



ATHABASCA

OIL CORPORATION
Annual Information Form

FOR THE YEAR ENDED DECEMBER 31, 2015

March 10, 2016

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INTRODUCTORY INFORMATION

Except as otherwise indicated, or unless the context otherwise requires, the term the “**Company**” refers to Athabasca Oil Corporation and the term “**Athabasca**” refers to one or more of the Company’s direct or indirect subsidiaries, or to the Company and its direct and indirect subsidiaries, collectively. Capitalized terms used herein and not otherwise defined have the meanings ascribed thereto in the Glossary of Defined Terms.

FORWARD LOOKING STATEMENTS

Certain statements contained in this Annual Information Form constitute forward-looking statements. These statements relate to future events or Athabasca’s future performance. All statements other than statements of historical fact are forward-looking statements. The use of any of the words “anticipate”, “plan”, “continue”, “estimate”, “expect”, “may”, “will”, “project”, “should”, “believe”, “predict”, “pursue” and “potential” and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. 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. These statements speak only as of the date of this Annual Information Form. In addition, this Annual Information Form may contain forward-looking statements and forward-looking information attributed to third party industry sources.

In particular, this Annual Information Form contains forward-looking statements pertaining to, but not limited to, the following:

- the business strategy, objectives and business strengths of Athabasca;
- Athabasca’s growth strategy and opportunities;
- Athabasca’s 2016 exploration and development budget and Athabasca’s capital expenditure programs;
- Athabasca’s expectations regarding its ability to raise capital;
- Athabasca’s plans to submit additional regulatory applications;
- the estimated quantity of Athabasca’s Proved Reserves, Probable Reserves and Contingent Resources;
- Athabasca’s projections of commodity prices, costs and netbacks;
- the timing of certain of Athabasca’s operations and projects, including the commencement of its planned Thermal Oil Division development projects, the exploration and development of Athabasca’s Light Oil assets, and the levels and timing of anticipated production;
- the finalization and timing of closing of the Murphy Transaction;
- the timing of the ramp-up of Hangingstone Project 1 production to close to nameplate capacity by the end of 2016;
- the timing of the project activities related to Hangingstone Project 1 and the Hangingstone Expansion;
- expected timing for completion of the pipeline linking the Placid area to the existing Kaybob Infrastructure Assets;
- the status and progression of the Dover West Sands regulatory application;
- the potential for future joint venture arrangements;
- the use of SAGD technology to produce bitumen from the Hangingstone Expansion, Dover West Sands and Birch assets and the use of CSS, SAGD or TAGD to produce bitumen from the Dover West Carbonates and Grosmont assets;
- expected timing of the Company’s Light Oil division wells coming on-stream;
- expected timing of the Company’s Hangingstone Expansion, Dover West Sands and Birch resources achieving first production and estimated best estimate capital costs to achieve first commercial production;
- Development plans and projected timelines for the Company’s Hangingstone Expansion, Dover West Sands, Birch and Dover West Carbonates assets;
- Expected or projected abandonment and reclamation obligation costs;
- Athabasca’s ability to comply with the covenants contained in the Amended Credit Facility, Term Loans, Senior Secured Notes, transportation agreements and any other third party agreement to which Athabasca is party;
- supply and demand fundamentals for crude oil, bitumen blend, natural gas, and SCO and other diluents;

- Athabasca's access to third-party infrastructure;
- industry conditions including with respect to project development;
- Athabasca's drilling plans and plans and results regarding the completion of wells that have been drilled and other exploration and development activities;
- realization of the anticipated benefits of acquisitions and dispositions; and
- Athabasca's treatment under governmental regulatory regimes and tax laws.

With respect to forward-looking statements and forward-looking information contained in this Annual Information Form, assumptions have been made regarding, among other things:

- the benefits expected to be realized by the Company from the Murphy Transaction, including the impact on the Company's financial position.
- future sources of funding for Athabasca's capital programs and Athabasca's ability to obtain financing on acceptable terms;
- future crude oil, bitumen blend, natural gas, SCO and other diluent prices;
- Athabasca's ability to obtain qualified staff and equipment in a timely and cost-efficient manner;
- the regulatory framework governing royalties, taxes, environmental matters and foreign investment in the jurisdictions in which Athabasca conducts and will conduct its business;
- Athabasca's ability to transport and market production of bitumen blend, conventional crude oil, shale oil, conventional natural gas, shale gas and NGLs, successfully to customers;
- Athabasca's future production levels;
- the applicability of technologies for the recovery and production of Athabasca's reserves and resources;
- the recoverability of Athabasca's reserves and resources;
- Athabasca's ability to develop its oil and gas properties in the manner currently contemplated;
- operating costs;
- future capital expenditures to be made by Athabasca;
- Athabasca's future debt levels;
- compliance of counterparties with the terms of contractual arrangements with Athabasca;
- success rates of future well drilling;
- well drainage areas;
- future well production rates;
- geological and engineering estimates in respect of Athabasca's reserves and resources being accurate in all material respects;
- the geography of the areas in which Athabasca is conducting exploration and development activities; and
- the impact of increasing competition on Athabasca.

Actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and included elsewhere in this Annual Information Form, including, but not limited to:

- weakness in the oil and gas industry;
- fluctuations in market prices for crude oil, natural gas and bitumen blend;
- general economic, market and business conditions in Canada, the United States and globally;
- the substantial capital requirements of Athabasca's projects and the ability to obtain financing for Athabasca's capital requirements;
- global financial uncertainty;
- failure to realize anticipated benefits of acquisitions or divestments;
- risks related to hydraulic fracturing;
- factors affecting potential profitability;
- failure to obtain regulatory approvals or maintain compliance with regulatory requirements;
- extent of, and cost of compliance with, government laws and regulations and the effect of changes in such laws and regulations from time to time;
- risks relating to changing royalty regimes;
- additional funding requirements and liquidity risk;

- variations in foreign exchange and interest rates;
- environmental risks and hazards and the cost of compliance with environmental regulations, including the licensee liability rating program, seismic activity regulations, GHG regulations and potential Canadian and U.S. climate change legislation;
- risks related to the Murphy Transaction, including the risk that the parties are unable to meet the conditions precedent to closing the Murphy Transaction or that the Murphy Transaction does not close on the timeline anticipated or at all, dependence on Murphy as the operator of the Kaybob assets, dependence on Murphy as the Company's joint venture participant in the Company's Kaybob and Placid assets and dependence on Murphy's continued ability to pay the Kaybob Carry Commitment;
- risks related to the Amended Credit Facility, Term Loans and the Senior Secured Notes;
- geopolitical risks;
- uncertainties inherent in estimating quantities of reserves and resources;
- contractual counterparty risks and operational dependence;
- risks related to future acquisition and joint venture activities;
- risks and uncertainties inherent in Athabasca's operations, including those related to exploration, development and production of petroleum, natural gas and oil sands reserves and resources, including the production of oil sands reserves and resources using SAGD, CSS or TAGD or other in-situ recovery technologies;
- failure to meet development schedules and potential cost overruns;
- aboriginal claims;
- reliance on, competition for, loss of, and failure to attract key personnel;
- financial assurance covenants and collateral requirements under the Company's pipeline transportation agreements;
- risks related to gathering and processing facilities and pipeline systems;
- availability of drilling and related equipment and limitations on access to Athabasca's assets;
- risk that increases in operating costs could make Athabasca's projects uneconomic;
- the effect of diluent and natural gas supply constraints and increases in the costs thereof;
- costs of new technologies;
- alternatives to and changing demand for petroleum products;
- gas over bitumen issues affecting operational results;
- risks related to Athabasca's filings with taxation authorities, including the risk of tax related reviews and reassessments;
- failure to accurately estimate abandonment and reclamation costs;
- the potential for management estimates and assumptions to be inaccurate;
- long term reliance on third parties;
- reliance on third party infrastructure;
- seasonality;
- hedging risks;
- risks associated with establishing and maintaining systems of internal controls;
- insurance risks;
- claims made in respect of Athabasca's operations, properties or assets;
- competition for, among other things, capital, the acquisition of reserves and resources, export pipeline capacity and skilled personnel;
- expiration of leases and permits or the failure of Athabasca or the holder of certain licenses, leases or permits to meet specific requirements of such licenses, leases or permits;
- breaches of confidentiality;
- inaccuracy of forward-looking information;
- expansion into new activities; and
- risks related to the Common Shares.

In addition, information and statements in this Annual Information Form relating to "reserves" and "resources" are deemed to be forward-looking information and statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and

that the reserves and resources described can be profitably produced in the future. Readers are cautioned that the foregoing list of risk factors should not be construed as exhaustive.

Although management of the Company believes that the assumptions underlying and the expectations reflected in the forward-looking information are reasonable, significant risks and uncertainties are involved in such information. Management can give no assurances that its assumptions, estimates and expectations will prove to have been correct. Forward-looking information should not be read as guarantees of future performance or results, and will not necessarily be accurate indications of whether or not, or the times at or by which, such performance or results will be achieved. Many factors that are beyond Athabasca's control could cause actual results to differ materially from the results discussed in the forward-looking statements.

The forward-looking statements included in this Annual Information Form are expressly qualified by this cautionary statement and are made as of the date of this Annual Information Form. The Company does not undertake any obligation to publicly update or revise any forward-looking statements, except as required by applicable securities laws.

