16)

(All amounts are expressed in $/bbl, unless otherwise noted)	Sensitivity Cases		Base Case
Bitumen Blend Value at Hardisty	39.22	55.65	72.08
Transportation Costs	(1.38)	(1.38)	(1.38)
Bitumen Blend Value at SAGD Project Site	37.85	54.27	70.70
Cost of Diluent (30% of a Barrel of Bitumen Blend)(4)	(16.78)	(23.03)	(29.28)
Dry Bitumen Value at SAGD Project Site (70% of a Barrel of Bitumen)(4)	21.06	31.24	41.42
Dry Bitumen Value at SAGD Project Site (100% of a Barrel of Bitumen)(4)	30.10	44.65	59.19

Source: GLJ

Notes:

(1) The Edmonton Par price is a $0.86 discount to WTI for light, sweet 40 degree API gravity crude oil.

(2) Heavy oil discount assumes a 19.5% price discount for Lloydminster Blend heavy oil at Hardisty to Edmonton Par, based on the historical average over the period from January 1995 to November 2011. Having consulted with our independent reserves evaluators, our independent reserves evaluators have confirmed the calculations in this table and consider the assumptions to be reasonable.

(3) Bitumen blend quality discount is defined as the differential between West Ells and Legend Lake bitumen blend and Lloydminster Blend at Hardisty resulting from differences in density and sulphur content.

(4) Our management assumes Pentanes Plus (condensate) as a diluent is used for bitumen blending purposes over the long-term. The resulting diluted bitumen (dilbit) product price assumes Pentanes Plus (condensate) price is a 2.0% premium over the Edmonton Par price with an additional premium of $4.73/bbl at the project site, which is inclusive of transportation costs. One barrel of the dilbit blend is composed of 30% condensate and 70% bitumen (0.43 barrel of condensate per barrel of bitumen). Our management anticipates that during the initial production Phase at West Ells the dilbit product will be trucked which will allow for a lower blending ratio of 23.0% during this phase. Management further anticipates that later in the project life a third party pipeline will be constructed and the blending ratio will increase to 30% at that time.

(5) GLJ's long-term price forecasts for our West Ells and Legend Lake properties as at October 1, 2011.

Royalties

Alberta requires royalties be paid on the production of natural resources from lands for which it owns the mineral rights. The Government of Alberta's royalty share from oil sands production is price-sensitive. The royalty range applicable to price sensitivities changes depending on whether the project's status is pre-payout or post-payout. "Payout" is 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. The base pre-payout royalty starts at 1% of gross revenue 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 post-payout royalty is based on net revenue – it 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 is $120 per barrel or higher. Specified capital and operating costs may be deducted to arrive at net revenue for this calculation. For further information, please refer to the section entitled *"Laws and Regulations"* in this AIF.

Customers and Suppliers

Customers

For the year ended December 31, 2009, we had no customers. For the years ended December 31, 2010 and 2011, we only had one customer. Sales made to our customer for the year ended December 31, 2010 and 2011 amounted to $0.5 million and $10.3 million, respectively, and accounted for all of our total pre-production revenue, which has been capitalised against our qualifying assets.

Our only customer is Legacy, a Canadian intermediate oil and natural gas company, which purchases and processes the conventional heavy oil that we produce at Muskwa for sale to the market. Legacy has been a customer of ours since September 2010, when it took over Bronco Energy Ltd., our customer since May 2010. We have been in discussions with other customers for the sale of our conventional heavy oil and our bitumen products in the future. We have no signed contracts for sales volume currently in place, nor does management expect to enter into any such agreements in the next 18 month period. Bitumen and heavy oil are oil commodity products with high demand and we do not expect any problems with selling its product. This strategy is considered by management to be normal course of business within the oil and gas industry in Canada.

Suppliers

During the Track Record Period we have engaged a number of different suppliers. These have primarily included suppliers of drilling services, construction, haulage, forest clearance, seismic and other land surveys in relation to our operations. For the year ended December 31, 2011, our largest suppliers were Trinidad Drilling Ltd., Weatherford Canada Partnership, Titan Drilling LLC, Northwell Oilfield Hauling Ltd. and Peak Energy Services Partnership owing to their involvement in the construction and drilling at our Muskwa site. In previous years, professional service firms such as McCarthy Tétrault LLP, Deloitte & Touche LLP, GLJ Petroleum Consultants Limited and DeGolyer & McNaughton Canada Limited are also significant service providers to Sunshine.

None of our Directors, senior management, their associates, or any Shareholders holding more than 5% of our issued share capital held any interest in any of our five largest suppliers or our five largest customers for the three years ended December 31, 2011.

Memorandum of Understanding for Strategic Cooperation with SIPC

We entered into a non-binding MOU in February 2012 with SIPC, a wholly owned subsidiary of Sinopec, with a view to forming a strategic alliance and to carry out strategic cooperation. Sinopec is one of the major state owned petroleum and petrochemical groups in China. The parties intend to examine opportunities for joint participation in the development, exploration and production of oil sands leases, as well as other mutually agreed investments and projects in Canada and globally. SIPC is a wholly owned subsidiary and integrated strategic business unit of Sinopec that is engaged in overseas oil and gas exploration and production investments and business operations, as well as carrying out Sinopec's overseas upstream investments and operations. One of Sunshine's strategies is to work closely with multinationals in areas such as logistics, procurement, construction, technology and financing in order to increase our production through joint exploration and development activities. We believe that a relationship with SIPC will assist in the implementation of this strategy.

However, at the present time, no specific details in relation to joint cooperation projects, the form and funding of any investments or their timing have been agreed between the Corporation and SIPC, nor have any such projects arisen.

Under the terms of the MOU, SIPC and Sunshine will, on a non-binding basis:

- mutually examine opportunities for joint participation in the exploration and development of oil sands leases;
- discuss opportunities for joint participation in our carbonate assets, including carrying out a joint experimental project;
- mutually examine opportunities for joint purchases of oils sands leases in Canada and globally; and
- give notice to each other of any future oil and gas exploration projects outside Canada, which have the potential to be developed by the SIPC and Sunshine on a joint basis.

We will commence the negotiation of a more formal strategic cooperation agreement with SIPC over the next few months and we have formed a strategic cooperation steering committee ("**SCSC**") and a working group to assist in the implementation of the strategic alliance. The SCSC shall meet quarterly and comprise representatives from both SIPC and Sunshine. The SCSC will also supervise the working group, which will be responsible for analysing and implementing specific cooperation projects.

The MOU is non-binding and terminates on December 31, 2013, unless such term is extended by the parties mutual agreement in writing.

Environmental, Community and Stakeholder Protection

Environmental Impact of Our Operations

Our operations have the potential to impact the environment and are required to comply with a wide variety of provincial and federal environmental laws and regulations protections. In particular, our operations can contribute towards the pollution of the air, land and water systems.

All of our bitumen resources are, and will be, recoverable through *in-situ* techniques. Primarily this will be by SAGD extraction, where steam is injected through wells into bitumen bearing formations to reduce the bitumen's viscosity and then pumped to the surface, as opposed to oil sands mining. SAGD operations do not require tailing ponds. Reclamation of land use areas for SAGD operations amounts to a fraction of the cost when compared to mining operations. SAGD operations use less water than mining operations as a SAGD self contained water treatment process will recycle up to 97% of facility water requirements, and SAGD GHG emissions are only slightly higher than other crude oil processes, but have seen reductions as strategies, actions and approaches have been developed and will continue to be developed to reduce GHG emissions.

In terms of our existing operations, we are actively pursuing the continuous improvement of air quality and GHG emissions at our Muskwa operations by improving energy conservation and efficiency, quantifying our fugitive emissions to reduce our emission intensity and adopting innovative technology for emission reduction. Further, as part of the preparation for our West Ells application, we commissioned an environmental study from Millennium EMS Solutions Ltd. to quantify the overall impact of our operations at West Ells on the environment, including the predicted impact on air quality, hydrogeology, hydrology, aquatic resources, soils, wildlife and an assessment of our conservation and reclamation plan. Having consulted with Millennium EMS Solutions Ltd., our proposed operations appear to be within the environmental guidelines laid down by the AEW and the federal regulators.

Air

Since little waste is normally generated by SAGD facilities, as compared to oil sands mining, the main environmental issue is air pollution. Air quality standards in Alberta are strict and the oil sands region is the one of the most intensely monitored airsheds in North America. The AEW has developed Ambient Air Quality Objectives to manage air quality and to quantify the desired environmental quality, which are based on an evaluation of scientific, social, technical, and economic factors. The LARP also contains the air quality management framework, which sets out regional thresholds and limits for NO_2 and SO_2 emissions which will impact the cumulative operations of all operators within the lower Athabasca region. All industrial facilities must be designed and operated such that the ambient air quality remains below the levels specified in the Ambient Air Quality Objectives and the air quality management framework.

Air pollution is normally measured and quantified by the existence of four key pollutants: nitrogen dioxide, sulphur dioxide, carbon monoxide and PM 2.5 (particulate matter less than 2.5 microns in diameter). Nitrogen dioxide, sulphur dioxide, carbon monoxide are all by-products of combustion and PM 2.5 is a measure of the amount of particulate matter, or "soot", that is discharged into the air following combustion. Each of these pollutants can be produced through the operation of our production facilities and are primarily created through fuel consumption in plant facilities and vehicles.

Millennium EMS Solutions Ltd.'s environmental report predicted that the levels of pollutants produced by our West Ells facility would remain within the air quality standards imposed by the AEW. Our Muskwa project will be subject to a baseline emission survey during the first quarter of 2012 to confirm that emissions at our Muskwa site are within the environmental guidelines laid down by the AEW. At Muskwa, we have ordered a VRU to collect venting emissions around our separation tanks, which we anticipate will be operational in the first quarter of 2012. This collects and reuses energy from emissions for tank burners and other heat units and will assist in reducing our overall GHG's from Muskwa.

Within our operations, systems are in place to ensure that facilities are designed and operated to meet or surpass ambient air quality standards. We participate in the air shed monitoring throughout our oil sands development locations. Our environmental strategies target corporate standards, operations compliance, energy efficiency, liability reduction, air emissions and GHG management. They also target incident response, water quality management, reduction of fresh water use on our planned developments, and minimising our landscape footprint. We are developing strategies to consider life cycle costs of emission reductions in all our project developments and we are looking to reduce the potential impacts of new facilities at the planning stage, as well as reviewing state-of-art low emission technologies.

Water

Our SAGD operations are not expected to have a material impact on ground water or surface water. Conventional heavy oil mining or bitumen mining operations require large multi-hectare tailings ponds that may have a larger impact on ground water or surface water aquatic ecosystems than SAGD operations, although none of our operations utilise these extraction techniques.

Our Conventional heavy oil operations in the Muskwa area do not require or impact any ground water or surface water for operations. The extraction of conventional heavy oil at Muskwa does produce "unusable" water, which is monitored and measured on a daily basis. This amount of "unusable produced water" can vary from to 2% to 40% of total production per day from each well. This produced water is disposed of as per regulatory requirements.

SAGD production utilises large amounts of water, and approximately 60-80% of the volume of a unit of emulsion produced is water. However, approximately 90% to 97% of this water will be recycled. In the long term we anticipate utilising brackish water for process water, which will enable us to recycle over 90% of the water. This water source will be identified through a Devonian drilling programme. The brackish water will be run through a cleanup process that will remove the particles and dissolved solids, making it acceptable as boiler feed water. We also anticipate that 97% of this process water could be recycled before losses, as it passes through a full cycle of boiler feed water. This process involves its conversion to steam, injection as steam to the reservoir, conversion to associated water in the reservoir production, separation and finally clean up prior to being reintroduced to the boiler feed water stream.

We intend to comply with new and emerging water use requirements including these set out in the Joint ERCB/AEW Draft Directive entitled Requirements for Water Measurement, Reporting, and Use for Thermal *In-situ* Oil Sands Schemes.

Land

Preparing sites for our operations requires forestry clearance and well pad preparation. As part of each regulatory application that we make, our projects must implement a reclamation plan to return the specified lands to an equivalent land capability in order to achieve a sustainable landscape similar to its pre-development state. For *in-situ* projects, yearly pre-disturbance assessment, conservation and reclamation plans must be submitted for approval. We intend to comply with all applicable environmental laws and regulations at our production sites.

Regulatory Clearances and Control Measures

The AEW approved our West Ells application on February 10, 2012 and confirmed that the project meets the required environmental standards. We intend to remain in compliance in all material respects with all ongoing monitoring and reporting obligations imposed by ERCB and AEW, as well as all environmental regulatory requirements. We believe that our existing operations are currently in material compliance with all applicable environmental laws and regulations.

We will monitor our SAGD operations to ensure that they comply with all applicable environmental laws, regulations and standards through the following control measures:

- Continuous air quality monitoring at several monitoring stations positioned downwind from the facilities, based on prevailing wind directions.

- Sampling of surface and ground water to be taken quarterly and analysed to ensure there is no variation from the baseline measurements of regulated water quality parameters.

- Annual surface casing vent flow checks on all wells to ensure there is no potential for wellbore fluids to migrate through the wellbore into water-bearing sands up-hole from our zone of interest.

- Casing integrity logging and pressure testing while wells are being serviced.

- Best-in-class drilling, completion, and operating procedures to ensure the number of thermal cycles wells are exposed to is limited, and that when cycles do occur we have casing and cement in place that can withstand the associated stresses.

- Formal communications with AEW and ERCB will be handled through our land and regulatory affairs department (with the exception of volumetric reporting and well service activities, which will be handled through our finance and production engineering departments, respectively.

Environmental Planning and Regulatory Applications

Each application that we make for a project requires an environmental impact assessment to be submitted to the ERCB and AEW for approval. When submitting regulatory applications for production sites, our capital plan includes estimates for required processes and equipment to ensure that all standards for environmental protection are met. This includes air, water and soil effluents. The environmental aspects in the West Ells plant area will be defined through the application process. These aspects are broadly characterised as water, air, fish, wildlife, noise and flora. The application process clearly identifies these critical aspects and generates mitigation plans to prevent or minimise impact.

Compliance Costs

During the Track Record Period, no costs have been incurred for compliance with applicable environmental laws and regulations. The Corporation's regulatory compliance fixed operating cost covers air, ground, water and environmental monitoring and miscellaneous studies required for regulatory compliance (including engineering costs). The expected cost of compliance going forward as SAGD Commercial Facilities become operational will be approximately \$0.05 – \$0.06 per bbl. This cost does not include carbon tax operating costs.

Community and Stakeholder Matters

In the Athabasca region key stakeholders include First Nations communities and holders of traditional traplines. We respect the history, heritage and culture of the First Nations communities in the Athabasca region and seek to engage and consult with these stakeholders on a regular basis. Our engagements with stakeholders build relationships in an open, transparent manner with regard to our proposed or existing activities. We proactively seek input into the design of the engagement process at the outset to ensure that communication and consultation needs are met. In adhering to our legal consultation obligations, we are respectful of legal rights, meet existing industry precedents during engagement activities, and seek out creative social investment opportunities in local communities to create mutually beneficial solutions with long-term value for the Corporation and the stakeholders.

Prior to the launch of any project, we will consult stakeholders, including members of the public, regulatory bodies and aboriginal communities who are, or may be, affected by proposed exploration and/or development activities. We will seek to ensure that a transparent, and respectful relationship is built and maintained with neighbours and stakeholders throughout the project region and encourages input into the design of the project.

Labour and Safety Matters

We operate in a responsible manner to ensure the health and safety of our employees, contractors and the communities in which we operate. We are committed to meeting applicable legal requirements and where possible seek to implement leading international industry standards in our operations. Our commitment to occupational health and safety extends directly to our Board of Directors.

We require our contractors to possess appropriate qualifications in their contracted tasks and in production safety. In addition, we require our contractors to enter into production safety contracts with us pursuant to which our contractors shall undertake appropriate safety measures.

We are subject to Alberta health and safety laws and regulations including the *Occupational Health and Safety Act* (OHSA), *Occupational Health and Safety Regulation* (OHSR) and *Occupational Health and Safety Code* (OHSC). The OHSA sets standards to protect and promote the health and safety of workers throughout Alberta. The OHSR addresses the requirements related to government policy and administrative matters. The OHSC specifies all the mandatory technical standards and safety rules that employers and workers have to comply with to fulfil their obligations. The OHSC covers areas such as general safety, noise, chemical hazards and first aid.

The OHSA, the OHSR and the OHSC are enforced by occupational health and safety officers from the workplace, health and safety section of the Alberta Department of Employment and Immigration.

We believe that we are currently in material compliance with all relevant occupational health and safety laws and regulations applicable to our business. As of the date hereof, the Muskwa project had not had any major or catastrophic incidents related to the health or safety of our employees, contractors or communities in which it operates.

Properties

Our total property interests comprised approximately 19.5% of our total assets as at December 31, 2011. Calculated on the same basis, the value of our most valuable property is equal to approximately 4.5% of our total assets as at December 31, 2011.

INDUSTRY CONDITIONS

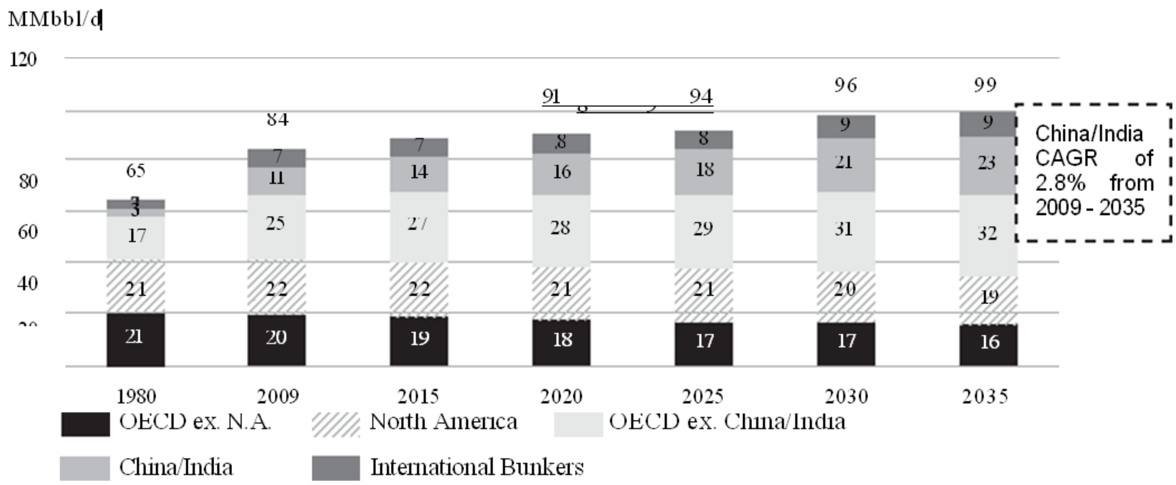
Both the Canadian and international oil industry are highly competitive. Oil producers compete with each other in a number of areas, including in attracting and retaining experienced and skilled management personnel and oil and gas professionals, the procurement of equipment for the extraction of bitumen, access to capital markets, the exploration for, and the development of, new sources of supply, the acquisition of oil interests, the distribution and marketing of petroleum products, and the obtainability of sufficient pipeline and other means of transportation. Sunshine will directly compete with other producers of bitumen, bitumen blends, synthetic crude oil and conventional crude oil. Some of these competitors may have lower costs and greater financial and other resources than Sunshine. A number of competitors have significantly longer operating histories and have more widely recognised brand names, which could give such competitors advantages in attracting customers and employees.

Unless otherwise specified, all of the information, data and statistics set out in this section have been extracted from various official government publications, private publications and industry sources. We believe that the sources of this information are appropriate sources for such information and have taken reasonable care in extracting and reproducing such information. We have no reason to believe that such information is false or misleading or that any fact has been omitted that would render such information false or misleading. The information has not been independently verified by us and no representation is given as to its accuracy or completeness.

Supply and Demand in Global Oil Markets

According to the BP Statistical Review of World Energy 2011 ("**BP Statistical Review**"), worldwide demand for oil in 2010 was 87 MMbbl/d, and approximately 53% of the total was consumed in OECD nations. Of that, approximately 22% was consumed within the United States, which is the world's single largest oil market. According to the International Energy Agency, world demand for oil is expected to grow to 99 MMbbl/d by 2035, with a significant portion of this growth expected to come from non-OECD countries such as China and India, which will account for approximately 23% of total demand in 2035. North America is also projected to remain a material consumer of oil, representing approximately 20% of total demand in 2035.

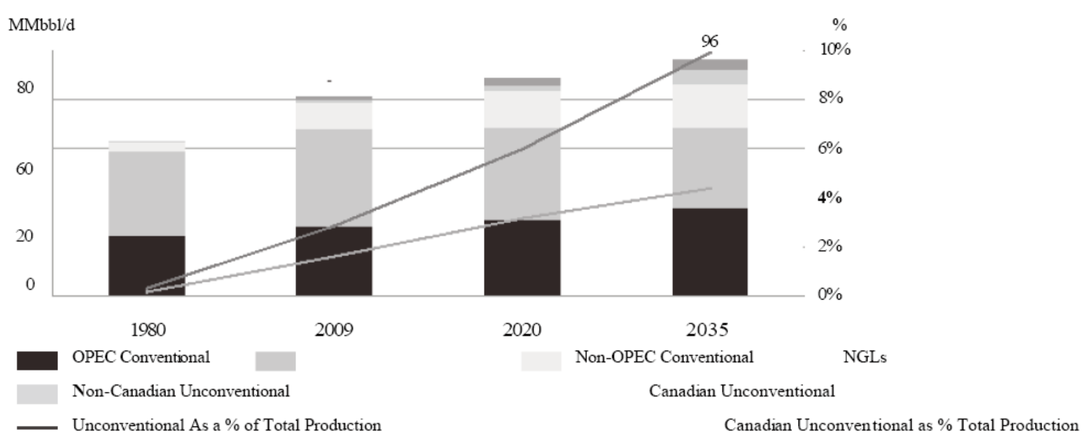
Primary Oil Demand By Region (1980 – 2035)



***Source** IEA, World Energy Outlook 2010*

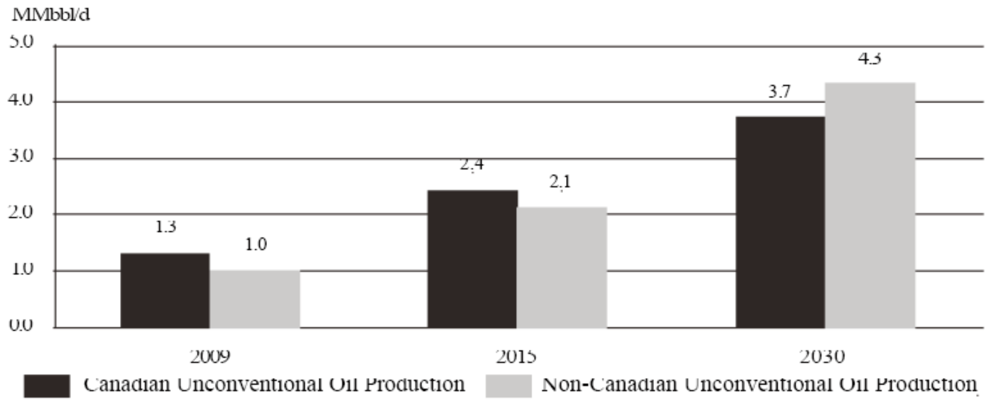
The IEA estimates that approximately one-third of the world's ultimately recoverable conventional oil resources have already been produced. By 2035, it is expected that over one-half of the world's ultimately recoverable conventional oil resources will have been produced. Non-OPEC conventional production is not expected to be sufficient to keep pace with growing demand. As a result, in order to meet projected demand, global oil production is expected to undergo a transition towards increased reliance on OPEC production and unconventional sources of crude oil (predominantly from extra heavy oil and bitumen). Specifically, growth in the production of unconventional oil is expected to contribute significantly to global oil production growth. Production from Canada's oil sands is expected to be a meaningful contributor to this growth. In 2009, approximately 2.3 MMbbl/d (2.8% of the total) of global oil production was classified as unconventional and approximately 1.3 MMbbl/d of this represented production from Canada's oil sands. By 2035, unconventional oil production of approximately 9.5 MMbbl/d is expected to account for 9.9% of global production, and production from Canada's oil sands is expected to contribute approximately 4.2 MMbbl/d, representing a growth rate of 4.6% annually during that period.

Oil Production By Region (1980 –2035)



***Source** IEA, World Energy Outlook 2010*

Unconventional Oil Production(1)(2)



Source: IEA, World Energy Outlook 2010

Notes:

(1) "Unconventional Oil" means extra heavy oil (including extra heavy oil secured from Venezuela), natural bitumen derived from oil sands, chemical additives, gas-to-liquids and coal-to-liquids (and excluding biofuels)

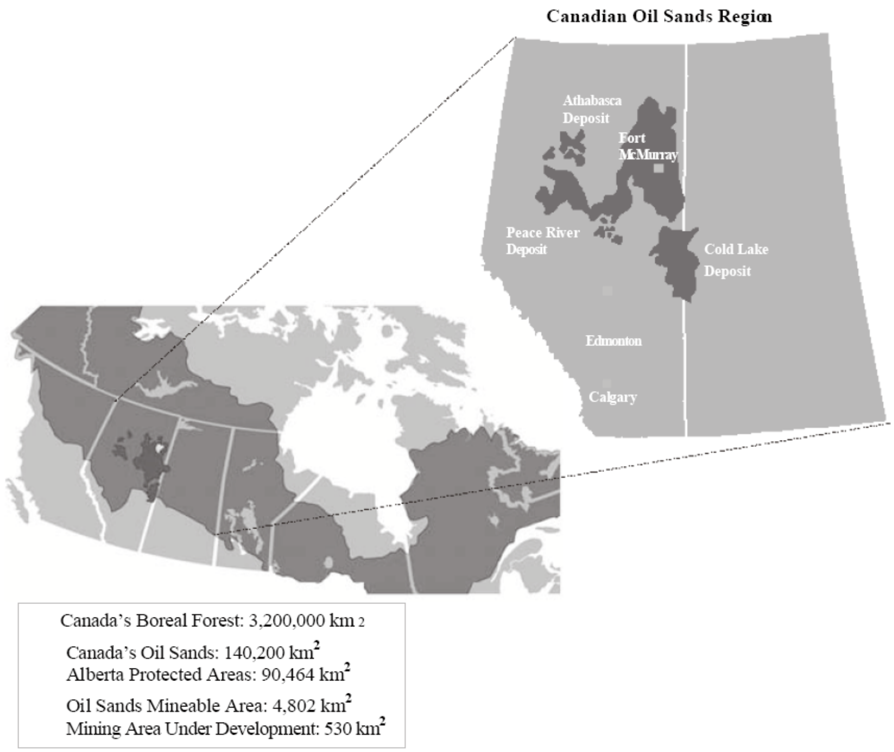
Canadian Conventional Heavy Oil

Canadian conventional heavy oil is generally defined as crude oil that is found in a liquid state in the ground, has the ability to flow into a wellbore, has a specific gravity of less than or equal to 20° API and is comprised of up to approximately 5% sulphur (depending on the heavy oil type). It is heavier and more sour than West Texas Intermediate, which has a specific gravity of 39° API with 0.34% sulphur. Heavy oil in Canada is produced through relatively shallow wells (depths of 350-1,000 metres) found mainly in the Heavy Oil Belt straddling the Alberta-Saskatchewan border, and in areas to the west and southwest of the Cold Lake oil sands deposit. Conventional heavy oil generally sells at a discount to light oil, reflecting the relative market value of the end products to refineries. At the end of 2010, conventional heavy oil accounted for approximately 13% of total Canadian oil production. According to the NEB, Canadian conventional heavy crude deposits are estimated to contain 470 MMbbl of petroleum-initially-in-place that are recoverable with known technology.

Heavy oil recovery methods include primary production, cold enhanced oil recovery and thermal production. The selection of these methods generally depends on factors such as the stage of production, formation and fluid properties, reservoir geology and available production and transportation facilities. Primary recovery is the first stage of heavy oil production in which natural reservoir energy, such as gravity drainage, displaces the oil from the reservoir into the wellbore and is pumped to the surface. As reservoir pressure drops, artificial lift systems must be used to recover oil. CHOPS is a primary recovery technique involving the continuous production of sand to improve the recovery of heavy oil from the reservoir. Cold EOR is the recovery of heavy oil using non-thermal methods including production from horizontal and multilateral wells with water, solvent and gas injection. Waterflooding is the most common EOR approach, which involves the injection of water to displace heavy oil. Thermal methods typically involve the injection of steam or hot water into the reservoir to improve the mobility of the heavy oil and provide a displacement mechanism. Of the three methods, thermal provides the highest recovery factors, but also results in the largest potential capital expenditures and operating costs.

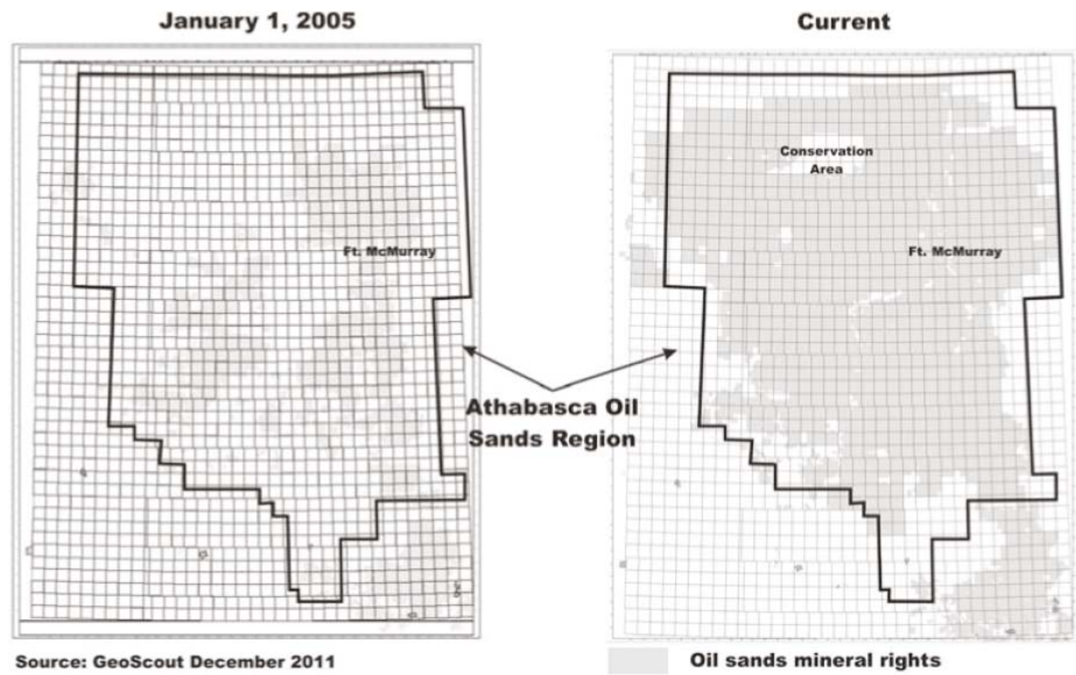
Overview of Canada's Oil Sands

Canada's three main oil sands deposits are located in the Athabasca, Peace River and Cold Lake areas in Alberta. According to the Department of Energy, these deposits underlie a total land base of approximately 14,020,124 hectares (140,200 square kilometres) in northern Alberta. The Athabasca region is the largest area, representing approximately 66% of the total Alberta oil sands land. According to the Department of Energy, 70% of the Athabasca region is currently under lease.



The Government of Alberta owns 97% of all oil sands mineral rights, and freehold owners hold the remaining 3%. The Department of Energy manages Crown-owned mineral rights on behalf of the citizens of the province. The majority of Oil Sands Leases are issued through public offerings commonly referred to as land sales. In land sales, the Crown sells the right to the minerals associated with a particular piece of land for a set term in exchange for a bonus payment, a one-time fee of $625, a rental fee for the first year of the agreement, calculated at the rate of $3.50 per hectare or a minimum amount of $50.00, and a royalty on recovered minerals. Oil sands rights are leased to the highest bidder. Oil Sands Lease types and terms have been standardised under two categories: primary leases, which are issued for a standard term of 15 years, and continued leases, which are extensions of primary leases and are classified as producing or non-producing. Oil Sands Leases are continued, or extended for an indefinite period, if a minimum level of evaluation at the relevant property is established under the *Oil Sands Tenure Regulation*. Minimum level criteria is based on a set amount of drilling and seismic work completed on the land prior to application for lease continuation. If leaseholders do not apply for continuation, the lease will expire. Oil Sands Permits are alternatives to leases, which are issued for terms of five years. Permit holders who have evaluated and proved up the land to an established minimal level may apply for lease selection at the end of their permit terms. The Department of Energy allows applicants to choose whether they wish to post a permit or a lease agreement. Since 2005, the oil sands sector has witnessed a significant influx of new entrants acquiring high quality lease positions, specifically in the Athabasca region. For more information, please refer to the section entitled *"Laws and Regulations in the Industry — Laws and Regulations Relating to Land"* in this AIF. The increase in activity over the last several years has left a small amount remaining of high quality Oil Sands Lease positions as seen in the maps below.

Oil Sands Mineral Rights in the Athabasca Region



Canada's oil sands contain crude deposits that are substantially heavier and more viscous than conventional crude oils. Oil sands are composed primarily of sand, clay, bitumen and water. Bitumen, like heavy crude oil, is a complex mixture of hydrocarbon components. It has a high content of carbon relative to hydrogen compared to conventional light crude oil. At room temperature, bitumen is viscous and therefore not suitable for transportation by pipeline. In order to become transportable and marketable, bitumen is processed into two principal forms: either as a bitumen blend, wherein bitumen is mixed with a diluent so that it can be transported through pipelines, or as an SCO, which is the resulting product after raw bitumen has been upgraded.

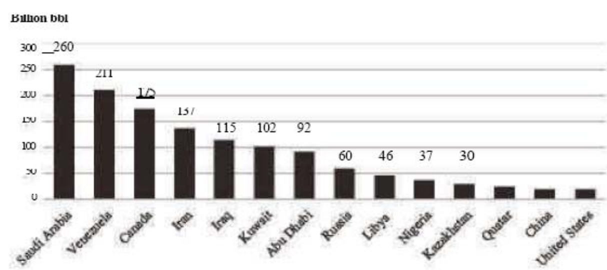
Bitumen resources in the oil sands are known to be contained in two distinct types of formations, clastics and carbonates. Clastics sediments form the largest portion of the reservoirs which are currently producing bitumen and heavy oil. Clastic reservoir systems are formed through the deposition of rock fragments by moving fluids in a variety of fluvial systems, such as rivers, deltas, shorelines and estuaries. Clastics are the formations from which all current commercial bitumen production in Alberta is derived. Clastic reservoir systems are formed through the sedimentation of rock fragments and are the product of sedimentary disposition at the cut-banks, beds and mouths of prehistoric rivers. In Alberta's case, these were formed in the Cretaceous period. Well-known clastic formations in the Alberta oil sands include layers such as the Wabiskaw and McMurray Formations, which are located between 150m and 450m below the surface. The benefit of extracting from a clastic reservoir is that permeability and porosity are largely predictable. Examples of common clastic sedimentary rocks include siliciclastic rocks such as conglomerate, sandstone, siltstone and shale. "Carbonate" means a class of sedimentary rock whose chief mineral constituents (95% or more) are calcite, aragonite and dolomite. Carbonates are the product of prehistoric coral reefs from the Devonian Period. Carbonate rocks are common hydrocarbon reservoirs, and contain more than 60% of the world's proved oil reserves. However, because of the unique technical challenges involved in the production of bitumen from carbonate reservoirs, there is currently no commercial production from bitumen-bearing carbonate formations in Alberta. One of the major challenges facing companies trying to extract bitumen from carbonate reservoirs is that the permeability and porosity of the rock tends to be very complex and difficult to predict. Despite the challenges, there are several ongoing early stage initiatives being undertaken by numerous industry participants.

Laricina recently achieved Canada's first successful carbonate SAGD results at its Saleski pilot project in northern Alberta. The Saleski pilot project is targeting carbonates from the Grosmont Formation. Laricina began injecting steam at Saleski in December 2010 with intentions of reaching targeted production rates of 1,800 bbl/d. Concurrently in

December 2010, Laricina submitted a regulatory application for its first commercial expansion phase at Saleski of 10,700 bbl/d, with start-up anticipated in 2013. Other companies targeting bitumen production from carbonates include AOSC, Husky Energy Inc., Osum Oil Sands Corp., Shell Canada Limited and our Company.

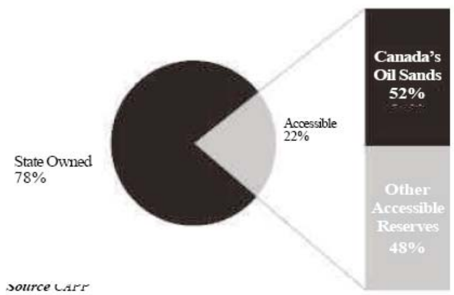
According to the Oil & Gas Journal, Canada currently ranks third behind Saudi Arabia and Venezuela in terms of proved world crude oil reserves, with the majority of Canada's reserves attributable to oil sands. The ERCB estimates that approximately 169 billion bbls of bitumen are remaining established reserves that can be recovered using current technology, and that up to 315 billion bbls may ultimately be recoverable. Not included in this estimate are bitumen volumes found in carbonate formations. The ERCB estimates that there are over 400 billion bbls of bitumen resources in place in carbonate formations in Canada's oil sands.

Estimated World Crude Oil Proved Reserves



Source Oil & Gas Journal (December 2010)

World Oil Reserves

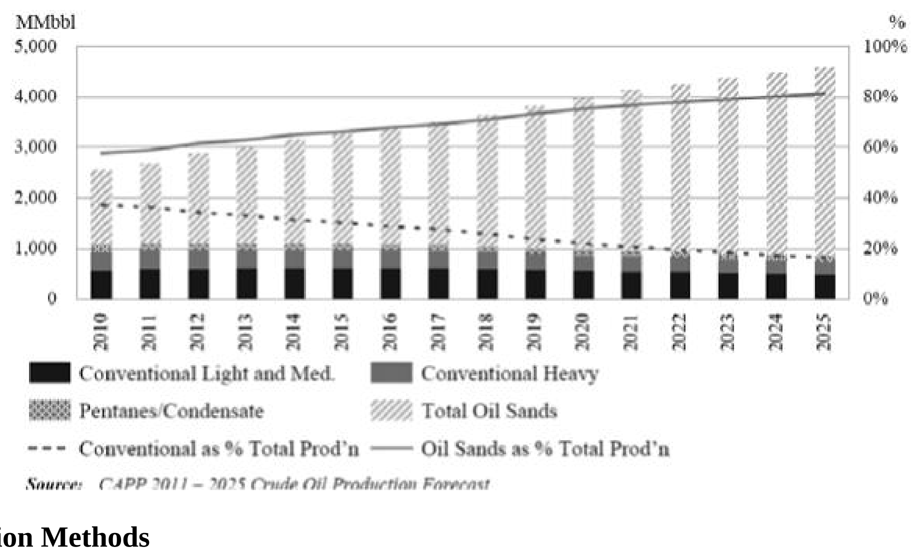


Source CAPP

Current and Projected Oil Sands Production

Companies have been producing from Canada's oil sands since the 1960s. According to the CAPP, 2010 oil sands production of 1.5 MMbbl accounted for 52% of Canadian crude oil output. By 2015, oil sands production is expected to grow to 62% of total Canadian crude oil output and 16% of total North American crude oil output. The CAPP estimates based on announced projects indicate the potential for oil sands production to increase to approximately 2.2 MMbbl in 2015 and up to 3.7 MMbbl in 2025. The expected increase in oil sands production is anticipated to occur over a period in which conventional oil production in Canada declines. Current production estimates from oil sands do not account for potential growth from bitumen bearing carbonate formations given the absence of commercial activity to-date.

Canadian Oil Production (2010-2025)



Source: CAPP 2011 – 2025 Crude Oil Production Forecast

Oil Sands Production Methods

There are two general types of oil sands production methods. Bitumen resource is extracted from oil sands reservoirs using either thermal methods or surface mining. Bitumen extraction using thermal methods is referred to as *in-situ*, or "in place" recovery. The determination of whether surface mining or *in-situ* recovery is appropriate is dependent primarily upon the depth of the reservoir. In most cases, if a particular reservoir is more than approximately 75 metres deep, oil sands are extracted utilising a form of the *in-situ* method. The ERCB estimated in 2010 that approximately 80% of the total bitumen ultimately recoverable in Canada will be recovered using *in-situ* techniques. In contrast, if the targeted reservoir is less than approximately 75 metres deep, oil sands are typically extracted using open pit surface mining operations.

Surface Mining

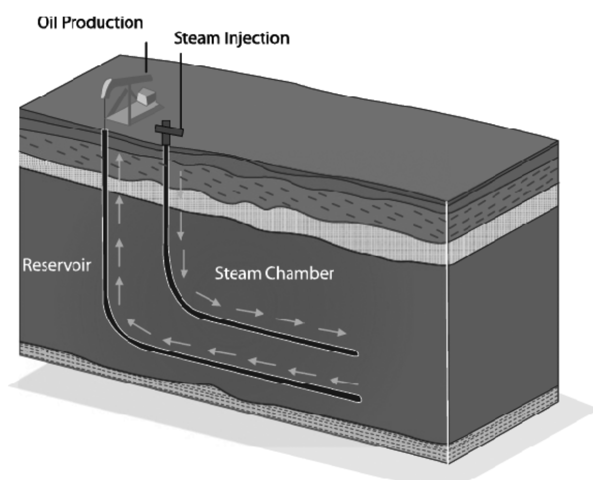
In 2010, the ERCB estimated that approximately 20% of the total bitumen recoverable in Alberta was suitable for surface mining methods. Original oil sands mining techniques employed the use of draglines and bucket wheel excavators which transported sand and bitumen to processing facilities by conveyor belts. However, it is now more common, and more economic, to use power shovels and large dump trucks to perform similar operations. Oil sands surface mining operations produce tailings ponds containing a mixture of water, sand, clay, and bitumen, which are ultimately reclaimed. Tailings ponds are required to settle the fine particles remaining in the water following the separation of bitumen in the mining process.

***In-situ* Recovery (Thermal Production Methods)**

In-situ production methods currently in commercial use apply heat to targeted reservoirs to decrease the viscosity of bitumen, which allows it to flow into wells and be pumped to the surface. *In-situ* recovery methods create significantly less surface disturbance than mining operations and do not produce tailings ponds. The two *in-situ* production methods currently in commercial use are SAGD and CSS. The determination as to whether SAGD or CSS is employed is dependent upon various reservoir characteristics.

Steam Assisted Gravity Drainage

The SAGD process was developed in the 1970s and was first tested in the Athabasca oil sands region in the 1980s. With the advent of horizontal well technology in the 1980s, well pairs could be drilled from the surface similar to how wells are drilled for conventional enhanced oil operations. In SAGD operations, two horizontal wells are drilled into the targeted reservoir, one near the bottom of the formation and a second approximately five metres above it. The wells are typically drilled in groups from central pads and can extend over one km horizontally from the surface location. In each well pair, steam is injected into the upper well bore and heat from the steam reduces viscosity of the bitumen allowing it to flow into the lower well bore where it is lifted to the surface. The ERCB indicates typical SAGD recovery factors of 40-50% and experienced SAGD operators, like Suncor Energy, report recovery factors of up to 60%.



The commercialisation of SAGD has occurred through the development of numerous projects since the late 1990s. Development and refinement of directional drilling techniques has led to an increase in SAGD use in the oil sands, as wells have become more accurate, less expensive to drill, and more efficient to operate. Additionally, the ongoing evolution of technology continues to drive significant improvements in recovery rates and cost efficiency levels.

Producing SAGD Projects in Alberta Oil Sands

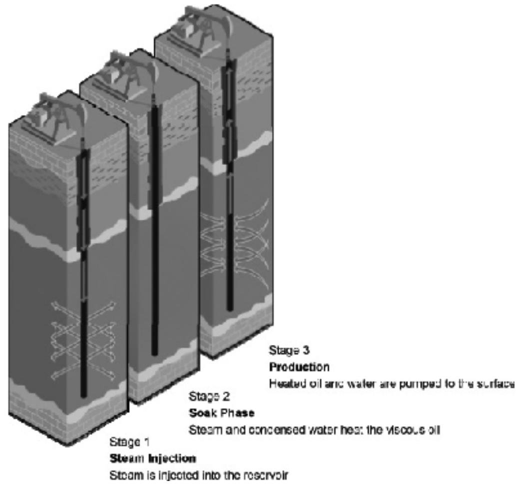
Project	Operator	Capacity	Start-up
		bbl/d	
Foster Creek (Phases 1A - 1E + debottleneck)	Cenovus	120,000	2001
Firebag (Phases 1-3 + cogeneration & expansion)	Suncor Energy	157,500	2004
Long Lake (Phase 1)	Nexen	72,000	2008
Jackfish (Phase 1-2)	Devon Canada	70,000	2007
MacKay River (Phase 1)	Suncor Energy	33,000	2002
Tucker (Phase 1)	Husky Energy	30,000	2006
Surmont (Phase 1 + Pilot)	Conoco	28,200	1997
Christina Lake (Phase 1-2)	MEG	25,000	2008
Great Divide (Pod 1 + Pod 2)	Connacher	20,000	2007
Christina Lake (Phases A-C)	Cenovus	58,800	2002
Orion (Phase 1)	BR Oil Sands (Shell)	10,000	2007
Hangingstone (Pilot)	JACOS	11,000	1999
Kai Kos Dehseh (Pilot)	Statoil Canada	18,750	2010

Source: Government of Alberta, Alberta Oil Sands Industry Quarterly Update (Winter 2011)

SAGD producers have been continuing to optimise operations and enhance project economics through the incorporation of evolutionary process improvements. Some of these improvements involve the enhancement of proven processes and technologies, such as the injection of steam additives into reservoirs in order to increase bitumen recovery factors and reduce natural gas requirements. Some methods are based on different technology than SAGD, such as high-pressure air injection and electrical conduction heating. Other evolving process improvements involve the utilisation of alternate well configurations in order to improve bitumen sweep efficiency and bitumen recovery factors, including “infill wells”, which are infill horizontal wells drilled between established, producing SAGD well pairs. Industry experts continue to study and test technologies focused on improving recovery efficiency late in the *in-situ* process. Please refer to the section entitled *“Overview of Canada’s Oil Sands - Oil Sands in-situ Recovery Technologies”* in this AIF.

Cyclic Steam Stimulation

CSS has been employed commercially in Alberta since the 1980s. Pioneered by Imperial Oil Limited at Cold Lake, several other key industry participants are producing from commercial CSS projects in Alberta, including Canadian Natural Resources Limited at Primrose and Wolf Lake and Shell Canada Limited at Peace River. The CSS process involves high pressure, high temperature steam being injected into a single well which acts as both the injection well and the production well. The steam is allowed to soak the reservoir for a period of time sufficient to reduce the viscosity of the bitumen. Upon reaching a viscosity that will allow the bitumen to flow and be pumped, the wells are switched from steam to production mode to allow bitumen to be pumped out of the well for a period of months. Once production falls below a predetermined target level, the cycle is repeated. This multi-stage process normally involves several weeks of initial steaming, followed by several weeks of reservoir soaking, and finally ending with an extended production phase. CSS can be completed through vertical, deviated, or horizontal wells. The CSS method has historically achieved lower recovery factors than the SAGD method. Recovery factors achieved using the CSS method are typically 20% to 30%.



Producing CSS Projects in Alberta Oil Sands

Project	Operator	Capacity bbl/d	Start-up
Cold Lake (Phases 1-10)	Imperial Oil	110,000	1985
Primrose South	Canadian Natural Resources	45,000	1985
Primrose East (Burnt Lake)	Canadian Natural Resources	32,000	2008
Primrose North	Canadian Natural Resources	30,000	2006
Cold Lake (Phases 11-13)	Imperial Oil	30,000	2002
Wolf Lake	Canadian Natural Resources	13,000	1985
Carmon Creek (Cadotte Lake)	Shell Canada	12,500	1986
Red Earth CSS Pilot	Southern Pacific Resources	1,000	2009

Source: Government of Alberta, Alberta Oil Sands Industry Quarterly Update (Winter 2011)

Oil Sands Capital Cost Trends

Prior to the second half of 2008, for several years oil sands developers experienced significant inflation in capital costs primarily related to global competition for the skilled labour and materials used in project construction. Rising costs were driven by strong global economic growth, rising commodity prices and significant access to capital markets. The demand for labour and materials in Alberta was exacerbated by the fact that several oil sands producers sanctioned the development of large scale projects, in most cases involving the construction of an upgrader.

Soon after the financial crisis of late 2008 and early 2009, the global recession and a decrease in oil and steel prices from record highs, a number of planned oil sands projects were withdrawn or postponed pending an improvement in macroeconomic conditions. The slowdown in project development resulted in a reduction in capital spending for the overall oil sands industry. Recently, the oil sands sector has returned to a period of accelerated development; however, various key industry dynamics have changed which are expected to mitigate the inflationary pressures experienced through the previous cycle.

Trend towards increased in-situ development versus mining: The majority of growth over the near-term will be focused on *in-situ* development, particularly non-integrated SAGD versus integrated mining. Average *in-situ* projects are built in phases ranging from 10,000 bbl/d to 30,000 bbl/d. Due to the smaller size and scope relative to integrated mining projects, *in-situ* projects are easier to manage, require a smaller peak labour force, and are therefore less likely to incur budget overruns.

Increased labour availability: The pace of construction during the previous inflationary cycle drove significant demands on the labour force across Canada. Depletion of Canada's labour pool forced oil sands developers to pursue additional resources internationally. Recently, however, labour availability has become more abundant in Canada, and more broadly, across North America resulting from the economic recovery following the financial crisis. Current unemployment rates in the United States of 8.6% are significantly higher than levels of 5.8% seen in 2008 at the peak of the cycle. Additionally, there are fewer large scale projects in the region that are competing for labour, for example, during the previous inflationary cycle, construction related to the Vancouver 2010 Winter Olympics competed aggressively for similar labour resources.

Fewer competing large scale projects: Oil sands industry consolidation, particularly in the mining sector, has created an increased level of coordination and reduced levels of competition. During the previous cycle, there were seven major mining projects competing for the same resources: Shell Canada Limited’s Athabasca Oil Sands Project; Canadian Natural Resources Limited’s Horizon; Imperial Oil/ExxonMobil’s Kearl Lake and Syncrude; Suncor Energy’s Voyageur, Petro-Canada’s Fort Hills and Total SA’s Joslyn. Since the previous cycle, consolidation has changed the composition of project ownership in the oil sands considerably. For example, as a result of its merger with Petro-Canada in 2008, and its joint venture with Total SA in 2010, Suncor Energy now holds significant influence over Syncrude, Fort Hills, and Joslyn in addition to its Voyageur Project. This consolidation has allowed for less competition related to project scheduling, which is a significant change from when all projects were competing independently.

Experiences gained from the late 2008 and early 2009 period in the oil sands industry have altered the way industry participants approach new developments. New projects expected to be developed in the near-term will not involve the construction of upgraders; a trend towards constructing smaller and more manageable phases, or ‘modular’ growth in production is underway amongst *in-situ* producers. As the global economy strengthens, industry participants are closely monitoring increases in the cost of materials, particularly steel. Steel, one of the largest input costs for oil sands projects, currently stands at materially lower levels than seen during the peak inflationary period of 2008. As of year-end 2010, steel prices were 55% below peak levels in 2008. Given the historical commodity price relationship between WTI and steel, cost escalation will need to be closely monitored and managed given the increase of oil sands project being approved and constructed.

Natural Gas and Diluent Supply

Extracting bitumen using SAGD and blending bitumen to make it transportable by pipeline requires the use of natural gas and diluent. Natural gas is used as an energy input, primarily to produce steam from water in a steam generating facility at the *in-situ* extraction site. The amount of steam required to extract one barrel of oil is commonly referred to as the steam-to-oil ratio or “SOR”. A higher SOR indicates that more steam, and therefore more natural gas is required, increasing the cost of development and operation.

CSUG estimated that in 2010 Canada had a remaining marketable natural gas resource base of approximately 700 to 1,300 trillion cubic feet, inclusive of unconventional gas resources (tight gas and shale gas). Western Canada natural gas production was approximately 14.2 billion cubic feet per day in 2010 according to the NEB and is expected to increase in the long-run as technologies to extract unconventional gas resources continue to improve. Based on supply projections made by the NEB, a sufficient supply of natural gas should be available on a cost effective basis over the long term.

Historic AECO Price[(1)]

Source: Bloomberg

Notes:

(1) The historic price is calculated as the monthly average of the AECO price from 2001 to 2012 (through January 31, 2012).

In order to create a bitumen blend that can be transported by pipeline, bitumen must first be blended with a diluent such as condensate or SCO. Diluents are less viscous than bitumen, and comprise approximately 30 – 50% of the total volume of a bitumen blend, depending on the type of diluent used and the viscosity and density of the bitumen. Condensate is less viscous than SCO. Consequently, a bitumen blend mixed with condensate, commonly referred to as dilbit, has a lower proportion of diluent (approximately 30%) than a bitumen blend mixed with SCO, commonly referred to as synbit (approximately 50%). Since condensate and SCO are similarly priced, the reduced diluent cost associated with dilbit typically enhances realised bitumen revenue for producers.

Condensate for blending is either sourced from regional production or imported into Canada, while SCO for blending is sourced from regional oil sands upgraders. According to CAPP, in 2010 an average of over 116,000 bbl/d of combined butane, diluents from upgraders and imported condensates supplemented the locally produced condensate supply. The NEB estimates that the requirement for imported diluent will reach 250,000 – 300,000 bbl/d by 2020 due primarily to the significant growth outlook from oil sands production. The oil sands industry has devoted substantial resources to increasing the supply of diluents by increasing rail imports of condensate and building new diluent import capacity. A large portion of this imported diluent will be shipped into Alberta by the 180,000 bbl/d Enbridge Inc. Southern Lights pipeline from the midwest United States, which has been in service since July 2010. The Southern Lights pipeline can be expanded to 330,000 bbl/d with minor looping, and to over 400,000 bbl/d with full looping. Additionally, as part of its Northern Gateway crude oil pipeline project, Enbridge Inc. is proposing a 193,000 bbl/d diluent import pipeline that would extend from Kitimat, British Columbia to Edmonton, Alberta. The NEB has scheduled a hearing on this project for January 2012.

Markets and Transportation for Bitumen Blend

Bitumen blends are priced using several benchmarks in Alberta at the Hardisty Hub, the most common benchmarks being Lloyd Blend, Bow River and more recently Western Canada Select. Bitumen blends trade at quality discounts to conventional light oil such as WTI or Edmonton Par. WTI is a light sweet crude oil, which is used as a benchmark grade of crude oil for North American price quotations and is referenced at a sales point in Cushing, Oklahoma. CAPP categorises various crude oil types that comprise western Canadian crude oil supply into four major categories: Conventional Light,

Conventional Heavy, Upgraded Light and Oil Sands Heavy. The different grades of crude are categorised by their respective density and sulphur content.

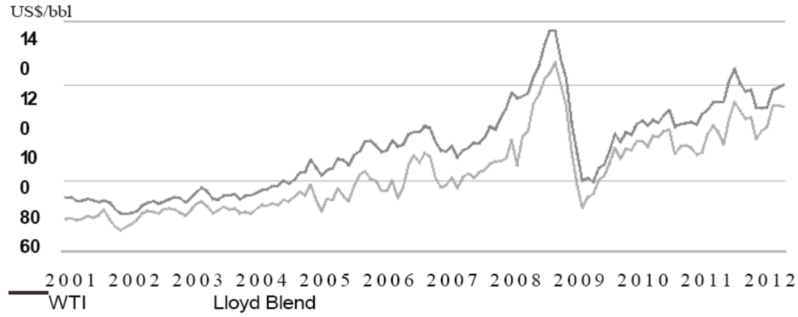
Oil Specifications by Type

Crude Type	2010 Year-end Price	Gravity	Sulphur Content
	$bbl	°API	% Weight
Benchmark Prices			
WTI @ Cushing	$91.20	39.0 – 40.0	0.34%
Edmonton Par @ Hardisty	$85.46	40.0	0.50%
Bow River @ Hardisty	$77.03	26.7	2.10%
Lloyd Blend @ Hardisty	$73.77	20.7	3.15%
Western Canadian Select @ Hardisty	$71.24	20.6	3.40%
Cold Lake Blend @ Hardisty	$75.04	21.2	3.70%
Diluents			
Sweet Synthetic Blend @ Hardisty	$87.28	30.0 – 32.0	0.10% - 0.20%
Condensate	$92.85	65.0	0.10%

Source: Bloomberg, Syncrude, Centre for Energy and Environment Canada as per the Oil & Gas Journal

The discount of heavy oil to light oil (commonly referred to as the "heavy oil differential") has historically been volatile, but has narrowed during the last four years, and is currently estimated by the petroleum engineering firms referenced below to average between 18% and 20% through 2015.

Historic WTI and Lloyd Blend Prices[(1)]

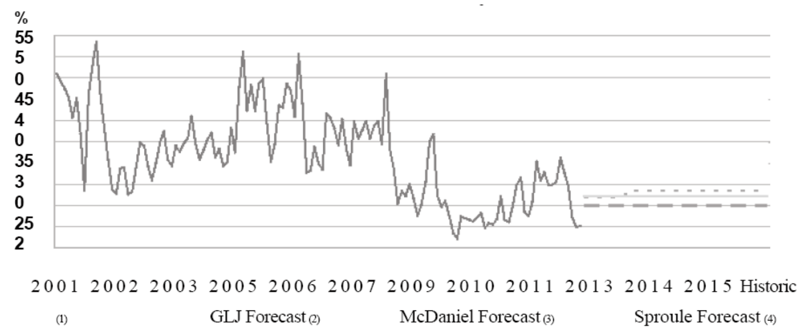


Source: Bloomberg

Notes:

(1) The historic prices are calculated as the monthly average of the WTI and Lloyd blend prices from 2001 to 2012 (through January 31, 2012).

Historic and Forecasted Heavy Oil Differential



Source: Bloomberg

Notes:

(1) The historic differential shows the average of the monthly Lloyd Blend differential from 2001 to 2012 (through January 31, 2012). It is calculated by dividing Lloyd Blend by Light Sweet Crude at Edmonton, and subtracting that number from one.

(2) The GLJ forecast is as of January 1, 2012. The differential is calculated by dividing Lloyd Blend Crude Oil Stream Quality at Hardisty by Light Sweet Crude Oil (40 API, 0.3% sulphur) at Edmonton, and subtracting that number from one.

(3) The McDaniel & Associates Consultants Ltd. Forecast is as of January 1, 2012. The differential is calculated by dividing Alberta Bow River Hardisty Crude Oil by Edmonton Light Crude Oil, and subtracting that number from one.

(4) The Sproule Associates Limited forecast is as of December 31, 2011. The differential is calculated by dividing Hardisty Lloyd Blend (20.5 API) by Edmonton Par Price, and subtracting that number from one.

The markets for Canadian oil have traditionally been in Western and Eastern Canada and the Midwest and Rocky Mountain regions of the United States, with small amounts transported to the west coast of the United States. According to the ERCB, the majority of the future incremental production volumes from Canada's oil sands are likely to be consumed in the United States. Asia also represents a significant potential future market for incremental Canadian oil sands production. Asia is currently the second largest global oil market after North America, and China is the second largest consumer of oil after the United States. Sunshine's potential customers are local and international companies with operations in North America, including refiners, upgraders, marketers who are intermediaries that connect producers and suppliers, and other oil sands companies who have their own upgrading operations, amongst others.

According to the EIA, as of 2010, Canada was the largest supplier of crude oil to the United States. Approximately 2.0 MMbbl/d or 22% of United States daily demand was imported from Canada. A large percentage of the United States' imported oil is sourced from regions that are, or have the potential to be, politically unstable. Over time, the growth in Canadian heavy crude production volumes, including oil sands volumes, is expected to partially meet increasing demand from the United States.

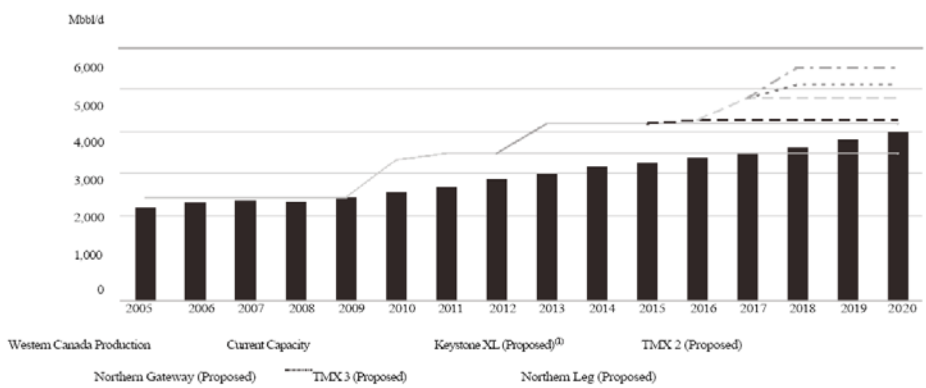
Western Canadian Crude Oil Demand

Area	PADD 2010 Refining Capacity	2010 Actual Demand	2015 Potential Additional Demand	2015 Forecasted Demand
	mbbl/d	Mbbl/d	Mbbl/d	Mbbl/d
PADD I (East Coast)	1,312	55	10	65
PADD II (Mid West)	3,736	1,231	483	1,714
PADD III (Gulf Coast)	8,996	119	380	499
PADD IV (Rockies)	613	237	8	245
PADD V (West Coast)	2,731	205	64	269

Source: CAPP 2011 – 2025 Crude Oil Production Estimate

Significant pipeline expansion and refining reconfiguration projects are forecast to increase transportation and refining capacity for Canadian oil sands production. In response to increased crude oil demand, several refinery expansion plans have been announced both in the United States and abroad. A significant portion of this expansion will allow refineries to process heavier grades of crude oil, such as Canadian oil sands volumes. According to CAPP, in 2010, in the U.S., the Midwest (PADD II) was Canada's largest market for bitumen and conventional heavy oil due to its close proximity, large size and established pipeline network. Several refiners have announced expansions or conversions at PADD II and PADD III to accommodate growing heavy crude oil demand, including bitumen blend (please refer to "Announced Refinery Upgrades" tables below). The steep decline of Mexico's Cantarell oil field, changing Venezuelan export dynamics, and increasing heavy oil transportation capacity are continuing to expand the U.S. Gulf Coast PADD III market for Canadian bitumen blends.

Western Canadian Production and Pipeline Capacity



Source: CAPP 2011 – 2025 Crude Oil Production Forecast, EnSys Keystone XL Assessment Report

Notes:

(1) In January 2012, the US State department rejected the issue of a permit for the Keystone XL pipeline.

Announced Refinery Upgrades in Eastern PADD II

Operator	Location	Current Capacity	Scheduled In-Service	Description
		mbbl/d		
WRB Refining	Roxana, IL	306	2011	Add a 65,000 bbl/d coker; increase total crude oil refining capacity by 50,000 bbl/d; increase heavy oil refining capacity to 240,000 bbl/d
BP	Whiting, IN	400	Late 2012 to Mid 2013	Construction of a new coker and a new crude distillation unit
Marathon	Detroit, MI	102	Mid 2012	Increase heavy oil processing capacity by 80,000 bbl/d and increase total crude oil refining capacity to 115,000 bbl/d

Source: CAPP 2011 – 2025 Crude Oil Production Estimate

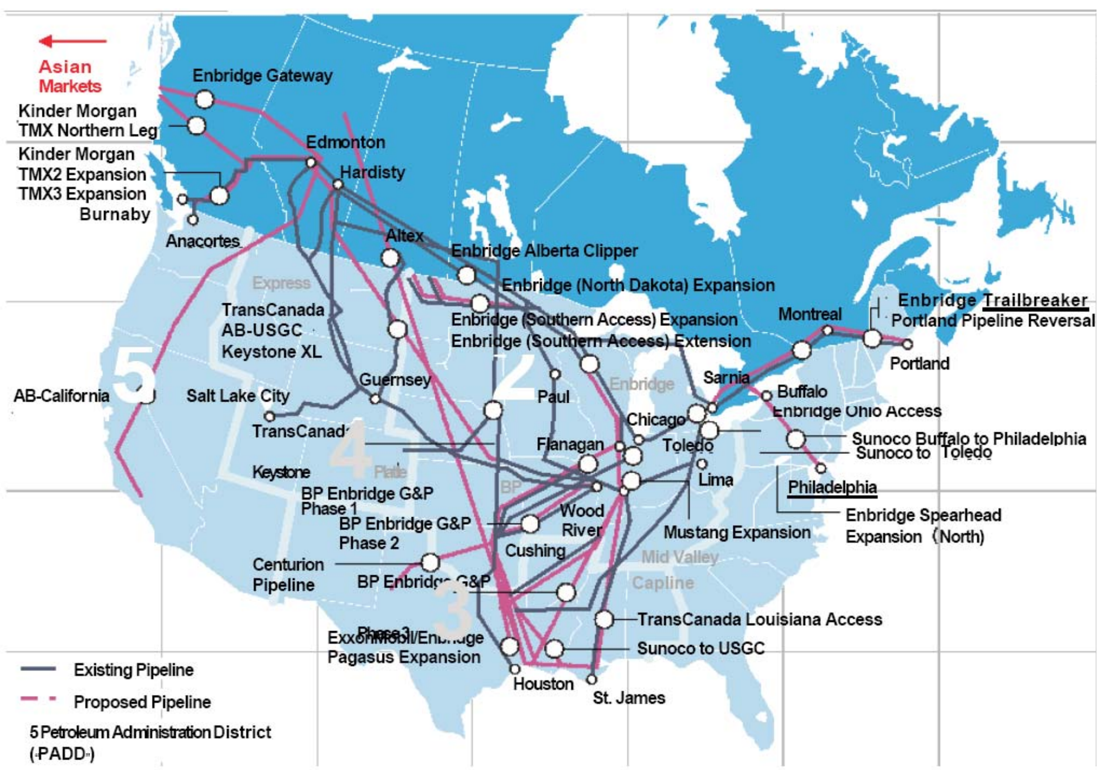
Announced Refinery Upgrades in Eastern PADD III

Operator	Location	Current Capacity	Scheduled In-Service	Description
		mbbl/d		
Hunt Refining	Tuscaloosa, AL	72	2010	Increased capacity from 52,000 bbl/d to 72,000 bbl/d. Delayed coker was expanded to double in size to 32,000 bbl/d.
Total	Port Arthur, TX	232	2011	Increased capacity from 175,000 bbl/d to 232,000 bbl/d. Project included a 50,000 bbl/d coker; a 55,000 bbl/d vacuum distillation unit and a 64,000 bbl/d distillate hydrotreater.
Motiva Enterprises	Port Arthur, TX	285	2012	Increase capacity by 325,000 bbl/d to over 600,000 bbl/d.
Valero	McKee, TX	170	2014	Increase capacity by 25,000 bbl/d. Expansion will process WTI and locally produced oil.

Source: CAPP 2011 – 2025 Crude Oil Production Estimate

Asian markets represent a very material potential growth opportunity for bitumen blends. Bitumen blends from the oil sands could potentially be exported to world markets as early as 2016/2017, assuming Enbridge Inc.'s Northern Gateway pipeline and a terminal on the west of Canada at Kitimat, British Columbia are completed as scheduled. Kinder Morgan Canada is also pursuing new pipeline expansions, including a significant expansion of its TransMountain Pipeline. If completed, these future pipelines will potentially allow oil sands producers to compete with other regions such as the Persian Gulf and South America given the proximal nautical distance between Kitimat and east Asia. These pipeline projects are currently being evaluated and constructed in response to strong support from oil sands producers.

Existing and Proposed Pipelines in North America



Source: ERCB, CAPP

Notes:

(1) In January 2012, the US State department rejected the issue of a permit for the Keystone XL pipeline.

Upgrading

Upgrading is a process performed by specialised refineries called upgraders that transform bitumen into higher value hydrocarbons, most of which require additional processing at a refinery to be turned into products which can be used by end users. The primary output of oil sands upgraders is SCO, which is a light crude oil. All oil sands mining projects currently in operation are integrated with upgraders, while most *in-situ* projects are not integrated. In recent years, the differential of heavy crude oil pricing to light crude oil pricing has narrowed considerably. The increased demand for bitumen relative to the available supply has reduced the economic attractiveness of upgrading and has resulted in higher netbacks for non-upgraded bitumen.

Environmental Considerations and Regulations

The rapid pace of investment for development in Canada's oil sands has attracted significant attention from environmental groups, the general public and governments. Similar to other large scale natural resource projects such as a hard-rock mining or large-scale hydroelectricity generation, oil sands projects face a number of environmental challenges. Oil sands development in Alberta is controlled by extensive provincial and federal government-approved environmental requirements. Detailed project applications, which are preceded by stakeholder consultation, are required to be submitted and are carefully reviewed by regulators before approvals are granted for projects. Once constructed, extensive environmental monitoring and reporting is an ongoing requirement from production to reclamation phase for oil sands projects.

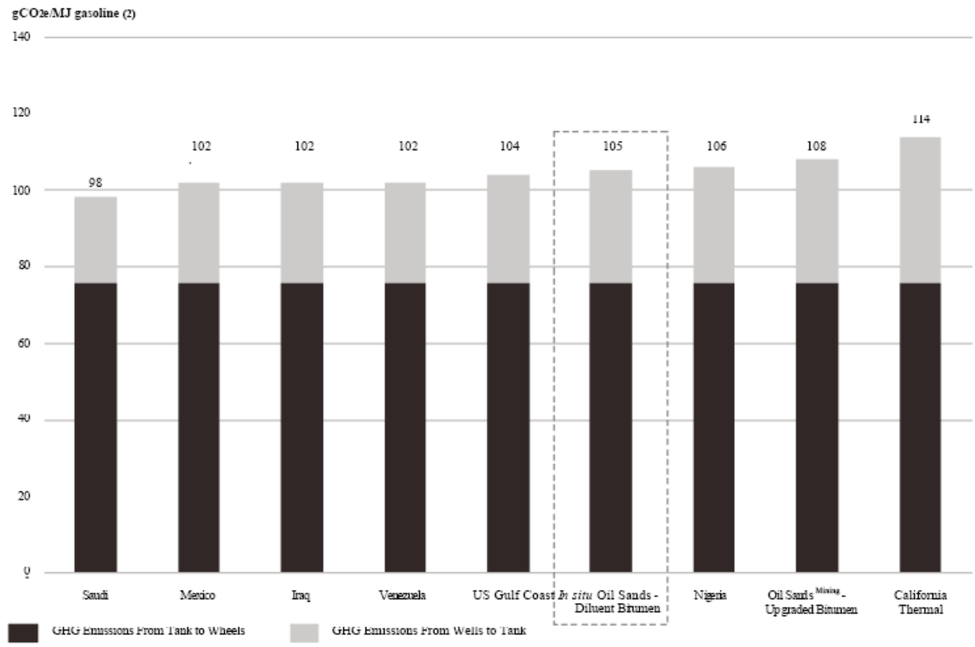
According to CAPP, the three most common environmental considerations are: GHG emissions, water use, and land use.

Greenhouse Gas Emissions

Production from oil sands cause higher GHG emissions than production from most conventional, light oil sources, although GHG emissions from oil sands production is comparable to GHG emissions from the production of many other oil sources from around the globe. Representatives of industry and government are currently focusing their efforts on finding technological solutions to reduce GHG emissions.

Many consultants use a full life-cycle approach when comparing GHG emissions. A full life-cycle approach compares the total emissions from various oil sources from extraction to its end use (typically being burned as gasoline) or as commonly referred to as, "wells to wheels." Research from the Alberta Energy Research Institute has found that ordinarily the majority of the GHG emissions on a life-cycle basis are from the burning of gasoline in motor vehicles, or from "tank to wheels."

Carbon Dioxide (CO_2) from Wells to Wheels[(1)]



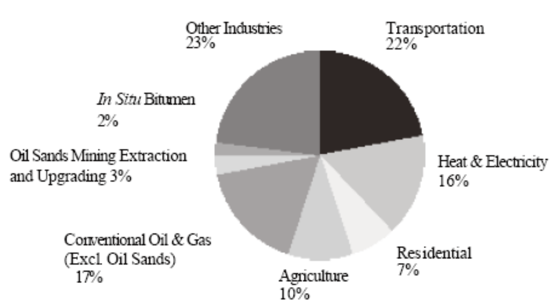
Notes:

(1) Jacobs Consultancy, Life Cycle Assessment of North American and Imported Crudes, June 2009 and CAPP presentation titled "Canada's Oil Sands — Partners in America's Energy Future".

(2) The term "gCO_2e/MJ" means grams of carbon dioxide equivalent per megajoule.

According to a report released by CAPP in 2011, total GHG emissions from the oil sands account for approximately 5% of Canada's total GHG emissions — that amount is equal to 0.5% of total U.S. GHG emissions and 0.1% of global GHG emissions. Provincial and Federal governments, together with oil sands producers are taking several steps to reduce GHG emissions from the oil sands, including introducing new government regulations and making investments in carbon capture and storage projects. *In-situ* projects will likely see new technologies and methods to reduce the industry's reliance on natural gas.

Canada's GHG Emissions by Sector



Source: Environment Canada, National Inventory Report Part 1 Greenhouse Gas Sources and Sinks in Canada (April 2010)

Existing *in-situ* extraction technologies are being refined to reduce the amount of steam required to be injected into the reservoir to heat bitumen, and a number of enhanced oil technologies are being developed to reduce or eliminate this need. Using less steam reduces GHG emissions caused by the burning of natural gas and also reduces the amount of water used to generate steam.

Greenhouse Gas Regulations

The Government of Alberta implemented GHG regulations in 2007 that requires facilities that generate in excess of 100,000 tonnes of GHG emissions per year to meet a 2% annual reduction in emissions intensity over a six-year period based on a baseline established in the third year of commercial operations. GHG emitters that cannot meet the targets must either pay a fee to the Climate Change and Emissions Management Fund, the proceeds of which are directed to research and technology development focused on reducing GHG emissions, or purchase emissions performance or emission offset credits. The Federal Government is also developing a carbon pricing system that is intended to drive further reductions in GHG emissions and create additional funds for technology development. The details of the Federal Government's proposed regulations have not been released but it is expected that federal GHG emissions reduction requirements will include an absolute cap on emissions rather than the emissions intensity approach used in Alberta.

Water Use

Both surface mining and *in-situ* oil sands production use water as part of the extraction process. Mining requires fresh water to separate bitumen from sands. Mines also require large tailings ponds to settle the fine particles remaining in the water following the bitumen separation process. *In-situ* production using SAGD or CSS requires water to produce steam that is injected into the reservoir. Water treatment facilities at *in-situ* project sites enable a large quantity of the water to be recycled (in excess of 90%). To minimise the use of fresh water, SAGD and CSS oil sands projects may also use saline and other non-potable water sources. Evolving water treatment technology is expected to reduce water demand even further in the future.

Land Use

While both oil sands mining and *in-situ* production methods impact the land, the surface footprint of *in-situ* production is significantly smaller than that of a mine. An open pit mine's footprint ultimately affects the entire surface area over the resource and also requires tailings ponds, while *in-situ* production requires only well pads on the surface for wellheads, similar to conventional oil and gas, but, with more barrels typically recovered per well pad. Both mining and *in-situ* production are subject to government reclamation requirements under *Conservation and Reclamation Regulation* under the EPEA, but the cost of reclamation for *in-situ* producers is much lower and can be accomplished sooner.

Current and Proposed SAGD Projects in Alberta Oil Sands

There are currently 14 companies producing from *in-situ* oil sands using SAGD and CSS extraction technologies according to information provided by the Government of Alberta. Furthermore, a number of these companies and others have proposals to construct new *in-situ* oil sands projects or expand existing projects.

Operator	Project(s)	Capacity bbl/d
Alberta Oilsands Inc.	Clearwater West	29,350
AOSC	Dover, Dover West Clastics, Dover West Leduc Carbonates, Hangingstone, MacKay River	567,000
BlackPearl Resources Inc.	Blackrod	80,000
CNRL	Birch Mountain, Gregoire Lake, Grouse, Kirby, Leismer	390,000
Cenovus	Christina Lake, Foster Creek, Grand Rapids, Narrows Lake, Telephone Lake/Borealis	660,000
Connacher	Great Divide	24,000
ConocoPhillips Company	Surmont	109,000
Devon Canada Corporation	Jackfish	35,000
E-T Energy Ltd	Poplar Creek	10,000
Grizzly Oil Sands ULC	Algar Lake	11,300
Harvest Operations Corp.	BlackGold	30,000
Husky Energy Inc.	Caribou, Sunrise	220,000
Ivanhoe Energy Inc.	Tamarack	40,000
Japan Canada Oil Sands Limited	Hangingstone	35,000
Koch Exploration Canada, LP	Gemini	10,000
Laricina	Germain, Saleski	165,700
MEG	Christina Lake, Surmont	285,000

Operator	Project(s)	Capacity bbl/d
Nexen Inc.	Long Lake	296,000
Osum Oil Sands Corp.	Taiga	35,000
Pengrowth Energy Corporation	Lindbergh	13,200
Petrobank Energy and Resources Ltd.	Dawson, May River, Whitesands	111,900
Shell Canada Limited	Orion	10,000
Southern Pacific Resource Corp.	STP-McKay	36,000
Statoil ASA	Corner, Hangingstone, Leismer, Northwest Leismer, South Leismer, Thornbury	240,000
Suncor Energy	Chard, Firebag, MacKay River, Meadow Creek, Lewis	450,500
Sunshine	Legend Lake, Thickwood, West Ells	200,000
Value Creation Inc.	Terre de Grace, TriStar	91,000

Source: Government of Alberta, Alberta Oil Sands Industry Quarterly Update (Winter 2011)

Current and Proposed CSS Projects in Alberta Oil Sands

Operator	Project(s)	Capacity bbl/d
Imperial Oil Limited	Cold Lake	30,000
Shell Canada Limited	Carmon Creek	80,000
Southern Pacific Resource Corp.	Red Earth	13,000

Source: Government of Alberta, Alberta Oil Sands Industry Quarterly Update (Winter 2011)

The simultaneous construction of a number of SAGD projects can lead to a tight supply of skilled labour and materials. SAGD projects compete amongst each other and other construction projects in Alberta and the rest of Canada to secure engineering and construction personnel and procure building materials. A tight supply of skilled labour and materials may lead to significant cost inflation or project delays. Once operational, SAGD producers will compete amongst each other and other oil sands producers to secure a source of diluent, natural gas and other fuels, and take-away pipeline capacity and storage.

Most of the oil sands properties in the Athabasca region have been leased, many by large international oil and gas companies. New entrants to Canada's oil sands will likely have to make an asset acquisition from, or corporate acquisition of, a company with existing oil sands properties. The scale of Canada's oil sands generally limits material acquisitions to large international companies with strong access to low cost capital.

LAWS AND REGULATIONS IN THE INDUSTRY

Laws and Regulations Relating to the Canadian Oil Sands Industry

Overview

The oil and gas industry is subject to extensive controls and regulations. In Alberta, provincial legislation and regulations govern land tenure, royalties, production practices and rates, environmental protection, the prevention of waste and other matters. Federal legislation and regulations may also apply. With the possible exception of the LARP, it is not expected that any of these controls and regulations will affect our operations in a manner materially different than they would affect other oil and natural gas producers of similar size. The relevant controls and regulations should be considered carefully by our prospective investors. The regulatory scheme as it relates to the oil sands industry is somewhat different from that related to the oil and gas industry generally. Outlined below are some of the more significant aspects of the legislation and regulations governing the recovery and marketing of bitumen from oil sands. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments may be enacted.

The Alberta Department of Energy is responsible for administering the legislation that governs the ownership, royalty and administration of Alberta's oil, gas, oil sands, coal, metallic and other mineral resources. The ERCB is an independent quasi-judicial agency of the Government of Alberta that regulates oil and gas activities in the province pursuant to the OSCA. The AEW and the SRD administer complementary environmental policies in the province. In particular, the AEW's central mandate is the protection and management of the environment and water resources, as well as certain other related matters such as waste management and climate change, pursuant to several statutory regimes and instruments, such as the EPEA and the *Water Act*.

In Alberta, the regulation of the construction, operation, decommissioning and reclamation of oil sands recovery, pipeline, and upgrade projects is generally undertaken jointly by the ERCB and by the AEW pursuant to various statutes, including the *Oil Sands Conservation Act*, the *Water Act*, the EPEA and others. ERCB approvals are required prior to the construction and operation of oil sands recovery, pipeline, and upgrader projects, and the legislation allows the ERCB to inspect and investigate operations. Similar powers are exercised by the AEW with regard to aspects of oil sands projects impacting human health and/or the environment. Electrical facilities of oil sands projects, including cogeneration facilities, are regulated by the AUC, and the Alberta electric systems operator also regulates access to the Alberta electricity grid and electricity market. Certain changes to oil sands recovery, pipeline, and upgrader projects require the approval of the ERCB, AEW, or both. Similarly, changes to the electrical facilities of oil sands projects may require regulatory approvals. Inspection and investigations by provincial regulators may result in, among other things, remedial orders.

A project proponent will first submit its development proposal, including an environmental impact assessment to the ERCB and the AEW. The ERCB and the AEW will then jointly develop a processing schedule while reviewing the application for completeness. If the application is deemed incomplete, it will be returned to the applicant for further development. If it is deemed complete, a public notice will be issued jointly by the above agencies while the application will proceed to technical review. At this point the agencies might again ask for further technical information from the proponent. At the same time, the nature and extent of the public response to the public notice, as well as the outcome of any statutorily mandated public consultation processes, will dictate whether or not public hearings will be necessary. If public hearings are deemed necessary, notice and other pre-meeting matters will have to be addressed prior to the conduct of the actual hearing. If a public hearing is not deemed necessary, or once the public hearing process has been completed, the ERCB and the AEW will then determine whether any unresolved issues remain. If unresolved issues remain, the agencies will likely require a meeting with the proponent. If no unresolved issues remain, the agencies will proceed to final determination. This will then lead to approval by the ERCB and the AEW or to a denial letter. As such, the total length of this process will depend on the complexity of the project, as well as whether the approval process is delayed by the incompleteness of the application, requests for additional technical information, the requirement of a public hearing process and the conduct of such process and/or any unresolved issues that arise or are otherwise identified.

Additionally, the construction, operation, decommissioning and reclamation of oil sands recovery, pipeline, upgrade projects, and associated electrical facilities, may invoke regulation by the Government of Canada under various federal statutes and regulations, which may include the *Canadian Environmental Assessment Act*, the *Canadian Environmental Protection Act*, the *Fisheries Act* and the *Navigable Waters Protection Act*. Certain federal approvals or authorisations may be needed prior to the construction, operation or modification of facilities. Inspections and investigations by federal regulators may result in, among other things, remedial orders.

Methods of Obtaining Mining Rights and Oil Sands Leases

The Department of Energy administers grants to the private sector of rights to explore for and develop energy and mineral resources in the province. The Crown owns 81% of Alberta's mineral rights (including both oil sands and non-oil sands resources). The remaining 19% are 'freehold' mineral rights owned by the federal government on behalf of the First Nations or in National Parks, and by individuals and companies. Such freehold leases were generally granted to homesteaders in connection with the operations of the Canadian Pacific Railway and the Hudson's Bay Company in the late nineteenth and early twentieth centuries.

In order to acquire oil sands rights, a corporation must be registered to conduct business in Alberta as required by the *Mines and Minerals Act*. Crown-owned oil sands rights are disposed by means of Oil Sands Leases issued under the *Oil Sands Tenure Regulation*, made under the *Mines and Minerals Act*, which convey the right to "drill for, win, work, recover and remove" oil sands that are owned by the Crown. There are two ways to acquire an Oil Sands Lease. The first is by way of a registered transfer of an existing Oil Sands Lease negotiated between private parties. The second is by way of public sale or direct purchase. The public oil sands offerings schedule is published two years in advance, as an attachment to an information letter produced by the Department of Energy and electronically distributed to a list of registered subscribers. Sales of Oil Sands Leases are initiated by posting requests submitted by companies or individuals. If no rights have been requested, there is no need to hold a sale. Oil Sands Leases designated for public sale are typically published by the Department of Energy eight weeks prior to the date of the sale. Direct purchases are only possible upon application in specific limited circumstances and in respect of specific drill spacing units.

Petroleum and natural gas rights owned by Alberta can also be acquired through a competitive bid auction held approximately every two weeks. On a yearly basis, the province holds an average of 24 land auctions and issues approximately 8,000 PNG Licences. As of December 31, 2009, the Department of Energy had issued 95,031 PNG Licences.

It is possible for the Crown to grant different mineral rights over a given parcel of land in separate geological horizons. It is not uncommon to have rights to specific geological horizons granted to different parties on different dates. As a result, the different rights of different parties on the same parcel of land can see conflicts arise as a result of competing interests. Where this occurs, the parties may work together to negotiate a compromise that maximises recovery for both parties. Where such a compromise is unattainable the authority of one of a number of administrative bodies such as the ERCB or the Surface Rights Board will be determinative while the ultimate result will be decided by the nature and particular characteristics of the conflict. The ultimate result of such conflicts cannot therefore be predicted in advance but may include the temporary suspension of the ability of a party to pursue its mineral rights.

Applicable Oil Sands Approval Processes Leading up to Production

Approvals and oil sands permits for the construction and operation of oil sands extraction facilities are provided by various levels and branches of the Canadian government, but primarily the ERCB and the AEW. Depending on the size, location and specific characteristics of an oil sands project, several other provincial and federal approvals, licenses and permits may also be required.

The OSCA specifically prohibits the construction or operation of facilities for the recovery of oil sands or crude bitumen without approval of the ERCB. All proposed activities must be screened by the ERCB, including the development, construction, operation and modification of all significant facilities and pipelines, as well as any associated processing plants. Opposed or “non-routine” applications must undergo a public hearing process before the necessary licence or permit will be granted by the ERCB. This process typically runs in conjunction with, and subject to, any environmental requirements. The approval process can take up to a year to compile, and a similar amount of time to be evaluated. However, in early 2011, the Government of Alberta announced plans to streamline the approval process going forward through the greater concentration of authority in a single regulatory body.

The ERCB (and its predecessors) has issued numerous guidelines regarding oil sands projects and operations, including Directive 023: Guidelines Respecting an Application for a Commercial Crude Bitumen Recovery and Upgrading Project. Directive 23 outlines the information required in an application to the ERCB under the OSCA for approval of a scheme for the recovery of oil sands, crude bitumen or products derived therefrom, in order to meet the needs of both the ERCB and AEW. Directive 23 applies to all commercial oil sands projects, though additional information may be required for larger-scale projects. An application for a commercial project for the recovery and upgrading of crude bitumen must include a brief summary of all aspects of the project, a statement of the general basis and objectives of the application, the types of approvals and permits that are requested, and the relevant legislation under which the application is being made. Technical and directly related economic details of the proposed development must also be included. Assessments of biophysical impact, social impact, and benefit-cost are also required. In total, sufficient information must be provided to permit the overall evaluation of whether the project will result in the economic and efficient use of resources and the protection of the environment.