GLOSSARY OF DEFINED TERMS

The following terms, used in the preparation of this Annual Information Form, have the following meanings:

"2-D seismic data" means two-dimensional seismic data, being interpretive data that allows a view of a vertical cross-section beneath a prospective area.

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

"2010 RSU" means a restricted share unit granted under the 2010 RSU Plan.

"2010 RSU Plan" means the restricted share unit plan of the Company originally dated effective as of February 25, 2010, as amended from time to time and which was replaced by the 2015 RSU Plan.

"2015 RSU" means a restricted share unit granted under the 2015 RSU Plan.

"2015 RSU Plan" means the restricted share unit plan of the Company dated effective as of March 11, 2015.

"2012 Credit Facilities" means, in connection with the issuance of the Senior Secured Notes, on November 30, 2012 the Company entered into a credit agreement with a syndicate of financial institutions providing for senior secured first lien revolving credit facilities in the aggregate amount of \$200 million, the 2012 Credit Facilities were replaced by the 2013 Credit Facilities on December 16, 2013.

"2013 Credit Facilities" has the meaning given to that term under *"General Development of the Business – Three Year History- 2013"*

"abandonment and reclamation costs" means all costs associated with the process of restoring Athabasca's property that has been disturbed by oil and gas activities to a standard imposed by applicable government or regulatory authorities.

"ABCA" means the *Business Corporations Act*, R.S.A. 2000, c. B-9, as amended, including the regulations promulgated thereunder.

"AER" means the Alberta Energy Regulator (the successor to the ERCB).

"AER Decision" has the meaning given to that term under *"General Development of the Business – Three Year History – 2013"*.

“Alberta Environment” means the Ministry of Environment and Sustainable Resource Development of the Government of Alberta (formerly, the Department of Environment and Water).

“Amended and Restated Credit Agreement” has the meaning given to that term under *“Description of Capital Structure – Revolving Senior Secured Credit Facility”*.

“Amended Credit Facility” means the amended and restated revolving senior secured first lien credit facility entered into by the Company on May 7, 2014 as more particularly described in *“Description of Capital Structure – Revolving Senior Secured Credit Facility”*

“AOC (Dover)” means AOC (Dover) Energy Inc., a wholly-owned subsidiary of the Company incorporated under the ABCA, which as at the closing date of the Dover Put Option Transaction held an undivided 40% interest in the Dover assets.

“AOC (Dover) Shares” means all of the issued and outstanding shares of AOC (Dover) Energy Inc.

“AOSC Newco” means 1487645 Alberta Ltd., a corporation incorporated under the ABCA, that: (a) prior to the closing of the PetroChina Share Purchase Agreement, was a wholly-owned subsidiary of the Company; and (b) following the closing of the PetroChina Share Purchase Agreement and prior to the amalgamation of AOSC Newco and Phoenix, was a wholly-owned subsidiary of Phoenix.

“API” means the American Petroleum Institute.

“°API” refers to an indication of the specific gravity of crude oil measured on the API gravity scale.

“Athabasca” means Athabasca Oil Corporation and/or its wholly-owned subsidiaries, as the context requires.

“Audit Committee” means the audit committee of the Board.

“Best Estimate” has the meaning given to that term under *“Schedule A – Supplemental Disclosure- Contingent Resource Estimates”*.

“Birch assets” means the interests of Athabasca in approximately 447,000 net acres of land as at December 31, 2015, located in northeastern Alberta (see map), that are more particularly described under *“Description of Athabasca’s Business – Thermal Oil Division- Other Thermal Oil Exploration Areas”*.

“Birch Project” means a staged development plan for a 170,000 bbls/d SAGD project, with an initial phase 1 of 12,000 bbls/d.

“bitumen” means a naturally occurring solid or semi-solid hydrocarbon, consisting mainly of heavier hydrocarbons with a viscosity greater than 10,000 milliPascal seconds (or centipoise) measured at the hydrocarbon’s original temperature in the reservoir and atmospheric pressure, on a gas-free basis and is not primarily recoverable at economic rates through a well without the implementation of enhanced recovery methods. Crude bitumen may contain sulphur and other non-hydrocarbon compounds.

“Board” means the Board of Directors of the Company.

“BOEs” means barrels of oil equivalent.

“Brion” means Brion Energy Corporation the successor to Phoenix by amalgamation which occurred on August 29, 2014.

“cap rock” means 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.

“carbonate” means 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. Although carbonate rocks can be clastic in origin, they are more commonly formed through processes of precipitation or the activity of organisms such as coral and algae. Carbonates form in shallow and deep marine settings, evaporitic basins, lakes and windy deserts. Carbonate rocks are common hydrocarbon reservoir rocks.

“CCAA” means the *Companies’ Creditors Arrangement Act*, R.S.C. 1983, c. C-36.

“CSS” means cyclic steam stimulation, an in-situ oil extraction method where a well cycles through steam injection, soak and oil production phases.

“clastic” means 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.

“COGE Handbook” means the Canadian Oil and Gas Evaluation Handbook maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter) as amended from time to time.

“Collateral Agent” means Olympia Trust Company, the collateral agent, pursuant to the Collateral Agent Agreement.

“Collateral Agent Agreement” has the meaning given to that term under *“Description of Capital Structure – Senior Secured Notes”*.

“Common Shares” means the common shares in the capital of the Company, as constituted on the date hereof.

“Company Interest” means Athabasca’s total working interest share before deduction of royalties and without excluding any royalty interests.

“Compensation and Governance Committee” means the compensation and governance committee of the Board.

“Computershare” means Computershare Trust Company of Canada.

“Contingent Resources” has the meaning given to that term under *“Schedule A – Supplemental Disclosure-Contingent Resource Estimates”*.

“conventional natural gas” means natural gas that has been generated elsewhere and has migrated as a result of hydrodynamic forces and is trapped in discrete accumulations by seals that may be formed by localized structural, depositional or erosional geological features.

“crude oil” or **“oil”** means a mixture consisting mainly of pentanes and heavier hydrocarbons that exist in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons but does not include liquids obtained from the processing of natural gas. Classes of crude are reported on basis of density, acceptable ranges are as follows: Light: less than 870kg/m³ (greater than 31.1 degrees (symbol) API), Medium: 870-920 kg/m³ (31.1-22.3 degrees API), Heavy 920-1000 kg/m³ (22.3-10 degrees API).

“DBRS” means DBRS Limited.

“developed non-producing reserves” has the meaning given to that term under *“Independent Reserves Evaluations – Reserves Classifications – Development and Production Status”*.

“developed producing reserves” has the meaning given to that term under *“Independent Reserves Evaluations – Reserves Classifications – Development and Production Status”*.

“**developed reserves**” has the meaning given to that term under “*Independent Reserves Evaluations – Reserves Classifications – Development and Production Status*”.

“**dilbit**” means a blend of condensate and bitumen.

“**diluent**” means lighter viscosity petroleum products that are used to dilute bitumen for transportation in pipelines.

“**D&M**” means DeGolyer and MacNaughton Canada Limited, an independent qualified reserve and resource evaluator.

“**D&M Report**” means the reports of D&M dated effective as of December 31, 2015 assessing and evaluating the Proved Reserves, Probable Reserves and Contingent Resources of Athabasca, as applicable, located in the Birch and Hangingstone areas of Alberta.

“**Dover assets**” means the former interests of the Participants in approximately 150,000 acres of land primarily between townships 92 to 97, ranges 15 to 18 west of the fourth meridian in northeastern Alberta near the city of Fort McMurray which after the closing date of the Dover Put Option Transaction on August 29, 2014, were owned exclusively by Phoenix (now Brion), including for greater certainty the Dover Oil Sands Leases, and such additional assets, benefits and interests as may be acquired, from time to time, by or for the benefit of the Participants of the Dover Joint Venture, or that otherwise derive therefrom, including all tangible depreciable property, facilities, equipment and inventory owned or leased for the benefit of conducting the business of the Dover Joint Venture, as well as contracts, agreements and other interests of a miscellaneous nature that are typically acquired, owned or held in order to explore, develop, construct and operate facilities in relation to, and produce, bitumen, together with cash and near cash equivalents, such as accounts receivable.

“**Dover Call Option**” means the option granted by the Company to Phoenix to require the Company to sell to Phoenix or an affiliate of Phoenix all of the shares of AOC (Dover) (or a wholly-owned subsidiary of AOC (Dover)) pursuant to the Put/Call Option Agreement.

“**Dover Joint Venture**” means the former joint venture between AOC (Dover) and Phoenix which was formed pursuant to the Dover Joint Venture Agreement.

“**Dover Joint Venture Agreement**” means the joint venture agreement dated February 10, 2010 among AOC (Dover), Phoenix and Dover JV Operator pertaining to the ownership and operation of the Dover assets.

“**Dover JV Operator**” means Brion Energy Corporation (formerly, Dover Operating Corp.), a corporation incorporated under the ABCA by AOC (Dover) and Phoenix in accordance with their respective Participating Interests in the Dover Joint Venture, which changed its name from “Dover Operating Corp.” to “Brion Energy Corporation” on May 31, 2013.

“**Dover Oil Sands Leases**” means the crown leases governed by the Dover Joint Venture Agreement.

“**Dover Oil Sands Project**” means the in-situ oil sands project in respect of the Dover assets which was the subject of the Dover Joint Venture Agreement between AOC (Dover), Phoenix and Dover JV Operator.

“**Dover Oil Sands Project Approval**” means, as it pertains to the Dover Oil Sands Project, AER approval pursuant to section 10 of the *Oil Sands Conservation Act* (Alberta) and Alberta Environment approval pursuant to Part 2, Division 2, of the *Environmental Protection and Enhancement Act* (Alberta).

“**Dover Put Option**” means the option granted to the Company by Phoenix to require Phoenix or an affiliate of Phoenix to acquire all of the shares or assets of AOC (Dover) (or a wholly-owned subsidiary of AOC (Dover)), as the case may be, pursuant to the Put/Call Option Agreement.

“**Dover Put/Call Option**” means, collectively, the Dover Call Option and the Dover Put Option.

“Dover Put Option Transaction” means the exercise by the Company of the Dover Put Option (which is more particularly described under *“General Development of the Business –Recent Significant Transactions- The Dover Put Option Transaction”*) and the sale by the Company of the AOC (Dover) Shares to Phoenix.

“Dover West assets” means the interests of Athabasca in approximately 233,000 net acres of land as at December 31, 2015 located within the Athabasca oil sands fairway in northeastern Alberta (see map) that are more particularly described under *“Description of Athabasca’s Business – Thermal Oil Division – Other Thermal Oil Exploration Areas- Dover West assets”*.

“Dover West Carbonates” means the resource within the Leduc and Cooking Lake Formations of the Devonian Woodbend Group, a carbonate reservoir in the Dover West assets.

“Dover West Sands” means the clastic bitumen reservoirs contained within the McMurray Formation and the Wabiskaw member of the Clearwater Formation in the Dover West assets.

“Dover West Sands Project 1” means a SAGD project in the Dover West area with a planned production capacity of up to 12,000 bbls/d.

“DSU” means a deferred share unit granted under the Company’s DSU Plan.

“DSU Plan” means the deferred share unit plan adopted by the Company and effective March 11, 2015 for directors of the Company.

“Enbridge” has the meaning given to that term under *“General Development of the Business – Three Year History – 2013”*.

“EODC” has the meaning given to that term under *“General Development of the Business – Three Year History – 2013”*.

“ERCB” means the Energy Resources Conservation Board of Alberta (predecessor to the AER).

“Established Technology” means methods that have been proven to be successful in commercial applications, as such term is defined in the COGE Handbook.

“Experimental Technology” means technology that is being field tested to determine the technical viability of applying a recovery process to unrecoverable discovered petroleum initially in place in a subject reservoir as such term is defined in the COGE Handbook. It cannot be used to assign any class of recoverable resources (i.e. reserves, contingent resources, prospective resources).

“FEED” means front end engineering and design.

“fines” means fragments or particles of rock or mineral that are too minute to be treated as ordinary coarse material.

“FMFN” means the Fort McKay First Nation.

“forecast prices and costs” means future prices and costs that are: (a) generally accepted as being a reasonable outlook of the future; or (b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which Athabasca is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in subparagraph (a).

“future net revenue” means a forecast of revenue, estimated using forecast prices and costs or constant prices and costs, arising from the anticipated development and production of resources, net of the associated royalties, operating costs, development costs, and abandonment and reclamation costs.

“**GHG**” means greenhouse gas.

“**GLJ**” means GLJ Petroleum Consultants Ltd., an independent qualified reserve and resource evaluator.

“**GLJ Report**” means the reports of GLJ dated effective as of December 31, 2015, assessing and evaluating the Contingent Resources of Athabasca, as applicable, located in the Dover West Sands area of Alberta and the Proved Reserves and Probable Reserves attributable to the Light Oil assets.

“**Grosmont assets**” refers to Athabasca’s interest in approximately 113,000 net acres of land in the Grosmont (Mikwa) area located in northeastern Alberta in which Athabasca, as at December 31, 2015 (see map), as more particularly described under “*Description of Athabasca’s Business – Thermal Oil Division – Other Thermal Oil Exploration Areas*”.

“**Gross Reserves**” or “**Gross**” in relation to reserves means a 100% working interest share (operating or non-operating) before deduction of royalties and without including any royalty interests of Athabasca.

“**HAF**” means the Heater Assembly Facility constructed and owned by Athabasca and used for assembly of cable-based well heaters for TAGD applications as described in “*Description of Athabasca’s Business- Thermal Oil Division- Other Thermal Oil Exploration Areas- Dover West Assets- Dover West Carbonates*”

“**Hangingstone assets**” means the interests of Athabasca in approximately 138,000 net acres of land located in the Athabasca oil sands fairway in northeastern Alberta (see map) as at December 31, 2015, that are more particularly described under “*Description of Athabasca’s Business – Thermal Oil Division –Hangingstone assets*”.

“**Hangingstone Expansion**” means an incremental expansion of the Hangingstone Projects by an additional 70,000 bbls/d via three separate projects: Hangingstone Project 2A, Hangingstone Project 2B and Hangingstone Project 3 in respect of which a regulatory application was filed with the AER and Alberta Environment on May 17, 2013.

“**Hangingstone Projects**” means Hangingstone Project 1, the Hangingstone Expansion and any future proposed in-situ oil sands projects in respect of the Hangingstone assets.

“**Hangingstone Project 1**” means a 12,000 bbl/d SAGD project in the Hangingstone area which received regulatory approval in October 2012 and which was sanctioned by the Board on November 27, 2012.

“**Hangingstone Project 2A**” has the meaning given to that term under “*Description of Athabasca’s Business – Thermal Oil Division – Hangingstone assets –Hangingstone Expansion*”.

“**Hangingstone Project 2B**” has the meaning given to that term under “*Description of Athabasca’s Business – Thermal Oil Division – Hangingstone assets –Hangingstone Expansion*”.

“**Hangingstone Project 3**” has the meaning given to that term under “*Description of Athabasca’s Business – Thermal Oil Division – Hangingstone assets –Hangingstone Expansion*”.

“**HS CPF**” means the Hangingstone Project 1 central processing facility.

“**hydrocarbon**” means a compound consisting of hydrogen and carbon, which, when naturally occurring, may also contain other elements such as sulphur.

“**Indenture Trustee**” means Olympia Trust Company, as trustee under the Note Indenture.

“**Independent Evaluators**” means, collectively, D&M and GLJ.

“**Independent Reports**” means, collectively, the D&M Report and the GLJ Report.

“in-situ” means “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, CSS or TAGD.

“IPP” means Inter Pipeline Polaris Inc.

“KA” has the meaning given to that term under *“Description of Athabasca’s Business – Light Oil Division”*.

“Kaybob assets” means the interests of Athabasca in approximately 252,500 net acres of land that are located primarily in northwestern Alberta (see map), as at December 31, 2015, as more particularly described under *“Description of Athabasca’s Business – Light Oil Division”*.

“Kaybob Carry Commitment” means a portion of the purchase price in the Murphy Transaction in the form of Murphy’s obligation to fund 75% of Athabasca’s share of Kaybob area asset development capital in the amount of \$225 million over a period of up to five years.

“Kaybob Infrastructure Assets” means the light oil transportation infrastructure assets located in the Kaybob area including a 63 kilometre, 12-inch pipeline, from the Kaybob and Placid areas to the Keyera Simonette Gas Plant and two oil batteries (the Kaybob West battery has a design capacity of 13,000 bbls/d of oil and 48 MMcf/d of natural gas and is located at 7-14-063-20-W5M and the Kaybob East battery has a design capacity of 13,000 bbls/d of oil and 24 MMcf/d of natural gas and is located at 16-03-065-18-W5M. Athabasca has a 50% interest in the Kaybob Infrastructure Assets as at December 31, 2015. Athabasca will sell 70% of its interest in the Kaybob Infrastructure Assets to Murphy as part of the Murphy Transaction.

“LIBOR” means the London Interbank Offered Rate.

“Light Crude Oil” or **“light crude oil”** means crude oil with a relative density greater than 31.1 degrees API gravity.

“Light Oil assets” means the interests of Athabasca in approximately 484,000 net acres of land as at December 31, 2015, primarily located in northwestern Alberta, which includes the Kaybob, Placid and Light Oil Exploration Areas.

“Light Oil Division” means Athabasca’s business unit which is primarily focused on the exploration for, and sustainable development and production of, light oil and liquids-rich natural gas.

“Light Oil Exploration Areas” means the interests of Athabasca in approximately 93,000 net acres of land that are located in the Grand Prairie, North Muskwa, South Muskwa, Caribou, Glenevis and Sawn Lake areas in northwestern Alberta as at December 31, 2015, which are more particularly described under *“Description of Athabasca’s Business – Light Oil Division – Light Oil Exploration Areas”*.

“Medium Crude Oil” or **“medium crude oil”** means crude oil with a relative density greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity.

“Murphy” means Murphy Oil Canada Ltd., a wholly owned subsidiary of Murphy Oil Corporation.

“Murphy Transaction” has the meaning given to such term under the heading *“General Development of the Business-Recent Significant Transactions”*.