Following the issuance of an initial ERCB approval, the proponent must obtain additional operating permits, licences, and approvals. The ERCB must issue mine and discard site approvals, as well as (when required) well licences (including for evaluation wells, experimental wells, primary production wells and water supply wells of a depth of more than 150 metres), pipeline permits and licences, and sub-surface waste disposal approvals. A development and reclamation approval must also be acquired from AEW, along with all other necessary permits and licences related to environmental matters.

Applications to AEW are generally filed under the EPEA, the *Water Act* and/or the *Public Lands Act*, and the AEW will generally issue its own approval for an oil sands project separate and apart from any ERCB approval. Environmental impact assessment reports are required, and must be prepared as prescribed, under the EPEA for activities such as oil sands projects and, as noted, are also necessary for project approval by the ERCB. Environmental impact assessment reports are undertaken pursuant to terms of reference from AEW for the subject project, and the environmental impact assessment reports must explain the environmental effects of the project and other existing and planned activities in the area related to the project. Typical information required as part of an environmental impact assessment report includes information in respect of public consultation, a project overview, an environmental assessment, environmental monitoring, public health and safety, historical resources and traditional land use and local socio-economic factors. The EPEA requires operators to plan for and employ effective conservation and reclamation measures. The AEW also allocates water licences under the *Water Act*.

Depending on the size, location and specific characteristics of an oil sands project, several other provincial and federal approvals, licenses and permits may also be required. In the event that oil sands operations include electrical energy generation or energy transmission, an application may be required to be made to the AUC. Notwithstanding that an oil sands project may be wholly within a province's borders, an application may also need to be made under the *Canadian Environmental Assessment Act*. The most common trigger for a CEAA application arises out of the federal government's constitutional jurisdiction over certain inland waterways and fisheries. In such circumstances, it is possible to have a project undergo a joint provincial/federal environmental assessment in certain circumstances. Under the *Fisheries Act* , the engagement of work which may result in the disruption or destruction of a fish habitat, or the deposition of a deleterious substance in water frequented by fish, must provide the Minister of Fisheries and Oceans with plans, specifications, studies and details of the proposed procedures. The *Surface Rights Act* provides that no operator has a right of entry in respect of the surface of any land until the operator obtains the consent of the owner and the occupant of the surface of the land or has become entitled to a right of entry by reason of an order of the Surface Rights Board. Where oil and gas operations are to take place on land to which aboriginal peoples have a claim or other rights of use or access, a license from the Department of Indian Affairs and Northern Development may also be required.

Rights and Obligations of Holders of Mining Rights

Companies obtaining the right to explore for and develop Crown resources are subject to numerous rights and obligations attached to the licenses and leases issued and imposed by various applicable statutory regimes. Tenure holders must meet all regulatory requirements. An Oil Sands Lease is proven to be productive by drilling, producing, mapping, being part of a unit agreement or by paying offset compensation. An Oil Sands Lease may be continued beyond the end of its initial term by application to the Department of Energy. An owner's Oil Sands Lease tenure will end when the holder can no longer prove that the subject lands are capable of producing oil or gas in paying quantities, if it is lost through rental or royalty payment default or by voluntary surrender.

Laws and Regulations Relating to the Pricing and Marketing of Crude Oil, Bitumen and Bitumen Blend

In Canada, 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 we receive depends in part on product quality, prices of competing fuels, the distance to market, the value of refined products, the supply/demand balance and other contractual terms.

Subject to certain exemptions, oil and gas exports from Canada must be made pursuant to short-term export orders or long-term licences obtained from the NEB. An export order for light crude oil, defined to include blended oils with a density less than or equal to 875.7 kg/m^3, may be granted for up to one year. An export order for heavy crude oil, defined to include blended oils with a density greater than 875.7 kg/m^3, may be granted for a period not exceeding two years. If a longer term for export approval is required, an export licence must be obtained from the NEB. Licences for the export of light or heavy crude oil may be granted for a period not exceeding 25 years, and require the approval of the governor in council in Alberta.

Laws and Regulations Relating to Taxation and Royalties

Taxes

Canadian taxation of the income of corporations resident in Canada is governed by the ITA as well as any applicable provincial or territorial taxing legislation (which, in Alberta is the Alberta Corporate Tax Act). For most purposes, the computation of a corporation's taxable income under the Alberta Corporate Tax Act mirrors the computation under the federal ITA.

A corporation is subject to taxation in each taxation year on its taxable income for that year, including (if any) net realised taxable capital gains, dividends, accrued interest, the corporation's share of certain partnership income and all amounts accrued in respect of any royalties the corporation holds in respect of any resource properties.

Generally, a corporation's taxable income for Canadian tax purposes is the corporation's income for the year less deductions allowed by the ITA. A corporation engaged in a resource business is generally entitled to deduct expenses incurred for the purpose of earning income from a business or property, including salaries and wages, the purchase of inputs, supplies and services, and other current expenses in computing its income. Interest expense incurred for the purpose of earning income is generally deductible and, for all periods after 2006, Crown royalties are fully deductible. Capital expenditures are generally not deductible except where expressly provided by the ITA. A deduction in respect of capital cost allowance is available to a resource corporation in respect of depreciable property owned by the corporation and used in its business. The rate of capital cost allowance that a corporation may claim varies by asset category and is generally based on the useful life of the asset.

Certain resource expenses incurred by a corporation engaged in resource activities may also be deducted on a current or declining-balance basis, subject to the specific limits and restrictions prescribed by the ITA. These categories of expenses are added to cumulative resource pools classified as "Canadian oil and gas property expense" (deductible at 10%), "Canadian development expense" (deductible at 30%) and "Canadian exploration expense" (deductible at 100%).

Operating losses generally may be carried back up to three years or carried forward up to 20 years to reduce taxable income in those years. Any capital losses realised by a corporation may only be used to reduce capital gains and may not be used to reduce other income. Capital losses may be carried back three years or carried forward indefinitely (subject to certain loss denial rules) to offset capital gains in those years.

The 2011 combined Canadian federal and provincial tax rate applicable to regular business income of corporation carrying on business in Alberta is approximately 26.5% (16.5% federal tax and 10% Alberta provincial tax). This rate is 25% in 2012 and thereafter (15% federal tax and 10% Alberta provincial tax).

The foregoing is a general description of the Canadian income tax regime applicable to a Canadian resource corporation and is not, and is not intended to be, legal, business or tax advice to any particular prospective investor. The rules in the ITA applicable to the resource sector are complex and this summary is not exhaustive of all Canadian tax considerations applicable to a Canadian resource corporation. Accordingly, prospective investors that require further information regarding the tax regime in Canada should consult with a Canadian tax adviser.

Royalty Regime

In addition to federal regulation, each Canadian province has legislation and regulations governing land tenure, royalties, production rates, environmental protection, and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas liquid and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral freehold owner and the lessee, although production from such lands may also be subject to certain provincial taxes. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery, depth of well, and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time-to-time, carved out of the owner's working interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profit interests, or net carried interests.

The Government of Alberta implemented a new oil and gas royalty framework, that was effective on January 1, 2009. The new 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, natural gas activities and oil sands projects. Under the January 1, 2009 framework, the calculation of conventional oil and natural gas royalties is made in accordance with sliding rate formulas, known as royalty curves, that adjust for market price and production volumes. Under the January 1, 2009 framework, royalty rates for conventional oil range from 0 - 50% and natural gas royalty rates range from 5 - 50%. On March 11, 2010, the Government of Alberta announced that, effective as of January 1, 2011, the maximum royalty rate on conventional oil will be reduced from 50% to 40% and the maximum royalty rate for natural gas will be reduced from 50% to 36%. Royalty curves that were effective as of January 1, 2011 were released by the Government of Alberta on May 17, 2010.

The oil sands royalty payable in Alberta is based on price-sensitive royalty rates. The royalty range applicable to price sensitivities changes depending on whether a project's status is pre-payout or post-payout. "Payout" is 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 is $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 is currently considering having a portion of its bitumen royalty in-kind volumes commercially upgraded to higher value products in the province.

Laws and Regulations Relating to Land

Land Tenure

The oil sands mineral rights in approximately 97% of Alberta's estimated 140,200 square kilometres (54,132 square miles) of oil sands areas are owned by the provincial Crown and managed by the Department of Energy. The remaining approximately 3% of oil sands mineral rights are held "freehold" by individuals and companies, or as a federal Crown estate, for example as Indian reserves and/or National Parks. Oil produced from oil sands owned by Alberta is produced pursuant to provincial Oil Sands Leases granted by the provincial Crown. Two types of oil sands agreements are issued under the *Oil Sands Tenure Regulation*, made under the *Mines and Minerals Act*. These are (i) Oil Sands Permits, which are issued for a five-year term and can be converted to leases; and (ii) Oil Sands Leases, which are issued for an initial 15-year term. The *Oil Sands Tenure Regulation* requires that exploration or development activities be undertaken according to prescribed levels of evaluation or production. Oil Sands Permits may generally be converted to leases provided certain minimum levels of exploration have been achieved and all lease rentals have been timely paid.

An Oil Sands Lease may generally be continued after the initial term as to all or any portion the Minister of Energy may determine, provided certain minimum levels of exploration or production have been achieved and all lease rentals have been timely paid. The surface rights required for pipelines, upgraders and cogeneration and other facilities are generally governed by leases, easements, rights-of-way, permits or licences granted by landowners or governmental authorities.

Land Use Regulation

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the ALUF. The ALUF provides an approach for the management of public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans. The ALSA came into in force in Alberta on October 1, 2009, providing legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA are deemed to be legislative instruments equivalent to regulations and are binding on the Government of Alberta and provincial regulators, including those governing the oil sands industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licences, approvals and authorisations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land and conservation directives, which are explicit declarations contained in a regional plan to permanently protect, conserve, manage and enhance the environment. The lower Athabasca region is a distinct region under the ALSA and will be subject to the provisions of LARP, once LARP is in force. Please refer to the section entitled *"Risk Factors — Risks Relating to Our Business — Our operations and assets could be adversely affected by the LARP"* in this AIF.

Laws and Regulations Relating to Environmental Protection

Environmental Regulation

The oil and natural gas industry in Canada is currently subject to environmental regulations under a variety of provincial and federal legislation (all of which are subject to governmental review and revision, from time to time). This environmental legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, environmental legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance can require significant expenditures and a breach of such requirements may result in the suspension or revocation of necessary licences and authorisations, civil liability for pollution damage, and the imposition of material fines and penalties.

In January 2011, the Government of Alberta chose a group of independent experts to assist in the creation of a world class environmental monitoring system in north-eastern Alberta. This group of independent experts formed the Alberta Environmental Monitoring Panel. The AEMP delivered its recommendations to the Government of Alberta on June 30, 2011 in the form of a report entitled "A World-Class Environmental Monitoring, Evaluation and Reporting System for Alberta". Generally, the AEMP reached the following three main conclusions, upon which they based their 20 recommendations: (i) Alberta needs a new environmental monitoring, evaluation and reporting system focused on cumulative effects monitoring grounded in rigorous scientific design; (ii) environmental monitoring, evaluation and reporting activities must be organised and integrated across the province and across, air, land, water and biodiversity to enable a more effective use of funds and to ensure a consistent approach; and (iii) the best way to ensure scientific oversight and organisation and integration of activities is to establish a permanent, sustainably-funded, arm's length environmental monitoring commission. On February 3, 2012, the Government of Canada and the Government of Alberta released the Joint Canada-Alberta Implementation Plan for Oil Sands Monitoring (the "**Oil Sands Monitoring Plan**"). The Oil Sands Monitoring Plan commits to a new, integrated, transparent and enhanced environmental monitoring program for the Canadian oil sands, which program is intended to be fully funded by companies operating within the oil sands region. Enhanced monitoring in the Canadian oil sands region will include increased sampling locations, parameters and frequency of new air, surface water and groundwater monitoring stations and sampling of areas such as river ice and snow. Monitoring programs are likely to further expand to include additional monitoring locations, initiation of new air, water and biodiversity studies, improved data management and data sharing to ensure the highest data quality, consistency, and transparency. It is anticipated that the Oil Sands Monitoring Plan will be fully implemented in 2015 and its implementation will be under the joint direction and management of the Government of Canada (Environment Canada) and the Government of Alberta (AEW) to ensure a comprehensive and integrated joint approach to oil sands monitoring.

Compliance with any new programmes, regulations, guidelines or legislation including the Oil Sands Monitoring Plan may create uncertainty for us and could require significant expenditures to comply. We will continue to monitor any further changes in Alberta's environmental policies and legislation to ensure that our reporting, monitoring and evaluation policies and procedures continue to evolve and comply with the changing policies and programmes of the AEW, the Government of Canada and the Government of Alberta.

Environmental legislation in Alberta is, for the most part, set out in the EPEA and the OSCA. The EPEA and the OSCA impose strict environmental standards with respect to releases of effluents and emissions, require stringent compliance, reporting and monitoring obligations, and impose significant penalties for non-compliance. The EPEA is administered and implemented by the AEW and the OSCA is administered and implemented by the ERCB.

Climate Change Regulations

Climate change regulations continue to evolve in Canada. Since 2002, the federal government has introduced a number of plans but has yet to establish broad regulations. Alberta has introduced provincial regulation that has set a price on CO_2. Alberta's regulations have also established reduction targets on the largest facilities in the province. The following is a brief discussion of federal and provincial policy and regulations to-date.

Government of Canada Regulations

Canada was a signatory to the United Nations Framework Convention on Climate Change (the "**Convention**") and ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nation-wide emissions of carbon dioxide, methane, nitrous oxide and other GHGs. However, the Government of Canada concluded that Canada would not meet its commitment to the Kyoto Protocol and has been developing an alternative strategy for reducing Canada's GHG emissions. On December 12, 2011, the Government of Canada announced that it would not agree to a second commitment period, once the present commitment expires in 2012.

In December 2009, government leaders and representatives from approximately 170 countries met in Copenhagen, Denmark (the "**Copenhagen Conference**") to attempt to negotiate a successor to the Kyoto Protocol. The primary result of the Copenhagen Conference was the Copenhagen Accord, which represents a broad political consensus rather than a binding international treaty like the Kyoto Protocol and has not been endorsed by all participating countries. The Copenhagen Accord reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. Although Canada has committed under the Copenhagen Accord to reducing its GHG emissions by 17% from 2005 levels by 2020, the Copenhagen Accord does not establish binding GHG emissions reduction targets. The Copenhagen Accord calls for a review of implementation of its stated goals before 2016.

Government of Alberta Regulations

Alberta currently regulates GHG emissions under the *Climate Change and Emissions Management Act*, the *Specified Gas Reporting Regulation*, which imposes GHG emissions reporting requirements, and the SGER, which imposes GHG emissions limits. GHG emissions of 50,000 tonnes or more from a facility in any year must be reported to the AEW under the SGER. The SGER 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) against baselines set out in 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 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 intensity is 12% from its baseline, and such reduction must be maintained over time. For a new facility, the emissions intensity reduction requirement from its baseline is phased in by annual 2% increments beginning in the fourth year of commercial operation until the maximum 12% reduction requirement imposed on established facilities is reached. There are three ways to comply with the reduction requirements: (i) actual physical reductions in GHG emissions intensity; (ii) purchase of Alberta based emission offset credits and/or emission performance credits; or (iii) purchase of fund credits at a price to be established by ministerial order, with the proceeds going to the Government of Alberta's Climate Change and Emissions Management Fund. Compliance reports for facilities subject to the SGER must be submitted to the AEW each year on March 31st. The Government of Alberta previously announced that it may modify the SGER to apply stricter standards in its 2008 provincial energy strategy. In addition, facilities in Alberta must also report emissions of industrial air pollutants and comply with all other obligations imposed in any applicable permits and environmental regulations.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act*, which deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions. The most recent step by the Government of Alberta was the promulgation of the *Carbon Sequestration Tenure Regulation* which provides greater details with respect to these new regulatory rules. This regulation clarifies the definition of pore space and creates a post-closure stewardship fund for the costs of ongoing monitoring and remedial work. Alberta is the first province in Canada to pass comprehensive legislation for carbon capture and storage.

The Future of GHG Emission Regulations

There will most certainly be a financial impact of GHG emission regulation on oil sands industry participants and their projects, including Sunshine and its projects, however the extent of that impact is not yet known. In particular, there is uncertainty regarding the ultimate GHG emission regulatory regime that will be applicable to Sunshine due to, among other things, the potential for changes to the United States' regulation of GHG emissions and the potential for the harmonisation of GHG emission regulatory regimes in Canada and the United States.

At present, there is no assurance that any new regulations implemented by the Government of Canada relating to the reduction of GHG emissions will be harmonised with the Government of Alberta's GHG emissions reduction regulations. In such case, the costs of meeting new federal government requirements could be considerably higher than the costs of meeting Alberta's current requirements. Please refer to the sections entitled *"Industry Overview — Environmental Considerations and Regulations" and "Risk Factors — Risks Relating to the Alberta Oil Sands Industry — Operations are subject to significant government regulation"* in this AIF.

Water Use

Due to the necessary use of water to create steam in traditional SAGD operations, fresh water consumption in oil sands production is of concern to a number of stakeholders and the Government of Alberta. Water-use licences and approvals are required by the *Water Act* before diverting or using fresh water. Water is critical in the production of mining and *in-situ* oil sands. Mining projects require fresh water to separate the bitumen from the sand, most of which is sourced from the Athabasca River. Although mining projects can recycle water, certain liquid wastes require storage and treatment in tailings ponds.

In-situ projects have alternatives to fresh water use such as deep non-potable water aquifers and enhanced recycling. *In-situ* projects require water to generate steam that is injected into the ground, and have facilities to treat and recycle the injected water. Water that is not re-used is typically disposed of through deep well injection, thus tailings ponds are not required.

The *Water Act* governs the process through which authorisation is given to divert or use surface or sub-surface water by way of licence or approval. AEW maintains primary responsibility over the application and approval process. However, when necessary, applications may be referred to other agencies such as the SRD for specific technical advice.

Licences are required for all diversions of surface and non-saline groundwater and require a completed application along with accurate drawings depicting water and wastewater conveyance structures; the location and cross-sections of intake structures, control structures, spillways, dams and reservoirs; and the layout of the water system. Applications in respect of projects of a more complex nature may be required to submit additional details of the proposed construction schedule, construction specifications, operational plans, water requirements and the method of operation. Submitted plans may also require the approval of an engineer registered with the APEGGA.

A licence may be issued where the water source can supply the needs of the applicant and the diversion of water has no adverse effect on the source, surrounding users or the environment. Licences may include conditions that require the licensee to submit water monitoring data and quantities of water diverted. Applicants may also be required to pay a fee for the projected annual diversion. An application in respect of lands not owned by the applicant must contain the landowner’s consent. Applicants may also be required to consult with First Nations and place a public notice of the application. However the Director designated under the *Water Act* (the “**Water Director**”) has discretion to waive such notice requirement.

Approvals are required for activities such as construction works or drilling, among others, in, or on any land, water or water body, that may affect the management of Alberta’s water resources, including both surface and groundwater. In considering whether or not to issue an approval, the Water Director will consider (i) the potential or cumulative effects of the water use on the aquatic environment; (ii) hydraulic, hydrological and hydrogeological effects; (iii) any possible effects on household users, licensees and traditional agriculture users; (iv) any possible effects on public safety; and (v) any other matters that the Water Director deems relevant.

Approval applications require drawings, technical specifications, construction schedules and other information similar to those required pursuant to a licence application. Approval applications are reviewed under both the *Water Act* and EPEA by the Water Director. However, where multiple authorisations are required, the AEW can set up a single window approach. As with licences, an approval application in respect of lands not owned by the applicant must contain the landowner’s consent. Similarly, approval applicants may also be required to consult with the First Nations where such notice requirement is not waived by the Water Director. Once the approval has been issued, the holder is given a defined time period within which to construct, maintain and/or operate the project. The approval holder may also be required to submit a signed certificate of completion and/or an environmental monitoring report following completion of construction.

General

Sunshine believes it is in material compliance with all environmental legislation in the jurisdictions in which it operates at this time. It is the Corporation’s practice to do all that we reasonably can to ensure we remain in material compliance with all applicable environmental legislation. We also believe that it is reasonably likely that the trend toward stricter standards in environmental legislation and regulation will continue. We are committed to meeting our responsibilities to protect the environment wherever it operates and will take such steps as required to ensure compliance with all applicable laws and regulations.

Other Relevant Laws and Regulations

Employment Laws and Regulations

Employer obligations in Alberta are established, regulated and adjudicated by various workplace statues and regulations. We are subject to the Alberta Employment Standards Code which establishes certain minimum standards applicable to all employees, such as overtime, holidays, parental leaves. Human rights prohibitions such as discrimination based on gender, age or physical disability are regulated by the *Human Rights Act*. Personal employee information which may be collected, used or disclosed by us is subject to the PIPA. This act requires an employer to assign an individual to establish and administer privacy policies in a company which are compliant with PIPA. We must safeguard personal information. Workplace injuries are subject to the *Worker’s Compensation Act*, which establishes a statutory insurance scheme and mandates all employers to contribute premiums to a government-sponsored fund to compensate workers that are injured due to occupational illness or injury. All employers are subject to the Labour Relations Code which sets out the process by which an employee may join a union and then have the union enter into collective bargaining on behalf of all employees with the company. There is a very low unionisation rate in the Alberta energy sector.

Securities Laws and Regulations

As advised by our Canadian legal advisers, no regulatory approval in Canada is required to permit us to be listed on the SEHK. However, in order to facilitate the Listing, we have applied for, and the ASC has granted Sunshine, exemptive relief from the requirement to file a prospectus in Alberta to qualify the distribution of the Offer Shares pursuant to the Global Offering (other than Offer Shares sold to investors in Canada) including any Shares issued pursuant to the exercise of the Over-Allotment Option. As part of this exemptive relief, one or more existing Shareholders may lend some of their Shares to the Stabilisation Manager to allow the Stabilisation Manager to satisfy over-allocations in the Global Offering, since such Shares are otherwise presently subject to resale restrictions pursuant to Alberta securities laws. In connection with our exemptive relief application, we have undertaken to the ASC to apply, within one month after completion of the Listing, to become a reporting issuer in Alberta.

Overseas Ownership Restrictions

Under the *Mines and Minerals Act* only corporations registered under the *Companies Act* or registered, incorporated or continued under the ABCA are eligible to own Oil Sands Leases or PNG Licenses. Therefore, any ownership by overseas companies or entities of Oil Sands Leases or the PNG Licences must be made indirectly through whole or part ownership of an eligible company. For further details on applicable overseas ownership restrictions, please refer to the section entitled *"Risk Factors — Risks Relating to the Alberta Oil Sands Industry — Ownership of Oil Sands Leases and PNG licences are subject to federal, provincial and local laws and regulations and Oil Sands Leases may be unable to be renewed"* to this AIF.

EMPLOYEES

For the year ended December 31, 2011, Sunshine had 65 full time employees. Employee numbers increased across all its areas of operation, particularly in its geology, drilling and operations departments due to increased activity levels associated with its winter drilling programmes.

RISK FACTORS

An investment in the securities of the Corporation is subject to certain risks. These can be categorized into (i) risks relating to the business of the Sunshine, (ii) risks relating to the oil sands industry; and (iii) risks relating to Alberta and Canada; and (iv) risks relating to our Shares. Investors should carefully consider the various risk factors associated with the business and operations of the Corporation.

Risks Relating to Our Business

Projects are currently in the early stages of development and may not be completed within expected time frames, within budget, or at all.

Our projects are currently in early development stages. The completion of our projects or the commencement of production and commercial sales of oil and bitumen from our projects could be delayed or experience interruptions or increased costs or may not be completed at all due to a number of factors, including:

- delays in obtaining or an inability to obtain, or conditions imposed by, regulatory approvals;
- disruption in the supply of energy and diluent;
- non-performance by third party contractors;
- inability to attract sufficient numbers of qualified workers;

- labour disputes or disruptions or declines in labour productivity;
- unfavourable weather conditions;
- contractor or operator errors;
- design errors;
- availability of infrastructure, pipeline and refining capacity;
- increases in materials or labour costs;
- catastrophic events such as fires, storms or explosions;
- the breakdown or failure of equipment or processes;
- construction, procurement and/or performance falling below expected levels of output or efficiency;
- changes in project scope;
- violation of permit requirements; and
- the pace of progress with respect to extraction technologies.

Given the stage of development of our projects, various changes to the applicable designs and concepts may be made prior to their completion, which could increase costs or delay project completion. We intend to grow our business in stages, and the potential production targets for our clastics and conventional heavy oil are approximately 200,000 bbl/d by 2024 and between 1,600-1,800 bbl/d by the end of 2012, respectively. We plan to recover our clastics and conventional heavy oil, and eventually, as the recovery technologies continue to evolve, our carbonate assets. However, we cannot assure you that our growth will proceed in the stages we expect due to the factors mentioned above or others that we may not be able to foresee.

Historically, some oil sands projects have experienced capital cost increases and overruns due to a variety of factors. While we have a schedule for developing our projects, including obtaining regulatory approvals and commencing and completing the construction of our projects, we cannot assure you that our expected timetables will be met without delays, or at all, which could have potentially adverse effects upon these projects' budgets. Any delays may increase the costs of our projects, requiring additional capital, and we cannot assure you that such capital will be available in a timely and cost-effective fashion.

The level of profitability expected may not be achieved.

The potential profitability of oil sands operations is dependent upon many factors beyond our control. As with any oil sands projects, we cannot assure you that bitumen will be produced pursuant to our Oil Sands Leases. In addition, the marketability of the bitumen produced from our projects will be affected by numerous factors beyond our control. These factors include fluctuations in market prices, the proximity and capacity of pipelines and upgrading and processing facilities, the development and condition of infrastructure necessary to carry out our operations, equipment availability and government regulations (including regulations relating to prices, taxes, royalties, land tenure, allowable production, importing and exporting of oil and gas and environmental protection). These factors could materially affect our financial performance and result in our not receiving an adequate return on invested capital.

In the event that our projects are developed and become operational, we cannot assure you that these projects will produce or transport bitumen or bitumen blends in quantities or at the costs anticipated, or that they will not cease production entirely in certain circumstances. Reservoir quality or equipment failures and design flaws could increase the costs of extracting bitumen at our projects. The costs of producing and transporting bitumen blends from oil sands may increase so as to render recovery of bitumen resources from our projects uneconomical. We cannot assure you that an adequate supply of natural gas and electricity will be available as fuel sources to support production operations at prices which would make our projects economically feasible.

Our estimates of operating costs have been based on current estimations for our projects. Actual operating costs may differ materially from such current estimates. Moreover, it is possible that other developments, such as increasingly strict environmental and safety laws and regulations and enforcement policies could result in substantial costs and liabilities, delays or an inability to complete our projects or the abandonment of our projects.

The development of projects requires significant and continuous capital investment that may be difficult to raise or may be raised under unfavourable terms.

The development of oil sands projects requires a significant amount of capital investment that occurs over a number of years and prior to the commencement of commercial operations at the relevant project. As a result, our projected capital expenditures required to develop commercial operations at our projects are expected to be significantly greater than currently available working capital. We currently do not have the capital or committed financing necessary to complete all of our planned future development phases and therefore will need to rely on additional equity or debt financing to obtain the funds necessary to complete our future development activities. Inflation risks subject us to potential erosion of future product netbacks. For example, domestic prices for construction equipment and services and oil production equipment and services can inflate the costs of project development and increase future operating costs. In addition, any construction or development delays at the projects could increase the capital expenditure required to develop the projects. If we face difficulty in raising sufficient capital or raise capital under unfavourable terms in order to meet our working capital requirements, our business, results of operations, financial position and growth prospects could be materially and adversely affected.

We had net current liabilities of approximately $6.0 million as of December 31, 2009, net current assets as of December 31, 2010 of approximately $27.1 million and net current liabilities of $7.1 million as of December 31, 2011.

We recorded net current liabilities as at December 31, 2009 primarily due to bank borrowings of approximately $5.3 million, which we used to finance our exploration and development activities. As general global economic conditions improved and the availability of liquidity in the capital markets increased in early 2010, we were able to pay down our bank borrowings and raise an aggregate of approximately $130.7 million in equity financing during 2009 and 2010. This resulted in net current assets which allowed us to further advance the development of our oil sands projects, specifically in the Muskwa area. For the year ended December 31, 2011, we raised a gross amount of $225.9 million in equity financing, which resulted in a net current liability position of approximately $7.1 million as at December 31, 2011. Despite the net current asset position we achieved as at December 31, 2010 the net current liability position as at December 31, 2011, we cannot assure you that we will be able to maintain such a position going forward or that we will not record net current liabilities in the future. If our exploration and development activities were to expand rapidly, resulting in a need to incur significant bank borrowings and exceeding the increase in our net current assets items such as cash and cash equivalents and trade and other receivables, then we will again be in a net current liabilities position. Any failure to finance our current liabilities or an increase in the cost of funding of our current liabilities could have a material and adverse effect on our business, results of operations, financial position and growth prospects. Please also refer to the section entitled "*Financial Information Capital Expenditures and Commitment, Net Current Liabilities and Contingent Liabilities Net current (liabilities) assets*" in this AIF.

We incurred net cash outflows from our operating activities. For the years ended December 31, 2009, 2010 and 2011, we recorded net cash used in operating activities of $2.6 million, $6.0 million and $13.8 million respectively, despite the net current asset position we achieved as at December 31, 2010 and net current liability position as at December 31, 2011. This was primarily due to the fact that our operations are at a relatively early stage of development and have not reached commercial production. In particular, we incurred significant expenditures in relation to winter drilling activities and pre production establishment and development of our conventional heavy oil project in the Muskwa area. Until the development of our core areas and related production and operation levels reach a sustainable level, we expect to continue to incur net cash outflows from operating activities for the foreseeable future due to the relatively early stage of our operations and our sizable capital expenditures plan. We cannot assure you that our business activities will generate sufficient cash flows from operations in the future in order to meet ongoing obligations, to service any future debts or to be sufficient for necessary capital expenditures, in which case, we may seek additional financing or consider refinancing some or all of our future debt. Please also refer to the section entitled *"Financial Information - Cash Flow"*.

The attraction, retention and training of key and other personnel is required to meet business and operational needs.

We rely on certain key members of our senior management team and employees who have experience in the oil sands industry to manage our business and growth. The unexpected loss or departure of any of our key officers, employees or consultants could negatively impact our business, results of operations, financial position and growth prospects.

Our projects will require experienced employees with particular areas of expertise. The number of persons skilled in the exploration and development of oil sands projects may be limited. We cannot assure you that all of the required employees with the necessary expertise will be available. There are other oil sands projects in Alberta that are planned for completion on timetables similar to those of our projects. Should those other projects or expansions proceed in the same timeframe as our projects, we may compete with our competitors for experienced employees and such competition may result in retention of an insufficient number of skilled employees and increases to compensation paid to such employees.

In addition, our ability to recruit and train operating and maintenance personnel is a key factor for the success of our business activities. Actual staffing needs may exceed our current projections. If we are not successful in recruiting, training and retaining the personnel we require in sufficient numbers, our business, results of operations, financial position and growth prospects could be materially and adversely affected.

Our operations and assets could be adversely affected by the LARP.

Our operations in the Lower Athabasca region could be adversely affected by the LARP which was released in April 2011 and updated in August 2011 by the Government of Alberta. The LARP contains draft management frameworks not yet approved as provincial law for air emissions, surface water quality and ground water quality that are intended to assist in the monitoring and management of long-term cumulative changes to the Lower Athabasca region. If finalised, and if the production of hydrocarbons under provincial law are subject to change as a result of the LARP draft management framework, then all oil sands companies operating within the Lower Athabasca region will be required to comply with both the terms of their specific approvals as well as the provisions of the LARP, including its land use management frameworks. The LARP also contains future planning to increase provincial conservation areas from 6% to 22% of the region's land base. Conservation areas will be managed to minimise and prevent land disturbance including the possibility of a prohibition on oil sands development. In April 2011, the SRD placed a Protective Notation ("**PNT**") on all surface access associated with the LARP. The PNT acts as a land identifier to the Government of Alberta and industry to identify lands that may be managed to achieve particular land use or conservation objectives, and can place a surface restriction which requires Oil Sands Lease holders to apply for access to proposed conservation areas for new surface and exploration activities. In particular, the PNT requires that lands are held "as is" pending the outcome of the LARP draft planning and, in some cases, can prohibit any activities relating to oil sands sub-surface tenure.

Both GLJ and D&M have independently assessed the potential impact of the LARP on all of our properties in September 2011 as set out in the table below:

	Best Estimate			
Property	**Total PIIP**	**Total PIIP LARP Impact**	**Remaining Total PIIP**	**Total PIIP Loss**
	MMbbl	**MMbbl**	**MMbbl**	**%**
Crow Lake	332	81	251	-24
Harper (Carbonates)	10,555	2,828	7,727	-27
Harper (Clastics)	5,581	199	5,382	-4
Total	**16,630**	**3,108**	**13,522**	**-19**

Both GLJ and D&M have indicated that based on the current LARP only our Crow Lake and Harper properties may be impacted by the proposed conservation areas. The best estimate total PIIP at our Crow Lake and Harper properties that may be impacted by the LARP accounts for approximately 6.9% of our total best estimate PIIP of 45,368 MMbbl as at November 30, 2011 as assessed by GLJ and D&M. The LARP has no impact on our reserves and best estimate contingent resources.

The PNT was amended in August 2011 which allowed oil sands sub-surface tenure applications to be accepted and assessed by the SRD on a case by case basis within the Harper area. We have submitted and received a PNT restriction variance from the SRD which deemed the surface and exploration activities for our proposed 2011/2012 winter drilling programmes in the Harper area to be within the PNT boundaries. However, given the PNT restriction variance applied only to the Harper area, our access to, and exploration activities with respect to other properties continue to be subject to LARP and are substantially restricted. Until the LARP is finalised, and approved as provincial law we are unable to make any definitive assessment of the impact of the LARP on our Oil Sands Leases. However, as the impacted areas contain high estimate contingent resources, prospective resources and PIIP, the execution of our business strategies and expansion plans may be negatively affected by restrictions imposed under the LARP, which could in turn affect our business, results of operations, financial position and growth prospects. In addition, the LARP affects only the Lower Athabasca region, which is one of seven regions of Alberta. We cannot assure you that the Government of Alberta will not impose policies or plans similar to the LARP to regulate environmental protection and preservation in respect of other regions in Alberta.

Our operations depend on infrastructure owned and operated by third parties and on services provided by third parties.

We depend on certain infrastructure owned and operated or to be constructed by others and on services provided by third parties, including, without limitation, processing facilities, pipelines or rail lines for the transportation of products to the market, natural gas, diluent, disposal pipelines, electrical grid transmission lines for the provision and/or sale of electricity to us, engineering, equipment procurement and construction contracts, maintenance contracts for key equipment, and contracts for services of a constant or recurring nature. The failure of any or all of these third parties to supply utilities, services, or, in connection with our SAGD projects, to construct necessary infrastructure on a timely basis and on acceptable commercial terms will negatively impact our operations and financial results.

We initially plan on trucking diluent to, and dilbit from, our SAGD projects to markets in the short term and are also investigating rail and pipeline alternatives. The ability to deliver diluent to our SAGD projects and ship dilbit to markets is dependent on, among other things, access to trucks and drivers, absence of unforeseen obstacles and accidents, weather and general road conditions. Delays or the inability to deliver diluent to our SAGD projects or ship dilbit to market could have a negative impact on our business, results of operations, financial position, growth prospects and cash flow.

Any pursued strategic alliances, partnerships and joint venture arrangements could present unforeseen integration obstacles or costs and may not enhance the business.

We may pursue potential strategic alliances and partnerships in the areas of infrastructure development for our clastic assets, as well as the development and application of new technologies to our carbonate resources and pursue joint venture arrangements with other oil and gas companies to develop our core areas. These arrangements involve a number of risks and present financial, managerial and operational challenges. We may not be able to realise any anticipated benefits or achieve the synergies we expect from these arrangements and we may be exposed to additional liabilities of any acquired business or joint venture. Any of these could materially and adversely affect our revenue and results of operations. In addition, future acquisitions or joint ventures may involve the issuance of additional Shares of the Corporation, which may dilute Shareholders' interests.

Carbonate resources may not be successfully developed.

We intend to apply current and future technologies for development of our carbonate resources, predominantly at our Harper, Muskwa and Portage project areas. The successful development of our carbonate reservoirs depends on, among other things, the successful development and application of SAGD and CSS or other recovery processes to carbonate reservoirs. Although the technology has been developed for application to non-carbonate reservoirs, there are no known successful commercial projects that use SAGD or CSS to recover bitumen from carbonate formations and there exists a large range in the expected recoverable volumes, the lower end of which may not be economically viable. The principal risks associated with SAGD and CSS recovery in carbonate reservoirs are (i) the possibility of unexpected steam channelling which would increase steam requirements resulting in increased costs and potentially reduced economically recoverable bitumen volumes; and (ii) potential mechanical operating problems due to production of fine sedimentary particles which could cause wellbore plugging and reduced bitumen production rates and potential interruption of surface production operations.

Development of carbonate reservoirs will involve significant financial and time investment and project payout is not assured. Our ability to develop our bitumen resources that are located in carbonate reservoirs on a commercially viable scale is contingent upon one or more of the following events occurring:

- using existing SAGD or CSS technology to successfully exploit carbonate reservoirs;
- adapting existing SAGD or CSS technology such that it can be successfully used to exploit carbonate reservoirs; or
- developing or acquiring new technology that can be used to successfully exploit carbonate reservoirs.

We cannot assure you that any of these events will occur. The development of such recovery processes will involve significant capital expenditures and a significant lag time between capital expenditures and the commencement of commercial sales. If a pilot project and/or the technology under development does not demonstrate potential commerciality in carbonate reservoirs then our projects on these assets may not proceed and this may occur only after significant expenditures have been incurred.

There could be claims related to infringement of oil and gas development rights and litigation in the ordinary course of business.

We are subject to the risk that a third party could claim that we have infringed such third party's oil and gas development rights. In addition, we could be involved in litigation in the ordinary course of business. Any claim, whether with or without merit, could be time-consuming to evaluate, result in costly litigation and cause delays in our operations, which could divert management's attention and financial resources from our normal operations.

It is possible for the Crown to grant different mineral rights over a given parcel of land in separate geological horizons. It is not uncommon for different parties to have different rights to specific geological horizons granted on different dates. As a result, different rights of different parties on the same parcel of land can result in conflicts due to their competing interests. Where this occurs, the parties may work together to negotiate a compromise that maximises recovery for all parties involved. Where such a compromise is unattainable, the authority of one of a number of administrative bodies, such as the ERCB or the Surface Rights Board, will be determinative while the ultimate result will be affected by the nature and particular characteristics of the conflict. The ultimate result of such conflicts cannot therefore be predicted accurately in advance and could include the temporary suspension of our ability to explore, develop and exploit our mineral rights.

Hedging arrangements are subject to risks.

The nature of our operations will result in exposure to fluctuations in currency and commodity prices. We may use financial instruments and physical delivery contracts to hedge our exposure to these risks. To the extent that we engage in hedging activities, we will be exposed to credit related losses in the event of non-performance by counterparties to the physical or financial instruments. Additionally, if product prices increase above those levels specified in any future commodity hedging agreements we enter into, we would lose the full benefit of commodity price increases. If we enter into hedging arrangements, we may suffer financial losses if we are unable to commence operations on schedule or are unable to produce sufficient quantities of oil to fulfil our obligations. We may also hedge our exposure to the costs of inputs to our projects such as natural gas. If the prices of these inputs fall below the levels specified in any future hedging agreements, we would lose the full benefit of commodity price decreases.

Risks Relating to the Alberta Oil Sands Industry

Revenue and results of operations are sensitive to changes in oil prices and general economic conditions.

Our revenue and results of operations are sensitive to movements in the market prices for crude oil and general economic conditions. The prices that we receive for our conventional heavy oil bitumen and bitumen blend will depend on crude oil prices. Crude oil prices have historically been subject to large fluctuations due to changes in the supply of, and demand for, oil (and the market perception thereof), which in turn are affected by factors beyond our control. These factors include, among other things, the condition of the Canadian, United States and global economies, actions taken by the Organisation of Petroleum Exporting Countries, governmental regulation, political stability in oil producing nations and elsewhere and war or the threat of war in oil producing regions. Adverse changes in general economic and market conditions could also negatively impact demand for crude oil, bitumen and bitumen blend, revenue, operating costs, results of financing efforts, fluctuations in interest rates, market competition, labour market supplies, timing and extent of capital expenditures or credit risk and counterparty risk.

Any significant reduction in oil prices would lower our selling prices, which could have a material and adverse effect on our revenue and profitability. In addition, a significant reduction in oil prices could render uneconomic the recovery, blending and transportation of our bitumen resources. For example, the global financial crisis that started in 2008 led to a significant drop in oil prices. As a result, a number of oil sands projects were withdrawn or postponed since oil prices at the time were not at a level which made oil sands projects economically feasible. We cannot assure you that oil prices will remain at commercially acceptable levels for oil sands developers in the future.

In addition, the market prices for conventional heavy oil and bitumen blends are lower than the established market indices for light and medium grades of oil, due principally to diluent prices and the higher transportation and refining costs associated with conventional heavy oil and bitumen blends. Future price differentials between heavier and lighter grades of crude oil are subject to uncertainty and any increase in the price differentials could have an adverse effect on our business, results of operations, financial position and growth prospects.

We conduct an assessment of the carrying value of our assets to the extent required by IFRS. If crude oil prices decline, the carrying value of our assets could be subject to downward revision, and our earnings could be adversely affected.

In the future, we may enter into hedging arrangements in order to reduce the impact of crude oil price fluctuations. For a discussion of the risks associated with those arrangements please refer to the section entitled *"Risks Relating to Our Business - Hedging Arrangements Are Subject to Risks"* above.

The Canadian oil sands industry could experience disruptions due to unfavourable or seasonal weather conditions.

The level of activity in the Canadian oil sands industry is influenced by seasonal weather patterns and could be affected by unfavourable weather conditions. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil producing and exploration areas (including many of the areas in which we operate) are located in regions that are inaccessible other than during the winter months because the ground surrounding the sites consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in development and production activities.

Bitumen in-situ recovery processes are subject to uncertainties.

The recovery of bitumen using *in-situ* processes such as SAGD or CSS is subject to uncertainty. Although several companies have utilised these processes to recover bitumen, we cannot assure you that our projects will achieve the same or similar results, or that any of our projects will produce bitumen at expected levels, on schedule or at all.

The quality and performance of the reservoir can also impact the timing, cost and levels of production using this technology. *In-situ* exploration and production operations are also subject to risks such as encountering unexpected formations or pressures and invasion of water into producing formations. With additional data and knowledge of a reservoir, we may realise that the reservoir does not show the same level of porosity and permeability as shown from the previous data set. Moreover, the actual production performance, including recovery rate and SOR, may not meet what has been predicted. In that case, the production plan may be changed or adjusted significantly.

The performance of SAGD or CSS facilities may differ from our expectations. The variances from expectations may include, without limitation:

- the ability to operate at the expected level of production;
- the reliability or availability of the SAGD and CSS facilities; and
- the amount of steam required to reduce the viscosity of bitumen resources.

If the SAGD or CSS facilities do not perform to our expectations or as required by regulatory approvals, we may be required to invest additional capital to correct deficiencies or we may not be able to meet our expected level of production. If these expectations are not met, our revenue, cash flow and relationships with customers could be materially and adversely affected.

Our profitability could be materially and adversely affected by fluctuations in natural gas prices.

Our profitability could be materially and adversely affected by fluctuations in natural gas prices. We utilise natural gas to produce steam and natural gas condensate as a diluent to reduce the viscosity of our bitumen resources. Natural gas prices have been subject to significant fluctuations due to changes in supply and demand. Factors which affect natural gas prices include, among other things, weather conditions in the United States and Canada, pipeline capacity and oil prices. We currently do not plan to enter into long term contracts for the purchase of natural gas or hedging arrangements related to movements in natural gas prices. If natural gas prices increase, our costs could increase and our profitability could be materially and adversely affected.