“Murphy Transaction Assets” means (a) 70% of the Company’s WI in a portion of the Kaybob assets and Simonette assets including approximately 200,000 acres of prospective Duvernay lands (**“Kaybob Murphy Transaction Assets”**) and (b) 30% of the Company’s WI in a portion of the Simonette assets including approximately 60,000 acres of prospective Montney lands (**“Simonette Murphy Transaction Assets”**).

“Murphy Purchase and Sale Agreement” means the Agreement of Purchase and Sale dated January 27, 2016 entered into between AOC Simonette Partnership, AOC Kaybob Partnership and AOC Light Oil Partnership as Vendors and Murphy Oil Canada Ltd. as Purchaser.

“**M\$**” means thousands of Canadian dollars.

“**MM\$**” means millions of Canadian dollars.

“**natural gas**” means a naturally occurring mixture of hydrocarbon gases and other gases, which may contain sulphur or other non-hydrocarbon compounds.

“**Net Reserves**” means Athabasca’s working interest (operating or non-operating) share after deduction of royalty obligations, plus Athabasca’s royalty interests in reserves.

“**NGL**” or “**natural gas liquids**” means the hydrocarbon components that can be recovered from natural gas as liquids, including, but not limited to ethane, propane, butanes, pentanes plus and condensates.

“**NI 51-101**” means National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*.

“**NI 51-102**” means National Instrument 51-102 *Continuous Disclosure Obligations*.

“**Note Indenture**” means the indenture dated November 19, 2012, among the Company, the Company’s subsidiary guarantors and the Indenture Trustee, relating to the Senior Secured Notes.

“**oil sands**” means deposits of sand, sandstone, carbonate or other mineral material containing bitumen.

“**Participant**” means a person that had a Participating Interest in the Dover Joint Venture and was a party to the Dover Joint Venture Agreement, in any case, as the context requires or permits.

“**Participating Interest**” means an undivided beneficial ownership interest in the Dover Joint Venture, the Dover assets and bitumen recovered from the lands underlying the Dover Oil Sands Leases, in any case, as the context requires or permits.

“**Performance Award**” means performance awards able to be granted to directors and other Company staff under the Company’s Performance Plan which was adopted by the Company on March 18, 2014.

“**Performance Plan**” means the performance award plan of the Company dated effective March 18, 2014.

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

“**PetroChina**” means PetroChina Company Limited, a joint stock company with limited liabilities existing under the laws of the People’s Republic of China.

“**PetroChina International**” means PetroChina International Investment Company Limited, a body corporate existing under the laws of the People’s Republic of China and a wholly-owned subsidiary of PetroChina.

“**PetroChina Share Purchase Agreement**” means the agreement dated February 10, 2010 between the Company and Phoenix, pursuant to which Phoenix acquired the AOSC Newco shares from the Company.

“**Phoenix**” means Phoenix Energy Holdings Limited, a wholly-owned subsidiary of PetroChina International and the successor entity resulting from the amalgamation of AOSC Newco and Cretaceous Oilsands Holdings Limited.

“**PIIP**” means that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum initially-in-place includes production, reserves and Contingent Resources; the remainder is unrecoverable.

“**Plan of Arrangement**” means the plan of arrangement under the ABCA effective March 22, 2010.

“**porosity**” means the volume of a rock available to contain fluids; 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.

“**Probable Reserves**” or “**probable reserves**” has the meaning given to that term under “*Independent Evaluations – Reserves Classifications – Reserves Categories*”.

“**Promissory Notes**” means the three interest-bearing promissory notes issued by Phoenix (now Brion) to the Company pursuant to the closing of the Dover Put Option Transaction on August 29, 2014. The promissory notes were and are due on the following dates and are in the following amounts (exclusive of interest): \$300 million due March 2, 2015; \$150 million due August 28, 2015; \$134 million due August 29, 2016.

“**Prosperity Act**” has the meaning given to that term under “*Industry Conditions – Pricing and Marketing – Oil*”.

“**Proved Reserves**” or “**proved reserves**” has the meaning given to that term under “*Independent Reserves Evaluations – Reserves Classifications – Reserves Categories*”.

“**Put/Call Option Agreement**” means the amended and restated agreement dated March 15, 2012 setting forth the Dover Put/Call Option, among the Company, Phoenix, AOC (Dover) and AOC Dover Corp.

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

“**Reserves**” or “**reserves**” has the meaning given to that term under “*Independent Reserve and Resource Evaluations – Reserves and Resources Classifications – Reserves Categories*”.

“**Reserves Committee**” means the reserves committee of the Board.

“**reservoir**” means a porous and permeable formation that contains a separate accumulation of petroleum that is confined by impermeable rock or water barriers and is characterized by a single pressure system.

“**Restricted Subsidiaries**” has the meaning given to that term under “*Description of Capital Structure – Senior Secured Term Loans*”.

“**Rights Plan**” means the shareholder rights plan of the Company having the terms set forth in the shareholder rights plan agreement entered into between the Company and Olympia Trust Company, as rights agent, on April 8, 2010, as described under “*Description of Capital Structure – Shareholder Rights Plan*”.

“**risk**ed” has the meaning given to that term under “*Schedule A – Supplemental Disclosure- Contingent Resource Estimates*”.

“**RSU**” means either a 2010 RSU or a 2015 RSU or both, as the context requires.

“**S&P**” means Standard and Poor’s Rating Services, a division of McGraw-Hill Companies (Canada) Corporation.

“**SAGD**” means steam assisted gravity drainage, an in-situ process used to recover bitumen from oil sands.

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

“**SCO**” or “**synthetic crude oil**” means a mixture of liquid hydrocarbons derived by upgrading bitumen, kerogen or other substances such as coal, or derived from gas to liquid conversion and may contain sulphur or other compounds.

“**Senior Secured Notes**” has the meaning given to that term under “*Description of Capital Structure – Senior Secured Notes*”.

“**shale gas**” means natural gas contained in dense organic-rich rocks, including low permeability shales, siltstones and carbonates, in which the natural gas is primarily adsorbed on the kerogen or clay materials and that usually requires the use of hydraulic fracturing to achieve economic production rates.

“**Shareholders**” means the holders, from time to time, of the Common Shares, collectively or individually, as the context requires.

“**Simonette assets**” means the interests of Athabasca in approximately 138,000 net acres of land that are located primarily in northwestern Alberta (see map) as at December 31, 2015 as more particularly described under “*Description of Athabasca’s Business – Light Oil Division*”.

“**SOC**” means statement of concern.

“**SOR**” means steam to oil ratio.

“**Stock Option**” means a stock option granted under the Stock Option Plan.

“**Stock Option Plan**” means the stock option plan of the Company originally dated effective as of September 1, 2009, as amended from time to time.

“**TAGD**” means thermal assisted gravity drainage.

“**TAGD Pilot and Demonstration Project**” means a TAGD pilot and demonstration project within the Company’s Dover West Carbonates asset area with a planned production capacity of up to 6,000 bbl/d in respect of which a regulatory application was submitted to the ERCB and Alberta Environment in December, 2011.

“**TCPL**” means TransCanada Pipelines Limited, a subsidiary of TransCanada Corporation.

“**Technology Under Development**” means a recovery process or process improvement project that has been determined to be technically viable via a field test and is being field tested further to determine its economic viability in the subject reservoir as such term is defined in the COGE Handbook.

“**Term Loans**” means the senior secured first lien term loans entered into by the Company on May 7, 2014 pursuant to the Term Loan Credit Agreement, all as more particularly described in “Description of Capital Structure – Senior Secured Term Loans”.

“**Term Loan Credit Agreement**” means the credit agreement with respect to the Term Loans dated May 7, 2014 between the Company, the lenders of the Term Loans and the Toronto Dominion Bank as agent for such lenders

“**Thermal Oil assets**” means the interests of Athabasca in over 1.24 million net acres of oil sands leases in the Athabasca region of northeastern Alberta, as at December 31, 2015.

“**Thermal Oil Division**” means Athabasca’s business unit which is primarily focused on the exploration for, and sustainable development and production of, bitumen from oil sands.

“**tight oil**” means crude oil contained in dense organic-rich rocks, including low permeability shales, siltstones and carbonates, in which the natural gas is primarily contained in microscopic pore spaces that are poorly connected to one another and that usually requires the use of hydraulic fracturing to achieve economic production rates.

“**TSX**” means the Toronto Stock Exchange.

“**undeveloped reserves**” has the meaning given to that term under “Independent Reserves Evaluations – Reserves Classifications – Development and Production Status”.

“**unrisked**” has the meaning given to that term under “*Schedule A – Supplemental Disclosure- Contingent Resource Estimates*”.

“**WCS**” means Western Canadian Select.

“**WI**” means working interest.

“**WTI**” means West Texas Intermediate grade crude oil at a reference sales point in Cushing, Oklahoma, a common benchmark for crude oils.

ABBREVIATIONS

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

bbl	barrel
bbls	barrels
bbl/d	barrels per day
BOE or boe	barrels of oil equivalent
Boe/d	barrels of oil equivalent per day
MMboe	million barrels of oil equivalent
Mbbl	thousand barrels
MMbbl	million barrels
Mcf	thousand cubic feet
Mcfe	thousand cubic feet equivalent
MMcf	million cubic feet
MMcf/d	million cubic feet per day
Bcf	billion cubic feet

BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

CONVERSIONS

The following table sets forth certain standard conversions from Standard Imperial units to the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.315
Bbls	cubic metres	0.159
cubic metres	Bbls	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

CONVENTIONS

Words importing the singular number only include the plural, and vice versa, and words importing any gender include all genders.