Drilling and other equipment for exploration and development activities may not be available when needed.

Oil exploration and development activities are dependent on the availability of drilling and related equipment in the areas where such activities will be conducted. If the demand for this equipment exceeds the supply at any given time, or if the equipment is subject to access restrictions, our exploration and development activities could be delayed. We cannot assure you that sufficient drilling and other necessary equipment will be available as needed by us. Shortages could delay our proposed exploration, development and sales activities, and could have a material adverse effect on the business, results of our operations, financial position and growth prospects.

Access to diluent supplies at favourable prices may be limited.

Bitumen is characterised by low API gravity or weight and high viscosity or resistance to flow. We plan on using condensate as a diluent. Diluent is required to facilitate the processing and transportation of bitumen. A shortfall in the supply of diluent may cause its cost to increase or require alternative diluent supplies to be purchased, thereby increasing the cost to transport bitumen to market and correspondingly increasing our operating cost and adversely impacting our overall profitability.

A lack of, or impediment to constructing sufficient pipeline, shipping or refining capacity could adversely affect our business, results of operations, financial position and growth prospects.

The primary market for Canadian-sourced oil has traditionally been the United States. Through proposed pipelines and shipping terminals, Canadian-sourced oil from Alberta could be transported to Asian markets when destination terminals are constructed along the west coast of Canada and when transportation proposals connecting the Athabasca region to west coast terminals are implemented. Currently there are a number of planned projects which could potentially increase the pipeline, shipping and refining capacity for bitumen and conventional heavy oil sourced from Alberta. However, we cannot assure you that these projects will increase pipeline, shipping or refining capacity at a rate which would be sufficient to match the demand for such capacity. If there is a shortage of pipeline, shipping and refining capacity for heavy conventional oil and bitumen, our business, results of operations, financial position and growth prospects could be materially and adversely affected.

Major infrastructure projects such as trans-continental pipelines to transport oil from Alberta to the United States require regulatory and government approvals from both the Canadian and US governments. If proposed pipeline construction projects are rejected by either government or if there are other technical or regulatory obstacles associated with the construction of the pipelines, new pipelines may not be constructed and our ability to transport oil using such pipelines would be negatively impacted. Similarly, any rejection by governments or regulatory bodies of proposals to build new shipping and refining capacity for heavy conventional oil and bitumen may also materially and adversely affect our business, results of operations, financial position and growth prospects.

Oil sands exploration and development is subject to operational risks and hazards.

The operation of our projects is subject to risks and hazards relating to recovering, transporting and processing hydrocarbons, such as fires, explosions, gas leaks, migration of harmful substances, blowouts and spills. The occurrence of any of these incidents might result in the loss of equipment or life, as well as injury or property damage. Our projects could be interrupted by natural disasters or other events beyond our control. Losses and liabilities arising from uninsured or under-insured events could have a material adverse effect on our projects and on our business, results of operations, financial position and growth prospects.

Our projects are expected to process large volumes of hydrocarbons at high pressure and at high temperatures in equipment with defined tolerances which will handle large volumes of high pressure steam. Equipment failures could result in damage to our facilities and liability to third parties against which we may not be able to fully insure or may elect not to insure due to high premium costs or for other reasons.

We expect that we will initially use trucks to bring our bitumen to the market. Normal hazards associated with trucking include collisions between vehicles and wildlife. We may also use rail or pipelines to transport dilbit to the market and diluent to our projects. Normal hazards associated with transportation by rail include collisions with vehicles and wildlife and rail line breaks. Normal hazards associated with transportation by pipeline include leakage and other potential environmental issues. These hazards could potentially disrupt the transportation of our products and materials and could materially and adversely affect our business, results of operations, financial position and growth prospects.

Our plans and assumptions for the development of Base Case Clastic Assets differ in some important respects from the plans and assumptions relied on by GLJ.

GLJ, one of our independent reserves evaluators, has provided a third party view of a development plan for our Base Case Clastic Assets. However, we intend to pursue our own development plans based upon our own assumptions for Base Case Clastic Assets. Certain of these plans and assumptions, including the development schedule, expected capital expenditures, operating cost, and production levels and other performance indicators differ from those employed by GLJ. In particular, our management assumptions and GLJ assumptions differ in the following principal respects:

- We have assumed a more conservative development schedule compared to the schedule assumed by GLJ, because we have taken into account additional possible constraints such as access to cost efficient capital.

- We have derived our production estimate from type curves created from a numerical reservoir simulator, which we believe incorporates more detailed reservoir and fluid characterisation than is inherently possible using the analytical model employed by GLJ. As a result, it allows us to conduct more rigorous sensitivity analysis to determine the impact of changes in parameters, resulting in a higher, project-specific production estimate than that of GLJ.

- We and GLJ have both assumed the use of infill wells to increase bitumen recovery. However, we have assumed that infill wells will begin production within two and half years after first steam as compared to four years based on the assumption of GLJ. In addition, we have assumed a smaller volume of steam is required to produce a barrel of bitumen than that assumed by GLJ, leading to an estimate of reduced fuel operating cost per barrel compared to GLJ's estimate.

- We have assumed NCG co-injection earlier in a well's productive life in order to achieve a reduction in overall steam requirements by one-third after one year of production. GLJ assumed NCG co-injection near the end of a well's productive life which will only lead to a steam reduction of 10%.

- We expect to have lower SOR requirements and a smaller central processing facility as a result of the different assumptions we adopted regarding infill wells and NCG co-injection, allowing us to estimate lower capital and operating costs per barrel of bitumen compared to GLJ's estimate.

While a number of our key assumptions may be more or less favourable than those adopted by GLJ, they do not affect the reserves and resources, as stated by GLJ. We cannot assure you that we will be able to achieve our planned production targets with the level of capital and operating expenditure which we currently anticipate. For example, if our actual SOR is higher than we anticipated, we will likely experience lower production levels or need to incur more capital and operating expenses in order to achieve our target production. Many of the assumptions made by us are subject to change and may, over time, deviate from actual events. If our management assumptions prove to be inaccurate, our actual results of operations may diverge from our estimates, and such divergence may be significant and adverse.

There are risks associated with reserves and resources definitions.

We have disclosed estimated volumes of our contingent resources, prospective resources and PIIP, in addition to estimates of values of contingent resources, in this AIF. None of the volumes or values of our resources have been risked for chance of development or, in the case of prospective resources, chance of discovery. Actual recovery may be substantially less. We are currently attributed with 419 million bbls of 2P reserves and 3.1 billion bbls of best estimate contingent resources.

Contingent resources are 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 which 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, established recovery technology or technology under development, corporate commitment, and/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 sub-classified based on project maturity and/or characterised by their economic status. There is a greater degree of risk associated with developing the carbonates in view of the distinction that established recovery technologies are methods proven to be successful in commercial applications, whilst technology under development is technology developed and verified by testing as feasible for future commercial application to the subject reservoir.

Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective resources are further sub-divided in accordance with the level of certainty associated with recoverable estimates, assuming their discovery and development, and may be sub-classified based on project maturity.

Total PIIP is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered. It is a measure derived from an aggregation of the total reserves, contingent resources and prospective resources held by a person, whether they are recoverable or unrecoverable.

The range of uncertainty of estimated recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. Resources should be provided as low, best, and high estimates as follows:

- Low Estimate: This is 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 at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

- Best Estimate: This is considered to be the best estimate of the quantity that will actually be 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 (P50) that the quantities actually recovered will equal or exceed the best estimate.

- High Estimate: This is 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 at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

This approach to describe uncertainty may be applied to reserves, contingent resources, prospective resources and PIIP. There may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production. We cannot assure you that it will be commercially viable to produce any portion of the contingent or prospective resources.

The reserves and resources data and present value calculations presented in this AIF are estimates based on a number of assumptions which may deviate from the actual figures over time.

There are numerous uncertainties inherent in estimating quantities of proved and probable reserves, quantities of contingent resources and future net revenues to be derived therefrom, including many factors beyond our control. The reserves, contingent resources and estimated financial information with respect to certain of our Oil Sands Leases have been independently evaluated by GLJ and D&M. These evaluations include a number of factors and assumptions made as of the date on which the evaluation is made such as geological and engineering estimates which have inherent uncertainties, the effects of regulation by governmental agencies such as initial production rates, production decline rates, ultimate recovery of reserves and contingent resources, timing and amount of capital expenditures, marketability of production, current and estimate prices of blended bitumen, crude oil and natural gas, our ability to transport our product to various markets, operating costs, abandonment and salvage values and royalties and other government levies that may be imposed over the productive life of the reserves and contingent resources. Reserves and contingent resources estimates may require revision based on actual production experience. Actual production and cash flow derived from our Oil Sands Leases may vary from GLJ and D&M's estimates on both, and such variations may be material and adverse.

We use PV10% to estimate the present value of future net revenues from our operations. Pre-tax PV10% is the estimated present value of our future net revenues generated from our proved reserves and contingent resources before taxes, discounted using an annual discount rate of 10%. Post-tax PV10% is the same calculation on an after tax basis. PV10% is not a measure of financial or operating performance, nor is it intended to represent the current market value of our estimated oil sands reserves and resources. Estimates with respect to reserves and contingent resources that may be developed and produced in the future are often based on volumetric calculations, probabilistic methods and analogy to similar types of reserves and resources, rather than upon actual production history, and are therefore generally less reliable. Subsequent evaluations of the same reserves or resources based on production history may result in material variations from current estimated reserves and contingent resources. Furthermore, estimates with respect to future revenue to be derived from proved reserves and contingent resources are inherently uncertain as they are often determined based on assumed oil prices and our operating costs and may be further impacted by assumptions we make in respect of a number of factors, such as market demand for oil, interest rate and inflation rate, all of which are not within our control. While we believe that the presentation of PV10% estimates provides useful information to investors in evaluating and comparing the relative size and value of our reserves and contingent resources, calculations of our future net revenues using PV10% are inherently uncertain as a result of the reasons outlined above and therefore should not be unduly relied on. Furthermore, both GLJ and D&M, have used a range of other discount rates to calculate present value of future net revenues which would produce different results from the use of PV10%. We make no representation that 10% is the correct or best discount rate to use and PV10% estimates are presented in this AIF for reference only.

Only positive PV10% values and the associated resource barrels are reported in this AIF for each region and classification category. In some scenarios, the low case estimate indicates a 0 value indicating that there are uneconomic results (negative PV10%) and the company would not proceed with development. This is consistent with reporting in the company's independent resource reports and COGEH guidelines that specify that contingent resources must be economic under current pricing.

Future delineation programmes may not be successful in adding to reserves and resources.

As part of our growth strategy, we intend to further delineate reserves and resources on our existing Oil Sands Leases land base. We cannot assure you that our delineation programmes will be successful in adding to our reserves and resources. If these programmes are not successful, our growth prospects could be materially and adversely affected.

The oil sands and oil industry in general are highly competitive.

The Canadian oil sands industry and international oil industry are highly competitive. Oil producers compete with each other in a number of areas, including in attracting and retaining experienced and skilled management personnel and oil and gas professionals, the procurement of equipment for the extraction of bitumen, access to capital markets, the exploration for, and the development of, new sources of supply, the acquisition of oil interests, the distribution and marketing of petroleum products, and the obtainability of sufficient pipeline and other means of transportation. Our business will compete with producers of bitumen, bitumen blends, synthetic crude oil and conventional crude oil. Some of these competitors may have lower costs and greater financial and other resources than us. A number of these competitors have significantly longer operating histories and have more widely recognised brand names, which could give such competitors advantages in attracting customers and employees. The expansion of existing operations and development of new projects by other companies could materially increase the supply of competing crude oil products in the marketplace. Depending on the levels of future demand, increased supplies could have a negative impact on prices for bitumen blend, which in turn could negatively affect our selling prices.

Ownership of Oil Sands Leases and PNG Licences are subject to federal, provincial and local laws and regulations and Oil Sands Leases may be unable to be renewed.

The *Mines and Minerals Act* regulates those natural persons and corporate entities eligible to own Oil Sands Leases or PNG Licences and limits ownership to a number of different types of locally registered corporate entities, including corporations registered under the *Companies Act* or corporations registered, incorporated or continued under the ABCA. Accordingly, overseas companies or entities may not directly own Oil Sands Leases or PNG Licences in Alberta. They may only do so indirectly through whole or part ownership of a Canadian registered or incorporated company.

The ICA also generally prohibits a reviewable investment to be made by an entity that is a "non-Canadian", unless after review, the minister responsible for the ICA is satisfied that the investment is likely to be of net benefit to Canada.

An investment in the Shares by a non-Canadian who is not a "WTO investor" (which includes governments of, or individuals who are nationals of, member states of the World Trade Organisation (including Canada) and corporations and other entities which are controlled by them), at a time when Sunshine was not already controlled by a WTO investor, would be subject to a net benefit review under the ICA in two circumstances. First, if it was an investment to acquire control (within the meaning of the ICA, and as described below) and the value of the Corporation's assets, as determined under ICA regulations, was $5 million or more. Second, the investment would also be reviewable if an order for review was made by the federal cabinet of the Canadian government on the grounds that the investment related to Canada's cultural heritage or national identity (as prescribed under the ICA), regardless of asset value.

An investment in our Shares by a WTO investor (or by a non-Canadian who is not a WTO investor at a time when the Corporation was already controlled by a WTO investor) would only be reviewable under the ICA if it was an investment to acquire control and the value of the Corporation assets, as determined under ICA regulations, was not less than a specified amount, which for 2012 is $330 million.

In addition to the foregoing circumstances, an investment would also be reviewable if an order for review is made by the federal cabinet of the Canadian government on the grounds that an investment by a non-Canadian could be injurious to national security.

As a result of legislative amendments not yet in force, the usual thresholds for review for direct acquisitions of Canadian businesses (other than acquisitions of cultural businesses) by foreign investors may change as of a date to be determined by the federal cabinet of the Canadian Government. At that time transactions will be reviewable only if the "enterprise value" of the assets of the Canadian business is equal to or greater than $600 million, in the case of investments made during the first two years after the amendments come into force, which threshold would increase in accordance with the regulations.

The ICA provides detailed rules to determine if there has been an acquisition of control. For example, a non-Canadian would acquire control of the Corporation for the purposes of the ICA if the non-Canadian acquired a majority of the Shares. The acquisition of less than a majority, but one-third or more, of the Shares would be presumed to be an acquisition of control of Sunshine unless it could be established that, upon such acquisition, Sunshine would not in fact be controlled by the acquirer. An acquisition of control for the purposes of the ICA could also occur as a result of the acquisition by a non-Canadian of all or substantially all of the Corporation's assets.

Further, the *Competition Act* provides that certain substantial transactions among significant parties may not be consummated unless a pre-merger notification thereof is made to the Commissioner and a stipulated waiting period expires. Where the Commissioner believes that a proposed transaction does not give rise to competition concerns, he may issue an Advance Ruling Certificate (an "**ARC**") that exempts the parties from the notification requirement and precludes the Commissioner from challenging the transaction in the future.

There are two thresholds that must be met in order for a transaction to be notifiable. The first threshold is the current $77 million "size of transaction" threshold. This threshold is set annually by the Canadian government and the 2012 threshold was recently published as $77 million. If the book value of the assets in Canada of Sunshine, or the revenues generated from sales in or from Canada by Sunshine and its affiliates exceed $77 million, the second $400 million "size of the parties" threshold must also be considered. Assuming the first threshold is exceeded, if the book value of the assets in Canada or the revenues generated in, from and into Canada of the purchaser and its affiliates and Sunshine and its affiliates exceeds $400 million, notification is required.

If a person (or affiliated group of persons) acquires more than 20% of the total issued and outstanding Shares and the above mentioned thresholds are exceeded, *Competition Act* approval may be required.

If a transaction is subject to notification, the parties thereto are required to file prescribed information in respect of themselves, their affiliates and the proposed transaction and pay a prescribed filing fee. The parties may also apply for an ARC or a "no action letter" which may be issued by the Commissioner in respect of a proposed transaction if she is satisfied that there are not sufficient grounds on which to apply to the Competition Tribunal for an order challenging the transaction at that time. As the Commissioner retains the right to challenge a transaction for up to three years after closing, the parties usually agree not to close until the Commissioner has completed her review and has issued either a no-action letter or an ARC. The Commissioner would likely only challenge a proposed transaction if the transaction prevents or lessens, or is likely to prevent or lessen, competition substantially in the market affected.

Oil produced from Oil Sands Leases in Alberta is produced pursuant to two types of oil sands agreements issued under the *Oil Sands Tenure Regulation* made under the *Mines and Minerals Act*. These are (i) permits, issued for a five-year term, which can be converted into leases; and (ii) leases, issued for an initial 15-year term, which can be continued as to all or any portion which the Minister of Energy may determine. The *Mines and Minerals Act* requires that exploration or development activities be undertaken according to prescribed levels of evaluation or production. Permits may generally be converted into leases provided certain minimum levels of exploration have been achieved and all lease rentals have been timely paid. Although an Oil Sands Lease may generally be continued after the initial term as to all or any portion which the Minister of Energy may determine, if the minimum levels of exploration or production have not been achieved and all lease rentals have been timely paid, we cannot assure you that we will be able to renew all of our Oil Sands Leases as they expire.

Operations are subject to significant government regulation.

Our business is subject to substantial regulation under provincial and federal laws relating to the exploration for, and the development, processing, marketing, pricing, taxation, and transportation of oil sands bitumen, its related products and other matters. Changes to current laws and regulations governing operations and activities of oil sands operations could have a material adverse impact on our business. We cannot assure you that laws, regulations and government programmes related to our projects and the oil sands industry will generally not be changed in a manner which may adversely affect our projects, cause delays or inability to complete our projects or adversely affect our profitability.

The permits, leases, licences and approvals which are necessary to conduct our operations may not be obtained or renewed or may be cancelled.

Permits, leases, licences, and approvals are required from a variety of regulatory authorities at various stages of our projects. We cannot assure you that the various government permits, leases, licences and approvals sought will be granted in respect of our projects or, if granted, will not be cancelled or will be renewed upon expiry. We cannot assure you that such permits, leases, licences, and approvals will not contain terms and provisions which may adversely affect the final design and/or economics of our projects. In addition, we cannot assure you that third parties will not object to the development of our projects during the regulatory process.

When resources and reserves have been extracted from projects, abandonment and reclamation costs will be incurred.

We will be responsible for compliance with the terms and conditions of environmental and regulatory approvals we receive and all the laws and regulations regarding the abandonment of our exploration and delineation wells, our projects and the reclamation of our lands at the end of their economic lives. These abandonment and reclamation costs may be substantial.

A breach of such approvals, laws or regulations may result in the issuance of remedial orders, the suspension of approvals, or the imposition of fines and penalties. It is not presently possible to estimate the abandonment and reclamation costs with certainty since they will be a function of regulatory requirements in the future. The value of salvageable equipment may not fully cover these abandonment and reclamation costs.

In addition, in the future we may be required by applicable laws or regulations to establish and fund one or more reclamation funds to provide for payment of future abandonment and reclamation costs, which could divert cash resources away from capital expenditure and working capital needs. We have made a provision for decommissioning obligations.

Our operations are subject to environmental regulation.

Our operations are, and will continue to be, affected in varying degrees by federal, provincial and local laws and regulations regarding the protection of the environment. Should there be changes to existing laws and regulations, our competitive position within the oil sands industry may be adversely affected, and other industry players may have greater resources than we have to adapt to legislative changes.

We cannot assure you that future environmental approvals, laws or regulations will not adversely impact our ability to develop and operate our oil sands projects or increase or maintain production of bitumen or control of our costs of production. Equipment which can meet future environmental standards may not be available on economically viable terms or on a timely basis and instituting measures to ensure environmental compliance in the future may significantly increase operating costs or reduce output. There is a risk that the federal and/or provincial governments could pass legislation that would tax air emissions or require, directly or indirectly, reductions in air emissions produced by energy industry participants, which we may be unable to mitigate.

All phases of the oil sands business present environmental risks and hazards and are subject to environmental legislation and 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 and emissions of various substances produced in connection with oil sands 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. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. Unlawful discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require us to incur costs to remedy such discharge. We cannot assure you that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise may have a material adverse effect on our business, results of operations, financial position and growth prospects.

Oil sands leases are subject to provincial stewardship and conservation guidelines, and as such, there is a risk that surface and subsurface access and activities could be altered to conserve and protect the diversity of ecological regions, migratory species and support the efficient use of lands. The ALSA defines regional outcomes (economic, environmental and social) and includes a broad plan for land and natural resource use for public and private lands.

Additionally, although we are currently not a party to any material environmental litigation, we cannot assure you that we will not become subject to such legal proceedings in the future, which may have a material adverse effect on our business, results of operations, financial position, growth prospects and reputation.

For further information on environmental regulation, please refer to the section entitled *"Laws and Regulations in the Industry - Laws and Regulations Relating to Land"* and the section entitled *"Laws and Regulations in the Industry - Laws and Regulations Relating to Environmental Protection"* in this AIF.

Operations could be adversely affected by climate change legislation.

As is the case for all producers, our exploration activities and production facilities emit GHG which directly subjects us to statutory regulation.

On July 1,2007, SGER came into force under the *Climate Change and Emissions Management Act* requiring Alberta facilities which emit or have emitted more than 100,000 tonnes of GHGs in 2003 or any subsequent year to reduce their GHG emissions intensity by 12% (from emission baseline levels). If a facility is not able to abate GHG emissions sufficiently to meet the reduction target, it may utilise the following compliance mechanisms: (i) emissions performance credits obtained from other regulated facilities; (ii) emissions offsets obtained from non-regulated facilities or projects which reduce or remove GHG emissions; or (iii) credits for contributions to the Climate Change and Emissions Management Fund. Regulated facilities may choose any combination of these compliance mechanisms to comply with their target. At present, we do not operate any facilities regulated by SGER. However, we cannot assure you that we will not incur material costs in the future if the relevant provisions contained in SGER are amended. The Government of Alberta also published a new climate change action plan in January 2008 wherein it set an objective to deliver a 50% reduction in GHG emissions by 2050 compared to business as usual, by employing: (i) mandatory carbon capture and storage ("**CCS**") for certain facilities and development across all industrial sectors; (ii) energy efficiency and conservation; and (iii) research and investment in clean energy technologies, including carbon separation technologies to assist CCS.

Changes in the regulatory environment such as increasingly strict carbon dioxide emission laws could result in significant cost increases. In 2008, the Government of Canada provided details of its environmental regulatory framework, originally announced on April 26, 2007. All industrial sectors in Canada were required to reduce their emissions intensity from 2006 levels by 18% by 2010, with 2% continuous improvement every year after that. Oil sands facilities that commence production after 2012 were to meet a stricter set of requirements that are based on CCS for *in-situ* and upgrading, which were to be effective in 2018. Draft regulations to implement the framework were originally scheduled to be made available for public comment in the fall of 2008 and introduced by January 2010, but have not yet been released. It is unknown when the regulations will be released or implemented.

Canada is a signatory to the UN Framework Convention on climate change and the Kyoto Protocol established thereunder pursuant to which it was required to reduce its GHG emissions by 6% below 1990 levels by the 2008-2012 timeframe. Subsequent to ratifying the Kyoto Protocol, the Government of Canada announced that it would be unable to meet its Kyoto commitments. In December 2009 representatives from approximately 170 countries met at Copenhagen, Denmark, to negotiate a successor to the Kyoto Protocol. That meeting resulted in the non-binding Copenhagen Accord which represents a broad political consensus rather than a binding international obligation. On January 30, 2010, the Government of Canada committed to a non-binding GHG emissions target of 17% below 2005 levels by 2020 pursuant to the Copenhagen Accord. On December 12, 2011, the Government of Canada announced that it would not agree to a second Kyoto compliance period following the expiration of the first period in 2012.

The Canadian government has stated on several occasions that it would like to align its GHG emissions regime with that of the US. It is currently unclear when such legislation will be enacted in the US or what it will entail. It is therefore unclear whether or when the Canadian federal government will implement a GHG emissions regime or what obligations might be imposed thereunder. Any Canadian federal legislation, once enacted, could have a material effect on our operations.

Future federal industrial air pollutant and GHG emission reduction targets, together with provincial emission reduction requirements contemplated in the *Climate Change and Emissions Management Act*, or emission reduction requirements in future regulatory approvals, may require the reduction of emissions or emissions intensity from our operations and facilities, payments to a technology fund or purchase of emission performance or off-set credits. The required emission reductions may not be technically or economically feasible for our projects and the failure to meet such emission reduction requirements or other compliance mechanisms may materially adversely affect our business and result in fines, penalties and the suspension of operations. In addition, equipment from suppliers which can meet future emission standards may not be available on an economic basis and other compliance methods of reducing emissions or emission intensity to required levels in the future may significantly increase our operating costs or reduce the output of our projects. Emission performance or off-set credits may not be available for acquisition by us, or may not be available on an economically feasible basis. There is also the risk that the provincial government could impose additional emission or emission-intensity reduction requirements, or that the federal and/or provincial governments could pass legislation which would tax such emissions.

Changes in foreign exchange rates could adversely affect our business, results of operations and financial position.

Our results are affected by the exchange rate between the Canadian and US dollar. The majority of our expenditures and other expenses are in Canadian dollars, and our reporting currency is the Canadian dollar. The majority of our revenues will be received in US dollars or from the sale of oil commodities that reflect prices determined by reference to US benchmark prices. An increase in the value of the Canadian dollar relative to the US dollar will decrease the revenues received and recorded in our financial statements from the sale of our products.

Shortages in electricity and natural gas, or increases in electricity and natural gas prices may adversely affect our business, results of operations and financial position.

We expect to consume substantial amounts of electricity and natural gas in connection with our bitumen recovery techniques, and our demand will increase as our production capabilities increase and our projects are developed. Any shortages or disruptions in our electricity or natural gas could lead to increased costs. Although we plan to generate electricity for our projects through the use of our cogeneration plant rather than through purchasing power from the local grid, we cannot assure you that this plant will sufficiently supply power to our projects. If we purchase electricity from the local grids, the electricity prices could be higher than the electricity sourced from our cogeneration plant, and our operating expenses could increase.

Shortages in water supply may adversely affect our business, results of operations and financial position.

In SAGD operations, water is used to create steam and it is also used to separate bitumen from sand. In order to use or divert fresh water, we must first obtain a water licence. Any shortages in our water supply could lead to increased costs, and any delays or difficulties in obtaining or maintaining a water licence could adversely affect our operations. For further details, please refer to the section entitled *"Laws and Regulations in the Industry - Water use"* in this AIF.

Our independent reserves evaluators have not undertaken site inspections of our Properties or independently verified the data provided to them by Sunshine.

Both GLJ and D&M rely on, amongst other things, the data provided to them by us in their evaluation of our reserves and resources. Our independent reserves evaluators have not undertaken site inspections of our Properties. Further, data provided to our independent reserves evaluators by us is considered by our independent reserves evaluators, but is only independently verified through public data, analogous developments and/or interpreted by utilising the GLJ and D&M's experience and industry knowledge. Our independent reserves evaluators provide independent evaluation of our resources based on all available data. We cannot be certain that our independent reserves evaluators would not have evaluated our reserves and resources, as disclosed in this AIF, differently, if they had conducted a site visit or relied only on public data sources not including the information directly provided by Sunshine.

Risks Relating to Alberta and Canada

Cash flow and profitability could be affected by changes in Alberta's royalty regime and by increased taxes.

The development of our resource assets will be directly affected by the applicable fiscal regime. The economic benefit of future capital expenditures for our projects is, in many cases, dependent on the fiscal regime. The Government of Alberta receives royalties on production of natural resources from lands in which it owns the mineral rights. On October 25, 2007, the Government of Alberta unveiled a new royalty regime. The new regime introduced new royalties for conventional oil, natural gas and crude bitumen and became effective on January 1, 2009. These royalties are linked to commodity prices and production levels and will apply to both new and existing oil sands projects and conventional oil and gas activities.

Under this regime, the Government of Alberta increased its royalty share from oil sands production by introducing price-sensitive formulas which will be applied both before and after specified allowed costs have been recovered. These changes to Alberta's oil sands royalty regime required changes to existing legislation, including the *Mines and Minerals Act*, and the implementation of certain new legislation, namely the *Oil Sands Royalty Regulation*, the *Oil Sands Allowed Cost (Ministerial) Regulation*, and the *Bitumen Valuation Methodology (Ministerial) Regulation*. While the intent of such revised and newly implemented legislation is to provide a fair, predictable and transparent royalty regime, each of the abovementioned statutes have been partially amended since 2009, and in some cases specifically remain open to changing circumstances and new categories of costs, and as such remain subject to further future modification, whether as a result of industry developments, renewed public and/or industry consultation or otherwise.

We cannot assure you that the Government of Alberta or the Government of Canada will not adopt a new fiscal regime or otherwise modify the existing fiscal regime governing oil sands producers in a manner that could materially affect the financial prospects and results of operations of oil sands developers and producers in Alberta, including us.

Claims may be made by aboriginal peoples.

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada based on historic use and occupation of lands, historic customs and treaties with governments. Such rights may include rights to access the surface of the lands, as well as hunting, harvesting and fishing rights. We are not aware that any claims have been made in respect of our specific properties or assets. However, if a claim arose and was successful such claim could, among other things, delay or prevent the exploration or development at our projects, which in turn could have a material adverse effect on our business, results of operations, financial position and growth prospects.

Prior to making decisions that may adversely affect existing or claimed aboriginal rights and interests, the government has a duty to consult with potentially affected aboriginal peoples. The time required for the completion of aboriginal consultations may affect the timing of regulatory authorisations. Furthermore, any agreements or arrangements reached pursuant to such consultation may materially affect our business, results of operations, financial position and growth prospects.

As a Canadian company, it could be difficult for our investors not resident in Canada to effect service of process on and recover against us or our Directors and officers. Shareholders who are not resident in Canada may face difficulties in protecting their interest.

We are a Canadian company and most of our officers and Directors are residents of Canada. A substantial portion of our assets and the assets of our officers and Directors, at any one time, are located in Canada. It could be difficult for investors not resident in Canada to effect service of process within Canada on our Directors and officers who reside outside their jurisdiction or to recover against us or our Directors and officers on judgments of foreign courts predicated upon the laws of other jurisdictions.

Our corporate affairs are governed by our charter documents, consisting of our Articles, and by the ABCA. The rights of our Shareholders and the fiduciary responsibilities of our Directors are governed by the laws of Alberta and Canada. The laws of Alberta and Canada relating to the protection of the interests of minority Shareholders differ in some respects from those established under statutes or judicial precedent in existence in Hong Kong. Investors not resident in Canada should be mindful about such differences.

Risks Relating to Our Shares

The price and trading volume of our Shares may be volatile, which could result in substantial losses for investors purchasing Shares.

Factors such as fluctuations in our revenue, earnings, cash flows, new investments, acquisitions or alliances, regulatory developments, additions or departures of key personnel, or actions taken by competitors could cause the market price of our Shares or trading volume of our Shares to change substantially and unexpectedly. In addition, stock prices have been subject to significant volatility in recent years. Such volatility has not always been directly related to the performance of the specific companies whose shares are traded. Such volatility, as well as general economic conditions, may materially and adversely affect the prices of shares, and as a result investors in our Shares may incur substantial losses.

Future sale or major divestment of Shares by any of our substantial Shareholders could adversely affect the prevailing market price of the Shares.

The Shares held by certain substantial Shareholders are subject to certain lock-up periods. We cannot assure you that after the restrictions of the lock-up periods expire that these Shareholders will not dispose of any Shares. Sales of substantial amounts of our Shares in the public market, or the perception that these sales may occur, may materially and adversely affect the prevailing market price of the Shares.

Future issuances or sales, or perceived issuances or sales, of substantial amounts of the Shares in the public market could materially and adversely affect the prevailing market price of the Shares and the Corporation's ability to raise capital in the future.

The market price of our Shares could decline as a result of future sales of substantial amounts of our Shares or other securities relating to our Shares in the public market, including by our substantial Shareholders, or our issue of new Shares, or the perception that such sales or issuances may occur. Future sales, or perceived sales, of substantial amounts of our Shares could also materially and adversely affect our ability to raise capital in the future at a time and at a price favourable to it, and our Shareholders would experience dilution in their holdings upon issuance or sale of additional securities in the future.

We may not be able to pay any dividends on the Shares.

We cannot guarantee when, if and/or in what form dividends will be paid on our Shares in the future. A declaration of dividends must be proposed by our Board and is based on, and limited by, various factors, including, without limitation, our business and financial performance, capital and regulatory requirements and general business conditions. We may not have sufficient or any profits to make dividend distributions to Shareholders in the future, even if our financial statements prepared under IFRS indicate that our operations have been profitable. For further details on our dividend policy, please refer to the section entitled *"Financial Information - Dividend Policy"* in this AIF.

Issuance of Shares pursuant to the Pre-IPO Share Option Scheme could result in dilution to our Shareholders.

We have granted options over our Shares pursuant to two Pre-IPO Share Option Schemes. As of the present date, there are outstanding options to subscribe for 204,383,800 Shares, representing approximately 6.71% of the Shares issued and outstanding on the Listing Date (assuming that all of the Share options granted under our Pre-IPO Share Option Schemes have been exercised in full and assuming that all of the Orient Shares are issued as at the Listing Date and excluding any Shares which may be issued pursuant to the conversion of any Class "H" Shares or Class "G" Shares as at the Listing Date). If these options are exercised, there would be an increase in our issued share capital, which in turn would dilute our existing Shareholders' shareholding interest in us and reduce the pro forma earnings per Share.

DIVIDENDS

The Corporation has not declared or paid any dividends since its incorporation. The Corporation does not have a present intention to pay any dividends. The payment of dividends in the future will be dependent on the Corporation's earnings, financial condition and such other factors as the board of directors considers appropriate.

DESCRIPTION OF SHARE CAPITAL

The authorized capital of the Corporation consists of an unlimited number of shares designated as Class "A" Common Voting Shares, Class "B" Shares, Class "C" Common Non-Voting Shares, Class "D" Common Non-Voting Shares, Class "E" Common Non-Voting Shares, Class "F" Common Non-Voting Shares, Class "G" Shares and Class "H" Shares.

As of the present date, the Corporation has 2,840,921,435 Shares, 64,140,000 Class "G" Shares and 22,200,000 Class "H" Shares of the Corporation issued and outstanding.

Common Shares

The Corporation is authorised to issue an unlimited number of Common Shares.

Holders of Shares and Class "B" Shares have the following rights, privileges, conditions and restrictions namely, the right to vote at any meeting of Shareholders, the right to receive the remaining property of the Corporation on dissolution, whether voluntary or involuntary. Such property shall be divided equally among all classes of Common Shares and the right to receive dividends as declared by the Corporation provided that such dividends may be declared on any class of Common Shares, or on any combination of classes of Common Shares, to the exclusion of any class or classes of Common Shares, or in part on each class.

Holders of Class "C" Common Non-Voting Shares, Class "D" Common Non-Voting Shares, Class "E" Common Non-Voting Shares, Class "F" Common Non-Voting Shares have the following rights, privileges, conditions and restrictions namely, no right to vote at any meeting of Shareholders, the right to receive the remaining property of the Corporation on dissolution, whether voluntary or involuntary. Such property shall be divided equally among all classes of Common Shares, and the right to receive dividends as declared by the Corporation provided that such dividends may be declared on any class of Common Shares, or on any combination of classes of Common Shares, to the exclusion of any class or classes of Common Shares, or in part on each class.

Preferred Shares

The Corporation is authorised to issue an unlimited number of Preferred Shares to eligible persons, namely, its Directors, officers, employees, consultants or advisers.

The Preferred Shares are non cumulative, redeemable and retractable (provided that purchases not made by tender, or through the market, shall be limited to a maximum price and, provided further, that if purchases are made by tender, tenders shall be available to all Shareholders alike) which may be issued for such consideration and bearing such rights, privileges, conditions and restrictions, in addition to the following, as determined by the Director(s) before issue:

(1) The holders of the Class "G" and Class "H" Preferred Non-Voting shares shall in each year be entitled, out of any or all profits or surplus available for dividends, to a non-cumulative cash dividend calculated at such a rate as the Directors set at the time of issuance. No dividend shall be declared and paid on or set apart for payment on the Common shares or any other shares that rank junior to the Class "G" and Class "H" Preferred Non-Voting shares in any fiscal year unless the dividends on all the Class "G" and Class "H" Preferred Non-Voting shares which are issued and outstanding at that time have been declared and paid for that fiscal year or set apart for payment, except with the consent in writing of all the holders of the Class "G" and Class "H" Preferred Non-Voting shares.

(2) Upon dissolution of the Corporation, the holders of the Class "G" and Class "H" Preferred Non-Voting shares shall take priority with regards to the return of capital and distribution of assets. They shall receive an amount equal to the amounts paid up on the shares held by them together with all declared and unpaid dividends thereon, if any. After payment to the holders of the Class "G" and Class "H" Preferred Non-Voting shares as provided for above, they shall not be entitled to share in any further distribution of the assets or property of the Corporation.

(3) The Class "G" and Class "H" Preferred Non-Voting shares shall not be entitled to vote at any meeting of the Shareholders, to receive notice of such meeting or to attend same, subject to the provisions of the *Business Corporations Act* (Alberta).

The Preferred Shares carry both redemption and retraction rights and are convertible, at the option of the holders, into Common Shares as per a conversion schedule. Notwithstanding the above, the Preferred Shares shall be automatically converted into Common Shares of Sunshine on the date that is the earlier of:

- the date that is 24 months after the date Sunshine completes the listing on the SEHK;
- the date upon which a change of control of the Corporation occurs; and
- in the event that the anticipated listing on the SEHK does not occur by the end of 2011, on December 31, 2013.

FUTURE PLANS AND USE OF PROCEEDS

Future Plans

Please refer to the section entitled *"Business — Our Strategies"* for a detailed description of our future plans.

Use of Proceeds

We received gross proceeds of approximately US$580 million (HK$4,487 million) from the Global Offering.

We intend to use the net proceeds we receive from the Global Offering for the following purposes:

- approximately 93% of the net proceeds from the Global Offering is expected to be used for funding the development of oil sands and heavy/light oil projects, out of which we intend to allocate as follows:

West Ells	64%
Delineation Drilling	12%
Muskwa	5%
Thickwood	3%
Other Projects	9%
Total	93%

and

- approximately 7% of the net proceeds is expected to be used as general working capital for corporate and other purposes.

To the extent that the net proceeds of the Global Offering are not immediately used for the purposes described above they will be placed in short term demand deposits and/or money market instruments.

We expect to fund our capital expenditure requirements through cash at bank and on hand, net proceeds from the Global Offering, cash generated from operating activities, further issuances of equity and utilisation of credit facilities where available, however, we currently do not have any plan for further issuances of equity. We intend to develop our projects in multiple phases with staggered start dates, which we expect will allow us to maximise the efficiency of our available capital. Our intention is that cash flows from the development of more mature projects will help to finance the capital requirements of subsequent project development work, thereby reducing our need for additional external financing. For more information, refer to the section entitled *"Business — Capital Expenditure"* for details of our anticipated capital requirements and cash flows from our various projects.

MARKET FOR SECURITIES

Trading Price and Volume

As of the date of this AIF, the Shares of the Corporation are listed and posted for trading on the SEHK under the stock code "2012". The following table sets forth the price range and trading volume of the Shares as reported by the SEHK for the period commencing March 1, 2012 to the date hereof:

	Class "A" Common Voting Share		
Month	**High**	**Low**	**Volume**
2012			
March – Present	4.86	4.41	47,529,000

Prior Sales

The following table summarizes the issuances of Common Shares and Preferred Shares for the 12-month period prior to the date hereof:

Date(s) of Issuance	Number of Shares	Issue Price per Security	Number of Class "B" Shares	Issue Price per Security	Number of Class "G" Shares	Number of Class "H" Shares	Issue Price per Security
May 16, 2011	-	-	-	-	100,000	Nil	0.0005
June 9, 2011	-	-	-	-	1,320,000	4,000,000	0.0005
July 6, 2011	500,000	0.0670	-	-	-	-	-
July 22, 2011	1,200,000	0.1375	-	-	-	-	-
September 12, 2011	-	-	-	-	150,000	Nil	0.0005
September 16, 2011	-	-	-	-	1,350,000	Nil	0.0005
September 28, 2011	-	-	-	-	Nil	4,000,000	0.0005

Date(s) of Issuance	Number of Shares	Issue Price per Security	Number of Class "B" Shares	Issue Price per Security	Number of Class "G" Shares	Number of Class "H" Shares	Issue Price per Security
November 16, 2011	-	-	-	-	80,000	Nil	0.0005
November 17, 2011	-	-	-	-	150,000	Nil	0.0005
December 20, 2011	-	-	-	-	4,000,000	Nil	0.0005
December 21, 2011	--	-	-	-	130,000	Nil	0.0005
January 3, 2012	-	-	-	-	650,000	Nil	0.0005
January 16, 2012	--	-	-	-	30,000	Nil	0.0005
February 1, 2012	-	-	-	-	100,000	Nil	0.0005
February 10, 2012	-	-	-	-	50,000	Nil	0.0005
February 29, 2012	13,566,395	0.6175	-	-	-	-	-
March 1, 2012	923,299,500	0.6172	-	-	-	-	-
Total	**938,565,895**	**-**	**-**	**-**	**8,110,000**	**8,000,000**	**-**

ESCROWED SECURITIES AND CANADIAN RESALE RESTRICTIONS

Securities of the Corporation Subject to Escrow

The following table summarizes the number of securities of the Corporation held, to the Corporation's knowledge, in escrow or that are subject to a contractual restriction on transfer and the percentage that number represents of the outstanding securities of that class for the Corporation's securities:

Designation of class	Number of securities held in escrow or that are subject to a contractual restriction on transfer	Percentage of class
Class "A" Common Voting Shares	1,520,403,640	53.52%

Securities of the Corporation Subject to Canadian Securities Law Restrictions

All of our Common Shares that are issued and outstanding prior to the completion of the Global Offering (the "**Pre-IPO Shares**") were issued by us in reliance upon exemptions from the prospectus and registration requirements under Alberta securities laws and the securities laws of the other provinces of Canada and other jurisdictions in which the Pre-IPO Shares were placed. Under Alberta securities laws, resales by purchasers who purchased Pre-IPO Shares under Alberta private placement exemptions are deemed to be "distributions", and therefore the resale itself is required to be qualified by a prospectus or be completed pursuant to a prospectus exemption. To ensure compliance with these requirements under the applicable Canadian securities laws, the share certificates issued in the private placements by us prior to the completion of the Global Offering (save for some limited exceptions) include a legend with respect to this resale restriction (the "**Legend**"). The form of share certificates issued in these prior private placements are of a type customary for a Canadian private company and are different in form than the form of certificate that the Corporation will use upon the completion of the Global Offering.

This regulatory resale restriction will remain in place for four months after we become a "reporting issuer" (i.e. a public reporting company) in Canada (unless we become a reporting issuer as a result of filing a prospectus with a Canadian securities regulator, in which case the resale restriction would cease immediately upon us becoming a reporting issuer). We will not automatically become a reporting issuer in Canada on the date we complete the Global Offering and is listed from trading on the HKSE. Instead, we will apply to become a reporting issuer in Canada by way of an application to the ASC, to have us deemed to be a reporting issuer or, alternatively, through the filing and clearing with the ASC of a prospectus. The Joint Global Coordinators have advised that it is important in the context of the Global Offering to provide restrictions on trading of all Pre-IPO Shares for a period of six months following the completion of the Global Offering. We have undertaken to the ASC that we will make an application to be deemed to be a reporting issuer within one month after the Listing Date, on the understanding that the earliest date on which the ASC would grant an order deeming us to be a reporting issuer would be the date that is two months after the Listing Date. This is expected to result in restrictions on trading of all Pre-IPO Shares for approximately six months following the Listing (the "**Restricted Period**") (save for certain limited trading of the Pre-IPO Shares permitted in Canada on an exempt basis under Alberta securities laws, as described below). In addition, any Class "G" Share or Class "H" Share issued prior to the Listing Date and converted into Common Shares during the Restricted Period will be subject to the same resale restrictions as are applicable to the Pre-IPO Shares.

The other rights that attach to the Pre-IPO Shares, such as the right to vote or the right to distributions or dividends, are not affected during the Restricted Period.

As an Alberta corporation, we are subject to Alberta and Canadian securities laws. To ensure that the above resale restrictions are effective under Alberta securities laws, we plan to take the following steps to ensure that the Pre-IPO Shares cannot be traded, other than in exempt transactions, until the end of the Restricted Period will have expired, upon which the resale restriction, and the Legend attaching to the share certificates for the Pre-IPO Shares ("**Old Share Certificates**") will no longer apply:

(a) we will instruct our Principal Share Registrar and Hong Kong Share Registrar to ensure that all Pre-IPO Shares will remain on the Principal Share Register and will not be entered onto the Hong Kong Share Register until the Restricted Period has lapsed.

(b) on the basis that we will become a "reporting issuer" in Canada approximately two months after the Listing Date, the holders of the Pre-IPO Shares will not be issued the new share certificates ("**New Share Certificates**") until the Restricted Period has lapsed. The New Share Certificates, when issued, will be in the same form as the share certificates for the Common Shares to be issued upon Listing and the Pre-IPO Shares will be eligible to be traded on the HKSE.

(c) at the end of the Restricted Period, we will send holders of the Pre-IPO Shares a letter of transmittal requesting the return of the Old Share Certificates to the Principal Share Registrar for safekeeping or destruction. Upon the issue of any New Share Certificates to holders of Pre-IPO Shares following the expiry of the Restricted Period, the Principal Share Registrar will mark the Old Share Certificates for such Pre-IPO Shares as cancelled on the Principal Share Register.

Notwithstanding the foregoing, holders of Pre-IPO Shares will be able to transfer such shares pursuant to transactions that are exempt from the prospectus requirements of Canadian securities laws. Common examples of exempt transactions include a sale by a Pre-IPO Share holder to a purchaser who meets certain financial criteria, or in a transaction whose value exceeds $150,000.

In the event that a holder of Pre-IPO Shares intends to execute an exempt transfer, we and our Principal Share Registrar will require reasonable evidence that the transaction is being made on an exempt basis before we authorise a transfer to be registered, and will not permit a transfer which may result in such Pre-IPO Shares being traded on the HKSE. Share certificates representing any Pre-IPO Shares that are transferred in an exempt transaction will continue to bear the Legend, as described above.

We intend to follow the procedures described above for all holders of Pre-IPO Shares including those held by Shareholders outside Canada. There is a slight possibility that a Shareholder outside Canada that holds Pre-IPO Shares subject to the resale restrictions (including a Shareholder who acquired Shares pursuant to an exempt resale) may attempt to sell its Pre-IPO Shares to a non-Canadian purchaser on a non-exempt basis within the Restricted Period. Such a holder might take the view that Canadian securities law resale restrictions do not apply to such a transaction, or that the Canadian securities regulators do not have jurisdiction to regulate such transfers. This could lead to a dispute or potentially litigation in Alberta or elsewhere requiring us to register a transfer on a non-exempt basis, or which may result is us paying damages to such a holder to compensate them for their inability to sell their Pre-IPO Shares during the Restricted Period. Although we believe that the likelihood of any such a dispute is low and that the risk of a court finding in favour of such a holder is even lower, there remains a small risk that a court require us to permit such transfers to be made. Of the 1,904,055,540 Pre-IPO Shares that are issued and outstanding prior to the Listing, approximately 108,557,560 Pre-IPO Shares are held by non-Canadian Shareholders who have not signed contractual lock-up agreements and, as such, may potentially have the right to bring an action, as noted above, in the event that they wish to pursue a non-exempt transfer during the Restricted Period.

We have provided equivalent disclosure in respect of the resale restrictions attaching to the Pre-IPO Shares, as well as a description of the above steps, in our management information circular for our Annual and Special Meeting held on January 26, 2012 (the "**Information Circular**"). The Information Circular was dispatched to all holders of the Pre-IPO Shares, and therefore reminded all such holders of the resale restriction attaching to their Pre-IPO Shares during the Restricted Period and fully informed them of the above steps. No questions or concerns were raised by any holders of the Pre-IPO Shares at the Annual and Special Meeting, and, some clarification questions or minor concerns have been raised with us since the date of the Annual and Special Meeting.

DIRECTORS AND OFFICERS

Name, Address, and Principal Occupations

The names, municipality of residence and principal occupation during the last five years of each of the directors and senior officers of the Corporation are as follows:

Name, Municipality of Residence & Current Position(s) with the Corporation	Principal Occupation in the Past Five Years	Director/Officer Since	Shares Beneficially Owned or Over Which Control or Direction Exercised as at December 31, 2011(5)
Michael J. Hibberd(1) Calgary, Alberta Canada *Co-Chairman and Director*	Co-Chairman of the Corporation since October 2008. Prior thereto, from August 2007 to October 2008, Chairman and Co-CEO of the Corporation. President and Chief Executive Officer of MJH Services Inc., a corporate finance advisory company, since January 1995. Chairman of Greenfields Petroleum Corporation since February 2010. Chairman of Canacol Energy Ltd. since October 2008. Chairman of Heritage Oil Plc. since March 2008. Chairman of Heritage Oil Corporation since November 2006. Director of Skope Energy Inc. since December 2011. Director of Pan Orient Energy Corp. since April 2005. Director of Montana Exploration Corp. (formerly AltaCanada Energy Corp.) since 1997.	May 9, 2007	53,240,000
Songning Shen(2) Calgary, Alberta Canada *Co-Chairman and Director*	Co-Chairman of the Corporation since October 2008. Prior thereto, President and Co-CEO of the Corporation from August 2007 to October 2008 and geology consultant at Koch Exploration Canada L.P. from March 2006 to June 2007.	February 22, 2007	51,959,660
Hokming Tseung(1) (3) Hong Kong China *Director*	Director of Orient International Resources Group Limited since April 2010 and Director of Orient International Petroleum & Chemical Limited since December 2004. Director of Orient Financial Holdings Limited since July 2002.	March 2, 2010	15,000,000
Tingan Liu(4) Kowloon, Hong Kong China *Director and Hong Kong Corporate Secretary*	Deputy chairman and president of China Life Insurance (Overseas) Company Limited since June 2008. Member of the Listing Committee of the SEHK since July 2010. Member of the Insurance Advisory Committee of the Government of Hong Kong S.A.R. since October 2010. Councillor of the Life Insurance Council of the Hong Kong Federation of Insurers since September 2003.	February 1, 2011 (director); August 26, 2011 (Hong Kong Corporate Secretary)	Nil

Name, Municipality of Residence & Current Position(s) with the Corporation	Principal Occupation in the Past Five Years	Director/Officer Since	Shares Beneficially Owned or Over Which Control or Direction Exercised as at December 31, 2011(5)
Haotian Li(1) Hong Kong China *Director*	Director of Bank of China Investment Limited and Director of BOCGI Zheshang Investment Fund Management (Zhe Jiang) Co., Ltd. since June 2010. Deputy Chief Executive Officer of Bank of China Group Investment Limited since November 2008. Prior thereto, Head of Client Relations of the corporate banking department (oil and gas sector coverage) at Bank of China Headquarters from July 1999 to November 2008.	February 14, 2011	Nil
Gregory Turnbull, QC(1) (3) Calgary, Alberta Canada *Director*	Regional Managing Partner of McCarthy Tétrault LLP, Calgary since January 2005.	August 24, 2007	10,700,000
Raymond Fong(2) (3) Calgary, Alberta Canada *Director*	Chief Executive Officer of China Coal Corporation of Calgary since May 2010. Prior thereto, director of Abenteuer Resources Ltd. from November 2000 to August 2008 and director of Stealth Ventures Ltd. from November 1999 to November 2007.	May 9, 2007	7,000,000
Robert J. Herdman(1) (3) (4) Calgary, Alberta Canada *Director*	Director of TriOil Resources Ltd. since February 2012 and Director of Black Diamond Group since March 2012. Chinook Energy Inc. since July 2010. Director of Chinook Energy Inc. since July 2010. Director of SemBioSys Genetics Inc. since June 2011. Director of Blackline GPS Corp. and Western Financial Group Inc. since April 2011 and April 2011 respectively. Prior thereto, Partner at PricewaterhouseCoopers LLP, Calgary from July 1989 to July 2010.	July 18, 2011	Nil
Wazir C. (Mike) Seth(2) (4) Calgary, Alberta Canada *Director*	President of Seth Consultants Ltd. since January 1981. Director of Enerplus Corporation since September 2005. Director of Connacher Oil and Gas Limited since December 2005. Director of Open Range Energy Corp. since May 2009. Director of Corridor Resources Inc. since January 2006. Director of Reliable Energy Ltd. and Torquay Oil Corp. since December 2008 and February 2010 respectively. Prior thereto, chairman, president and managing director of McDaniel & Associates Consultants Ltd. from January 1989 to June 2006.	September 1, 2008	Nil
Gerald F. Stevenson(1) (2) (4) Calgary, Alberta Canada *Director*	Director of Southwest Energy Trust since August 2011. Prior thereto, from January 2006 to April 2011, head of oil & gas acquisitions and divestitures for CIBC World Markets Inc., Calgary.	July 15, 2011	Nil
John Empey Zahary Calgary, Alberta, Canada *President and Chief Executive Officer*	President and Chief Executive Officer of the Corporation since December 2011. Prior thereto, from February 2006 to January 2012, President and Chief Executive Officer of Harvest Operations Corp. and from April 2004 to February 2006, President and Chief Executive Officer of Viking Energy Trust, a predecessor to Harvest Operations Corp.	December 20, 2011	4,000,000

Name, Municipality of Residence & Current Position(s) with the Corporation	Principal Occupation in the Past Five Years	Director/Officer Since	Shares Beneficially Owned or Over Which Control or Direction Exercised as at December 31, 2011(5)
John Stanley Kowal Calgary, Alberta, Canada *Strategic Advisor*	Strategic Adviser of the Corporation since December 2011. Prior thereto, from October 2008 to December 2011, Co-Chief Executive Officer of the Corporation and from June 2008 to October 2008, Senior Vice President, Capital Markets of the Corporation and from January 2006 to January 2008, Vice-President, Finance and Chief Financial Officer at Total E&P Canada Ltd.	June 2, 2008	6,300,000
Douglas Stewart Brown Calgary, Alberta, Canada *Chief Operating Officer*	Chief Operating Officer of the Corporation since October 2008. Prior thereto, from October 2008 to December 2011, Co-Chief Executive Officer of the Corporation. From October 2007 to October 2008, engineering consultant at JBD Services Ltd. and from September 2005 to June 2007, Vice President, Engineering and Production at Rally Energy Corp.	October 6, 2008	12,505,000
Thomas Kenneth Rouse Calgary, Alberta, Canada *Chief Financial Officer & Vice President, Finance*	Vice President, Finance and Chief Financial Officer of the Corporation since August 2008. Prior thereto, from February 2008 to August 2008, Controller of the Corporation. From April 2007 to December 2007, Chief Financial Officer of Patch International Inc., and from May 2004 to February 2007, Vice President, Finance and Chief Financial Officer of Great Plains Exploration Inc.	August 22, 2008	3,050,000
David Owen Sealock Airdrie, Alberta, Canada *Executive Vice President, Corporate Operations*	Executive Vice President, Corporate Operations of the Corporation since June 2010. Prior thereto, from June 2008 to June 2010, Vice President, Corporate Operations of the Corporation. From January 2007 to June 2008, Vice President, Corporate Services, Investor Relations and Corporate Secretary at MegaWest Energy Corp.	June 14, 2010	2,570,000
Tonino Sabelli Calgary, Alberta, Canada *Senior Vice President, Operations*	Senior Vice President, Operations of the Corporation since December 2011. Prior thereto, from August 2010 to December 2011, Vice President, Drilling, Completions and Construction. From September 2006 to May 2008, founder and officer of Rising Sky Energy Ltd.	August 16, 2010	2,440,000
Dr. Songbo Cong Calgary, Alberta, Canada *Vice President, Facilities Engineering*	Vice President, Facilities and Engineering of the Corporation since January 2008. Prior thereto, from May 2007 to January 2008, director of the Corporation. From January 2005 to December 2007, principal software engineer at Honeywell Process Solutions.	January 9, 2008	5,000,000
Daniel Joseph Dugas Calgary, Alberta, Canada *Vice President, Field Operations*	Vice President, Field Operations of the Corporation since March 2008. Prior thereto, from May 2001 to June 2008, member of the operations team at Encana Oil & Gas Partnership's Foster Creek SAGD facility.	March 1, 2008	2,062,860
Jason James Hancheruk Calgary, Alberta, Canada *Vice President, Land and Regulatory Affairs*	Vice President, Land and Regulatory Affairs of the Corporation since May 2011. Prior thereto, from February 2008 to May 2011, Vice President, Regulatory, Environmental and Stakeholder Affairs.	May 27, 2011	1,810,900

Name, Municipality of Residence & Current Position(s) with the Corporation	Principal Occupation in the Past Five Years	Director/Officer Since	Shares Beneficially Owned or Over Which Control or Direction Exercised as at December 31, 2011(5)
Albert Norman Stark Calgary, Alberta, Canada *Controller*	Controller of the Corporation since February 2009. Prior thereto, from May 2006 to January 2009, Controller and Finance Director at Rally Energy Corp.	February 1, 2009	1,400,000
Richard Walter Pawluk Calgary, Alberta, Canada *Canadian Corporate Secretary*	Partner, McCarthy Tétrault LLP since January 2003.	May 9, 2007	2,941,000

Notes:
(1) Member of the Corporate Governance Committee.
(2) Member of the Reserves Committee.
(3) Member of the Compensation Committee.
(4) Member of the Audit Committee.
(5) Includes Shares, Class "G" Shares and Class "H" Shares and the total numbers have been adjusted to reflect the 20 for 1 share split that was effective as of February 10, 2012.

Share Ownership by Directors and Officers

The Corporation's officers and directors beneficially own, as a group, or exercise control or direction over, directly or indirectly 181,979,420 Shares. As at December 31, 2011, the Shares held by the Corporation's officers and directors represent approximately 9.6% of the issued and outstanding Shares and 13.9% of the issued and outstanding Shares on a fully diluted basis including options held by the Corporation's officers and directors.

Corporate Cease Trade Orders or Bankruptcies

Except as disclosed herein, to the knowledge of the management of the Corporation, no director of Sunshine, is at the date of this AIF, or has been, within 10 years before the date of this AIF, a director, chief executive officer or chief financial officer of any company (including the Corporation) that, while that person was acting in that capacity:

- was subject to a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days; or

- was subject to an event that resulted, after the director, chief executive officer or chief financial officer ceased to be a director, chief executive officer or chief financial officer, in the company being the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days; or

- within a year of after the director, chief executive officer or chief financial officer ceased to be a director, chief executive officer or chief financial officer, in the company 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 or the assets of the proposed director.

Mr. Turnbull was a director of Action Energy Inc., a company engaged in the exploration, development and production of oil and gas in Western Canada. Action Energy Inc. was placed into receivership on October 28, 2009 by its major creditor and Mr. Turnbull resigned as a director immediately thereafter.

Michael J. Hibberd was an independent director of Challenger Energy Corp. ("**Challenger**") from December 1, 2005 to September 16, 2009. Challenger obtained a creditor protection order under the *Companies' Creditors Arrangement Act* (CCAA), from the Court of Queen's Bench of Alberta, Judicial District of Calgary on February 27, 2009. On June 19, 2009, Challenger announced that it had entered into an arrangement agreement providing for the acquisition by Canadian Superior Energy Inc. of Challenger. On September 17, 2009, all Common Shares of Challenger were exchanged for Common Shares of Canadian Superior and all creditor claims were fully honoured.

Penalties or Sanctions

To the knowledge of the management of the Corporation, no director of Sunshine is at the date of this AIF has been subject to:

- any penalties or sanctions imposed by the court relating to a securities legislation or by a securities regulatory authority or has entered in a settlement agreement with a securities regulatory authority; or
- any other penalties or sanctions imposed by the court or regulatory body that would likely be considered important to a reasonable security holder in deciding whether to vote for a proposed director.

Personal Bankruptcies

None of Sunshine's directors, officers or principal shareholders, or a personal holding company of any such persons, have, within 10 years prior to the date of this AIF, become bankrupt, made a proposal under any bankruptcy or insolvency legislation, been subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold their assets.

Conflicts of Interest

Certain officers and directors of Sunshine are also officers and/or directors of other companies engaged in the oil and gas business generally. As a result, situations arise where the interests of such directors and officers conflict with their interests as directors and officers of other companies. The resolution of such conflicts is governed by applicable corporate laws, which require that directors act honestly, in good faith and with a view to the best interests of the Corporation.

SELECTED FINANCIAL INFORMATION

Our Auditors and Accounting Standards

The following sets out certain financial information and operating results of the Corporation for the periods indicated. This information has been derived from the Audited Financial Statements, attached hereto as Schedule "A". These results should also be read in conjunction with the disclosure under the heading "*Management's Discussion and Analysis*". The operating results for these periods should not be relied upon as any indication of results for any future periods.

Significant Factors Affecting Our Results of Operations

Historically, Sunshine's activities have mainly consisted of the exploration and development of our Oil Sands Leases. We did not engage in any commercial production of bitumen during 2009, 2010 and 2011 and therefore did not record any revenue during those financial periods. All costs directly associated with exploration and evaluation activities are initially capitalised. These costs include unproved property acquisition costs, geological and geophysical costs, exploration and evaluation drilling, expenditures directly attributable to exploration and evaluation activities (including share based payments), borrowing costs and consequential operating costs, and annual rent expense for oil and gas leases. E&E assets are those expenditures for an area where technical feasibility and commercial viability have not yet been determined. While we commenced the initial pre-production and sale of bitumen from our conventional heavy oil assets in September 2010, the determination of commercial production has not yet been made. Please refer to the section entitled *"Certain Statements of Financial Position Items — Exploration and Evaluation Assets*" below. In accordance with Sunshine's accounting policies, the decision to transfer assets from E&E assets to development and producing assets occurs when the technical feasibility and commercial viability of the project is determined. We anticipate that we will make this determination in 2012 and we will then be in a position to recognise revenue, royalties and operating expenses in our statement of operations and comprehensive income. Therefore, our historical operating results are not indicative of our future operating results.

Our financial position and operating results have primarily been affected by costs associated with our exploration and development activities, including, among other things, the costs of acquiring our Oil Sands Leases, labour costs, construction costs and plant and equipment costs. All qualifying capital expenditures are capitalised until the time when the related projects are deemed to meet our management determination and criteria for commercial production and are deemed to be technically feasible by our management team. Our results of operations will continue to be affected by these and other costs associated with pre-production stages of development given that we intend to develop our business through a number of stages.

We anticipate that the following factors are likely to significantly affect our results of operations, cash flows and financial condition going forward.

Oil Prices

Crude oil prices, in particular both base WTI prices as well as WTI-LLB differentials, are expected to have a significant impact on our future results of operations. We anticipate that our bitumen will be sold as a blend. Bitumen blends are priced using several benchmarks in Alberta at the Hardisty Hub, the most common benchmarks being Lloyd Blend, Bow River and more recently Western Canadian Select. Bitumen blends trade at quality discounts to conventional light oils such as WTI or Edmonton Par. WTI is a light sweet crude oil which is used as a benchmark grade of crude oil for North American price quotations and is referenced at a sales point in Cushing, Oklahoma. Currently, the market for bitumen blend is strong and production from the Athabasca region is primarily sold to refineries in Canada, the Midwest (PADD II) and the Rocky Mountains (PADD IV) in the United States. Our conventional heavy oil is typically priced off West Canadian Select, which is priced at the Hardisty Hub at a monthly floating differential to WTI. WTI prices and WTI-LLB differentials are in turn impacted by factors such as the available supply of crude oil from oil producing nations such as Mexico and Venezuela, heavy oil refining capacity in North America and consequent demand, pipeline and infrastructure to transport heavy oil from Canada to the United States, the condition of the Canadian, United States and global economies, actions taken by the Organisation of Petroleum Exporting Countries, governmental regulation, political stability in oil producing nations and elsewhere and war or the threat of war in oil producing regions.

We expect that the selling prices of our products will be significantly affected by changes in oil prices. Increases in crude oil prices would lead to increases in our selling prices, potentially increasing our revenue and overall profitability. Decreases in crude oil prices would lower our revenue and potentially reduce our profitability. Fluctuations in oil prices could affect our pace of growth. If oil prices fall below commercially acceptable levels, we may choose to delay the exploration, development and commencement of commercial production of some of our projects.

Production Capacity and Costs

We expect that our revenues will be significantly affected by our sales volume, which in turn will be determined by the demand for our products and our ability to meet such demand based on our production capacity and costs of production.

Production Capacity

Our ability to achieve our desired production capacity could be affected by, among other things, the following:

- our level of, and ability to access, capital to fund ongoing and future exploration, evaluation and development of our Oil Sands Leases;
- our ability to hire, retain and engage experienced and talented employees, consultants and third party contractors to construct, manage and operate our projects;
- our management's capacity to manage and operate the increasing scale of our operations and projects;

- the SOR levels we achieve in our clastics projects; and
- our ability to complete our projects on schedule.

Costs

We expect that the following factors, among other things, will affect our costs:

- commodity prices, specifically natural gas and diluent prices;
- power prices, specifically the cost of producing cogeneration power for the simultaneous generation of both electricity and heat for our projects and electricity prices for SAGD projects not utilising cogeneration;
- financing costs associated with any future debt facilities or debt or equity issuances;
- our ability to complete our projects on schedule and within our budget;
- the pace of development in the oil sands regions in Canada. If demand for skilled labour and materials necessary to complete and operate the projects increases, our costs could increase or we could experience shortages of labour and materials;
- our ability to operate in accordance with design specifications;
- the SOR levels we achieve in our clastics projects;
- the amount of royalties we receive; and
- tax, specifically the timing and terms of a carbon tax by the Government of Alberta.

For discussion on how commodity prices may affect our results and the related sensitivity analyses, please refer to the section entitled *"Business — Production Economics for Clastic Assets"*.

Exchange Rates

Our results of operations are expected to be affected by the exchange rate between the Canadian and US dollar. The majority of our expenditures and other expenses are in Canadian dollars. Even though we are currently receiving and may in the future receive our revenue in Canadian dollars, such sales of oil commodities reflect prices determined by reference to US benchmark prices and so an appreciation of the Canadian dollar relative to the US dollar will decrease the revenues received from the sale of our products. A depreciation of the Canadian dollar relative to the US dollar would increase our revenues.

For more information on other drivers for our results of operation, please refer to the section entitled *"Business — Production Economics for Clastic Assets"*.

Revenue and Cost Structure Upon Commercial Production

Revenue from bitumen sales represents the amounts received and receivable for our product sold. Revenue from bitumen sales reflects the average selling price and sales volume of our bitumen which is produced from our Muskwa site. During the Track Record Period, in accordance with our accounting policy for revenue recognition and capitalisation of costs included in E&E assets, we have capitalised our revenue, less royalties and operating expenses from the sale of bitumen from the Muskwa area as the Muskwa project is currently in pre-production.

As the Muskwa project is currently in pre-production, the above revenue and volume information is not reflective of the anticipated performance of the Muskwa project once it has been determined to meet the appropriate criteria for technical feasibility and commercial viability.

Once the Muskwa project, where all our current production sales to our customer, Legacy, are occurring, has been determined to meet the appropriate criteria for technical feasibility and commercial viability, revenue less royalties and operating expenses will be recognised in the statement of operations and comprehensive loss when our product is delivered and title to the bitumen passes to the customer. We expect this to occur in 2012.

We consider technical feasibility and commercial viability is achieved when a project has identified proved reserves, is able to economically lift the oil in a consistent and predictable manner with a reasonable operating cost, produce consistent daily volumes and experience consistent well performance. We will determine whether technical feasibility and economic viability is met with respect to our Muskwa project with reference to IFRS.

Average Selling Price

Crude oil prices, in particular both base WTI prices as well as WTI-LLB differentials, are expected to have a significant impact on our future results of operations. Our oil produced at Muskwa is sold as a blend. Bitumen blends are priced using several benchmarks in Alberta, the most common benchmarks being LLB, Bow River and more recently WCS.

WTI prices and LLB or WCS differentials are in turn impacted by factors which are beyond our control, such as those highlighted above in the section entitled *"Significant Factors Affecting Our Results of Operations — Oil Prices"*.

Sales Volume

The average daily pre-production volume at Muskwa increased significantly at the end of 2011 compared to the pre-production volume for the year ended December 31, 2011. This growth came from the additional drilling and production facility construction completed at Muskwa during the fourth quarter of 2011.

Royalties

Alberta requires royalties to be paid on the production of natural resources from lands for which it owns the mineral rights. The royalty range applicable to price sensitivities changes depending on whether a project's status is pre-payout or post-payout. "Payout" is 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. For pre-payout and post-payout royalty range, please refer to the section entitled *"Business — Production Economics for Clastic Assets — Royalties"*.

Transportation, Diluent and Operating Expenses

Transportation and diluent expenses are incurred in relation to getting the product to market. Blending and other processing is completed in order to have the oil market-ready for delivery to the pipeline. Transportation charges are incurred once the bitumen has been blended and processed to the required standards for pipeline receipt. Operating expenses consist mainly of manpower costs, road and other maintenance, chemicals and other expenses. All these operating related expenses will be recognised in the statement of operations and comprehensive loss when commercial production is achieved, which is expected in 2012.

The above revenue and cost structure is also applicable to the future commercial production of bitumen from our clastics and carbonates assets.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon our Audited Financial Statements, which have been prepared in accordance with IFRS. The preparation of the financial statements requires us to make judgments, estimates and assumptions that affect the reported amounts of assets, liabilities, expenses, and related disclosure of contingent assets and liabilities. We continually evaluate these estimates and assumptions based on the most recently available information, our own historical experience and various other assumptions that we believe to be reasonable under the circumstances. Since the use of estimates is an integral component of the financial reporting process, actual results could differ from those estimates.

An accounting policy is considered critical if it requires an accounting estimate to be made based on assumptions about matters that are highly uncertain at the time such estimate is made, and if different accounting estimates that reasonably could have been used, or changes in the accounting estimates that are reasonably likely to occur periodically, could materially impact the Audited Financial Statements. We believe that the following accounting policies represent critical accounting policies as they involve a higher degree of judgment and complexity in their application and require us to make significant accounting estimates. The following descriptions of critical accounting policies, judgments and estimates should be read in conjunction with our Audited Financial Statements and other disclosures included in this AIF.

Oil and Gas Reserves

The process of estimating quantities of reserves is inherently uncertain and complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. Reserve estimates are based on current production estimates, prices and economic conditions.

Reserve estimates are critical to many accounting estimates including:

- determining whether or not an exploratory well has found economically recoverable reserves. Such determinations involve the commitment of additional capital to develop the field based on current production estimates, prices and other economic conditions;

- calculating unit-of-production depletion rates. Proved and probable reserves are used to determine rates that are applied to each unit-of-production in calculating depletion expense; and

- assessing development and production assets for impairment. Estimated future net cash flows used to assess impairment of our development and production assets are determined using proved and probable reserves.

Our Independent Qualified Reserves Evaluators' Reports provide reserve estimates for each property at least annually and issue a report thereon. The reserve estimates are reviewed by our engineers and operational management familiar with the property.

Recoverability of Exploration and Evaluation Assets

E&E assets are capitalised by cash generating unit and are assessed for impairment when circumstances suggest that the carrying amount may exceed its recoverable value. This assessment involves judgment as to: (i) the likely future commerciality of the asset and when such commerciality should be determined; (ii) future revenues based on forecasted oil and gas prices; (iii) future development costs and production expenses; (iv) the discount rate to be applied to such revenues and costs for the purpose of deriving a recoverable value; and (v) the potential value to future E&E activities of any geological and geographical data acquired.

As at December 31, 2009, 2010 and 2011, the carrying amount of our E&E assets was $134.6 million, $197.8 million and $382.3 million, respectively.

Decommissioning Provision

A provision is required to be recognised for the future retirement obligations associated with property and equipment or E&E assets. The decommissioning provision is based on estimated costs, taking into account the anticipated method and extent of restoration consistent with legal, regulatory and constructive requirements, technological advances and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying the amount provided, including the cost to plug and abandon depleted wells, removal of tangible equipment and facilities and the restoration of the site. These individual assumptions can be subject to change based on actual experience and a change in one or more of these assumptions could result in a materially different amount.

As at December 31, 2009, 2010 and 2011, the carrying amount of our provision for decommissioning obligations were $0.4 million, $2.2 million and $6.4 million respectively.

Share-based Payments

We recognise compensation payments on options, share appreciation rights, warrants and preferred shares granted. Compensation payment is based on the estimated fair value of each option, share appreciation right, warrant and preferred share at its grant date, the estimation of which requires management to make assumptions about the future volatility of our stock price, future interest rates and the timing with respect to exercise of the options. The effects of a change in one or more of these variables could result in a materially different fair value.

During the years ended December 31, 2009, 2010 and 2011, we recognised $1.5 million, $10.8 million and $15.2 million, respectively, as share-based payments, of which $0.6 million, $3.9 million and $8.1 million, respectively, were recognised directly to profit or loss, $0.9 million, $4.6 million, and $7.1 million were capitalised in E&E assets, nil, $2.3 million and nil, respectively, were recorded as share issue costs and included in equity, and the remaining nil, nil and $6.4 million, respectively, were recorded as direct cost on issuance of redeemable shares and net against the gross proceeds of the redeemable shares issued.

Revenue Recognition

Revenue is measured at the fair value of the consideration received or receivable and represents amounts receivable for goods sold in the normal course of business, net of sales related tax.

Revenue from the sale of goods is recognised when all the following conditions are satisfied:

- we have transferred to the buyer the significant risks and rewards of ownership of the goods;
- we retain neither continuing managerial involvement to the degree usually associated with ownership nor effective control over the goods sold;
- the amount of revenue can be measured reliably;
- it is probable that the economic benefits associated with the transaction will flow to us; and
- the costs incurred or to be incurred in respect of the transaction can be measured reliably.

Revenue from sale of goods is recognised when goods are delivered.

Interest income from a financial asset is recognised when it is probable that the economic benefits will flow to us and the amount of revenue can be measured reliably. Interest income from a financial asset is accrued on a time basis, by reference to the principal outstanding and at the effective interest rate applicable, which is the rate that exactly discounts the estimated future cash receipts through the expected life of the financial asset to that asset's net carrying amount on initial recognition.

Description of Selected Statement of Comprehensive Income Line Items

Interest Income

Interest income primarily consists of interest income from term deposits held in interest bearing bank accounts.

Other Income

Other income primarily consists of income earned from granting road usage to third parties requiring access through our properties.

General and Administrative Expenses

General and administrative expenses mainly consist of salaries, consulting fees for engineering and geological consulting services, consulting fees for services provided by our co-chairmen, Mr. Michael John Hibberd and Mr. Songning Shen, employee benefits expense, rent, legal and audit fees and other miscellaneous expenses.

Depreciation

Depreciation expenses consist of the depreciation on computer and office equipment. During the Track Record Period, we did not have any depletion of development and production costs, as our assets were in the exploration and evaluation stage of classification.

Share-based Payments

Share-based payments consist of compensation payments on options, share appreciation rights, warrants and preferred shares granted to directors, officers, employees, consultants and advisers.

Compensation is based on the estimated fair value of each option, warrant, share appreciation right and preferred share granted at its respective grant date using the Black-Scholes option pricing model.

Fair Value Loss on Warrants

Fair value loss on Warrants represents mark to market adjustment of the fair value of our Warrants arising from certain amendments we entered into with the holders of certain Purchase Warrants and all Fee Warrants, pursuant to which we could, at our sole discretion, elect to issue a Common Share instead of making a cash payment to the holder, upon the exercise by a holder of a Purchase Warrant or a Fee Warrant. Please refer to the Audited Financial Statements which is attached hereto as Schedule "A" .

Finance Costs

Finance costs primarily consist of interest expense from bank borrowings and accretion of the carrying value of asset decommissioning obligations estimated to be incurred between 2010 and 2059, excluding amounts capitalised in our exploration and evaluation assets for the funds borrowed under our bank borrowings. Asset decommissioning costs and liabilities can include statutory, contractual, constructive or legal obligations associated with site restoration and abandonment of tangible long-lived assets.

In the year ended December 31, 2011, we recorded effective interest on redeemable shares of $32.1 million in relation to an equity financing undertaken by us which was completed early in 2011. In February 2011, Sunshine entered into the Subscription Agreements with investors in relation to such redemption shares. Pursuant to the terms of the Subscription Agreements, Sunshine issued at a subscription price of $0.48 per share, a total of 433,884,300 Common Shares, of which 289,256,200 were Shares and the remaining 144,628,100 were Class "B" Shares for total proceeds of $210 million. Each subscriber also has share redemption rights as per the terms and condition of the subscription agreements ("**Share Redemption Rights**").

According to the Share Redemption Rights, the subscribers may, in specific circumstances and at the option of the subscribers, require Sunshine to repurchase, for cancellation, all Common Shares issued under the Subscription Agreements at a redemption price equivalent to the subscription price plus a 15% annual rate of return, compounded annually, if Sunshine does not complete an IPO either (a) on or before December 31, 2011; or (b) in any event, by December 31, 2013.

In addition to the Share Redemption Rights, each of the subscribers of 289,256,200 Shares and the subscriber of 144,628,100 Class "B" Shares, may require Sunshine to repurchase, for cancellation, the above Shares and the Class "B" Shares if the initial offering price per Share at the IPO is not at least 1.3 times the Hong Kong dollar equivalent of the subscription price of the Shares and the Class "B" Shares under the Subscription Agreement or at least $0.62 per Share.

If an IPO is not completed on or before the applicable dates, each subscriber may exercise its right to have the Corporation repurchase the redeemable shares by delivering a redemption notice on or before the 90th day after such date. If a subscriber does not deliver a redemption notice on or before the 90th day after such date, the right of the subscriber to sell the redeemable shares to the Corporation and to require the Corporation to purchase the redeemable shares as provided herein shall terminate automatically.

Within 90 days of receipt of a redemption notice, Sunshine shall repurchase the redeemable shares for cash at an aggregate purchase price equal to the aggregate subscription price plus an amount equal to a 15% annual rate of return on the aggregate subscription price, compounded annually.

As a result, Sunshine has presented these subscriptions as a financial liability on our statements of financial position. If Sunshine completes the Listing before December 31, 2013, the redeemable shares will be reclassified from financial liability to equity and form part of the issued capital. If Sunshine does not complete an IPO before December 31, 2013, and a redemption notice is presented; the redeemable shares will become due on December 31, 2013 along with the 15% annual rate of return on the aggregate subscription price, compounded annually.

Subsequent to year end, the Corporation successfully closed the Global Offering on the SEHK. Pursuant to this event, the balance of the share repurchase obligation, including 433,884,300 Common Shares comprising of 289,256,200 Shares and 144,628,100 Class "B" Shares, has been reclassified to share capital as the terms of the Subscription Agreements were agreed to have been met with the subscription holders and the share repurchase obligation has been extinguished. The Class "B" Shares were also surrendered for cancellation and exchanged for Shares.

Income Tax Expense/Credit

We and our subsidiary are subject to Canadian federal and provincial tax which is calculated at 29.0%, 28.0% and 26.5%, respectively, of the estimated assessable profit for the years ended December 31, 2009, 2010 and 2011, respectively.

Summary of Results of Operations

The following table sets forth, for the periods indicated, selected data from our consolidated statements of comprehensive income.

	Year ended December 31,		
	2009	**2010**	**2011**
	$	**$**	**$**
Interest income from bank deposits	3,060	257,067	1,624,507
Other income	3,835	7,602	—
Interest and other income	6,895	264,669	1,624,507
General and administrative expenses	(2,829,716)	(5,789,076)	(12,809,423)
Depreciation	(105,589)	(111,551)	(185,729)
Share-based payments	(555,871)	(3,946,638)	(8,075,446)
Allocation of IPO expenses	—	—	(3,547,085)
Fair value loss on warrants	—	—	(20,297,567)

	Year ended December 31,		
	2009	2010	2011
	$	$	$
Finance costs	(140,745)	(93,030)	(25,469,650)
Total expenses	**(3,631,921)**	**(9,940,295)**	**(70,384,900)**
Loss before tax	(3,625,026)	(9,675,626)	(68,760,393)
Income tax expense (recovery) credit	777,009	(181,315)	1,367,853
Loss for the year/period and comprehensive loss attributable to equity holders of the Corporation	**(2,848,017)**	**(9,856,941)**	**(67,392,540)**
Loss per share[(1)]			
Basic[(2)]	(0.00)	(0.01)	(0.05)
Diluted[(2)]	(0.00)	(0.01)	(0.05)

Notes:

(1) During the period ending December 31, 2011, redeemable shares were not included in the denominator in the calculation of basic and dilutive loss per share because redeemable shares do not meet the definition of ordinary shares or potential ordinary shares under IAS 33.

(2) The weighted average number of Common Shares for the purpose of calculating basic/diluted loss per share has been adjusted for the effect of the 20 for 1 share split.

Period to Period Comparison of Results of Operations

Year ended December 31, 2011 Compared to the Year ended December 31, 2010

Interest income and other income

Interest income and other income increased by $1.3 million from $0.3 million in the year ended December 31, 2010 to $1.6 million in the year ended December 31, 2011, primarily due to increased interest income from bank deposits as a result of a significant increase in our cash balances and cash equivalents from the year ended December 31, 2010 to December 31, 2011. The increase in cash balances and cash equivalents was primarily due to equity financings undertaken by us in February 2011.

Expenses

Our expenses increased by $60.5 million, from $9.9 million in the year ended December 31, 2010 to $70.4 million in the year ended December 31, 2011, primarily due to increases in finance costs, general and administrative expenses, share-based payments and fair value loss on Warrants.

General and administrative expenses

Our general and administrative expenses increased by $7.0 million, from $5.8 million in the year ended December 31, 2010 to $12.8 million in the year ended December 31, 2011, primarily due to increases in salaries, consulting fees and employees benefits as well as other general and administrative expenses. Salaries, consulting and benefits increased by $4.3 million primarily due to an increase in our headcount from 39 full time employees in the year ended December 31, 2010 to 65 full time employees in the year ended December 31, 2011. Employee numbers increased across all our areas of operation, particularly in our geology, drilling and operations departments due to increased activity levels associated with our winter drilling programmes. Other general and administrative expenses increased by $2.0 million in the year ended December 31, 2011 compared to the year ended December 31, 2010 primarily due to expenses incurred for our Independent Qualified Reserves Evaluators' Reports of approximately $0.9 million and miscellaneous expenses incurred in relation to computer consulting, advertising and promotion and regulatory, environmental studies and assessments. Legal and audit increased by $0.3 million in the year ended December 31, 2011 compared to the year ended December 31, 2010 due to an increase in costs incurred for auditor involvement with the review of internal controls, policies and procedures and other audit related charges.

Share-based payments

The fair value of share-based compensation associated with the granting of stock options and Preferred Shares is recognized by the Corporation in its financial statements. Fair value is determined using the Black-Scholes option pricing model. Share-based compensation expense for the year ended December 31, 2011 was $8.1 million compared to $3.9 million for the year ended December 31, 2010. The increase in share-based compensation expense is primarily the result of the additional expense related to Preferred Shares which the Corporation began granting in September 2010, higher Black-Scholes valuations for the Corporation's stock options based on the increase in the Corporation's share price, the underlying volatility within the share price and the increase in the number of employees. The Corporation capitalizes a portion of the share-based compensation expense associated with capitalized salaries and benefits. For the year ended December 31, 2011, the Corporation capitalized $7.2 million (year ended December 31, 2010 - $4.6 million) of share-based compensation to exploration and evaluation assets.

Finance costs

Total finance expense for the year ended December 31, 2011 increased compared to the same period in 2010 primarily due to non-cash finance costs attributable to the share repurchase obligation and the mark to market loss on warrants, which are accounted for using the liability method. The Corporation recognized finance costs of $32.1 million in total on the share repurchase obligation. Of this amount, $6.8 million has been capitalized in exploration and evaluation assets and the remaining amount of $25.3 million has been expensed in the year ended December 31, 2011 compared to $Nil for the same period in 2010. The finance cost associated with the redeemable shares is a result of the accounting treatment of these shares. In conjunction with an equity financing completed in February 2011, Common Shares were issued to subscribers whereby a 15% put right ("**Share Redemption Rights**") was agreed to pursuant to the terms and conditions of the subscription agreements ("**Subscription Agreements**"). According to the Share Redemption Rights, the subscribers may, in specific circumstances and at the option of the subscribers, require the Corporation to repurchase, for cancellation, all Common Shares issued under the Subscription Agreements at a redemption price equivalent to the subscription price plus a 15% annual rate of return, compounded annually, if the Corporation does not complete an IPO either (a) on or before December 31, 2012; or (b) in any event, by December 31, 2013. As a consequence, the put right resulted in these shares being presented as financial liabilities in the Corporation's statement of financial position. The redeemable shares were accounted for using amortized cost and the effective interest on the redeemable shares for the period is included in finance expense.

Subsequent to year end, the Corporation successfully closed the Global Offering and listed on the SEHK. Pursuant to this event, the balance of the share repurchase obligation, including 433,884,300 Common Shares comprising of 289,256,200 Shares and 144,628,100 Class "B" Shares, has been reclassified as the terms of the Subscription Agreements were acknowledged to have been met with the subscription holders and the share repurchase obligation has been extinguished. The Class "B" Shares were exchanged for Common Shares and cancelled.

Accretion for the unwinding of decommissioning obligation was $0.1 million for the year 2011 compared to $68,347 for the same period 2010. There was no interest expense on bank loans recorded for the year ended December 31, 2011 compared to $70,721 as a result of repayment on all bank borrowings in 2010.

Fair value loss on Warrants

During 2010 and 2011, we issued a total of 173,326,200 Warrants to Warrant holders. We issued 12,499,920 Fee Warrants between February and May 2010 and 21,694,220 Fee Warrants between February and May 2011 as compensation for finders' fee services provided to certain Shareholders in respect of certain fund raisings undertaken by Sunshine. We also issued 139,132,060 Purchase Warrants between February and May 2010 in conjunction with a unit private placement undertaken by Sunshine.

In 2011, holders of 124,719,900 Purchase Warrants agreed with Sunshine to amend the Purchase Warrants so that upon the exercise of each Purchase Warrant, the holder is entitled to a cash payment in Canadian dollars equal to the market value of one Common Share in Sunshine on the exercise date of each such Purchase Warrant subject to Sunshine, at its sole option and discretion, electing to satisfy the cash payment by the delivery of Common Shares of equivalent value. Such fair market value was to be determined with reference to the closing trading price of the Shares, and if the Shares were not listed and traded, such market value would be reasonably determined by our board of Directors. Accordingly, at the date of amendment, we reclassified 124,719,900 Purchase Warrants at a fair value of $32.7 million and presented a liability in the statement of financial position. For the year ended December 31, 2011, we recognised a fair value adjustment on the Purchase Warrants of $17.3 million.