All dollar amounts set forth in this Annual Information Form are in Canadian dollars, except where otherwise indicated.

Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

THE COMPANY

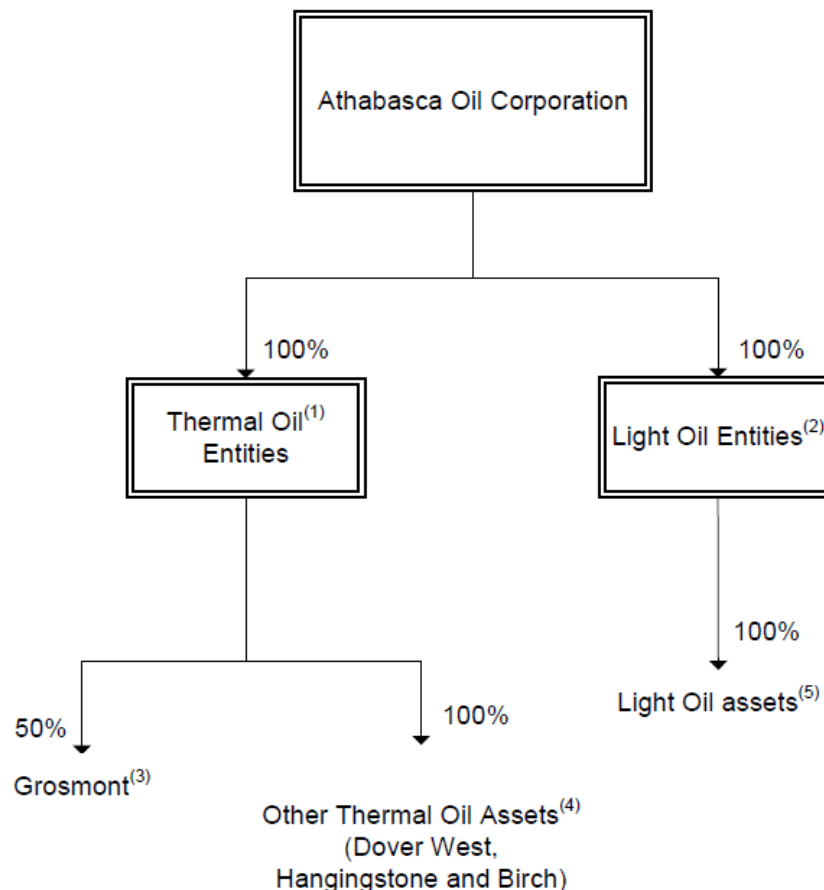
Name, Address and Incorporation

The Company was incorporated as “Athabasca Oil Sands Corp.” under the ABCA on August 23, 2006. On September 1, 2006, the Company filed articles of amendment to remove its private company restrictions. On March 22, 2010, the Company filed articles of arrangement to give effect to the Plan of Arrangement and filed articles of amendment to create first preferred shares, issuable in series, and second preferred shares, issuable in series. On May 10, 2012, the Company filed articles of amendment to change its name from “Athabasca Oil Sands Corp.” to “Athabasca Oil Corporation”.

The Company’s head office is located at Suite 1200, 215 – 9th Avenue S.W., Calgary, Alberta T2P 1K3, and its registered office is located at Suite 2400, 525 – 8th Avenue S.W., Calgary, Alberta T2P 1G1.

Intercorporate Relationships

The following simplified organizational chart and related notes illustrate the intercorporate relationships of the Company and its material subsidiaries, as at December 31, 2015, including the percentage of votes attaching to all voting securities of such entities that are beneficially owned, or controlled or directed, directly or indirectly, by the Company. Each of the Company’s subsidiaries is incorporated or formed under the laws of the Province of Alberta.



Notes:

- (1) The “Thermal Oil Entities” are corporations and partnerships that hold the Company’s Thermal Oil assets and that are directly or indirectly wholly-owned by the Company: AOC Dover West Corp., AOC Grosmont Ltd., AOC Carbonates Ltd., AOC (ELE) Corp., AOC Birch Corp., AOC Dover West Partnership, AOC Grosmont Partnership, AOC Carbonates Partnership, AOC Hangingstone Partnership and AOC Birch Partnership,
- (2) The “Light Oil Entities” are corporations and partnerships that hold the Company’s Light Oil assets and that are directly or indirectly wholly-owned by the Company: AOC Light Oil Corp., AOC Kaybob Corp., AOC Grande Prairie Corp., AOC Simonette Corp., AOC Muskwa North Corp., AOC Muskwa South Corp., AOC Caribou Corp., AOC Light Oil Partnership, AOC Kaybob Partnership, AOC Grande Prairie Partnership, AOC Simonette Partnership, AOC Muskwa North Partnership, AOC Muskwa South Partnership and AOC Caribou Partnership.
- (3) See “*Description of Athabasca’s Business – Thermal Oil Division – Other Thermal Oil Exploration Areas- Grosmont assets*” for a description of Athabasca’s 50% working interest in the Grosmont area. ZAM Ventures Alberta Inc., a family investment entity advised by Ziff Brothers Investments, L.L.C. (and an affiliate of ZAM Investments Luxembourg, s.à.r.l.), holds the remaining 50% working interest in the Grosmont area.
- (4) See “*Description of Athabasca’s Business – Thermal Oil Division – Other Thermal Oil Exploration Areas- Dover West assets*”, “*Description of Athabasca’s Business – Thermal Oil Division – Principal Properties- Hangingstone assets*” and “*Description of Athabasca’s Business – Thermal Oil Division – Other Thermal Oil Exploration Areas- Birch assets*” for descriptions of Athabasca’s 100% working interests in the Dover West assets, Hangingstone assets and Birch assets.
- (5) See “*Description of Athabasca’s Business – Light Oil Division*” for a description of Athabasca’s interests in the Light Oil assets.

Overview of Athabasca’s Business

Athabasca is primarily focused on the exploration for, and sustainable development and production of, light oil and liquids-rich natural gas from regions in northwestern Alberta, Canada and bitumen from oil sands in the Athabasca region of northeastern Alberta, Canada. Athabasca is organized into the following two divisions:

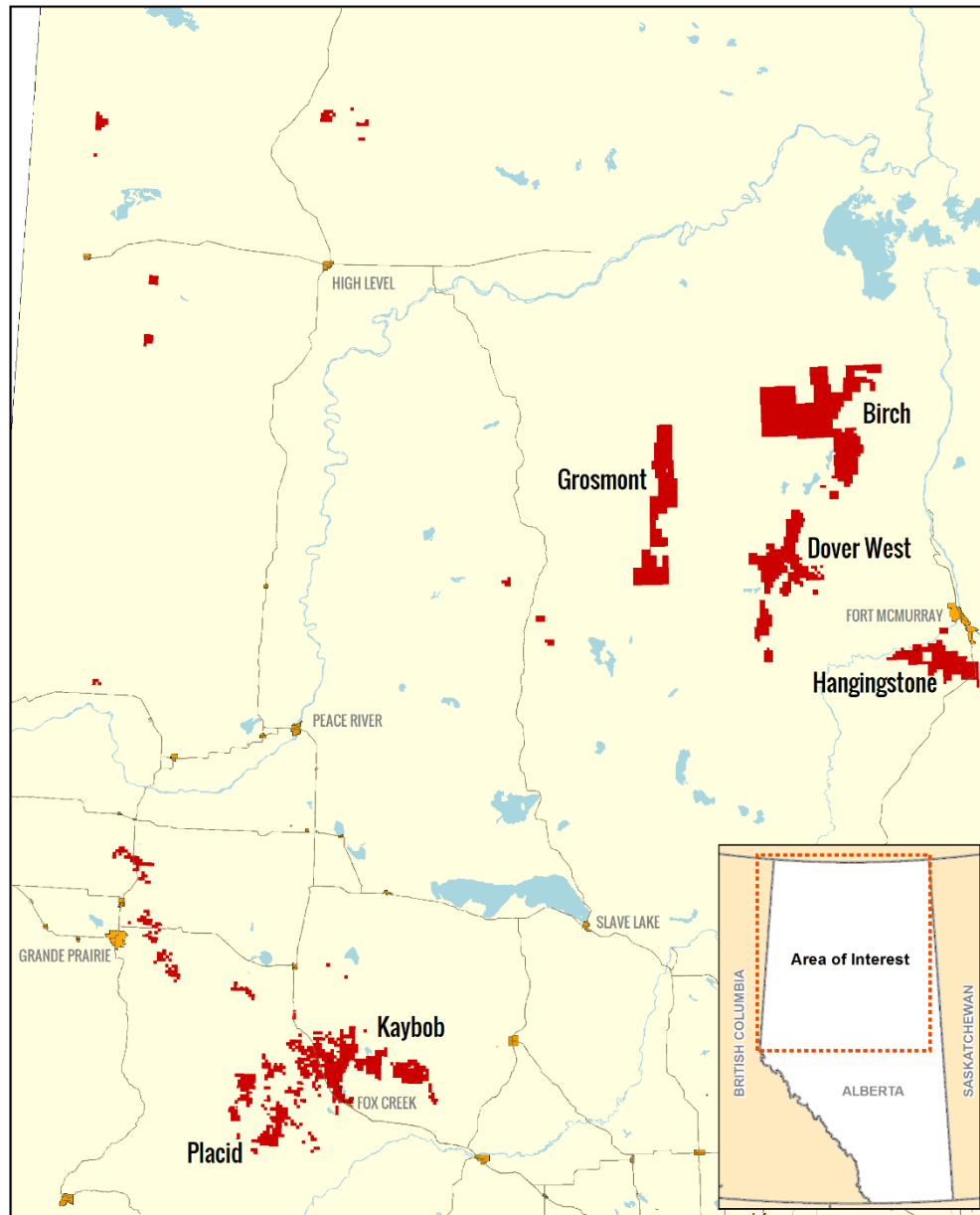
Light Oil Division

As at December 31, 2015, Athabasca held approximately 484,000 net acres of petroleum and natural gas leases, predominately in northwestern Alberta. Athabasca produces light oil and liquids-rich natural gas from unconventional reservoirs utilizing horizontal drilling and multi-stage hydraulic fracturing technology. Initial developments have been focused in the Kaybob and Placid asset areas near the town of Fox Creek, Alberta. The target zones are the Duvernay formation and the Montney formation. Athabasca recently entered into the Murphy Purchase and Sale Agreement with Murphy with respect to the Murphy Transaction Assets which the Company is progressing towards closing in the second quarter of 2016, subject to certain conditions and regulatory approvals. (See “*General Development of the Business-Recent Significant Transactions*” and “*Description of Athabasca’s Business- Light Oil Division*”).

Thermal Oil Division

As at December 31, 2015, Athabasca held over 1.24 million net acres of oil sands leases in the Athabasca region of northeastern Alberta. Athabasca’s primary focus is Hangingstone Project 1 (100% WI). Athabasca commenced production in July, 2015 from Hangingstone Project 1, a 12,000 bbl/d SAGD project. Other potential project areas include the Hangingstone Expansion (100% WI), Dover West carbonates (100% WI), Dover West sands (100% WI), Birch (100% WI) and Grosmont (50% WI). Development targets include oil sands in the McMurray and Wabiskaw formations as well as carbonates in the Leduc and Grosmont formations. The Company expects to produce its recoverable bitumen using in-situ recovery methods such as SAGD or other suitable Experimental Technologies such as CSS or TAGD. (See “*Description of Athabasca’s Business – Thermal Oil Division*”).

The following map illustrates the locations of Athabasca's Light Oil assets and Thermal Oil assets, as at December 31, 2015:



The Company's Common Shares trade on the TSX under the trading symbol "ATH".

GENERAL DEVELOPMENT OF THE BUSINESS

Recent Significant Transactions

Murphy Transaction

On January 27, 2016, certain subsidiaries of the Company (AOC Kaybob Partnership, AOC Light Oil Partnership and AOC Simonette Partnership) entered into an Agreement of Purchase and Sale to sell the Murphy Transaction Assets to Murphy Oil Canada Ltd., a wholly owned subsidiary of Murphy Oil Corporation for a purchase price of \$475

million net. Murphy will pay the purchase price as follows: \$250 million (approximate, subject to adjustments) upon closing of the Murphy Transaction; the \$225 million (approximate) balance as a capital carry commitment whereby Murphy will fund 75% of the Company's share of development capital in the Kaybob asset area for up to five (5) years (the "**Kaybob Carry Commitment**"). Upon closing of the Murphy Transaction, Murphy will assume operatorship of the Kaybob Murphy Transaction Assets and the Company will retain operatorship of the Simonette Murphy Transaction Assets. The Company will retain operatorship of the Kaybob Infrastructure Assets for at least the near term. The Company is progressing towards closing the Murphy Transaction in the second quarter of 2016, subject to certain conditions and regulatory approvals.

The Dover Put Option Transaction

Sale of a 60% Interest in the Dover Oil Sands Project

On February 10, 2010, pursuant to the PetroChina Share Purchase Agreement, the Company sold all of the issued and outstanding shares of AOSC Newco, a wholly-owned subsidiary of the Company, to Phoenix for consideration of \$1.9 billion. AOSC Newco was the owner of (as well as certain other oil sands assets) an undivided 60% interest in the Dover Oil Sands Project. As part of this transaction, the Company and Phoenix (and various subsidiaries) entered into the Put/Call Option Agreement allowing the Company to require Phoenix to purchase, or Phoenix could exercise the right to acquire, the Company's remaining 40% working interest in the Dover Oil Sands Project.

As described under "*General Development of the Business –Three Year History*" below, the Company exercised the Dover Put Option on April 17, 2014. The Dover Put Option Transaction was completed on August 29, 2014, with the final Promissory Note in the amount of \$134 million due on August 29, 2016.

Three Year History

The following is a summary description of the development of Athabasca's business over the last three completed financial years.

2013

On March 21, 2013, Athabasca announced that it had entered into an agreement with Enbridge Pipelines (Athabasca) Inc. ("**Enbridge**") for the transportation and terminaling of dilbit to be produced from Hangingstone Project 1.

A hearing with the AER that was requested by the Dover JV Operator in response to certain objections that were filed by the FMFN with respect to the Dover Oil Sands Project began on April 23, 2013 and was completed on April 29, 2013. On August 6, 2013, the AER announced that the Dover JV Operator's application in respect of the Dover Oil Sands Project was approved, subject to the conditions set forth in the AER's written decision (the "**AER Decision**"), including the approval of the Lieutenant Governor in Council. The FMFN subsequently sought the approval of the Court of Appeal of Alberta to appeal the AER Decision. On October 18, 2013, the Court of Appeal of Alberta granted the FMFN leave to appeal on a specific question of law that arose from the AER Decision.

On May 6, 2013, the Company formed an Executive Operational and Development Committee ("**EODC**") that was tasked with refining the Company's operational performance plan to target top-tier performance and incorporate the flexibility required to address available corporate financing. The Board appointed Mr. Ronald Eckhardt, a director and the Chairman of the Reserves and HSE Committee, to chair the EODC. The Company announced that the EODC had completed its mandate on October 30, 2013.

On May 17, 2013, Athabasca submitted a regulatory application to the AER and Alberta Environment in respect of an incremental 70,000 bbls/d of production from its Hangingstone assets (the "**Hangingstone Expansion**").

Athabasca's regulatory application in respect of the TAGD Pilot and Demonstration Project was approved by the AER on September 19, 2013 and by Alberta Environment on December 17, 2013.

On November 6, 2013, Athabasca entered into a long term Condensate Transportation Services Agreement with IPP. Pursuant to the agreement, IPP agreed to construct and operate a pipeline for the transportation of diluent to Hangingstone Project 1 and to provide diluent transportation for the Hangingstone Expansion, if the Hangingstone Expansion is sanctioned and an election is made by Athabasca.

On December 16, 2013, the Company entered into the Amended and Restated Credit Agreement providing for senior secured first lien credit facilities in the aggregate amount of \$350 million to replace the 2012 Credit Facilities (the “**2013 Credit Facilities**”).

Athabasca sold a 50% working interest in the Kaybob Infrastructure Assets to a third party for gross cash consideration of \$145.9 million on December 23, 2013. Athabasca continues to be the operator of the Kaybob Infrastructure Assets.

2014

On February 21, 2014, the Dover JV Operator entered into a Long Term Sustainability Agreement with the FMFN, resulting in the FMFN discontinuing its appeal of the AER Decision and withdrawing its concerns with respect to the Dover Oil Sands Project.

On March 6, 2014, the Company reduced its workforce by approximately 15%, which staff reductions largely affected employees associated with projects for which funding was not to be allocated in the near term.

On March 13, 2014, the Dover JV Operator received the approval of the Lieutenant Governor in Council in respect of the Dover Oil Sands Project.

On March 14, 2014, Thomas Buchanan was appointed as Chairman of the Board to replace William Gallacher, who resigned from the Board. A new Board member, Peter Sametz, was also appointed to the Board on March 14, 2014.

The Dover JV Operator received Alberta Environment approval of the Dover Oil Sands Project on April 16, 2014. The Company subsequently exercised its Dover Put Option on April 17, 2014 requiring Phoenix to purchase the Company’s subsidiary AOC (Dover) which held a 40% interest in the Dover Oil Sands Project.

The Company entered into new credit facilities on May 7, 2014 providing for approximately \$425 million of funding. The credit facilities consist of a US \$225 million senior secured first lien term loan maturing on May 7, 2019 and an additional US \$50 million senior secured first lien term loan which the Company may draw upon at any time up to May 7, 2016, subject to compliance with covenants (collectively the “**Term Loans**” as defined herein). If the Company has not redeemed or refinanced its Senior Secured Notes prior to May 19, 2017, then the maturity date of the Term Loans will be accelerated to May 19, 2017. The Term Loans bear interest at LIBOR plus 7.25%, with a LIBOR floor of 1%. Concurrently, the Company entered into an amended and restated credit agreement with a syndicate of financial institutions (the “**Amended and Restated Credit Agreement**” as defined herein) for a \$125 million senior secured first lien revolver with an initial maturity date of April 30, 2017. These new credit facilities replace the Company’s 2013 Credit Facilities which had a maturity date of December 31, 2014. Pursuant to an agreement between the holders of the Term Loans and the lenders under the Amended Credit Facility, the Amended Credit Facility ranks in priority to the Term Loans. Both the Term Loans and the Amended Credit Facility rank in priority to the Senior Secured Notes.

On August 29, 2014, the Company closed the Dover Put Option Transaction completing the sale of its subsidiary AOC (Dover) which held a 40% interest in the Dover assets and was a Participant in the Dover Oil Sands Project for net proceeds of \$1.184 billion. Upon closing of the Dover Put Transaction, the Company received cash proceeds of \$600 million and the Promissory Notes which are backed by unconditional, irrevocable letters of credit issued by HSBC Bank Canada which matured or shall mature as follows: March 2, 2015- \$300 million, August 28, 2015- \$150 million and August 29, 2016- \$134 million.

Effective September 30, 2014, Sveinung Svarte retired as President and CEO of the Company. He was succeeded by Thomas Buchanan who was appointed to the role of President and CEO. Thomas Buchanan remains Chairman of the Board, Ron Eckhardt assumed the role of Lead Director of the Board and replaced Thomas Buchanan on the

compensation and governance committees of the Board. Peter Sametz replaced Thomas Buchanan on the audit committee of the Board.

The Light Oil Division 2014 drilling program in the Duvernay successfully continued approximately 95% of Athabasca's core land position into the intermediate term.

2015

On January 7, 2015, Carlos Fierro and Paul Haggis were appointed to the Company's Board of Directors. On the same date Robert Broen was promoted to the position of President and Chief Operating Officer.

On March 2, 2015, Brion paid to Athabasca \$302.5 million, being the principal and interest payable under the Promissory Note.

On March 16, 2015, Sveinung Svarte resigned from the Company's Board of Directors.

On March 23, 2015, the Company achieved a significant milestone with commencement of well pair steaming at its Hangingstone Project 1.

On April 21, 2015, Tom Buchanan stepped down from the role of Chief Executive Officer and Rob Broen was appointed to the position of President and Chief Executive Officer. Tom Buchanan remained in his role as Chairman of the Board.

In July, 2015 Hangingstone Project 1 achieved first commercial oil production.

On August 28, 2015, Brion paid to the Company approximately \$152.6 million, representing the principal and interest payable on the second Promissory Note.

During the third quarter of 2015, the Company commenced a drilling and completions program that achieved material cost reductions with the transition to pad style operations in the Duvernay and Montney formations.

The dilbit sales pipeline from the HS CPF to the Enbridge Cheecham terminal was completed, started-up and operational in December 2015. The diluent supply line to the HS CPF had previously been completed and was operational in April 2015.

The Company conducted multiple rounds of staff reductions during 2015 in its head office and in its field locations, resulting in an overall reduction of staff of approximately 40% from year-end 2014 staff levels as part of a review and realignment of its cost structure, including annualized general and administrative expenses.

Recent Developments

On January 27, 2016, the Company entered into the Murphy Purchase and Sale Agreement to sell the Murphy Transaction Assets to Murphy Oil Canada Ltd., a wholly owned subsidiary of Murphy Oil Corporation for \$475 million net. The Murphy Transaction is being progressed towards closing in the second quarter of 2016, subject to certain conditions and regulatory approvals. For a more detailed description see "*General Development of the Business- Recent Significant Transactions- Murphy Transaction*".

Reorganizations

Other than as disclosed above, Athabasca has not completed any material reorganization within the three most recently completed financial years or during the current financial year.

Significant Acquisitions

Athabasca did not complete any significant acquisitions during the year ended December 31, 2015 for which disclosure is required under Part 8 of NI 51-102.

DESCRIPTION OF ATHABASCA'S BUSINESS

Athabasca's Development Strategy for its Principal Properties

Athabasca is focused on the exploration and development of unconventional resources plays in Alberta, Canada and is organized into two divisions, Light Oil Division and Thermal Oil Division. As at December 31, 2015, Athabasca's principal properties were its Kaybob and Placid asset areas located in northwestern Alberta in its Light Oil Division and the Hangingstone asset in its Thermal Oil Division. Athabasca's other asset areas include Dover West (Sands and Carbonates), Birch and Grosmont in its Thermal Oil Division and the Light Oil Exploration Areas.

In its Light Oil Division, Athabasca produces light oil and liquids-rich natural gas from unconventional reservoirs utilizing horizontal drilling and multi-stage hydraulic fracturing technology. Athabasca's current focus in its Light Oil Division is on retaining core acreage, demonstrating wellpad drilling cost efficiencies and ongoing appraisal and delineation of the Duvernay volatile oil window. In late January 2016, the Murphy Transaction Assets were the subject of a sale transaction with Murphy, which is being progressed towards closing in the second quarter of 2016, subject to certain conditions and regulatory approvals. See "*General Development of the Business – Recent Significant Transactions- Murphy Transaction*"

In its Thermal Oil Division, Athabasca's primary focus is on the successful ramp-up to nameplate capacity of its Hangingstone Project 1. During 2015 Athabasca completed construction and commissioning of Hangingstone Project 1 and commenced first steaming of well pairs late in Q1 2015. First production was achieved from Hangingstone Project 1 in July 2015 and by year end 2015, 21 of 25 well pairs had been converted to bitumen production. Production ramp-up will continue throughout 2016 with the target of achieving close to the Hangingstone Project 1 design capacity of 12,000 bbl/d by year-end 2016. Decisions surrounding the sanctioning of Hangingstone Project 2A will be dependent on the continuation of the successful ramp-up of Hangingstone Project 1, favourable market conditions and securing a suitable means of financing. Athabasca will be limiting capital development of its other thermal oil assets for the near future.

Athabasca's 2016 activities are expected to be funded with existing cash and short term investments, the remaining Promissory Note, proceeds from the Murphy Transaction, the Kaybob Carry Commitment, cash flow from operations and available credit. Athabasca's current business plan for developing its properties beyond 2016 anticipates that Athabasca will fund its activities and other requirements through some combination of cash flow from operations, cash equivalents, short term investments, the remaining Promissory Note, the Kaybob Carry Commitment, a reasonable level of debt and other external financing options including potential joint ventures or equity issuances. See "*Risk Factors – Substantial Capital Requirements and Liquidity Risk and Additional Funding Requirements*" for additional information.

Light Oil Division

As at December 31, 2015, Athabasca held approximately 484,000 net acres of petroleum and natural gas rights in its Light Oil asset areas, which include rights in the Duvernay, Montney, Charlie Lake, Nordegg, Slave Point, and Muskwa Formations. From its Light Oil asset areas, for the year ended December 31, 2015, Athabasca produced 5,587 boe/d, a decline of 9% from the prior year. The decrease was due to natural well declines (partially offset by bringing new wells on-stream during 2015) and unplanned pipeline restrictions on the TCPL system and Alliance Pipeline transportation systems during 2015.

Athabasca's current principal light oil development properties are located in its Kaybob and Simonette areas focusing on the Duvernay and the Montney formations. To date, Athabasca has focused its oil and natural gas drilling efforts in the Duvernay and Montney formations using the combined application of horizontal drilling and multi-stage fracturing technology. In addition Athabasca has previously conducted exploration and limited development activities

in the Light Oil Exploration Areas. Athabasca deployed approximately \$176 million of capital in its Light Oil Division in 2015, primarily related to drilling and completion of wells from the 2014/2015 drilling season, commencement of drilling activities for the 2015/2016 drilling season and commencement of construction of a pipeline inter-connect linking the Placid asset area and the Company's existing Kaybob Infrastructure Assets.

Athabasca's Light Oil Division sells the majority of its oil into the Pembina Pipeline system which transports and sells the product based on Edmonton prices. The majority of Athabasca's natural gas is sent to Keyera Corp.'s Simonette Gas Plant where it is processed and sold into the TransCanada Pipeline or Alliance Pipeline systems. In addition, Athabasca's Kaybob Infrastructure Assets are connected to SemCAM's Kaybob Amalgamated ("KA") gas plant via a flow-splitter ensuring that Athabasca's facilities are connected to a second large midstream plant in the Kaybob area providing Athabasca with additional options for processing its production. As of December 2015, Athabasca's natural gas typically receives Chicago-based pricing, adjusted for energy content. Athabasca's NGLs that are separated at the Simonette Gas Plant are transported through the Pembina Pipeline system and receive Edmonton prices. Construction of a pipeline inter-connect linking the Placid asset area to the existing Kaybob Infrastructure Assets is expected to be completed early in the second quarter of 2016.

Kaybob assets

As at December 31, 2015, the Kaybob asset area was comprised of approximately 252,500 net acres of land, of which approximately 19,680 acres had been developed and 232,800 acres remained undeveloped. GLJ has assigned approximately 11.4 MMboe of Proved Reserves and 35.8 MMboe of Total Proved plus Probable Reserves on a Gross Reserves basis to Athabasca's interests in the Kaybob Partnership Area, as at December 31, 2015. See "*Independent Reserves Evaluations*".