In 2011, holders of 12,499,920 Fee Warrants agreed with Sunshine to amend the Fee Warrants so that upon the exercise of each Fee Warrant, the holder is entitled to a cash payment in Canadian dollars equal to the value of one Common Share in Sunshine on the exercise date of each such Fee Warrant subject to Sunshine, at its sole option and discretion, electing to satisfy the cash payment by the delivery of Common Shares of equivalent value. Such fair market value was to be determined with reference to the closing trading price of the Shares, and if the Shares were not listed and traded, such market value was to be reasonably determined by our board of Directors. Accordingly, we reclassified 12,499,920 Fee Warrants at a fair value of $3.7 million and presented a liability in the statement of financial position.

During the year ended December 31, 2011, Sunshine issued 21,694,220 Fee Warrants in connection with the $210.0 million equity financing in February 2011. These Fee Warrants had the same cash settlement right as those Fee Warrants with the amended terms described above. The 21,694,220 Fee Warrants were recorded at a fair value of $6.4 million and charged to share issue costs associated with the equity offering.

For the year ended December 31, 2011, we recognised a fair value loss of $3.0 million on the 34,194,140 Fee Warrants.

As a result of the foregoing, we recorded a fair value loss on Warrants of $20.3 million for the year ended December 31, 2011 and a liability relating to the Warrants of $63.0 million as at December 31, 2011. For more information, please refer to Note 25(e) and Note 25(f) of the Audited Financial Statements which is attached hereto as Schedule “A”.

Allocation of other assets

Allocation of other assets relates to amortization of IPO costs, which qualified for capitalization as deferred costs. $3.5 million was expensed during the year ended December 31, 2011 compared to $Nil for the year ended December 31, 2010.

Loss before tax

As a result of the foregoing factors, our loss before tax increased by $59.1 million, from $9.7 million in the year ended December 31, 2010 to $68.8 million in the year ended December 31, 2011.

Income tax expense

We recorded an income tax expense of $0.2 million in the year ended December 31, 2010 and income tax credit of $1.4 million in the year ended December 31, 2011.

Our income tax expense can be reconciled to the loss before tax recorded in our consolidated statements of operations and comprehensive income as follows:

	Year ended December 31,	
	2010	2011
	$	$
Domestic income tax rate	28.0%	26.5%
Loss before tax	(9,675,626)	(68,760,393)
Tax at the domestic income tax rate	(2,709,175)	(18,221,504)
Tax effect of expenses that are not deductible in determining taxable profit	1,105,059	14,234,238
Effect on deferred tax recognised at different tax rate	227,706	136,706
Effect of tax loss not recognised	—	1,215,541
Flow-through obligations	1,557,725	1,267,166
Income tax expense (recovery) for the period	**181,315**	**(1,367,853)**

Income tax expense increased in the year ended December 31, 2011 compared to the same period in 2010 primarily due to an increase in the tax effect of expenses that are not deductible in determining taxable profit due to an increase in share-based payments and finance costs related to the issuance of redeemable shares. The remainder of the increase relates to flow-through obligations renounced as tax credit due to the issuance of flow-through equity instruments.

As at December 31, 2010 and 2011, we had unused tax losses of approximately $77.3 million and $125.6 million, respectively, available for offset against future profits. The tax losses will expire at various times within a period of 20 years from the year the losses were incurred. In addition, we had unused tax pools of approximately $98.1 million and $238.3 million, respectively, as at December 31, 2010 and 2011, which are also available for offset against future taxable income. These tax pools have no expiry date, but we may only use the stipulated allowable tax deduction per year.

Net loss and comprehensive loss attributable to equity holders of the Corporation

As a result of the foregoing, our net loss and comprehensive loss attributable to equity holders of the Corporation increased by $57.5 million, from $9.9 million in the year ended December 31, 2010 to $67.4 million in the year ended December 31, 2011.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

Interest income and other income

Interest income and other income increased by $0.3 million from $6,895 in 2009 to $0.3 million in 2010, primarily due to increased interest income on bank deposits as a result of a significant increase in our bank balances and cash from 2009 to 2010. The increase in bank balances and cash was primarily due to several rounds of equity financings undertaken by us in late 2009 and 2010.

Expenses

Our expenses increased by $6.3 million, from $3.6 million in 2009 to $9.9 million in 2010, primarily due to increases in general and administrative expenses and share-based payments.

General and administrative expenses

Our general and administrative expenses increased by $3.0 million, from $2.8 million in 2009 to $5.8 million in 2010, primarily due to increases in salaries, consulting fees and employees benefits, other general and administrative expense, as well as legal and audit fees. Salaries, consulting fees and employees benefits increased by $1.6 million primarily due to an increase in our headcount to 39 full time employees in 2010 as compared to 18 full time employees in 2009. Employee numbers increased mainly in our geology, drilling and operations departments due to increased winter drilling activity and due to the commencement of pre-production commercial conventional heavy oil in the Muskwa area in the second half of 2010. Other general and administrative expenses increased by $0.6 million in the year ended December 31, 2009 and December 31, 2010, primarily due to a vendor penalty of $0.5 million that did not occur in 2009. Furthermore, legal and audit costs increased in 2010 due to costs incurred in relation to our private placement equity financings and the conversion to IFRS and internal control process implementation and reviews.

Share-based payments

Our share based payments increased by $3.3 million, from $0.6 million in 2009 to $3.9 million in 2010. We record a large proportion of each share based payment in the year of its grant in accordance with the applicable vesting provisions. With our staff increase as noted above, the number of share options granted were insignificant in 2009 as compared to the share options granted in 2010.

Finance costs

Our finance costs decreased by $47,715, from $140,745 in 2009 to $93,030 in 2010, primarily due to a decrease in interest on bank loans, partially offset by an increase in accretion of the carrying value of asset decommissioning obligations. The decrease in interest payments on bank loans from approximately $1.5 million in 2009 to $70,721 in 2010 was primarily due to the full repayment of the bank loan in early 2010. Accretion of the carrying value of provision for decommissioning obligations which is estimated to be incurred between 2010 and 2059 increased from $10,778 in 2009 to $68,346 in 2010. This related primarily to the decommissioning obligations associated with road construction and pad development for the production of conventional heavy oil at the Muskwa project.

Loss before tax

As a result of the foregoing factors, our loss before tax increased by $6.1 million, from $3.6 million in 2009 to $9.7 million in 2010.

Income tax expense

We recorded an income tax expense of $0.8 million in 2009 and income tax expense of $0.2 million in 2010.

Our income tax expense can be reconciled to the loss before tax recorded in our consolidated statements of operations and comprehensive income as follows:

	Year ended December 31,	
	2009	**2010**
	$	**$**
Domestic income tax rate	29.0%	28.0%
Loss before tax	(3,625,026)	(9,675,626)
Tax at the domestic income tax rate	(1,051,258)	(2,709,175)
Tax effect of expenses that are not deductible in determining taxable profit	161,203	1,105,059
Effect on deferred tax recognised at different tax rate	143,755	229,342
Future tax deductible expenses transferred upon renouncement of flow-through obligations	61,250	2,703,582
Flow-through obligations renounced as tax credit	(147,000)	(1,145,856)
Others	55,041	(1,637)
Income tax expense (recovery) for the year	**(777,009)**	**181,315**

The change from tax credit in 2009 to tax expense in 2010 was primarily due to an increase in the tax effect of expenses that are not deductible in determining taxable profit due to an increase in share-based payments. The remainder of the increase relates to flow-through obligations renounced as tax credit due to the increased issuance of flow-through equity instruments in 2010.

As at December 31, 2009 and 2010, we had unused tax losses of approximately $50.5 million and $77.3 million, respectively, available for offset against future profits. The tax losses will expire at various times within a period of 20 years from the year in which the losses were incurred. In addition, we had unused resource tax pools of approximately $99.0 million and $102.1 million, respectively, as at December 31, 2009 and 2010, which are also available for offset against future taxable income. These resource tax pools have no expiry date, and we may only use the stipulated allowable tax deduction per year.

Net loss and comprehensive loss attributable to equity holders of the Corporation

As a result of the foregoing, our net loss and comprehensive loss attributable to equity holders of Sunshine increased by $7.1 million, from $2.8 million in 2009 to $9.9 million in 2010.

Liquidity and Capital Resources

Historically, we have financed our capital expenditures and working capital requirements through a series of equity financings, the issuance of financial instruments, and through bank borrowings. As of the date hereof, other than the loan we drew down in respect of the Orient Credit Facility as discussed in the section entitled *"Indebtedness — Bank Loans and Other Loans"* below, we did not have any outstanding bank or other borrowings.

We intend to finance our future capital expenditures and meet our working capital requirements through our cash and cash equivalents, net proceeds from the Global Offering, cash generated from operating activities, further issuances on the debt and equity capital markets and through credit facilities where available. We currently do not have any plan for further issuances of equity in the foreseeable future.

Warrants

Historically, the Corporation issued Warrants from time to time as a part of certain equity financings. During 2010 and 2011, we issued a total of 173,326,200 Warrants to warrantholders. We issued 12,499,920 Fee Warrants, exercisable at $0.30 between February and May 2010 and 21,694,220 Fee Warrants exercisable at $0.48 in February 2011 as compensation for the solicitation of investors in respect of certain fund raisings that we undertook. We also issued 139,132,060 Purchase Warrants exercisable at $0.40 between February and May 2010 in conjunction with a unit private placement that we undertook. As of December 31, 2011, all Warrants were outstanding. In 2011, we reached an agreement with holders of 124,719,900 Purchase Warrants and 12,499,920 Fee Warrants to modify the terms of such Warrants so that upon the exercise of each Purchase Warrant or Fee Warrant, as the case may be, the holder would be entitled to receive a cash payment in Canadian dollars equal to the market value of one Common Share in Sunshine on the exercise date of each such Purchase Warrant or Fee Warrant. Please refer to the section entitled *"Period to Period Comparison of Results of Operations — Year Ended December 31, 2011 Compared to Year Ended December 31, 2010 — Expenses — Fair value loss on Warrants"* above. Purchase Warrants and Fee Warrants with the cash-settlement feature are classified as derivative financial instruments in the statement of financial position and recorded at fair value at the end of each reporting period.

After failing to obtain an exemption from the SEHK to allow warrants to remain outstanding after the completion of the Global Offering, we were required to cancel all outstanding warrants, before commencing the Global Offering, as a condition of Listing. We reached an agreement with all warrant holders on October 28, 2011 and executed agreements for the cancellation of all Warrants. We agreed to cancel the Warrant for an aggregate sum of approximately $68.9 million, which was paid in full to the warrantholders on January 4, 2012 in cash, upon which the Warrants were cancelled and extinguished in full. We funded such payment using our internal cash resources. The agreed amount for terminating the Warrants was arrived at after arm's length negotiations between the parties and was agreed by an independent committee of our Board.

For those Warrants classified as our own equity instruments, the cancellation of the Warrants will be accounted for as a repurchase of our own equity instruments. Where we repurchase our own equity instruments, these equity instruments are deducted from equity in our consolidated statement of financial position. No gain or loss is recognised in the profit or loss in respect of the repurchase or cancellation of the equity instruments. The repurchase of our own equity instruments represents a transfer between owners and any consideration paid is recognised in equity on the statement of financial position.

For those Warrants classified as derivative financial instruments, the cancellation of those Warrants will be accounted for as derecognition of derivative financial instruments. The derivative financial instruments will be carried at fair value at the date of Warrant termination with the change in fair value recognised immediately in profit or loss. Since the Warrants holders are Shareholders of Sunshine, the difference between the fair value of the Warrants and the cancellation consideration is adjusted to equity.

Cash Flow

The following table sets forth selected cash flow data from our consolidated cash flow statements for the periods indicated:

	Year ended December 31,		
	2009	2010	2011
	$	$	$
Net cash used in operating activities	(2,598,410)	(5,961,534)	(13,779,243)
Net cash used in investing activities	(8,361,315)	(43,493,460)	(154,366,815)
Net cash generated from financing activities	10,994,482	90,419,612	211,563,085
Net increase in cash and cash equivalents	34,757	40,964,618	43,417,027
Cash and cash equivalents at beginning of year	541,012	575,769	41,540,387
Cash and cash equivalents at end of year	**575,769**	**41,540,387**	**84,957,414**

Cash Flow Used in Operating Activities

Our net cash used in operating activities was $13.8 million in the year ended December 31, 2011. Cash used in operations prior to changes in working capital was $12.8 million. Changes in working capital contributed a net cash outflow of $1.0 million, comprising an increase in trade and other receivables of $1.6 million and an increase in prepaid expenses and deposits of $0.5 million, partially offset by an increase in trade and other payables of $1.1 million. The increase in trade and other receivables reflected our winter drilling activities and pre-production development of conventional heavy oil in the Muskwa area.

We had net cash used in operating activities of $6.0 million in 2010. Cash used in operations prior to changes in working capital was $5.8 million. Changes in working capital contributed a net cash outflow of $0.2 million, comprising (i) an increase in trade and other receivables of $0.4 million; and (ii) an increase of prepaid expenses and deposits of $0.3 million, partially offset by an increase in trade and other payables of $0.5 million. The increase in trade and other receivables and prepaid expenses and deposits reflected our general increased business activity and expanded operations in 2010, including the commencement of winter delineation and drilling programmes and production of heavy oil in the Muskwa area.

We had net cash used in operating activities of $2.6 million in 2009. Cash used in operations prior to changes in working capital was $2.8 million. Changes in working capital contributed a net cash inflow of $0.2 million, represented by an increase in trade and other payables of $0.2 million. In 2009, due to the global economic downturn, we closely managed our financial resources and fully utilised available credit terms from our vendors for trade and other payables in order to optimise our cash flow.

Cash Flow Used in Investing Activities

Net cash used in investing activities in the year ended December 31, 2011 amounted to $154.4 million. This net cash outflow primarily reflected expenditures incurred for exploration and evaluation activities amounting to $155.6 million which included delineation and development drilling, seismic costs and the installation of production facilities at our Muskwa heavy oil property and partially offset by interest earned of $1.6 million.

Net cash used in investing activities in 2010 amounted to $43.5 million. This net cash outflow primarily reflected payments for E&E assets amounting to $43.2 million which were primarily expenditures incurred to drill and evaluate exploratory wells on our lands.

Net cash used in investing activities in 2009 amounted to $8.4 million. This net cash outflow primarily reflected payments for exploration and evaluation assets amounting to approximately $7.2 million and interest paid and capitalised into E&E assets of $1.2 million. The significant decrease in investing activities, in particular a reduction in payments for E&E assets reflected a significant decrease in activities related to our winter drilling programme resulting from the global economic downturn in 2009.

Cash Flow from Financing Activities

Net cash generated from financing activities in the year ended December 31, 2011 amounted to $211.6 million. This cash inflow was primarily due to proceeds from the issue of redeemable shares amounting to $210.0 million and the issue of Common Shares, and Preferred Shares net of $0.8 million of share issue costs amounting to $15.1 million. These were partially offset by issue cost of redeemable shares we incurred and paid of $11.4 million and by expenses incurred for the Global Offering and SEHK listing for $6.9 million, of which $2.2 million was paid in the 2011 year.

Net cash generated from financing activities in 2010 amounted to $90.4 million. This cash inflow was primarily due to proceeds of equity issuances throughout the year, including proceeds from the issue of Common Shares, common flow-through shares, Preferred Shares and Warrants amounting to $98.9 million. These were partially offset by payments for share issue costs amounting to $3.9 million and the full repayment of bank borrowings amounting to $5.3 million.

Net cash generated from financing activities in 2009 amounted to $11.0 million. This cash inflow was primarily due to proceeds from equity issuances throughout the year and proceeds from bank borrowings. Equity issuance proceeds primarily included proceeds from the issue of Common Shares, common flow-through shares, Preferred Shares and Warrants amounting to $31.0 million. Net proceeds from bank borrowings included a $9.5 million drawdown on our $35.0 million syndicated revolving credit facility in 2008, partially offset by a $29.4 million repayment of bank borrowings under the same facility during the year.

Certain Statements of Financial Position Items

Exploration and Evaluation Assets

	Exploration and evaluation expenditures	**Land and leaseholds**	**Total**
	$	$	$
As at December 31, 2008	66,826,383	57,649,008	124,475,391
As at December 31, 2009	73,455,835	61,166,990	134,622,825
As at December 31, 2010	129,617,305	68,219,040	197,836,345
As at December 31, 2011	307,622,910	74,654,348	382,277,258

All costs directly associated with exploration and evaluation and land and leaseholds are initially capitalised.

Exploration and evaluation costs are those expenditures for an area where technical feasibility and commercial viability has not yet been determined. These costs include geological and geophysical costs, exploration and evaluation drilling, capitalised general and administrative costs, pre-production revenues, net of operating cost, capitalised stock based payments costs and asset retirement costs.

Land and leaseholds costs include the costs of acquiring the oil sands and petroleum and natural gas rights from Alberta. The Oil Sands Leases have an initial term of 15 years from the date of acquisition. These lease terms are extended for the life of the resource once a minimum level of activity has occurred on the lease. Also included under land and leaseholds are the annual lease rental payments made to Alberta.

The decision to transfer assets from exploration and evaluation to development and producing assets occurs when the technical feasibility and commercial viability of the project is determined, based on economically recoverable reserves being assigned to the project. As of the date hereof, we had not made the determination to transfer assets from exploration and evaluation to development and producing assets and as a result, no depletion expense has been recorded.

Our E&E assets increased as at December 31, 2011 compared to December 31, 2010 by $184.4 million as a result of the completion of our winter drilling season and the development of our conventional heavy oil property in the Muskwa area.

Our E&E assets increased as at December 31, 2010 compared to December 31, 2009 by $63.2 million as a result of an increase in our operational activities in 2010 including a winter drilling programme of over 100 wells and road construction and pad development for the production of conventional heavy oil at the Muskwa project. Our E&E assets increased as at December 31, 2009 by only $10.1 million which reflected the economic downturn and a general decline in our operational activities in 2009.

Our land and leaseholds increased as at December 31, 2011 compared to December 31, 2010 and 2009 primarily due to the acquisition of additional Oil Sands Leases from Alberta. During the year ended December 31, 2011, we acquired approximately 30,574 hectares of Oil Sands Leases, whilst for the years ended December 31, 2009 and 2010, we acquired approximately nil hectares and 34,442 hectares, respectively.

Trade and Other Receivables

Our trade and other receivables primarily consist of trade receivables for bitumen produced and sold, fuel charged back to vendors and goods and services tax receivable due from the CRA and to a receivable for $1.3 million related to a farm out arrangement with an arm's length third party company (Petro Energy Corp) in respect of the Thickwood Farmout. We retained a 50% share of assets, liabilities, income and expenses arising from the operations of these assets in the specific oil sands zones. There has been no activity on this jointly controlled asset since inception and no activity is planned in the near term. We ultimately did not receive this final payment of $1.3 million and so we determined to retain our interest in the two sections of land that this receivable related to and removed the receivable from our consolidated statement of financial position during the year ended December 31, 2009.

We recorded trade receivables of $0.3 million and $2.1 million as at December 31, 2010 and December 31, 2011, respectively, relating to the sale of our pre-production bitumen from the Muskwa project late in 2010. Our trade receivables increased significantly as at December 31, 2011 compared to December 31, 2010 primarily due to increased sales volumes of pre-production bitumen originating at our Muskwa heavy oil project.

Our trade and other receivables composition during the Track Record Period is as follows:

	As at December 31,		
	2009	**2010**	**2011**
	$	**$**	**$**
Trade receivables	—	313,684	2,047,804
GST receivable	67,878	785,537	1,522,985
Farm out receivable	—	—	—
Other receivables	12,687	174,337	12,164
	80,565	**1,273,558**	**3,582,953**

We allow an average credit period of 30 days to our trade customers. We are generally paid for our bitumen produced in the month following delivery. An aging of our trade receivables during the Track Record Period is as follows:

	As at December 31,		
	2009	**2010**	**2011**
	$	**$**	**$**
0 - 30 days	—	—	1,259,911
31-60 days	—	201,829	781,194
61 - 90 days	—	111,855	6,699
—	**—**	**313,684**	**2,047,804**

As at December 31, 2009, 2010 and 2011, included in our trade receivables are debtors with aggregate carrying amounts of nil, $0.3 million and $0.8 million, respectively, which are past due as at the reporting date for which we have not provide for impairment loss. We do not hold any collateral over these balances, but our management believes that all amounts remain collectible. As at December 31, 2010 and December 31, 2011, the average age of these trade receivables were 56 days and 31 days, respectively.

With respect to our trade receivables of $2.0 million outstanding as at December 31, 2011, we had subsequently received all such amounts as of the date hereof.

Trade and Other Payables

Trade payables mainly represent payables to subcontractors of exploration and evaluation services. Other payables mainly represent accruals for operations, expenditures on E&E assets, expenses incurred with respect to the Global Offering and other financing costs. The average credit period is 90 days. We have financial risk management policies in place to ensure that all payables are paid within the pre-agreed credit terms. An aging of our trade payables during the Track Record Period is as follows:

	As at December 31,		
	2009	**2010**	**2011**
	$	**$**	**$**
Trade payables			
0 - 30 days	552,778	6,101,044	7,225,897
31 - 60 days	160,904	1,368,367	4,066,802
61 - 90 days	—	—	448,245
90 - 180 days	36,750	253,983	210,558
	750,432	7,723,394	11,951,502
Other payables and accruals	541,994	9,798,404	21,413,936
Total	**1,292,426**	**17,521,798**	**33,365,438**

Our trade payables increased as at December 31, 2011 compared to December 31, 2010 by $4.2 million and increased as at December 31, 2010 compared to December 31, 2009 by $7.0 million, respectively, as a result of an increase in our operational activity in 2010 and 2011 including a winter drilling programme of over 100 wells and road construction and pad development for the production of conventional heavy oil at the Muskwa project.

Our other payables and accruals increased as at December 31, 2011 compared to December 31, 2010 by $11.6 million as a result of an increase in accruals for continued development and expansion activity in the Muskwa area, including expenditures on seismic, drilling and delineation activities as well as completion of our first carbonate pilot programme. Our other payables increased as at December 31, 2010 compared to December 31, 2009 as a result of an increase in accrual for continued development and expansion activity of $9.3 million relating to the initial production and completion of our first production pads in the Muskwa area.

We had trade payables of $210,558 aged over 90 days as at December 31, 2011 due to late receipt and processing of vendor invoices. Accordingly, these balances appear to be overdue. Such late receipt of invoices from our vendors is not unusual in the industry. We did not experience any material dispute with any of our suppliers nor any financial difficulty in settling trade and other payables during the Track Record Period.

Capital Expenditures and Commitments, Net Current Liabilities and Contingent Liabilities

Capital Expenditure

During the Track Record Period, our principal capital expenditure comprised both exploration activities and development activities. Our exploration activities included exploration of land and acquisition of Oil Sands Leases in identified areas, drilling delineation programmes, geological studies and our carbonate pilot programmes. Our development activities included the clastics development in West Ells, Thickwood and Legend Lake, reservoir testing, geological studies and work on conventional heavy oil assets at the Muskwa project including the drilling of production wells, production pad construction, road construction to provide access to the production pad, testing for future pad locations and seismic work.

A typical oil sands project requires several years and stages of exploration and development before commercial production. The process of exploring and developing discovered resources requires considerable capital. However, a SAGD project is considerably less capital intensive than an oil sands mining project. The initial exploration phase includes the acquisition of Oil Sands Leases in identified areas, which can vary considerably in cost.

As of December 31, 2011, we had spent an aggregate of approximately $74.7 million on the acquisition of Oil Sands Leases. Of this amount, approximately $26.4 million relates to Oil Sands Leases and permits that form our two initial projects: the Muskwa conventional heavy oil project and the West Ells SAGD project.

Subsequent to acquiring Oil Sands Leases, we incur capital on acquiring 2D seismic data over the acreage and on the drilling of initial exploration/appraisal wells. This initial phase is often followed by 3D seismic data acquisition and infill drilling into promising hydrocarbon deposits. The average cost of our delineation wells varies significantly depending on factors such as location, depth and the complexity of the formation. Overall, our clastics coreholes have an average cost of approximately $0.4 million to $0.5 million per well. The amount of seismic data and the number of delineation wells required varies from project to project. However, these costs represent a small portion of the total capital cost of a commercial oil sands project.

Following the successful delineation of a bitumen resource, we conduct an initial engineering assessment of the site, which is required in order to complete the regulatory applications and environmental impact assessments submitted to the ERCB and AEW in order to commence a project. We usually undertake detailed engineering work during the period that ERCB and the AEW conduct their review and approval process. The detailed engineering work is intended to outline specific development plans for the bitumen resource.

When plans have been finalised and ERCB and Alberta environmental approvals have been received, the construction process begins with site preparation and road construction. We also procure and fabricate major equipment at this stage. The process continues with facility construction and the drilling of well pairs. Construction takes approximately 18 months to complete and is the most capital intensive part of our project development process. Once operating at design, a SAGD Project, will require additional well pairs be drilled in order to offset production declines over the project's producing life.

The following table sets forth our capital expenditure for the periods indicated:

	Year ended December 31,		
	2009	**2010**	**2011**
	$	**$**	**$**
Exploration activities			
Exploration Land (land and leasehold payments)	2,217,982	7,052,050	6,435,308
Drilling delineation programme	630,392	21,648,004	67,885,103
Geological Study (including seismic)	319,468	2,771,931	5,029,288
Carbonate pilot programmes	—	620,739	4,328,730
Other (Engineering studies and environmental studies)	1,741,444	1,098,009	4,295,883
Directly Attributable Capitalised Expenses	2,191,204	4,704,970	7,834,753
Total	**7,100,490**	**37,895,703**	**95,809,065**

	Year ended December 31,		
	2009	**2010**	**2011**
	$	**$**	**$**
Development activities			
West Ells	—	—	17,899,576
Muskwa Production pads	—	2,487,334	34,761,636
Other Muskwa (including road, capitalised costs, seismic)	—	2,805,390	7,233,515
	—	5,292,724	59,894,727
Total	**7,100,490**	**43,188,427**	**155,560,859**

Our exploration activities decreased significantly in 2009 due to the general economic downturn and credit tightening in 2009 which led to a slowdown in our exploration activities. As the economy and market conditions improved in 2010, we were able to raise capital in the equity market and our exploration activities picked up significantly compared to 2009. During the year ended December 31, 2011, our exploration activities increased because we completed our largest winter capital programme to date, which was completed in the first quarter of 2011. This winter capital programme included 99 delineation wells, seismic programs in exploration lands and completion of our first carbonate pilot program.

Our development activities commenced in the second half of 2010 and primarily involved the initial production pad at our Muskwa project. Our development activities in the year ended December 31, 2011 primarily related to the completion of our second and third production pads at Muskwa. Other development activities related to Muskwa seismic, production tests and exploratory step out wells.

The development of our West Ells project involved activities of engineering, seismic and procurement of long lead equipment in the year ended December 31, 2011.

We intend to develop our projects in multiple phases with staggered start dates, which we expect will allow us to maximise the efficiency of our available capital. Our intention is that cash flows from the development of more mature projects will help to finance the capital requirements of subsequent project development work, thereby reducing our need for additional external financing. For more information, please refer to the section entitled *"Business — Capital Expenditure"* in this AIF for details of our anticipated capital requirements and cash flows from our various projects. We intend to fund the development of our projects primarily through internal resources of cash and bank balances as well as the net proceeds from the Global Offering.

The following table sets forth the proportion of the net proceeds from the Global Offering to be applied to each of our projects to fund their respective expected capital expenditures:

	Net proceeds from the Global Offering	
	%	**$ in millions(1)**
West Ells	64	366.3
Delineation Drilling	12	68.7
Muskwa	5	28.6
Thickwood	3	17.2
Other Projects	9	51.5
Total	**93**	**532.3**

Notes:
(1) The amount of expenditure to be funded by the net proceeds from the Global Offering is calculated based on net proceeds of $572.3 million (HK$4,287.2 million), assuming an Offer Price of HK$4.86 per Share, being the mid-point of the estimated Offer Price range.

For further information on use of the net proceeds from the Global Offering, please refer to the section entitled *"Future Plans and Use of Proceeds"*.

Capital Commitments and Operating Leasing Commitments

Capital Commitments

The following table sets forth our contractual obligations as at the dates indicated:

	As at December 31,		
	2009	**2010**	**2011**
	$	**$**	**$**
Contracted but not provided for			
Flow-through shares and special warrant obligations	2,000,598	622,296	—
E&E expenditure	—	—	73,785,000
	2,000,598	**13,605,665**	**73,785,000**

Our commitments in E&E expenditures relate to the services of various drilling rigs and other equipment and services of our ongoing drilling programmes.

Operating Leasing Commitments

The following table sets forth our minimum lease payments under operating leases in respect of offices premises as at the dates indicated:

	Year ended December 31,		
	2009	2010	2011
	$	$	$
Minimum lease payments under operating leases during the Relevant Periods in respect of office premises	522,738	548,995	1,203,949

We have an annual obligation of $1.6 million for Oil Sands Lease rentals and $10,752 for petroleum and natural gas lease rentals. Each Oil Sands Lease has an initial 15 year term from the date of acquisition. Each petroleum and natural gas lease has an initial four year term from the date of acquisition.

We had commitments for future minimum lease payments under non-cancellable operating leases in respect of premises which fall due as follows:

	As at December 31,		
	2009	2010	2011
	$	$	$
Within one year	1,896,362	1,951,006	3,238,252
In the second to fifth year (inclusive)	5,933,848	6,112,984	14,637,402
Over five years	11,056,080	10,728,898	14,107,450
	18,886,290	**18,792,888**	**31,983,104**

Net Current (Liabilities) Assets

The following table sets forth our current assets and current liabilities as at the dates indicated:

	As at December 31		
	2009	2010	2011
	$	$	$
Current assets			
Trade and other receivables	80,565	1,273,558	3,582,953
Prepaid expenses and deposits	234,152	1,910,487	797,718
Cash and cash equivalents	575,769	41,540,387	84,957,414
	890,486	44,724,432	89,338,085
Current liabilities			
Trade and other payables	1,292,426	17,521,798	33,365,438
Bank borrowings	5,328,200	—	—
Provision for decommissioning obligations	—	116,734	68,365
Provision for flow-through share obligations	250,075	19,914	—
Warrants	—	—	63,000,304
	6,870,701	17,658,446	96,434,107
Net current (liabilities) assets	**(5,980,215)**	**27,065,986**	**(7,096,022)**

We recorded net current liabilities as at December 31, 2009 primarily due to bank borrowings of approximately $5.3 million, which we used to finance our exploration and development activities. As general global economic conditions improved and the availability of liquidity in the capital markets increased in early 2010, we were able to pay down our bank borrowings and raise an aggregate of approximately $130.7 million in equity financing during 2009 and 2010. This resulted in net current assets of $27.1 million to further advance the development of our oil sands projects, specifically in the Muskwa area. For the year ended December 31, 2011, we raised a gross amount of $225.9 million in equity financing, offset by exploration and development activities, which resulted in a net current liability position of approximately $7.1 million.

Contingent Liabilities

As of the date hereof, we had no material contingent liabilities.

Off-balance Sheet Transactions

As of the date hereof, we did not have any off-balance sheet transactions.

Indebtedness

Bank Loans and Other Loans

The table below sets forth our bank borrowings as at the dates indicated.

	As at December 31,		
	2009	2010	2011
	$	$	$
Secured and repayable within one year	5,328,200	—	—

In 2008, we negotiated a syndicated revolving credit facility with a commitment amount of $35.0 million from four Canadian banks. The credit agreement had a maturity date of July 8, 2009, and was subject to extension upon request by us and approval by the syndicate of lenders. The credit agreement was subsequently amended to allow for an extension to March 9, 2010 (as approved by the syndicate). During the first quarter of 2010, we repaid all outstanding amounts and elected not to renew the credit facility. As at December 31, 2011, we did not have any outstanding bank borrowings.

On October 18, 2011, Sunshine entered into the Orient Credit Facility in the principal amount of $100 million, for general corporate purposes. The Orient Credit Facility is unsecured and may be subordinated if another lender requires it to be subordinated, with no penalty chargeable upon early repayment or cancellation of the Orient Credit Facility. The Orient Credit Facility is interest-free until May 31, 2012, and commencing on June 1, 2012 an annual interest rate charged at 5% per annum on the outstanding principal will be payable on a semi-annual basis to Orient International Resources Group Limited. The annual interest rate was determined upon commercial negotiations between Orient International Resources Group Limited and Sunshine. The Corporation understands that current market rates for oil sands companies in the developmental stages are approximately 400 basis points plus bankers' acceptances (1.2% as of October 25, 2011) equating to an interest rate of 5.25%. As of the date hereof, we had $Nil drawn of the Orient Credit Facility.

As at December 31, 2011, we did not have any outstanding bank or other borrowings.

We are currently in discussions with the Bank of China in relation to a possible credit facility in the amount of US$200 million pursuant to a non-binding letter of intent dated February 3, 2012. Entry into any binding credit facility arrangement will be subject to further negotiations between the parties regarding the terms and conditions of the credit facility and the Bank of China's approval. The letter of intent is valid for one year and will expire in February 2013. As of the date hereof, we had not entered into any binding credit facility agreement with the Bank of China.

Other Outstanding Indebtedness

We had redeemable shares, being 1,289,256,200 Shares and 144,628,100 Class "B" Shares, amounting to $224.4 million as at December 31, 2011 as a result of our equity financing activities in February 2011, which are classified as non-current financial liability. We also had a liability of $63.0 million, being 158,914,040 Warrants, as at December 31, 2011 in respect of the estimated fair value of Warrants. For more information, please refer to the section entitled *"Description of Selected Statement of Comprehensive Income Line Items — Finance costs"* above. Save for the redeemable shares, we did not have other outstanding indebtedness or any loan capital issued and outstanding or agreed to be issued, bank overdrafts, loans or similar indebtedness, liabilities under acceptances (other than normal trade bills), acceptance credits, debentures, mortgages, charges, finance leases or hire purchase commitments, guarantees or other contingent liabilities. We confirm that there has not been any material change in our indebtedness and contingent liabilities since December 31, 2011 until the date of this AIF.

Subsequent to year end, the Corporation successfully closed the Global Offering on the SEHK. Pursuant to this event, the balance of the share repurchase obligation, including 433,884,300 common shares comprising of 289,256,200 Shares and 144,628,100 Class "B" Shares, has been reclassified to share capital as the terms of the Subscription Agreements were agreed to have been met with the subscription holders and the share repurchase obligation has been extinguished. The Class "B" Shares were surrendered for cancellation and exchanged for common shares.

Advisory Agreement with Orient Financial

We entered into an Advisory Agreement on January 20, 2010 and a series of subsequent amendment agreements between December 2010 and October 2011 with Orient Financial Holdings Limited, a company with substantial Asian and international capital markets connections and resources. At the time of the entry into the Advisory Agreement, Sunshine was still in its early phases of development and was in need of additional investment to help fund our further growth and development. However, the economic environment in the aftermath of the global financial crisis and the economic situation in North America in particular, made it difficult for an early phase company such as Sunshine to seek the necessary funding from the North American market and investors. As a result, we determined that Asia presented the greatest potential to us for obtaining further investment. We anticipated that Orient Financial, wholly owned by Mr. Hok Ming Tseung, who also directly and indirectly holds 82% of Orient, with its substantial Asian and international capital markets connections and resources, would be an important strategic partner for us in positioning ourselves for capital raisings in Asia and potentially an IPO on an Asian stock exchange. We anticipated that Orient would assist us in establishing connections and providing introductions to Asian market participants, such as PRC oil companies and oil related equipment companies. These were crucial for us to create an identity and establish relationships in the Asian market, which we otherwise would not have been able to establish.

During the last two years, Orient has supported us by inviting us for visits to Hong Kong and the PRC in order to be introduced to Asian market participants, such as PRC oil companies and oil related equipment companies as well as introducing investment banks, legal counsel, public relations firms and other professionals in Hong Kong and the PRC to us. Furthermore, Orient has provided us with assistance with our feasibility studies, research and discussions into adopting the strategy of an IPO on the SEHK and contributed strategically through the advice provided by Mr. Hok Ming Tseung as a director of Sunshine since March 2010; assisting in the selection and renovation of our Hong Kong office and handling other logistical matters. We embarked on the process of an IPO, and in particular a Listing on the Hong Kong Stock Exchange, due largely to the advice and support of Orient.

In consideration for the services rendered under the Advisory Agreement, we are required to pay to Orient Financial an amount in cash equal to 0.75% of the number of issued and outstanding Shares at the time of the pricing of the Global Offering multiplied by the Offer Price per Share. However, we may at our sole option and discretion elect to satisfy up to 95% of the Advisory Fee through the issuance of Shares at the Offer Price and 5% through a cash payment.

Subsequent to year end, the Corporation successfully completed its Global Offering. Pursuant to this event, the obligation owing for the advisory fee was recognized and 13,566,395 Common Shares issued and a cash fee of $440,933 was paid.

Market Risks

We are exposed to various types of market risks as described below:

Market Risk

Market risk is the risk that changes in market prices, such as currency risk, commodity price risk and interest rate risk will affect our net loss. The objective of market risk management is to manage and control market risk exposures within acceptable limits. There have been no changes over the Track Record Period to our objectives, policies or processes to manage market risks.

Although we do not sell or transact in foreign currency, the US dollar influences the price of petroleum sold in Canada. Furthermore, exchange rate fluctuations can affect the fair value of future cash flows. We had no forward exchange rate contracts in place as at or during the Track Record Period.

Commodity Price Risk

Commodity price risk is the risk that the value of future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum are impacted by world economic events that dictate the levels of supply and demand. We are a development stage entity and have limited current production. We have not attempted to mitigate commodity price risk through the use of various financial derivative and physical delivery sales contracts.

Interest Rate Risk Management

We are exposed to fair value interest rate risk in relation to the redeemable shares. We currently do not enter into any hedging instrument for fair value interest rate risk.

We are exposed to cash flow interest rate risk in relation to our cash and cash equivalents and variable bank borrowings. Our cash flow interest rate risk is mainly concentrated on the fluctuation of Canadian Prime Rate arising from our borrowings and the Canadian deposits rate from our bank balances and term deposits.

Sensitivity Analysis

As the impact on our profit or loss of interest rate is insignificant, no sensitivity analysis was considered necessary.

Credit Risk

Credit risk is the risk of financial loss to us if a counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from our cash, deposits and receivables from joint venture partners and GST receivables. However, as at December 31, 2010, our receivables consisted of 61.7% from GST receivables, 24.6% from trade receivables and 13.7% from other receivables. As at December 31, 2011, our receivables consisted of 57.2% from oil sale receivables, 42.5% from GST receivables and 0.3% from other receivables.

We are exposed to credit risk on amounts held in individual banking institutions for balances that are above nominal guaranteed amounts. We regularly monitor published and available credit information of all these banking institutions.

We are exposed to credit risk from our receivables from purchasers of our bitumen and deposits. As at December 31, 2011, the allowance for impairment of accounts receivable was nil and we did not provide for any doubtful accounts nor were we required to write off any receivables, as no receivables were considered past due or impaired. We consider any amounts in excess of 30 days past due.

Liquidity Risk

Liquidity risk is the risk that we will not be able to meet our financial obligations as they become due. Our approach to managing liquidity is to plan that we will have sufficient liquidity to meet our liabilities when due, using either equity or bank debt proceeds. We expect to settle all accounts payable and accrued liabilities within 90 days.

We utilise authorisations for expenditures to manage planned capital expenditures and actual expenditures are regularly monitored and modified as considered necessary.

Dividend Policy

Our Board may declare dividends in the future after taking into account our operations, earnings, financial condition, cash requirements and availability and other factors as it may deem relevant at such time. Any declaration and payment as well as the amount of dividends will be subject to our constitutional documents and the ABCA. In addition, our Directors may from time to time pay such interim dividends as appear to our Board to be justified by our profits, or special dividends of such amounts and on such dates as they think fit. No dividend shall be declared or payable except out of our profits and reserves lawfully available for distribution. Our future declarations of dividends may or may not reflect our historical declarations of dividends and will be at the absolute discretion of the Board.

Sunshine did not declare or pay any dividends during the Track Record Period, nor do we have any present intentions of paying any dividends in the near term.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("**MD&A**"), a review of the Corporation's financial condition and results of operations as at and for the year ended December 31, 2011 and 2010, is attached hereto as Schedule "B". The MD&A should be read in conjunction with the Audited Financial Statements of the Corporation, which is attached hereto as Schedule "A".

STATEMENT OF EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

The Compensation Committee of the Board (the "**Compensation Committee**") exercises general responsibility regarding overall employee and executive officer compensation. The Compensation Committee is comprised of Messrs. Gregory Turnbull, QC (Chair); Hokming Tseung; Raymond Fong and Robert J. Herdman.

The objective of the Corporation's executive compensation policy is to create a remuneration package that will both attract and retain experienced and qualified individuals to assist the Corporation in the furtherance of its business. Such remuneration packages generally consist of competitive salaries, stock option grants pursuant to the Amended and Restated Stock Option and the Post-IPO Stock Option Plan.

Option-based Awards

The purpose of each of the Amended and Restated Stock Option Plan and the Post-IPO Stock Option Plan is to advance the interests of the Corporation by encouraging the directors, officers, employees of, or providers of services to, the Corporation and its subsidiaries to acquire Shares, thereby: (i) increasing the proprietary interests of such persons in the Corporation; (ii) aligning the interests of such persons with the interests of the Corporation's Shareholders generally; (iii) encouraging such persons to remain associated with the Corporation; and (iv) furnishing such persons with an additional incentive in their efforts on behalf of the Corporation. All option-based awards for the executive officers individually, and for the Corporation's employees in the aggregate, are reviewed by the Compensation Committee based on recommendations by the Executive Co-Chairmen of the Corporation. After the Compensation Committee has considered and determined what stock options should be granted, it makes a recommendation to the Board for consideration and, if deemed appropriate, approval. Previous grants of stock options, individual and corporate performance, competitive pressures and numerous other factors are taken into account when the Compensation Committee and the Board are considering new stock option grants.

Summary Compensation Table

The following table provides a summary of compensation earned during the years ended December 31, 2009, 2010, and 2011 by the Co-Chief Executive Officers, the Chief Financial Officer, the Executive VP, Corporate Operations and the Executive Co-Chairmen (collectively the "**Named Executive Officers**").

Name & Principal Position	Year	Salary ($)	Share-Based Awards ($)[8][9]	Option-Based Awards ($)[9]	Non-Equity Incentive Plan Compensation ($)		Pension Value ($)	All Other Compensation ($)[10]	Total Compensation ($)
					Annual Incentive Plans	Long-Term Incentive Plans			
Michael J.	2011	-	-	-	520,000	-	-	486,393	1,006,393
Hibberd[1]	2010	-	3,019,852	395,383	400,000	-	-	96,663	3,911,898
Co-Chairman	2009	-	-	-		-	-	100,119	100,119
Songning Shen[2]	2011	-	-	-	520,000	-	-	487,393	1,007,393
Co-Chairman	2010	-	3,019,852	395,383	400,000	-	-	96,663	3,911,898
	2009	-	-	-	-	-	-	100,447	100,447
John Zahary[3]	2011	-	1,934,040	467,079	-	-	-	-	2,401,119
President and	2010	-	-	-	-	-	-	-	-
Chief Executive	2009	-	-	-	-	-	-	-	-
Officer									
Doug Brown[4]	2011	226,000	-	-	170,000	-	-	6,829	402,829
Chief Operating	2010	207,000	823,596	395,383	150,000	-	-	6,787	1,582,766
Officer	2009	188,000	-	-	-	-	-	9,729	197,729
John Kowal[5]	2011	226,000	-	-	170,000	-	-	31,758	427,758
Strategic Advisor	2010	207,000	823,596	395,383	150,000	-	-	7,549	1,583,528
	2009	188,000	-	-	-	-	-	6,871	194,871
Tom Rouse[6]	2011	204,167	-	-	135,000	-	-	23,729	362,896
Chief Financial	2010	178,300	658,877	247,115	100,000	-	-	7,462	1,191,754
Officer	2009	166,000	-	-	-	-	-	6,773	172,773
David Sealock[7]	2011	204,167	-	-	135,000	-	-	31,949	371,116
Executive VP,	2010	177,500	658,877	247,115	100,000	-	-	7,495	1,190,987
Corporate	2009	165,000	-	-	-	-	-	10,702	175,702
Operations									

Notes:

(1) Mr. Hibberd was Co-Chief Executive Officer from August, 2007 to October 5, 2008. He has been the Executive Co-Chairman since October 6, 2008.

(2) Mr. Shen was Co-Chief Executive Officer from August, 2007 to October 5, 2008. He has been the Executive Co-Chairman since October 6, 2008.

(3) Mr. Zahary was appointed President and Chief Executive Officer on December 20, 2011, at which time Mr. Brown's position reverted to Chief Operating Officer and Mr. Kowal assumed the position of strategic advisor to the Corporation.

(4) Mr. Brown was Co-Chief Executive Officer and Chief Operating Officer from October 6, 2008 to December 19, 2011, and was Chief Operating Officer from November 1, 2007 to October 5, 2008. Since December 20, 2011, Mr. Brown remains the Chief Operating Officer of the Corporation.

(5) Mr. Kowal was Co-Chief Executive Officer from October 6, 2008 to December 19, 2011, and was Senior Vice President, Capital Markets from June 2, 2008 to October 5, 2008. On December 20, 2011, Mr. Kowal was appointed as strategic advisor to the Corporation.

(6) Mr. Rouse was appointed Vice President, Finance and Chief Financial Officer on August 22, 2008 and was Controller from February 1, 2008 to August 21, 2008.

(7) Mr. Sealock was appointed Executive Vice President, Corporate Operations on June 14, 2010 and was Vice President, Corporate Operations from July 1, 2008 to June 14, 2010.

(8) These share-based awards relate to the conversion of Class "G" Shares that were subject to performance conditions that were met in September, 2008, and Class "G" Shares issued in 2010.

(9) Share-based awards and option-based awards are valued at the "call option value" using the Black-Scholes model. All values are calculated based on International Financial Reporting Standards.

(10) These amounts relate to vacation pay and benefits such as parking, health and medical coverage. In the case of the Co-Chairmen, these amounts include fees paid pursuant to their respective advisory services contracts.

Narrative Discussion of Summary Compensation Table

Please refer to the disclosure under the heading *"Statement of Executive Compensation – Compensation Discussion and Analysis"* and the above footnotes to the Summary Compensation Table for a description and explanation of any significant factors necessary to understand the information disclosed in the Summary Compensation Table. The Corporation did not make any downward re-pricing of stock options during the fiscal period ended December 31, 2011.

Incentive Plan Awards

Outstanding Share-Based Awards and Option-Based Awards

The following table sets forth for each Named Executive Officers, the option-based awards and the share-based awards that were outstanding as at December 31, 2011. The number of securities underlying unexercised options has been adjusted to reflect the 20 for 1 share split. As a result, the option exercise price has been divided by 20 and rounded to the nearest $0.01.

	Options-based Awards(1)				Share-based Awards(2)	
Name	**Number of Securities Underlying Unexercised Options (#)**	**Option Exercise Price ($)**	**Option Expiration Date**	**Value of Unexercised in-the-money Options(3) ($)**	**Number of Shares or Units of Shares That Have Not Vested (#)**	**Market or Payout Value of Share-Based Awards That Have Not Vested**
Michael J. Hibberd	1,200,000	0.06	Jun 15, 2012	Nil	11,000,000	$5,500
Co-Chairman	7,200,000	0.07	Jul 20, 2012			
	4,900,000	0.08	Aug 24, 2012			
	3,070,000	0.15	Oct 9, 2012			
	7,146,000	0.14	Jan 9, 2013			
	1,404,000	0.20	Mar 31, 2013			
	1,380,000	0.20	Jun 13, 2013			
	1,980,000	0.20	Aug 1, 2013			
	2,400,000	0.28	Mar 2, 2015			
Songning Shen	1,400,000	0.06	Jun 15, 2012	Nil	11,000,000	$5,500
Co-Chairman	7,200,000	0.07	Jul 20, 2012			
	4,900,000	0.08	Aug 24, 2012			
	3,070,000	0.15	Oct 9, 2012			
	7,146,000	0.14	Jan 9, 2013			
	1,404,000	0.20	Mar 31, 2013			
	1,380,000	0.20	Jun 13, 2013			
	1,980,000	0.20	Aug 1, 2013			
	2,400,000	0.28	Mar 2, 2015			
John Zahary *President and Chief Executive Officer*	2,000,000	0.48	December 20, 2016	Nil	4,000,000	$2,000
Doug Brown	4,284,000	0.14	Jan 9, 2013	Nil	3,000,000	$1,500
Chief Operating Officer	1,296,000	0.20	Mar 31, 2013			
	1,300,000	0.20	Jun 13, 2013			
	1,980,000	0.20	Aug 1, 2013			
	2,400,000	0.28	Mar 2, 2015			
John Kowal	3,300,000	0.20	Apr 1, 2013	Nil	3,000,000	$1,500
Strategic Advisor	1,300,000	0.20	Jun 13, 2013			
	1,980,000	0.20	Aug 1, 2013			
	2,400,000	0.28	Mar 2, 2015			

Name	Options-based Awards[1] Number of Securities Underlying Unexercised Options (#)	Option Exercise Price ($)	Option Expiration Date	Value of Unexercised in-the-money Options[3] ($)	Share-based Awards[2] Number of Shares or Units of Shares That Have Not Vested (#)	Market or Payout Value of Share-Based Awards That Have Not Vested
Tom Rouse	400,000	0.14	Feb 1, 2013	Nil	2,400,000	$1,200
Chief Financial Officer	900,000	0.20	Mar 31, 2013			
	1,100,000	0.20	Jun 13, 2013			
	800,000	0.20	Aug 1, 2013			
	1,500,000	0.28	Mar 2, 2015			
David Sealock	3,000,000	0.20	Jun 13, 2013	Nil	2,400,000	$1,200
Executive Vice President,	400,000	0.20	Aug 1, 2013			
Corporate Operations	1,500,000	0.28	Mar 2, 2015			

Notes:

(1) The Shares are not listed on a recognized stock exchange at December 31, 2011. As such there is no established market value for the Shares to compare the exercise price of stock options to.

(2) The Class "G" Shares and Class "H" Shares have not vested as at December 31, 2011.

(3) As at December 31, 2011, the Shares were not listed on a recognized stock exchange. As such, there was no established market value for the Shares to compare the exercise price of stock options to.

The following table sets forth for each Director, the option-based awards and the share-based awards that were outstanding as at December 31, 2011. The number of securities underlying unexercised options has been adjusted to reflect the Share Split. As a result, the option exercise price has been divided by 20 and rounded to the nearest $0.01.

Name	Options-based Awards[1] Number of Securities Underlying Unexercised Options (#)	Option Exercise Price ($)	Option Expiration Date	Value of Unexercised in-the-Money Options[3] ($)	Share-based Awards[2] Number of Shares or Units of Shares That Have Not Vested (#)	Market or Payout Value of Share-Based Awards That Have Not Vested
Hokming Tseung	1,000,000	0.28	Mar 2, 2015	Nil	15,000,000	$7,500
Tingan Liu	-	-	-	Nil	-	Nil
Haotian Li	1,000,000	0.48	Feb 17, 2016	Nil	-	Nil
Kevin Flaherty	300,000	0.15	Oct 9, 2012	Nil	-	Nil
	200,000	0.14	Jan 9, 2013			
	100,000	0.20	Mar 31, 2013			
	100,000	0.20	Aug 1, 2013			
	400,000	0.28	Mar 2, 2015			
Raymond Fong	400,000	0.07	Jul 20, 2012	Nil	-	Nil
	100,000	0.08	Aug 24, 2012			
	300,000	0.15	Oct 9, 2012			
	200,000	0.14	Jan 9, 2013			
	100,000	0.20	Mar 31, 2013			
	400,000	0.28	Mar 2, 2015			
Zhijan Qin	900,000	0.20	Mar 31, 2013	Nil	-	Nil
	400,000	0.28	Mar 2, 2015			
Wazir C. (Mike) Seth	1,200,000	0.14	Jan 9, 2013	Nil	-	Nil
	100,000	0.20	Mar 31, 2013			
	400,000	0.28	Mar 2, 2015			
Gregory G. Turnbull	800,000	0.15	Oct 9, 2012	Nil	600,000	$300
	200,000	0.14	Jan 9, 2013			
	100,000	0.20	Mar 31, 2013			
	100,000	0.20	Aug 1, 2013			
	400,000	0.28	Mar 2, 2015			

Name	Options-based Awards(1) Number of Securities Underlying Unexercised Options (#)	Option Exercise Price ($)	Option Expiration Date	Value of Unexercised in-the-Money Options(3) ($)	Share-based Awards(2) Number of Shares or Units of Shares That Have Not Vested (#)	Market or Payout Value of Share-Based Awards That Have Not Vested
Robert Herdman	1,000,000	0.48	Jul 14, 2011	Nil	-	Nil
Gerald Stevenson	1,000,000	0.48	Jul 14, 2011	Nil	-	Nil

Notes:

(1) The Shares are not listed on a recognized stock exchange at December 31, 2011. As such there is no established market value for the Shares to compare the exercise price of stock options to.

(2) The Class "G" Shares and Class "H" Shares have not vested as at December 31, 2011.

(3) As at December 31, 2011, the Shares were not listed on a recognized stock exchange. As such, there was no established market value for the Shares to compare the exercise price of stock options to.

Incentive Plan Awards – Value Vested or Earned During the Year

The following table sets forth for each Named Executive Officers, the incentive plan awards that were earned during the year ended December 31, 2011.

Name	Option-based awards – Value vested during the year ($)	Share-based awards – Value vested during the year ($)	Non-equity incentive plan compensation – Value earned during the year ($)
Michael J. Hibberd *Co-Chairman*	Nil	Nil	520,000
Songning Shen *Co-Chairman*	Nil	Nil	520,000
John Zahary *President and Chief Executive Officer*	Nil	Nil	Nil
Doug Brown *Chief Operating Officer*	Nil	Nil	170,000
John Kowal *Strategic Advisor*	Nil	Nil	170,000
Tom Rouse *Chief Financial Officer*	Nil	Nil	135,000
David Sealock *Executive Vice President, Corporate Operations*	Nil	Nil	135,000

The following table sets forth for each Director, the incentive plan awards that were earned during the year ended December 31, 2011.

Name	Option-based Awards – Value Vested During the Year ($)	Share-based Awards – Value Vested During the Year ($)	Non-equity Incentive Plan Compensation – Value Earned During the Year ($)
Hokming Tseung	Nil	Nil	Nil
Tingan Liu	Nil	Nil	Nil
Haotian Li	Nil	Nil	Nil
Kevin Flaherty	Nil	Nil	Nil
Raymond Fong	Nil	Nil	Nil
Zhijan Qin	Nil	Nil	Nil

Name	Option-based Awards – Value Vested During the Year ($)	Share-based Awards – Value Vested During the Year ($)	Non-equity Incentive Plan Compensation – Value Earned During the Year ($)
Wazir C. (Mike) Seth	Nil	Nil	Nil
Gregory G. Turnbull	Nil	Nil	Nil
Robert Herdman	Nil	Nil	Nil
Gerald Stevenson	Nil	Nil	Nil

Narrative Discussion of Option-based and Share-based Awards

Please see attached hereto as Schedule "C", for a description of the significant terms of the Corporation's new Post-IPO Stock Option Scheme that was approved by the Shareholders at the Annual and Special Meeting on January 26, 2012 and is now effective as of the Listing Date.

Pension Plan Benefits

The Corporation has no defined benefit plans, retirement plans or deferred compensation plans or other forms of retirement compensation for its employees.

Termination and Change of Control Benefits

The Corporation currently intends to formalize employment contracts between the Corporation and the Named Executive Officers at an appropriate time in the future. Such contracts may contain termination and change of control benefits.

Director Compensation for 2011

Director Compensation Table

Name(1)	Fees Earned ($)	Share-Based Awards(3) ($)	Option-Based Awards(2),(3) ($)	Non-Equity Incentive Plan Compensation ($)	Pension Value ($)	All Other Compensation ($)	Total ($)
Hokming Tseung	24,333	5,318,802	-	-	-	-	5,343,135
Tingan Liu	-	-	-	-	-	-	-
Haotian Li	22,333	-	288,037	-	-	-	310,370
Kevin Flaherty	-	-	-	-	-	-	-
Raymond Fong	27,333	-	-	-	-	-	27,333
Zhijan Qin	-	-	-	-	-	-	-
Wazir C. (Mike) Seth	29,000	-	-	-	-	-	29,000
Gregory G. Turnbull	26,667	-	-	-	-	-	26,667
Robert Herdman	28,667	-	276,118	-	-	-	304,785
Gerald Stevenson	27,333	-	276,118	-	-	-	303,451

Notes:

(1) Compensation for Michael Hibberd and Songning Shen is disclosed under the Summary Compensation Table above.

(2) As of December 31, 2011, the Shares were not listed on a recognized stock exchange. As such, there is no established market value for the Shares to compare the exercise price of stock options to.

(3) Share-based and option-based awards are valued at the "call option value" using the Black-Scholes model. All values are calculated based on International Financial Reporting Standards.

Narrative Discussion of Director Compensation to December 31, 2011

The Corporation's non-executive directors do not have service contracts with respect to their roles as directors. All directors are reimbursed for reasonable expenses incurred by them in their capacity as directors, including travel and other out of pocket expenses incurred in connection with meetings of the Board or any committee of the Board. The Corporation pays its directors $40,000 per year as salary and $1,000 per meeting fee. An additional $20,000 retainer is paid to each Co-Chairmen of the Board, and $10,000 is paid to the chair of the Audit Committee and $5,000 is paid to chairs of all other committees of the Board. We have not in the past incurred any large amounts in this area. In addition, the directors are entitled to participate in the Post-IPO Stock Option Plan. Director compensation has been reviewed during 2012 and changes are being made to conform to director's compensation to that paid by companies of comparable size.

Securities Authorized for Issuance Under Equity Compensation Plans

Equity Compensation Plan Information

The following table sets forth information, as at December 31, 2011, with respect to compensation plans under which equity securities are authorized for issuance, aggregated for all compensation plans previously approved by the Shareholders and all compensation plans not previously approved by the Shareholders. The number of Shares to be issued upon exercise of outstanding options has been adjusted to reflect the 20 for 1 share split effective as of February 10, 2012.

Plan Category	Number of Shares to be Issued Upon Exercise of Outstanding Options	Weighted Average Exercise Price of Outstanding Options	Number of Shares Remaining Available for Future Issuance Under Equity Compensation Plans
Equity compensation plans approved by security holders	202,958,540	0.22	7,041,460
Equity compensation plans not approved by security holders	-	-	-
Total	**202,958,540**	**0.22**	**7,041,460**

Narrative Discussion of Equity Compensation Plan Information

Please see attached hereto as Schedule "C", for a description of the significant terms of the Corporation's new Post-IPO Stock Option Scheme that was approved by the Shareholders at the Annual and Special Meeting on January 26, 2012 and is now effective as of the Listing Date.

PROMOTERS

Messrs. Hibberd and Shen are considered to be promoters of the Corporation in that they took the initiative in founding and organizing the Corporation. Messrs. Hibberd and Shen currently own or control 42,240,000 Shares (1.5%) and 11,000,000 Class "G" Shares (17.1%) and 40,959,660 Shares (1.4%) and 11,000,000 Class "G" Shares (17.1%) respectively. Messrs. Hibberd and Shen have 30,680,000 and 30,880,000 options outstanding with the option to purchase 30,680,000 and 30,880,000 Shares, respectively. The number of Shares and options above have been adjusted to reflect the 20 for 1 share split effective as of February 10, 2012.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Save as described below, to the knowledge of the Corporation, there are no legal proceedings or regulatory actions material to the Corporation or its subsidiary to which the Corporation or its subsidiary is a party, or was a party to in 2011, or of which any of its properties is the subject matter, or was the subject matter of in 2011, nor are there any such proceedings known to the Corporation or its subsidiary to be contemplated. There have been no penalties or sanctions imposed against the Corporation or its subsidiary by a court relating to securities legislation or by a securities regulatory authority and the Corporation or its subsidiary has not entered to any settlement agreements with a court or securities regulatory authority.

The Corporation, as plaintiff, filed a statement of claim at the Court of Queen's Bench of Alberta on February 1, 2011 in which Perpetual Energy Operating Corp. ("**Perpetual**") was named as defendant (the "**Statement of Claim**"). The Statement of Claim relates to the extraction of solution gas in certain lands located in the West Ells area. We have exclusive rights over the area in question by virtue of the Oil Sands Leases granted by the Crown to win, work, and recover bitumen, including solution gas. Perpetual have certain direct and indirect rights by virtue of leases from the Crown, to win, work and recover native natural gas in the area.

Sunshine successfully obtained an interim shut-in order from the ERCB on October 15, 2009 which led to the interim shut down of those wells and intervals identified relating to the extraction of solution gas. The ERCB approved the request for a permanent shut-in order on December 13, 2011 and the order requiring the shut-in of gas was issued on December 15, 2011.

The Statement of Claim has not been served and is therefore not proceeding at this time. The Corporation has one year and have applied for, and received an extension of an additional three months from filing within which to serve the Statement of Claim, with the expiry date being April 30, 2012.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as disclosed in this AIF, none of Sunshine's directors or executive officers, nor any person who beneficially owns directly or indirectly or exercises control or direction over securities carrying more than 10% of the voting rights attaching to the shares in the capital of the Corporation, nor any known associate or affiliate of these persons had any material interest, direct or indirect in any transaction since the commencement of the Corporation's last completed financial year which has materially affected the Corporation, or in any proposed transaction which has materially affected or would materially affect the Corporation or any of its subsidiaries.

On October 18, 2011, the Corporation entered into a two-year credit facility with Orient in the principal amount of $100 million for general corporate purposes. The facility commences on the date of the first drawdown. Mr. Hokming Tseung, one of the current directors of the Corporation, is the sole director of Orient. The facility is interest-free until May 31, 2012 and, commencing on June 1, 2012, an annual interest rate charged at five percent (5%) per annum on the outstanding principal will be payable on a semi-annual basis to Orient. The annual interest rate was determined through commercial negotiations between Orient and the Corporation. As at December 31, 2011, the Corporation had $Nil drawn on the credit facility.

TRANSFER AGENT AND REGISTRAR

The Corporation maintains a central securities register in Canada and a branch securities register in Hong Kong. The transfer agent and registrar for the central securities register in Canada is Alliance Trust Company located at Suite 450, 407 – 2nd Street SW, Calgary, Alberta, T2P 2Y3. The transfer agent and registrar for the branch securities register in Hong Kong is Computershare Hong Kong Investor Services Limited located at Hopewell Centre 46th Floor, 183 Queen's Road East Wan Chai, Hong Kong, and the People's Republic of China.

MATERIAL CONTRACTS

Other than as set forth below and other than those contracts entered into in the normal course of business as summarized herein, the Corporation did not enter into any material contracts that are still in effect:

(a) the Hong Kong Underwriting Agreement;

(b) the International Underwriting Agreement;

(c) the credit agreement dated October 18, 2011 entered into by the Corporation (the borrower) and Orient International Resources Group Limited (the lender), pursuant to which the lender has agreed to provide a credit facility in the maximum principal amount of $100 million to the borrower;

(d) the consulting agreement dated January 1, 2011, as amended on October 26, 2011, entered into between MJH Services Inc. and the Corporation;

(e) the consulting agreement dated January 1, 2011, as amended on October 26, 2011, entered into between 1226591 Alberta Inc. and the Corporation;

(f) the memorandum of understanding for strategic cooperation dated February 1, 2012 entered into between the Corporation and SIPC in relation to forming a strategic alliance and to carry out strategic cooperation with Sinopec;

(g) the form of lock-up agreements executed by each of the following for the benefit of the Corporation and the underwriters of the Global Offering:

    (i) Michael J. Hibberd dated February 10, 2012;

    (ii) Songning Shen dated February 10, 2012;

    (iii) Gregory G. Turnbull dated February 10, 2012;

    (iv) Raymond Fong dated February 13, 2012;

    (v) John Kowal dated February 13, 2012;

    (vi) Douglas Stewart Brown dated February 10, 2012;

    (vii) Thomas K. Rouse dated February 10, 2012;

    (viii) David Sealock dated February 13, 2012;

    (ix) Songbo Cong dated February 10, 2012;

    (x) Richard Walter Pawluk dated February 10, 2012;

    (xi) 1226591 Alberta Inc. dated February 10, 2012; and

    (xii) MJH Services Inc. dated February 10, 2012.

Copies of these agreements may be inspected at Sunshine's principal place of business located at Suite 1020, 903 - 8th Avenue SW, Calgary, Alberta, T2P 0P7, Canada.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report, valuation or opinion described or included in a filing, or referred to in a filing, made under NI 51-102 - *Continuous Disclosure Obligations* by the Corporation during, or related to, the Corporation's most recently completed financial year other than GLJ and D&M, the Corporation's independent engineering evaluators. As at the date hereof, to the knowledge of management of the Corporation, none of the aforementioned persons or companies, or principals thereof, had any registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation or of our associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them.

In addition, the Audited Financial Statements of Sunshine for the year ended December 31, 2011 were audited by the Corporation's auditors, Deloitte & Touche LLP who is independent in accordance with the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

AUDIT COMMITTEE

The purpose of Sunshine's Audit Committee is to provide assistance to its Board of Directors in fulfilling its legal fiduciary obligations with respect to matters involving the accounting, auditing, financial reporting, internal control and legal compliance functions of the Corporation. The Audit Committee has a defined mandate and is responsible for reviewing and overseeing the external audit function, recommending the external auditor and the terms of such appointment or discharge, reviewing external auditor reports and significant findings and reviewing and recommending for approval to the Board of Directors all public financial disclosure information such as financial statements, management's discussion and analysis, AIFs and prospectuses. The Audit Committee also pre-approves all non-audit services to be conducted by the external auditors and ensures that management has effective internal control systems, investigates any recommendations for improvement of internal controls and meets at least annually with the Corporation's external auditors without management present and at least quarterly with management present. Sunshine does not have internal auditors and, given the size of the Corporation, Sunshine considers this to be practical and appropriate. The Audit Committee expects to convene no less than four times each year and as circumstances otherwise warrant.

The full text of the Audit Committee's Charter is which is attached hereto as Schedule "D".

Composition of the Audit Committee

The Audit Committee is comprised of Mr. Robert John Herdman, Mr. Gerald Franklin Stevenson, Mr. Wazir Chand Seth, Mr. Tingan Liu. The Chair of the Audit Committee is Mr. Robert John Herdman. Each of the members of the Audit Committee is financially literate under Section 1.5 of National Instrument 52-110 – *Audit Committees* ("**NI 52-110**"). Mr. Herdman, Mr. Stevenson and Mr. Seth are independent as such term is described under Section 1.4 of NI 52-110.

Relevant Education and Experience

The following is a description of the education and experience of each audit committee member that is relevant to the performance of his responsibilities as an audit committee member.

Mr. Robert John Herdman

Mr. Herdman is a fellow chartered accountant and was formerly a partner at Price Waterhouse and PricewaterhouseCoopers LLP from 1989 to 2010 in Calgary serving the firm's Calgary based public clients including service to companies operating in both the mining and thermal recovery of oil sands. Following a 34 year career with PricewaterhouseCoopers LLP, Mr. Herdman retired from practice in 2010. He currently serves on the boards of directors of Chinook Energy Inc., SemBioSys Genetics Inc., Blackline GPS Corp. and Western Financial Group Inc. He recently completed a six year term on the board of governors of the Chartered Accountants Education Foundation and has served on a number of other committees overseeing the practice of accounting in Alberta and as a director for a number of non-profit making organisations. Mr. Herdman graduated with a bachelor of education degree from the University of Calgary in 1974.

Mr. Gerald Franklin Stevenson

Mr. Stevenson has over 37 years of experience in oil and natural gas operations including senior management positions at a number of Canadian and international energy companies. Mr. Stevenson is currently on the board of directors of Southwest Energy Trust. He was head of oil & gas acquisitions and divestitures for CIBC World Markets Inc. in Calgary, Alberta from January 2006 to April 2011 where he was responsible for selling oil and gas companies or individual oil and gas properties, and was involved in Mergers & Acquisitions and financing activities.

Mr. Stevenson was at Suncor Inc. from July 1985 to June 1991, North Canadian Oils Limited from July 1991 to June 1993, Waterous & Co from July 1993 to August 1997, February 2000 to October 2001, and March 2003 to July 2005, Enerplus Resources Fund October 2001 to March 2003, where he was responsible for acquisitions and divestitures. He was vice-president, production of Hurricane Hydrocarbons from April 1998 to October 1998 and was appointed interim President, Chief Executive Officer and director of Hurricane Hydrocarbons in October 1998.

Mr. Wazir Chand Seth

Mr. Seth has over 40 years of experience in the oil and natural gas industry. He is President of Seth Consultants Ltd. From January 1989 to June 2006, he served as chairman, president and managing director of McDaniel & Associates Consultants Ltd., one of the preeminent oil and gas engineering evaluators in Canada and internationally.

Mr. Seth is currently on the board of directors of Enerplus Corporation, Connacher Oil and Gas Limited, Open Range Energy Corp., Corridor Resources Inc., Reliable Energy Ltd. and Torquay Oil Corp. He is also the founder and director of Energy Navigator Inc., a private software development firm servicing the petroleum industry. Mr. Seth has previously served as a director of Redcliffe Exploration Inc. and Triton Energy Corp.

Mr. Tingan Liu

Mr. Liu is the deputy chairman and president of China Life Insurance (Overseas) Company Limited. Mr. Liu also holds a number of positions of responsibility in various professional and industry bodies, including serving as a member of the Listing Committee of the Stock Exchange of Hong Kong Limited, as a member of the Insurance Advisory Committee of the Government of Hong Kong S.A.R., as a councillor of the Life Insurance Council of the Hong Kong Federation of Insurers, as an executive director of the Hong Kong Chinese Enterprises Association and as a council member and fellow of the Hong Kong Institute of Directors. Mr. Liu received the Director of the Year Award, organised by The Hong Kong Institute of Directors, in 2009 in the category of "Private Company Executive Directors" and he was also a winner of China's "Top 10 Economic Talents Special Award 2009".

Audit Committee Oversight

Since the commencement of the Corporation's most recently completed financial year, there has not been a recommendation of the Audit Committee to nominate or compensate an external auditor which was not adopted by the Corporation's Board.

Pre-Approval Policies and Procedures

The Audit Committee has adopted specific policies and procedures for the engagement of non-audit services, including tax advisory and compliance services. The Audit Committee has the authority to establish financial thresholds for fees for non-audit services to be provided by the external auditors without advance approval of the Audit Committee. See the *Other Responsibilities* provisions of the Audit Committee Charter which is attached hereto as Schedule "D".

External Auditor Service Fees

The fees paid to the Corporation's external auditor in each of the last two fiscal years are as follows:

Financial Year Ending	Audit Fees(1)	Audit-Related Fees(2)	Tax Fees(3)	All Other Fees(4)
December 31, 2011	$724,842	$388,720	Nil	Nil
December 31, 2010	$134,100	$23,000	Nil	Nil

Notes:

(1) The aggregate fees billed by the Corporation's auditor for audit fees.

(2) The aggregate fees billed for assurance and related services by the Corporation's auditor that are reasonably related to the performance of the audit or review of the Corporation's financial statements and are not disclosed in the "Audit fees" column.

(3) The aggregate fees billed for professional services rendered by the Corporation's auditor for tax compliance, tax advice, and tax planning.

(4) The aggregate fees billed for professional services rendered by the Corporation's auditor in relation services other than the services reported under (1), (2), and (3) above.

CORPORATE GOVERNANCE COMMITTEE

We have established a corporate governance committee (the "**Corporate Governance Committee**") to deal with nomination and corporate governance issues, with written terms of reference. The full text of the Corporate Governance Committee Charter is which is attached hereto as Schedule "D".

The primary functions of the Corporate Governance Committee in respect of nominations include, but are not limited to:

(a) making recommendations to the Board on relevant matters relating to the appointment or re-appointment of directors and succession planning for directors, in particular the chairman and the chief executive officer; and

(b) assessing the independence of independent non-executive Directors.

Further, the Corporate Governance Committee has certain duties in respect of other corporate governance matters, including:

(a) to consider and review the Corporation's corporate governance principles, practices and processes and to make recommendations to the Board;

(b) to review and monitor the training and continuous professional development of Directors and senior management; and

(c) to review the Corporation's compliance with the Code on Corporate Governance. The Corporate Governance Committee meets at least once annually.

The current members of the Corporate Governance Committee are Mr. Gregory George Turnbull, who is the chairman, Mr. Michael John Hibberd, Mr. Hok Ming Tseung, Mr. Robert John Herdman, Mr. Gerald Franklin Stevenson and Mr. Haotian Li.

As four out of the six members of the Corporate Governance Committee are not independent non-executive Directors, the Corporate Governance Committee is not currently comprised of a majority of independent non-executive Directors (as will be required under provisions A.5.1 and D.3.2 of the Corporate Governance Code from April 1, 2012). We expect to move towards full compliance with the Corporate Governance Code in this respect by April 1, 2012. On or prior to this date Mr. Gregory George Turnbull will step down as chairman of the Corporate Governance Committee and will be replaced by an independent non-executive Director of Sunshine. In addition, on or prior to April 1, 2012, the Corporate Governance Committee will be reconstituted to consist of a majority of independent non-executive directors. However, given the experience of Mr. Gregory George Turnbull, Mr. Michael John Hibberd, Mr. Haotian Li and Mr. Hok Ming Tseung respectively, we consider it necessary for the time being, to include such executive and non-executive directors on the Corporate Governance Committee.

We will introduce a shareholder communication policy on or before April 1, 2012 in compliance with Provision E.1.4 of the Code of Corporate Governance.

COMPENSATION COMMITTEE

We have established a remuneration committee (known as and referred to herein as the "**Compensation Committee**") with written terms of reference. These terms of reference can be accessed at our website at http://www.sunshineoilsands.com/about/committee-charters.html and the website of the SEHK at http://www.hkexnews.hk/listedco/listconews/advancedsearch/search_active_main.asp.

The current members of the Compensation Committee are Mr. Gregory George Turnbull, who is the chairman, Mr. Hok Ming Tseung, Mr. Robert John Herdman and Mr. Raymond Shengti Fong.

As two out of the four members of the Compensation Committee are not independent non-executive Directors, the Compensation Committee is not currently comprised of a majority of independent non-executive Directors (as required under provision B.1.1 of the Corporate Governance Code). Sunshine expects to move towards full compliance with the Corporate Governance Code in this respect in due course, though, given the experience of Mr. Gregory George Turnbull and Mr. Hok Ming Tseung respectively, Sunshine considers it necessary to, for the time being, to include such non-executive directors on the committee. In compliance with the Code of Corporate Governance, on or prior to April 1, 2012, Mr. Gregory George Turnbull will step down from his role as Chairman, to be replaced by Mr. Robert John Herdman, an independent non-executive Director of the Corporation, which will ensure that the Compensation Committee will have a majority of independent non-executive Directors and will be chaired by an independent non-executive Director.

The primary duties of the Compensation Committee are to review and make recommendations to the Board in respect of the compensation of our directors, officers and employees. The Compensation Committee also reviews our compensation and other human resource philosophies and policies and undertakes the review of our bonuses, stock options and share purchase plan(s) (if any). Further, the Compensation Committee submits an annual report for inclusion in our relevant public documents. The Compensation Committee is required to convene at least annually.

RESERVES COMMITTEE

We have established a reserves committee (the "**Reserves Committee**") which has the primary responsibility for reviewing our procedures relating to the disclosure of information with respect to oil and gas activities, including reviewing its procedures for complying with its disclosure requirements and restrictions set forth under applicable securities requirements. These terms of reference of the Reserves Committee can be accessed at our website at http://www.sunshineoilsands.com/about/committee-charters.html

Specifically, the reserves committee's responsibilities include, but are not limited to:

(a) reviewing and approving management's recommendations for the appointment, or proposed changes of independent evaluators;

(b) reviewing our procedures for providing information to the independent evaluators;

(c) meeting with management and the independent evaluator to review the reserves data and report;

(d) recommending to the Board whether to approve the content of the independent evaluators' report; and

(e) reviewing our procedures for reporting on other information associated with oil sands producing activities and generally reviewing all public disclosure of estimates of our reserves.

The Reserves Committee is comprised of four members of the Board, who must each meet certain independence criteria as set out by the Board in the committee's written terms of reference. The Reserves Committee meets at least once annually.

The Reserves Committee is currently comprised of Mr. Wazir Chand Seth, who is the chairman, Mr. Songning Shen, Mr. Gerald Franklin Stevenson and Mr. Raymond Shengti Fong.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Shares and securities authorized for issuance under equity compensation plans, is contained in the Corporation's Management Information Circular dated December 31, 2011 for the most recent annual meeting of Shareholders that involved the election of directors.

Additional financial information is provided for in our financial statements and management's discussion and analysis for the year ended December 31, 2011. Documents affecting the rights of securityholders, along with other information relating to the Corporation, may be found on the Corporation's website at http://www.sunshineoilsands.com/.

SCHEDULE “A”

FINANCIAL STATEMENTS OF THE CORPORATION

SCHEDULE “B”

MANAGEMENT’S DISCUSSION AND ANALYSIS

SCHEDULE "C"

SHARE OPTION SCHEME

A. POST-IPO SHARE OPTION SCHEME

The following is a summary of the principal terms of our Post-IPO Share Option Scheme conditionally approved and adopted by our Shareholders on January 26, 2012, the implementation of which is conditional on Listing. The terms of our Post-IPO Share Option Scheme are in accordance with the provisions of Chapter 17 of the Listing Rules.

Purpose of our Post-IPO Share Option Scheme

The purpose of our Post-IPO Share Option Scheme is to attract skilled and experienced personnel, to incentivise them to remain with the Corporation and to motivate them to strive for the future development and expansion of Sunshine by providing them with the opportunity to acquire equity interests in Sunshine.

Participants of our Post-IPO Share Option Scheme and Basis For Determining the Eligibility of the Participants

Our Board may, at its discretion, grant options pursuant to our Post-IPO Share Option Scheme to the Directors (including executive Directors, non-executive Directors and independent non-executive Directors), the directors of our subsidiary, the officers and employees and any other persons (including consultants and advisers) who our Board considers, in its absolute discretion, have contributed or will contribute to Sunshine (the "**Participants**").

Status of Our Post-IPO Share Option Scheme

(a) Conditions of our Post-IPO Share Option Scheme

Our Post-IPO Share Option Scheme shall take effect subject to (i) the Listing Committee of the Stock Exchange granting the listing of, and permission to deal in, the Shares to be issued pursuant to the exercise of any options to subscribe for Shares granted pursuant to our Post-IPO Share Option Scheme and (ii) the commencement of trading of our Shares on the Main Board of the Stock Exchange (the "**Conditions**").

(b) Term of our Post-IPO Share Option Scheme

Subject to the Conditions being satisfied, our Post-IPO Share Option Scheme shall be valid and effective for a period of 10 years commencing on the date of its conditional adoption by our Shareholders (the "**Term**"), after which period no further options shall be offered or granted but the provisions of our Post-IPO Share Option Scheme shall remain in full force and effect in all other respects. Options granted during the Term shall continue to be valid in accordance with their terms of grant after the end of the Term.

Grant of Options

(a) Making an offer

An offer of the grant of an option shall be made to a Participant by a notice of grant requiring the Participant to undertake to hold the option on the terms on which it is to be granted (which may include a minimum period for which the option must be held before it can be exercised and a performance target that must be reached before the option can be exercised in whole or in part) and to be bound by the terms of our Post-IPO Share Option Scheme.

(b) Acceptance of an offer

An offer of the grant of an option is accepted by the Participant (the "**Grantee**") when we receive from the Grantee the duplicate notice of grant duly executed by the Grantee and a remittance of the sum of HK$1.00 (or such other amount in any other currency as our Board determines) as consideration for the grant of an option. Such remittance is not refundable in any circumstances. An offer may be accepted in full or in part provided that if it is accepted in part, the acceptance must be in respect of a board lot of Shares or an integral multiple thereof.

The offer shall remain open for acceptance for such time to be determined by our Board, provided that no such offer shall be open for acceptance after the expiry of the Term or after the termination of our Post-IPO Share Option Scheme in accordance with its terms or after the Participant to whom the offer is made has ceased to be a Participant. To the extent that the offer is not accepted within the time period and in the manner specified in the offer, the offer will be deemed to have been irrevocably declined and will lapse.

(c) Restrictions on time of grant

A grant of an option may not be made after a price sensitive event has occurred or a price sensitive matter has been the subject of a decision until we have published such price sensitive information in accordance with the requirements of the Listing Rules. In particular, during the period commencing one month immediately preceding the earlier of:

(i) the date of the meeting of our Board (as such date is first notified to the Stock Exchange in accordance with the Listing Rules) for the approval of our results for any year, half year, quarterly or any other interim period (whether or not required under the Listing Rules); and

(ii) the deadline for us to publish an announcement of our results for any year or half-year under the Listing Rules, or quarterly or any other interim period (whether or not required under the Listing Rules),

and ending on the date of the results announcement, no option may be granted; and where a grant of an option is to a Director, no option may be granted on any day on which our financial results are published and during the period of:

(iii) 60 days immediately preceding the publication date of our annual results or, if shorter, the period from the end of the relevant financial year up to the publication date of our results; and

(iv) 30 days immediately preceding the publication date of our quarterly results (if any) and half-year results or, if shorter, the period from the end of the relevant quarterly or half year period up to the publication date of our results.

(d) Grant to connected persons

Any grant of an option to any Director, chief executive or substantial Shareholder of the Corporation, or any of their respective associates, shall be subject to the prior approval of our independent non-executive Directors (excluding the independent non-executive Director who is the proposed Grantee of the option in question).

(e) Grant to substantial Shareholders and independent non-executive Directors

Where any grant of options to a substantial Shareholder or an independent non-executive Director of the Corporation, or any of their respective associates, would result in the Shares issued and to be issued upon the exercise of all options already granted and to be granted (including options exercised, cancelled and outstanding) to such person pursuant to our Post-IPO Share Option Scheme and any of our other share option schemes in the 12 month period up to and including the offer date:

(i) representing in aggregate over 0.1% of our Shares issued and outstanding on the offer date; and

(ii) having an aggregate value, based on the closing price of our Shares as stated in the daily quotations sheets issued by the Stock Exchange on the offer date, in excess of HK$5 million, such further grant of options shall be subject to prior approval by our Shareholders in general meeting and all connected persons of the Corporation shall abstain from voting in favour of the resolution relating to the grant of such options at such general meeting.

Any change in the terms of an option granted to any Director, chief executive or substantial Shareholder of the Corporation, or any of their respective associates, shall also be subject to the prior approval of our Shareholders in general meeting and all connected persons of the Corporation shall abstain from voting in favour of the resolution.

Exercise Price

The price per Share at which a Grantee may subscribe for Shares upon the exercise of an option (the "**Exercise Price**") shall be determined by our Board in its absolute discretion but in any event shall not be less than the higher of:

(a) the closing price of the Shares as stated in the daily quotations sheets issued by the HKSE on the offer date, which must be a Business Day; and

(b) the average closing price of the Shares as stated in the daily quotation sheets issued by the HKSE for the five Business Days immediately preceding the offer date, provided that for the purpose of determining the Exercise Price where the Shares have been listed on the Stock Exchange for less than five Business Days, the Offer Price shall be used as the closing price of the Shares for any Business Day falling within the period before the Listing.

Maximum Number of Shares Available for Subscription

(a) Scheme Mandate Limit

At any time during the Term, the maximum aggregate number of Shares in respect of which options may be granted pursuant to our Post-IPO Share Option Scheme shall be calculated in accordance with the following formula:

$$X = A - B - C$$

where:

X = the maximum aggregate number of Shares in respect of which options may be granted pursuant to our Post-IPO Share Option Scheme;

A = the total number of Shares in respect of which options may be granted pursuant to our Post-IPO Share Option Scheme and any other share option schemes of the Corporation, being (i) 284,092,143 Shares representing approximately 10% of our Shares issued and outstanding at the date of completion of the Global Offering (excluding any Shares which may be issued pursuant to the exercise of the Over-Allotment Option) or (ii) 10% of our Shares issued and outstanding as at the New Approval Date (as defined below) (as the case may be) (the "**Scheme Mandate Limit**");

B = the maximum aggregate number of Shares underlying the options already granted pursuant to our Post-IPO Share Option Scheme which in the event that there has been a New Approval Date (as defined in paragraph (b) below), shall only include those Shares underlying options that have been granted since that most recent New Approval Date; and

C = the maximum aggregate number of Shares underlying the options already granted pursuant to any of our other share option schemes.

Shares in respect of options which have lapsed in accordance with the terms of our Post-IPO Share Option Scheme and any of our other share option schemes will not be counted for the purpose of determining the maximum aggregate number of Shares in respect of which options may be granted pursuant to our Post-IPO Share Option Scheme.

(b) Renewal of Scheme Mandate Limit

The Scheme Mandate Limit may be renewed subject to prior Shareholders' approval, but in any event, the total number of Shares in respect of which options may be granted pursuant to our Post-IPO Share Option Scheme and any of our other share option schemes following the date of approval of the renewed limit (the "**New Approval Date**") under the limit as renewed must not exceed 10% of our Shares issued and outstanding as at the New Approval Date. Shares in respect of options granted pursuant to our Post-IPO Share Option Scheme and any of our other share option schemes (including those outstanding, cancelled, lapsed in accordance with our Post-IPO Share Option Scheme or any of our other share option schemes or exercised options) prior to the New Approval Date will not be counted for the purpose of determining the maximum aggregate number of Shares in respect of which options may be granted following the New Approval Date under the limit as renewed. For the avoidance of doubt, Shares issued prior to the New Approval Date pursuant to the exercise of options granted pursuant to our Post-IPO Share Option Scheme and any of our other share option schemes will be counted for the purpose of determining the number of Shares issued and outstanding as at the New Approval Date.

(c) Grant of options beyond the Scheme Mandate Limit

Notwithstanding the foregoing, we may grant options beyond the Scheme Mandate Limit to Participants if:

(i) separate Shareholders' approval has been obtained for granting options beyond the Scheme Mandate Limit to Participants specifically identified by us before such Shareholders' approval is sought; and

(ii) in connection with the seeking of such separate Shareholders' approval, we have first sent a circular to Shareholders containing such information as may be required by the Listing Rules.

(d) Maximum number of Shares issued pursuant to the exercise of options

At any time, the maximum number of Shares which may be issued upon the exercise of all outstanding options which have been granted and have yet to be exercised pursuant to our Post-IPO Share Option Scheme and any of our other share option schemes shall not exceed 30% of the Shares in issue from time to time.

(e) Grantee's maximum holding

Subject to the paragraph below, the maximum number of Shares issued and to be issued upon the exercise of the options granted to each Participant pursuant to our Post-IPO Share Option Scheme (including both exercised and outstanding options) in any 12-month period shall not (when aggregated with any Shares underlying the options granted during such period pursuant to any of our other share option schemes other than those options granted pursuant to a specific approval by our Shareholders in a general meeting) exceed 1% of our Shares issued and outstanding for the time being.

Where any further grant of options to a Participant would result in the Shares issued and to be issued upon the exercise of all options granted and to be granted to such person (including exercised, cancelled and outstanding options) in the 12-month period up to and including the date of such further grant (when aggregated with any Shares pursuant to options granted during such period pursuant to any of our other share option schemes other than those options granted pursuant to a specific approval by our Shareholders in a general meeting) representing in aggregate over 1% of our Shares in issue, such further grant must be separately approved by Shareholders in general meeting with such Participant and his associates abstaining from voting. We must send a circular to our Shareholders disclosing the identity of the Participant in question, the number and terms of the options to be granted (and options previously granted to such Participant) and such other information required under the Listing Rules.

Rights Attached to the Options

The options do not carry any right to vote at our general meetings, or any dividend, transfer or other rights (including those arising on the winding up of the Corporation).

No Grantee shall enjoy any of the rights of a Shareholder by virtue of the grant of an option pursuant to our Post-IPO Share Option Scheme, unless and until the Shares underlying the option are actually issued to the Grantee pursuant to the exercise of such option.

Rights Attached to the Shares

No dividends or distributions shall be payable in respect of any Shares underlying an option which has not been exercised.

Subject to the foregoing, the Shares which are allotted and issued upon the exercise of an option shall be subject to all the provisions of our Articles and By-laws for the time being in force and shall rank pari passu in all respects with, and shall have the same voting, dividend, transfer and other rights (including those rights arising on a winding-up of the Corporation) as, the existing fully paid Shares issued and outstanding on the date on which those Shares are allotted and issued upon the exercise of the option and, without prejudice to the generality of the foregoing, shall entitle the holders to participate in all dividends or other distributions paid or made on or after the date on which the Shares are allotted and issued, other than any dividends or distributions previously declared or recommended or resolved to be paid or made if the record date thereof shall be before the date on which the Shares are allotted and issued.

Assignment of Options

An option shall be personal to the Grantee and shall not be assignable or transferable by the Grantee and the Grantee shall not in any way sell, transfer, charge, mortgage, encumber or create any interest in favour of any third party over or in relation to any option.

Exercise of Options

(a) General

The period during which an option may be exercised by a Grantee (the "**Option Period**") shall be the period to be determined and notified by our Board to the Grantee at the time of making an offer, which shall not expire later than 10 years from the offer date.

Subject to any restrictions applicable under the Listing Rules, an option may be exercised in whole or in part (but if in part only, in respect of a board lot of Shares or any integral multiple thereof) by the Grantee at any time during the Option Period in accordance with the terms of our Post-IPO Share Option Scheme and the terms on which the option was granted. If the vesting of Shares underlying an option is subject to the satisfaction of performance or other conditions and such conditions are not satisfied, the option shall lapse automatically on the date on which such conditions are not satisfied in respect of the relevant Shares underlying the option.

(b) Rights on a takeover

In the event a general offer by way of takeover or otherwise (other than by way of scheme of arrangement pursuant to (c) below) is made to all our Shareholders (or all such Shareholders other than the offeror and/or any person controlled by the offeror and/or any person acting in association or concert with the offeror) by any person and such offer becomes or is declared unconditional prior to the expiry of the Option Period of the relevant option, we shall, as soon as practicable, give notice to each Grantee of such offer. Notwithstanding any other terms on which the option was granted, the Grantee shall be entitled to exercise the option (to the extent not already exercised) to its full extent or, if we give the relevant notification, to the extent notified by us, by the Grantee giving us notice at any time thereafter and up to the close of such offer (or, as the case may be, revised offer). Subject to the foregoing, the option (to the extent not already exercised) will lapse automatically on the date on which such offer (or, as the case may be, revised offer) closes.

(c) Rights on a scheme of arrangement

In the event a general offer for Shares by way of plan or scheme of arrangement is made by any person to all our Shareholders and has been approved by the necessary number of Shareholders at the requisite meetings prior to the expiry of the Option Period of the relevant option, we shall, as soon as practicable, give notice to each Grantee of such approval. Notwithstanding any other terms on which the option was granted, each Grantee shall be entitled to exercise the option (to the extent not already exercised) to its full extent or, if we give the relevant notification, to the extent notified by us, by the Grantee giving us notice at any time thereafter and up to the record date for determining entitlements under such scheme of arrangement. Subject to the foregoing and to the scheme of arrangement becoming effective, the option (to the extent not already exercised) will lapse automatically on the record date for determining entitlements under such scheme of arrangement.

(d) Rights on a compromise or arrangement

If, pursuant to the ABCA, a compromise or arrangement (other than a scheme of arrangement contemplated in paragraph (c) above) between us and our Shareholders and/or our creditors is proposed for the purposes of or in connection with a scheme for the reconstruction or re-organisation of the Corporation or the amalgamation of the Corporation with any other company or companies prior to the expiry date of the Option Period of the relevant option, we shall give notice thereof to all the Grantees on the same day as we dispatch to our Shareholders and/or our creditors a notice summoning the meeting to consider such a compromise or arrangement and, notwithstanding any other terms on which the option was granted, each Grantee shall be entitled to exercise the option (to the extent not already exercised) to its full extent or, if we give the relevant notification, to the extent notified by us, by the Grantee giving us notice, such notice to be given not later than three Business Days prior to the date of the proposed meeting. We shall as soon as possible and in any event no later than one Business Day immediately prior to the date of the proposed meeting, allot and issue such number of Shares to the Grantee which falls to be issued on such exercise of the option, credited as fully paid and shall issue to the Grantee (or his custodian agent) share certificates in respect of the Shares so allotted. With effect from the date two Business Days before the date of such meeting, the rights of all Grantees to exercise their respective options shall forthwith be suspended. Our Board shall endeavour to procure that the Shares issued upon the exercise of the options in such circumstances shall for the purposes of such compromise or arrangement form part of our issued share capital on the effective date thereof and that such Shares shall in all respects be subject to such compromise or arrangement. If, for any reason, such compromise or arrangement is not approved by the relevant court (whether upon the terms presented to the relevant court or upon any other terms as may be approved by such court), the rights of the Grantees to exercise their respective options shall, with effect from the date of the making of the order by the relevant court and to the extent they had not been exercised at the date such rights were suspended, be restored in full as if we had not proposed such compromise or arrangement and neither we nor the Directors shall be liable for any loss or damage suffered or sustained by any Grantee as a result of the aforesaid suspension of rights.

(e) Rights on a voluntary winding-up

In the event we give notice to our Shareholders to convene a general meeting for the purposes of considering and, if thought fit, approving a resolution to voluntarily wind-up the Corporation prior to the expiry date of the Option Period of the relevant option, we shall give notice thereof to all the Grantees on the same day as we dispatch to our Shareholders the notice convening the meeting and, notwithstanding any other terms on which the option was granted, each Grantee shall be entitled to exercise the option (to the extent not already exercised) to its full extent or, if we give the relevant notification, to the extent notified by us, by the Grantee giving us notice, such notice to be given not later than three Business Days prior to the date of the proposed meeting. We shall as soon as possible and in any event no later than one Business Day immediately prior to the date of the proposed meeting, allot and issue such number of Shares to the Grantee which falls to be issued on such exercise of the option, credited as fully paid and shall issue to the Grantee (or his custodian agent) share certificates in respect of the Shares so allotted. With effect from the date two Business Days prior to the date of such meeting, the rights of all Grantees to exercise their respective options shall forthwith be suspended. If, for any reason, the resolution for the voluntary winding-up of the Corporation is not approved by our Shareholders, the rights of the Grantees to exercise their respective options shall be restored in full, to the extent that they had not been exercised at the date such rights were suspended, as if we had not proposed such resolution for the voluntary winding-up of the Corporation and neither we nor the Directors shall be liable for any loss or damage suffered or sustained by any Grantee as a result of the aforesaid suspension of rights.

Upon the occurrence of any of the events referred to in paragraphs (b) to (e) above, we may in our discretion and notwithstanding the terms of the relevant option also give notice to a Grantee that his option may be exercised at any time within such period as we shall notify (which period shall not expire after the expiry of the periods for exercising the options referred to in paragraphs (b) to (e) above) and/or to the extent (not being more than the extent to which it could then be exercised in accordance with its terms) notified by us. If we give such notice that any option may be exercised in part only, the balance of the option shall lapse.

Lapse of Options

An option shall lapse automatically and not be exercisable (to the extent not already exercised) on the earliest of:

(a) the expiry of the Option Period (subject to the provisions of our Post-IPO Share Option Scheme);

(b) the date of termination of the Grantee's employment or service by us or our subsidiary for Cause (as defined below);

(c) the date on which the Grantee: (i) becomes an officer, director, employee, consultant, adviser, partner of, or a shareholder or other proprietor owning more than a 5% interest in, any Competitor (as defined below); or (ii) knowingly performs any act that may confer any competitive benefit or advantage upon any Competitor;

(d) the expiry of the period for exercising the option referred to above in the event of a takeover or scheme of arrangement;

(e) the date on which the compromise or arrangement becomes effective;

(f) the date of the commencement of the winding-up of the Corporation;

(g) in the event of the Grantee's employment or service terminating other than for Cause, the expiry of the period for exercising the option referred to below;

(h) the date on which the Grantee (whether intentionally or otherwise) commits a breach of the prohibition on assignment of options above;

(i) the date on which the Grantee is declared bankrupt or enters into any arrangement or composition with his creditors generally; and

(j) (in respect of such Shares which are subject to vesting condition(s)) the date on which the condition(s) to vesting of the relevant Shares underlying the option are not satisfied.

Our Board shall have the right to determine whether the Grantee's employment or service has been terminated for Cause, the effective date of such termination for Cause and whether someone is a Competitor, and such determination by our Board shall be final and conclusive.

If the Grantee's employment or service with us or our Subsidiary is terminated for any reason other than for Cause (including by reason of resignation, retirement, death, Disability or non-renewal of the employment, service or other agreement upon its expiration for any reason other than for Cause) prior to the expiry of the Option Period of any option, then notwithstanding any other terms on which the option was granted, our Board shall determine at its absolute discretion and shall notify the Grantee whether the Grantee shall be entitled, following such termination of employment or service, to exercise the option (to the extent not already exercised) in respect of vested and unvested Shares as at the date the Grantee's employment or service is terminated and the period during which such option may be exercised. If our Board determines that such option may not be exercised following such termination of employment or service, such option shall automatically lapse with effect from the date on which the Grantee's employment or service is terminated.

For the purpose of our Post-IPO Share Option Scheme:

(A) "**Cause**" means, with respect to a Grantee and subject to applicable laws, such event which will entitle the Corporation and/or our Subsidiary to terminate the employment or services of the Grantee with immediate notice without compensation under the relevant agreement or, if it is not otherwise provided for in the relevant agreement, (I) the commission of an act of theft, embezzlement, fraud, dishonesty, ethical breach or other similar acts or commission of a criminal offence, (II) a material breach of any agreement or understanding between the Grantee and the Corporation and/or our subsidiary, including any applicable invention assignment, employment, non-competition, confidentiality or other agreement, (III) misrepresentation or omission of any material fact in connection with his employment or services, (IV) a material failure to perform the customary duties of our employee and/or an employee of our subsidiary, to obey the reasonable directions of a supervisor or to abide by the policies or codes of conduct of the Group or (V) any conduct that is materially adverse to the name, reputation or interests of the Group;

(B) "**Competitor**" means any corporation, partnership, joint venture, trust, individual proprietorship, firm, governmental unit or other enterprise (including any of their respective affiliates) that carries on activities for profit or is engaged in or is about to become engaged in any activity of any nature that competes (directly or indirectly) with a product, process, technique, procedure, device or service of the Corporation or our subsidiary; and

(C) "**Disability**" means a disability, whether temporary or permanent, partial or total as determined by our Board in its absolute discretion.

Cancellation of Options

Our Board may at any time with the consent of and on such terms as may be agreed with the relevant Grantee cancel options previously granted to but not yet exercised by a Grantee. Where we cancel options and offer new options to the same Grantee, the offer of such new options may only be made with available options to the extent not yet granted (excluding the cancelled options) within the limits prescribed on pages VI-56 to VI-57 above.

Reorganisation of Capital Structure

(a) Adjustments

In the event of an alteration in our capital structure by way of a capitalisation of profits or reserves, bonus issue, rights issue, open offer, subdivision or consolidation of shares or reduction of our share capital in accordance with applicable laws and the Listing Rules (other than any alteration in our capital structure as a result of an issue of Shares as consideration in a transaction to which we or our subsidiary is a party or in connection with any of our share option, restricted share or other equity incentive schemes) whilst any option remains unvested or has vested but not yet been exercised and/or satisfied, such corresponding adjustments (if any) shall be made to:

(i) the Scheme Mandate Limit;

(ii) the number of Shares underlying the option so far as unvested, unexercised or exercised but not yet satisfied; and/or

(iii) the Exercise Price,

or any combination thereof, provided that:

(iv) any such adjustments give a Grantee the same proportion of our share capital as that to which that Grantee was previously entitled; and

(v) notwithstanding paragraph (iv), any adjustments as a result of an issue of securities with a price-dilutive element, such as a rights issue, open offer or capitalisation issue, should be based on a scrip factor similar to the one used in accounting standards in adjusting the earnings per share figures.

In respect of any such adjustments, our auditors or our independent financial adviser (as the case may be) must confirm to our Board in writing that the adjustments are in their opinion fair and reasonable.

(b) Auditors or independent financial adviser certification

We shall engage our auditors or our independent financial adviser to certify in writing, either generally or as regards any particular Grantee, that the adjustments we made satisfy the requirements set out in paragraphs (iv) and (v) above.

Alteration of our Post-IPO Share Option Scheme

Save as provided in our Post-IPO Share Option Scheme, our Board may alter any of the terms of our Post-IPO Share Option Scheme at any time. Those specific provisions of our Post-IPO Share Option Scheme which relate to the matters set out in Rule 17.03 of the Listing Rules cannot be altered to the advantage of Participants and changes to the authority of our Board in relation to any alteration of the terms of our Post-IPO Share Option Scheme shall not be made, in either case, without the prior approval of Shareholders in general meeting.

Any alterations to the terms and conditions of our Post-IPO Share Option Scheme which are of a material nature or any changes to the terms of the options granted must be approved by our Shareholders in general meeting, except where the alterations or changes take effect automatically under the existing terms of our Post-IPO Share Option Scheme. The Board's determination as to whether any proposed alteration to the terms and conditions of our Post-IPO Share Option Scheme is material shall be conclusive. Our Post-IPO Share Option Scheme so altered must comply with Chapter 17 of the Listing Rules.

Termination of our Post-IPO Share Option Scheme

We may by ordinary resolution in general meeting or our Board may at any time terminate our Post-IPO Share Option Scheme and in such event, no further options may be offered or granted but in all other respects the terms of our Post-IPO Share Option Scheme shall remain in full force and effect in respect of options which are granted during the life of our Post-IPO Share Option Scheme and which remain unvested or which have vested but not yet been exercised immediately prior to the termination of the operation of our Post-IPO Share Option Scheme.

Administration of our Post-IPO Share Option Scheme

Our Post-IPO Share Option Scheme shall be subject to the administration of our Board whose decision as to all matters arising in relation to our Post-IPO Share Option Scheme or its interpretation or effect shall (save as otherwise provided in our Post-IPO Share Option Scheme) be final and binding on all parties.

General

An application has been made to the Listing Committee of the Stock Exchange for the listing of, and permission to deal in, the new Shares which may be issued pursuant to the exercise of the options which may be granted pursuant to our Post-IPO Share Option Scheme.

As of the current date, we had not granted or agreed to grant any option pursuant to our Post-IPO Share Option Scheme.

Details of our Post-IPO Share Option Scheme, including particulars and movements of the options granted during each of our financial years, and our employee costs arising from the grant of the options will be disclosed in our annual report.

SCHEDULE "D"

SUNSHINE OILSANDS LTD.
TERMS OF REFERENCE OF THE AUDIT COMMITTEE

1. The Board of Directors' Mandate for the Audit Committee

(a) Purpose

The Audit Committee (the "**Audit Committee**") is a committee of non-executive directors appointed by the Board of Directors of the Corporation (the "**Board of Directors**"). The Audit committee's mandate is, inter alia, to provide assistance to the Board of Directors in fulfilling its financial reporting and control responsibility to the shareholders and the investment community, The committee is, however, independent of the Board of Directors and the Corporation and in carrying out their role shall have the ability to determine its own agenda and any additional activities that the Audit Committee shall carry out.

(b) Composition of Committee

a) The Committee will be comprised of at least three non-executive directors of the Corporation, all of whom will be financially literate. In addition, at least one member of the Audit Committee shall have accounting or related financial expertise as such qualifications are interpreted by the Board of Directors in accordance with rule 3.10(2) of the Rules Governing the Listing of Securities on the Stock Exchange of Hong Kong Limited (the "**Listing Rules**"). A majority of the members of the Committee must also be "independent" in accordance with the Listing Rules. A "financially literate" director is a director who has the ability to read and understand a set of financial instruments that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the financial statements of the Corporation.

b) Unless otherwise designated by the Board, the members of the Committee shall elect a Chairperson (the "**Chair**") from among the independent non-executive directors present and the Chair shall preside at all meetings of the Committee.

(c) Reliance on Experts

In contributing to the Committee's discharging of its duties under this mandate, each member of the Committee shall be entitled to rely in good faith upon:

a) financial statements of the Corporation represented to him or her by an officer of the Corporation or in a written report of the external auditors to present fairly the financial position of the Corporation in accordance with GAAP consistently applied; and

b) any report of a lawyer, accountant, engineer, appraiser or other person whose profession lends credibility to a statement made by any such person.

(d) Limitations on Committee's Duties

In contributing to the Committee's discharging of its duties under the Terms of Reference (defined at II below), each member of the Corporation shall be obliged only to exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. Nothing in the Terms of Reference is intended, or may be construed, to impose on any member of the Committee a standard of care or diligence that is in any way more onerous or extensive than the standard to which all Board members are subject. The essence of the Committee's duties is monitoring and reviewing to endeavour to gain reasonable assurance (but not to ensure) that the relevant activities are being conducted effectively and that the objectives of the Corporation's financial reporting are being met and to enable the Committee to report thereon to the Board.

2. Audit Committee Terms of Reference

The Audit Committee's Terms of Reference (the "**Terms of Reference**") outline how the Committee will satisfy the requirements set forth by the Board in its mandate. Terms of Reference reflect the following:

- operating principles;
- operating procedures; and
- specific responsibilities and duties.

(a) Operating Principles

The Committee shall fulfill its responsibilities within the context of the following principles:

(i) Committee Values

The Committee expects the management of the Corporation to operate in compliance with corporate policies, reflecting laws and regulations governing the Corporation and to maintain strong financial reporting and control processes.

(ii) Communications

The Committee and members of the Committee expect to have direct, open and frank communications throughout the year with management, other Committee Chairpersons, the external auditors, and other key Committee advisors or Corporation staff members as applicable.

(iii) Financial Literacy

All Committee members should be sufficiently versed in financial matters to read and understand the Corporation's financial statements and also to understand the Corporation's accounting practices and policies and the major judgments involved in preparing the financial statements.

(iv) Annual Audit Committee Work Plan

The Committee, in consultation with management and the external auditors, shall develop an annual Committee work plan responsive to the Committee's responsibilities as set out in these Terms of Reference. In addition, the Committee, in consultation with management and the external auditors, shall participate in a process for review of important financial topics that have the potential to impact the Corporation's financial disclosure.

The work plan will be focused primarily on the annual and interim financial statements of the Corporation. However, the Committee may at its sole discretion, or the discretion of the Board, review such other matters as may be necessary to satisfy the Committee's Terms of Reference.

(v) Meeting Agenda

Committee meeting agendas shall be the responsibility of the Chair in consultation with Committee members, senior management and the external auditors and shall be circulated on a timely basis prior to the Committee meetings.

(vi) Committee Expectations and Information Needs

The Committee shall communicate its expectations to management and the external auditors with respect to the nature, timing and extent of its information needs. The Committee expects that written materials will be received from management and the external auditors at a reasonable time in advance of meeting dates.

(vii) External Resources

To assist the Committee in discharging its responsibilities, the Committee may at its discretion, in addition to the external auditors, at the expense of the Corporation, retain one or more persons having special expertise, including independent counsel.

(viii) In Camera Meetings

At the discretion of the Committee, the members of the Committee shall meet in private sessions with the external auditors.

(ix) Reporting to the Board

The Committee, through its Chair, shall report after each Committee meeting to the Board at the Board's next regular meeting.

(x) Committee Self Assessment

The Committee shall annually review, discuss and assess its own performance. In addition, the Committee shall periodically review its role and responsibilities.

(xi) The External Auditors

The Committee expects that, in discharging their responsibilities to the shareholders, the external auditors shall report directly to and be accountable to the Board through the Committee. The external auditors shall report all material issues or potentially material issues, either specific to the Corporation or to the financial reporting environment in general, to the Committee.

(b) Operating Procedures

A. The Committee shall meet at least four times annually, or more frequently as circumstances dictate. At least once a year the Committee shall meet with the external and internal auditors without executive Board members present.

B. Meetings shall be held at the call of the Chair, upon the request of two members of the Committee or at the request of the external auditors.

C. A quorum shall be a majority of the Committee members and the rules for calling, holding, conducting and adjourning meetings of the Committee shall be the same as those governing the Board unless otherwise determined by the Committee or the Board.

D. At all meetings of the Committee every question shall be decided by a majority of the votes cast, with each member of the Committee, including the Chair, having one vote, and with the Chair having no tie breaker vote.

E. The Chair shall preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee present shall designate from among the independent non-executive directors the Chair for the purposes of the meeting.

F. A member or members of the Committee may participate in Committee meetings by means of such telephonic, electronic or other communication facilities as permit all persons participating in the meeting to communicate adequately with each other, and a member participating in such a meeting by any such means is deemed to be present at that meeting.

G. Unless the Committee otherwise specifies, the secretary of the Corporation (or his or her deputy), or such other person as designated by the Committee shall act as the secretary (the "**Secretary**") of all meetings of the Committee.

H. Minutes of the Committee will be maintained by the Secretary and made available to each director of the Corporation as soon as practicable following a Committee meeting.

(c) Specific Responsibilities and Duties

The specific responsibilities and duties of the Committee include:

(i) Financial Reporting:

a) review, prior to public release, the Corporation's annual and quarterly financial statements with management and, to the extent required, the external auditors. In its review of such financial statements the Committee shall focus in particular on:

i) any changes in accounting policies and practices;

ii) major judgemental areas;

iii) significant adjustments resulting from the audit or review;

iv) the going concern assumption;

v) compliance with accounting standards; and

vi) compliance with stock exchange and legal requirements.

The Committee shall report thereon to the Board before such financial statements are approved by the Board;

b) receive from the external auditors reports of their audit of the annual financial statements and if the auditors are engaged, their reviews of the quarterly financial statements;

c) review, prior to public release, and, if appropriate, recommend approval to the Board, of news releases and reports to shareholders issued by the Corporation with respect to the Corporation's annual and quarterly financial statements;

d) review and, if appropriate, recommend approval to the Board of prospectuses, material change disclosures of a financial nature, management discussion and analyses, annual information forms and similar disclosure documents to be issued by the Corporation;

e) assess whether the Corporation's accounting policies are being adequately disclosed in the Corporation's financial reporting;

f) review and validate procedures for the receipt, retention and resolution of complaints received by the Corporation from any party regarding accounting, auditing or internal controls. For greater certainty, the Committee's responsibilities in this area will not include complaints about minor operational issues.

Examples of minor operational issues include late payment of invoices, minor disputes over accounts owing or receivable, revenue and expense allocations and other similar items characteristic of the normal daily operations of the accounting department of an oil and gas corporation;

(ii) Accounting Policies:

a) review with management and the external auditors the appropriateness of the Corporation's financial and accounting policies and practices, disclosures, reserves, key estimates and judgments, including changes or variations thereto;

b) obtain reasonable assurance that the Corporation's accounting policies are in compliance with GAAP consistently applied from management and external auditors and report thereon to the Board;

c) review with management and the external auditors the apparent degree of conservatism of the Corporation's underlying accounting policies, key estimates and judgments and provisions along with quality of financial reporting; and

d) participate, if requested, in the resolution of disagreements, between management and the external auditors;

(iii) Risk and Uncertainty:

a) acknowledging that it is the responsibility of the Board, in consultation with management, to identify the principal business risks facing the Corporation, determine the Corporation's tolerance for risk and approve risk management policies, the Committee shall focus on financial risk and gain reasonable assurance that financial risk is being effectively managed or controlled;

b) review policies and compliance therewith that require significant actual or potential liabilities, contingent or otherwise, to be reported to the Board in a timely fashion;

c) review foreign currency, interest rate and commodity price risk mitigation strategies, including the use of derivative financial instruments;

d) review the adequacy of insurance coverages maintained by the Corporation; and

e) review regularly with management, the external auditors and the Corporation's legal counsel, any legal claim or other contingency, including tax assessments, that could have a material effect upon the financial position or operating results of the Corporation and the manner in which these matters have been disclosed in the financial statements;

(iv) Financial Controls and Control Deviations:

a) review the plans of the external auditors to gain reasonable assurance that applicable internal financial controls are comprehensive, coordinated and cost effective;

b) receive regular reports from management and the external auditors on all significant deviations or indications/detection of fraud and the corrective activity undertaken in respect thereto;

c) institute a procedure that will permit any employee, including management employees, to bring to the attention of the Board, under conditions of confidentiality, concerns relating to financial controls and reporting which are material in scope and which cannot be addressed, in the employee's judgment, through existing reporting structures in the Corporation;

d) review and periodically assess the adequacy of controls over financial information disclosed to the public, which is extracted or derived from the Corporation's financial statements;

e) to review the Corporation's statement on internal control systems (where one is included in the annual report) prior to endorsement by the Board;

f) to discuss the internal control system with management to ensure that management has performed its duty to have an effective internal control system. This discussion should include the adequacy of resources, staff qualifications and experience, training programs and budget of the Corporation's accounting and financial reporting function;

g) (where an internal audit function is in operation) to review the internal audit programme, ensure co-ordination between the internal and external auditors, and ensure that the internal audit function is adequately resourced and has appropriate standing within the Corporation; and

h) to consider the major findings of internal investigations and management's response;

(v) Compliance with Laws and Regulations:

a) review regular reports from management and others (e.g. external auditors) with respect to the Corporation's compliance with laws and regulations having a material impact on the financial statements including:

i) tax and financial reporting laws and regulations;

ii) legal withholding requirements; and

iii) other laws and regulations which expose directors to liability; and

b) review the filing status of the Corporation's tax returns;

(vi) Relationship with External Auditors:

a) recommend to the Board the appointment, re-appointment and, if necessary, dismissal, of the external auditors;

b) to review and monitor the external auditor's independence and objectivity and the effectiveness of the audit process in accordance with applicable standards;

c) approve the remuneration and the terms of engagement of the external auditors as set forth in the engagement letter and receive a copy of the finalized version of the engagement letter;

d) to review the external auditors management letter and management's response;

e) to ensure that the Board will provide a timely response to the issues raised in the external auditors management letter;

f) review the performance of the external auditors annually or more frequently as required;

g) receive a report annually from the external auditors with respect to their independence, such report to include a disclosure of all engagements (and fees related thereto) for non-audit services to the Corporation;

h) review with the external auditors the scope of the audit, the areas of special emphasis to be addressed in the audit, and the materiality levels which the external auditors propose to employ;

i) meet with the external auditors in the absence of management to determine, inter alia, that no management restrictions have been placed on the scope and extent of the audit examinations by the external auditors or the reporting of their findings to the Committee;

j) establish effective communication processes with management and the Corporation's external auditors to assist the Committee to monitor objectively the quality and effectiveness of the relationship among the external auditors, management and the Committee; and

k) establish a reporting relationship between the external auditors and the Committee such that the external auditors can bring directly to the Committee matters that, in the judgment of the external auditors, merit the Committee's attention. In particular, the external auditors will advise the Committee as to disagreements between management and the external auditors regarding financial reporting and how such disagreements were resolved; and

(vii) Other Responsibilities:

a) approve annually the reasonableness of the expenses of the Co-Chairpersons of the Board and the Chief Executive Officer;

b) after consulting with the Chief Financial Officer and the external auditors, to consider at least annually the quality and sufficiency of the Corporation's accounting and financial personnel and other resources;

c) to develop and implement policy on the engagement of an external auditor to supply non-audit services, including tax advisory and compliance services provided by the external auditors;

d) ensure that an effective "whistle blowing" procedure exists to permit stakeholders to express any concerns regarding accounting or financial matters to an appropriately independent individual;

e) investigate any matters that, in the Committee's discretion, fall within the Committee's duties;

f) perform such other functions as may from time to time be assigned to the Committee by the Board;

g) review and update the Terms of' Reference on a regular basis for approval by the Board;

h) review disclosures regarding the organization and duties of the Committee to he included in any public document, including quarterly and annual reports to shareholders, information circulars and annual information forms; and

i) ensure that an appropriate code of conduct is in place and understood by employees and directors of the Corporation.

February 6, 2012

SCHEDULE "E"

SUNSHINE OILSANDS LTD.
TERMS OF REFERENCE OF THE CORPORATE GOVERNANCE COMMITTEE

The Board of Directors' Mandate for the Corporate Governance Committee

A. ROLE AND OBJECTIVE

The purpose of the Corporate Governance Committee (the "Committee") is to assist the board of directors (the "Board") of Sunshine Oilsands Ltd. (the "Corporation") in fulfilling its responsibilities under the Business Corporations Act (Alberta) by, inter alia, reviewing matters relating to the appointment of new directors, assessing the performance of the Board, its committees and its directors and responding to and implementing the corporate governance guidelines set forth by applicable regulatory authorities.

B. MEMBERSHIP OF THE COMMITTEE

1. Unless otherwise determined by the Board, the Committee shall be comprised of a majority of such independent non executive members of the Board as the Board may, from time to time, designate. Where appropriate, independent directors must be "independent" in accordance with the Rules Governing the Listing of Securities on the Stock Exchange of Hong Kong Limited (the "Listing Rules").

2. Unless otherwise designated by the Board, the members of the Committee shall elect a Chairperson (the "Chair") from among the independent non executive directors present and the Chair shall preside at all meetings of the Committee.

C. MANDATE AND RESPONSIBILITIES OF THE COMMITTEE

The Committee's primary responsibilities are twofold. First, the Committee is responsible for proposing to the Board new nominees to the Board and for assessing the performance of the Board, its committee and its directors on an ongoing basis. Second, the Committee is responsible for the Corporation's response to and implementation of the guidelines set forth from time to time by any applicable regulatory authorities (the "Guidelines"). The specific functions of the Committee in carrying out these two areas of responsibility are:

Nominating and Assessment:

(a) To review the structure, size and composition (including skills, knowledge and experience) of the Board at least annually and make recommendations on any proposed changes to the Board to complement the Corporation's corporate strategy;

(b) to consider and recommend candidates to fill new positions on the Board created by either expansion or vacancies that occur by resignation, retirement or for any other reason:

(c) to review candidates recommended by shareholders

(d) to conduct inquiries into the backgrounds and qualifications of possible candidates;

(e) to recommend the director nominees for approval by the Board and the shareholders;

(f) to consider questions of possible conflicts of interest of Board members;

(g) to recommend members and Chairs of the Audit Committee, Reserves Committee and Compensation Committee;

(h) to review the performance of the Board, its committees and its directors;

(i) to establish and implement an orientation and education program for new members of the Board;

(j) assess the independence of independent non-executive directors; and

(k) make recommendations to the Board on the appointment or re-appointment of directors and succession planning for directors in particular the chairman and the chief executive officer.

Corporate Governance:

(a) to consider and review the Corporation's corporate governance principles, practices and processes and to compare the same to the Guidelines and make recommendations to the Board;

(b) to propose changes to the Board necessary to respond to or comply with the Guidelines:

(c) to review the Corporation's disclosure of its corporate governance program and compliance with the Guidelines in the management proxy circular for each annual general meeting;

(d) to review and monitor the Corporation's policies and practices on compliance with legal and regulatory requirements;

(e) to review internal corporate policies annually;

(f) to review and monitor the training and continuous professional development of directors and senior management;

(g) to develop, review and monitor the code of conduct and compliance manual (if any) applicable to employees and directors; and

(h) to review the Corporation's compliance with the Code on Corporate Governance as set out from time to time in the Listing Rules and disclosure in the corporate governance report section of its financial statements.

D. MEETING AND ADMINISTRATIVE MATTERS

1. At all meetings of the Committee every question shall be decided by a majority of the votes cast, with each member of the Committee, including the Chair, having one vote, and with the Chair having no tie breaker vote.

2. The Chair shall preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee present shall designate from among the independent non-executive present the Chair for purposes of the meeting.

3. A quorum for meetings of the Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee shall be the same as those governing the Board unless otherwise determined by the Committee or the Board.

4. Meetings of the Committee should be scheduled to take place at least once per year and at such other times as the Chair of the Committee may determine.

5. A member or members of the Committee may participate in a meeting of the Committee h~ means of such telephonic, electronic or other communication facilities as permit all persons participating in the meeting to communicate adequately with each other, and a member participating in such a meeting by any such means is deemed to be present at that meeting.

6. Committee meeting agendas shall be the responsibility of the Chair in collaboration with Committee members, and, where appropriate, senior management.

7. The Committee may invite such officers, directors and employees of the Corporation as it may see fit from time to time to attend at meetings of the Committee and assist thereat in the discussion and consideration of the matters being considered by the Committee.

8. A member of the Committee or an officer of the Corporation, or any other person selected b~ the Committee, shall be appointed at each meeting to act as secretary for the purposes of recording the minutes of each meeting.

9. Minutes of the Committee will be maintained and made available at a subsequent meeting of the Committee and upon request of the Board.

10. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation.

11. Any members of the Committee may be removed or replaced at any time by the Board and shall cease to be a member of the Committee as soon as such member ceases to be a director.

February 6, 2012

SCHEDULE “F”

REPORT ON RESOURCES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Sunshine Oilsands Ltd. (the “**Corporation**”):

1. We have evaluated the Corporation’s resources data as at November 30, 2011 estimated using forecast prices and costs. The resources data are estimates of both the volumes and values of our, contingent resources and PIIP, however, none of the volumes or values of our resources have been risked for chance of development.

2. The resources data are the responsibility of the Corporation’s management. Our responsibility is to express an opinion on the resources data based on our evaluation.

   We carried out our evaluation in accordance with resources and reserves definitions, standards and procedures contained in the Society of Petroleum Engineers Petroleum Resource Management System (“**SPE-PRMS**”). We understand that there are differences between the SPE-PRMS and the Canadian Oil and Gas Evaulation Handbook (“**COGEH**”), however there are no material differences between the volumes and values reported in our evaluation reports and the corresponding volumes or values that would have been reported had they been derived by evaluations conducted in accordance with COGEH.

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

4. The following table presents a summary of the reserves and resources attributable to the Corporation’s main asset groups as at November 30, 2011.

			Total PIIP(1) (3)			Contingent Resources(1)			Pre-Tax PV10%(1)		
Property	**Region**	**Number of Oil & Gas Leases**	**Low Estimate**	**Best Estimate**	**High Estimate**	**Low Estimate**	**Best Estimate**	**High Estimate**	**Low Estimate Contingent Resources**	**Best Estimate Contingent Resources**	**High Estimate Contingent Resources**
Conventional Heavy Oil											
Muskwa	Muskwa	21	47	86	120	0	0	0	0	0	0
Total Conventional Heavy Oil			**47**	**86**	**120**	**0**	**0**	**0**	**0**	**0**	**0**
Clastics											
West Ells	West Ells	26	1,918	1,918	1,918	401	745	1,011	1,082	1,811	2,548
Thickwood	Thickwood	4	1,403	1,403	1,403	258	325	419	65	513	890
Legend Lake	Legend Lake	27	1,730	1,844	1,844	255	449	673	477	891	1,801
Pelican Lake	Pelican Lake	2	375	375	384	77	118	185	100	270	596
Opportunity	Legend Lake	27	949	2,235	2,235	0	37	131	0	(4)	128
East Long Lake	East Long Lake	5	113	162	162	15	33	74	64	160	353
Crow Lake	Crow Lake	2	225	332	332	0	0	14	0	0	24
Portage Grand Rapids	Portage	14	232	232	367	0	0	4	0	0	4
Harper	Harper	38	5,581	5,581	7,512	0	326	780	0	491	2,068
Muskwa/Godin	Muskwa	21	1,163	1,482	1,870	270	418	643	136	231	437
Portage Wabiskaw	Portage	14	381	445	592	0	0	0	0	0	0
Total Clastics			**14,070**	**16,009**	**18,619**	**1,276**	**2,450**	**3,934**	**1,924**	**4,363**	**8,849**
Carbonates											
Harper	Harper	38	8,780	10,555	11,819	0	393	1,405	0	243	2,668
Ells Leduc	West Ells	26	856	997	997	0	159	271	0	448	904
Goffer	Goffer	2	1,289	1,732	2,158	0	0	521	0	0	71
Muskwa	Muskwa	21	8,209	10,841	14,583	0	0	1,810	0	0	1,308
Saleski	Saleski	1	538	596	762	0	0	123	0	0	243
South Thickwood	South Thickwood	9	243	287	402	0	0	56	0	0	63
Portage Nisku	Portage	14	3,597	4,265	4,853	0	64	961	0	8	2,771
Goffer Keg River	Goffer	2	0	0	22	0	0	0	0	0	0
Total Carbonates			**23,512**	**29,273**	**35,596**	**0**	**616**	**5,147**	**0**	**699**	**8,028**
Combined Total		**151**	**37,629**	**45,368**	**54,335**	**1,276**	**3,066**	**9,081**	**1,924**	**5,062**	**16,877**
Pre-tax PV10%(2)									**1,866**	**4,837**	**16,520**
Post-tax PV10%(2)									**869**	**2,555**	**9,723**

Source: GLJ Report and D&M Report, dated November 30, 2011.

Notes:

(1) Total PIIP and Contingent Resources in million barrels. Pre-Tax PV10% in million dollars.

(2) Both GLJ's and D&M's Pre-Tax PV10% and Post-Tax PV10% in this table incorporate GLJ's October 1, 2011 price forecasts for oil, bitumen and natural gas and are denominated in $ millions. PV10% is not a measure of financial or operating performance, nor is it intended to represent the current value of our reserves and resources.

(3) Total PIIP is a sum of discovered and undiscovered PIIP components as defined in GLJ and D&M Reports.

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

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

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

Executed as to our report referred to above. GLJ Petroleum Consultants Limited, Calgary, Alberta, Canada, April 30, 2012.	Executed as to our report referred to above. DeGolyer and MacNaughton Canada Limited. Calgary, Alberta, Canada, April 30, 2012.

(signed) "*Caralyn Bennett*"
Caralyn Bennett, P. Eng.
Vice-President

(signed) "*Nahla Boury*"
Nahla Boury, P. Eng.
Vice President Engineering and Director

SCHEDULE “G”

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Sunshine Oilsands Ltd. (the “**Corporation**”):

1. We have evaluated the Corporation’s reserves data as at November 30, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at November 30, 2011, estimated using forecast prices and costs.

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

3. We carried out our evaluation in accordance with resources and reserves definitions, standards and procedures contained in the Society of Petroleum Engineers Petroleum Resource Management System (“**SPE-PRMS**”). We understand that there are differences between the SPE-PRMS and the Canadian Oil and Gas Evaulation Handbook (“**COGEH**”), however there are no material differences between the volumes and values reported in our evaluation report and the corresponding volumes or values that would have been reported had they been derived by evaluations conducted in accordance with COGEH.

4. 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 SPE-PRMS.

5. The following table presents a summary of the reserves attributable to the Corporation’s main asset groups as at November 30, 2011.

			Reserves[1]		Pre-Tax PV10%[1]	
Property	**Region**	**Number of Oil & Gas Leases**	**1P**	**2P**	**1P**	**2P**
Conventional Heavy Oil						
Muskwa	Muskwa	21	2.4	5.5	38	56
Total Conventional Heavy Oil			**2.4**	**5.5**	**38**	**56**
					0	
Clastics						
West Ells	West Ells	26	0	158	0	407
Thickwood	Thickwood	4	0	164	0	218
Legend Lake	Legend Lake	27	0	91	0	166
Pelican Lake	Pelican Lake	2	0	0	0	0
Opportunity	Legend Lake	27	0	0	0	0
East Long Lake	East Long Lake	5	0	0	0	0
Crow Lake	Crow Lake	2	0	0	0	0
Portage Grand Rapids	Portage	14	0	0	0	0
Harper	Harper	38	0	0	0	0
Muskwa/Godin	Muskwa	21	0	0	0	0
Portage Wabiskaw	Portage	14	0	0	0	0
Total Clastics			**0**	**413**	**0**	**790**
Carbonates						
Harper	Harper	38			0	0
Ells Leduc	West Ells	26	0	0	0	0
Goffer	Goffer	2	0	0	0	0
Muskwa	Muskwa	21	0	0	0	0
Saleski	Saleski	1	0	0	0	0
South Thickwood	South Thickwood	9	0	0	0	0
Portage Nisku	Portage	14	0	0	0	0
Goffer Keg River	Goffer	2	0	0	0	0
Total Carbonates			**0**	**0**	**0**	**0**
Combined Total		**151**	**2**	**419**	**38**	**846**
Pre-tax PV10%[2]					**30**	**829**
Post-tax PV10%[2]					**21**	**482**

Source: GLJ Report and D&M Report, dated November 30, 2011.

Notes:

(1) Reserves in million barrels. Pre-Tax PV10% in million dollars.

(2) Both GLJ's and D&M's Pre-Tax PV10% and Post-Tax PV10% in this table incorporate GLJ's October 1, 2011 price forecasts for oil, bitumen and natural gas and are denominated in $ millions. PV10% is not a measure of financial or operating performance, nor is it intended to represent the current value of our reserves and resources.

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

7. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after its preparation date.

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

Executed as to our report referred to above. GLJ Petroleum Consultants Limited, Calgary, Alberta, Canada, April 30, 2012.	Executed as to our report referred to above. DeGolyer and MacNaughton Canada Limited. Calgary, Alberta, Canada, April 30, 2012.

(signed) "*Caralyn Bennett*"
Caralyn Bennett, P. Eng.
Vice-President

(signed) "*Nahla Boury*"
Nahla Boury, P. Eng.
Vice President Engineering and Director

SCHEDULE "H"

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Sunshine Oilsands Ltd. (the "**Corporation**") is responsible for the preparation and disclosure of information with respect to the (Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves and resources data which are estimates of both the volumes and values of our possible reserves, contingent resources and PIIP in addition to proved reserves and probable reserves and related future net revenue as at November 30, 2011, estimated using forecast prices and costs¸ however, none of the volumes or values of our resources have been risked for chance of development.

Independent Qualified Reserves Evaluators have evaluated and reviewed the Corporation's reserves and resources data. The report of the Independent Qualified Reserves Evaluators will be filed with the securities regulatory authorities concurrently with this report.

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

(a) reviewed the Corporation's procedures for providing information to the Independent Qualified Reserves Evaluators;

(b) met with the Independent Qualified Reserves Evaluators to determine whether any restrictions affected the ability of the Independent Qualified Reserves Evaluators to report without reservation; and

(c) reviewed the reserves and resources data with management and the Independent Qualified Reserves Evaluator.

The Reserves Committee of the board of directors has reviewed the Corporation'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, on the recommendation of the Reserves Committees approved:

(d) the content and filing with securities regulatory authorities of the AIF containing reserves, resources data and other oil and gas information;

(e) the filing of the reports of the Independent Qualified Reserves Evaluators on the reserves and resources data; and

(f) the content and filing of this report.

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

Dated effective April 30, 2012.

(signed) *"John Zahary"*
John Zahary
Chief Executive Officer

(signed) *"Michael Hibberd"*
Michael Hibberd
Director

(signed) *"Doug Brown"*
Doug Brown
Chief Operating Officer

(signed) *"Wazir Seth"*
Wazir (Mike) Seth
Director