In 2015, Athabasca concentrated on realizing drilling efficiencies by utilizing a fit-for-purpose rig and construction of multi-well pad sites and ongoing appraisal and delineation of the Duvernay volatile oil window.

Six Duvernay wells were brought on-stream in 2015. A two well pad was rig-released at Kaybob East in the Duvernay volatile oil window in the third quarter of 2015 and both wells were brought on-stream in the first quarter of 2016 following a planned soak period. The completion design of this two well pad was intended to test proppant loading in the volatile oil window. Industry has seen a positive trend in productivity and ultimate recoveries by increasing proppant loading in both regional Duvernay data and also in other leading North American shale plays.

A four well pad was spud at Kaybob West in the condensate rich gas window in mid-October 2015. The first three wells had been rig-released by year-end 2015 and drilling on the remaining well is expected to be completed in early 2016. The completion of the four well pad is expected to commence in the second quarter of 2016 with a planned on-stream date in the third quarter of 2016.

Simonette assets

As at December 31, 2015, the Simonette asset area was comprised of approximately 138,000 net acres of land, of which approximately 16,492 acres were developed and 121,612 acres were undeveloped. GLJ has assigned approximately 15.2 MMboe of Proved Reserves and 29.4 MMboe of Total Proved plus Probable Reserves on a Gross Reserves basis to Athabasca's interests in the Simonette Partnership asset area, as at December 31, 2015. See "*Independent Reserves Evaluations*".

During 2015 at Placid (which is contained within the Simonette asset area), Athabasca brought one additional Montney well on-stream. A three well Montney pad was spud at Placid in September 2015. Drilling operations concluded in December 2015, completions operations are expected to occur in the first-quarter of 2016 and tie-in is expected in the second-quarter of 2016. During the latter part of 2015, Athabasca commenced construction of a pipeline inter-connect linking the Placid area to the existing Kaybob Infrastructure Assets which is expected to be completed early in the second quarter of 2016.

Light Oil Exploration Areas

The Light Oil Exploration Areas include Athabasca's oil and gas interests in approximately 93,000 net acres of land in the following areas in northwestern Alberta, as at December 31, 2015: Grand Prairie, North Muskwa, South Muskwa, Caribou, Glenevis and Sawn Lake.

GLJ has assigned approximately 0.2 MMboe of Proved Reserves and 0.2 MMboe of Probable Reserves on a Gross Reserves basis to Athabasca's interests in the Grande Prairie asset area, as at December 31, 2015. See "*Independent Reserve Evaluations*". No capital expenditures were approved for any further appraisal or development of the Light Oil Exploration Areas as part of Athabasca's 2016 capital budget.

Thermal Oil Division

Athabasca's primary focus in its Thermal Oil Division in 2016 is on the successful ramp-up to nameplate capacity of its Hangingstone Project 1. During the year ending December 31, 2015, Athabasca spent \$114.2 million in its Thermal Oil Division primarily on completion and start-up operations at Hangingstone Project 1. First production was achieved from Hangingstone Project 1 in July 2015 and by year end 2015, 21 of 25 well pairs had been converted to bitumen production. In its Thermal Oil Division, Athabasca averaged 1,973 bbl/d of bitumen production during 2015 and achieved an exit production rate of 7,462 bbl/d (December 2015 average) exceeding the previously announced production guidance of 5,000-7,000 bbl/d.

Athabasca does not have current plans and has not allocated any capital in its 2016 budget to develop its Thermal Oil exploration areas located at Dover West (Sands and Carbonates), Birch and Grosmont, but will revisit possible development of these areas once market conditions allow.

Hangingstone assets

Location and Size

The Hangingstone assets are located within the Athabasca oil sands fairway of northeastern Alberta. The leases are approximately 15 to 20 kilometres southwest of the city of Fort McMurray and are near existing infrastructure, including high voltage power, fuel gas and diluent supply and bitumen blend sales pipelines. The main highway leading to the city of Fort McMurray, Highway 63, runs through the assets. The Hangingstone assets comprise a concentrated, contiguous land base of approximately 138,000 acres in which Athabasca owns a 100% working interest. The reservoir suitable for in-situ recovery is the McMurray Formation. A large portion of the assets remain unexplored.

D&M has assigned approximately 95.1 MMbbl of Proved Reserves and 129.8 MMbbl of Probable Reserves on a Gross Reserves basis, and 586.1 MMbbl of risked Best Estimate Contingent Resources on a Company Interest basis, to the Hangingstone assets as at December 31, 2015. See "*Independent Reserves Evaluations*" and "*Schedule A – Supplemental Disclosure- Contingent Resource Estimates*".

Project Development - Hangingstone Project 1

Athabasca is developing the Hangingstone assets using SAGD with a staged development strategy. Once fully developed, the Hangingstone assets are expected to have overall potential production capacity of approximately 80,000 bbl/d.

In October 2012, Athabasca received regulatory approval for the development of Hangingstone Project 1 and in November 2012, the Board sanctioned Hangingstone Project 1 which included the central processing facility, wells and supporting regional infrastructure. The acquisition of the Hangingstone asset, delineation drilling and future phase engineering were not included in this budget amount and are accounted for separately. Hangingstone Project 1 is comprised of the HS CPF and twenty five SAGD well pairs on five well pads and has a planned annual production capacity of 12,000 bbl/d (including planned maintenance outages).

The recoverable bitumen volumes associated with Hangingstone Project 1 were first attributed as probable reserves in the December 31, 2011 GLJ report, following the filing of the regulatory applications in respect of Hangingstone

Project 1 in March of 2011. Certain of those probable reserves were subsequently converted to proved undeveloped reserves in the December 31, 2012 D&M report after the applicable regulatory approvals and internal corporate management approvals were received in respect of Hangingstone Project 1 in October and November of 2012, respectively. The proved undeveloped reserves attributable to Hangingstone Project 1 were converted to proved developed non-producing reserves in the December 31, 2014 D&M Report. This was due to the fact that greater than 85% of the project capital had been spent (including the capital associated with 25 drilled well pairs) and the Hangingstone Project 1 facility construction had been substantially completed as at December 31, 2014. The proved undeveloped non-producing reserves attributable to Hangingstone Project 1 were converted to proved developed producing reserves in the December 31, 2015 Independent Reports due to the fact that Hangingstone Project 1 started up in March 2015 and commenced production in July 2015. Approximately 44.4 MMbbl of the Probable Reserves attributable to the Hangingstone assets were converted to proved undeveloped reserves in the December 31, 2015 Independent Reports. This was due to the Hangingstone environmental impact assessment being deemed to be technically complete on October 19th 2015 and the existence of 3D seismic and development level delineation drilling density in the areas adjacent to the Hangingstone Project 1 area. The probable undeveloped reserves of bitumen attributed to the Hangingstone Expansion would transition to proved developed reserves with the sanctioning, construction, commissioning and start-up of the Hangingstone Expansion.

During the year ending December 31, 2015, Athabasca completed commissioning and start-up of Hangingstone Project 1. Significant milestones were achieved with steaming of well pairs commencing late in the first quarter of 2015, and first production in July, 2015.

By December 31, 2015, 21 of 25 well pairs had been converted to SAGD production, and production ramp-up is continuing throughout 2016. Hangingstone Project 1 averaged 1,973bbl/d of bitumen production for the year ending December 31, 2015 with an exit production rate of 7,462 bbl/d (December average). Reservoir performance continues to align with subsurface modelling and supports steam chamber maturity to continue to reduce SOR. Athabasca continues to target close to nameplate production of 12,000 bbl/d by year end 2016 with only minimal additional development and maintenance capital required during the initial years of production. Through management of the existing SAGD well pairs, Athabasca forecasts that Hangingstone Project 1 will have a relatively flat production profile during the first five to six years once it reaches nameplate production levels.

The diluent supply line to the HS CPF was completed, started up and operational in April 2015 and the dilbit sales pipeline from the HS CPF to Enbridge's Cheecham terminal was completed and commissioned in December 2015.

Hangingstone Expansion

On May 17, 2013, Athabasca submitted a regulatory application to the AER and Alberta Environment in respect of the Hangingstone Expansion. Originally Athabasca intended to develop the Hangingstone Expansion through two projects: a 40,000 bbl/d project and a 30,000 bbl/d project which was reflected in the regulatory application, however via its response to the first round of supplemental information requests submitted on July 29, 2014, Athabasca modified its regulatory application relating to the Hangingstone Expansion to three subsequent projects: Hangingstone Project 2A, an 8,000 bbl/d incremental debottleneck project ("**Hangingstone Project 2A**"), Hangingstone 2B, a project which is planned to have a production capacity of 32,000 bbl/d ("**Hangingstone Project 2B**") and Hangingstone 3, which is planned to have a production capacity of 30,000 bbl/d ("**Hangingstone Project 3**"). Athabasca responded to the second and third rounds of supplemental information requests on April 30, 2015 and August 14, 2015 respectively. The environmental impact assessment for the Hangingstone Expansion was deemed to be technically complete by the AER on October 19, 2015.

During 2014, Athabasca completed work on the FEED for Hangingstone Project 2A and Hangingstone Project 2B. Future expansions at Hangingstone, including Hangingstone Project 2A, are not expected to be sanctioned by the Board until Athabasca demonstrates a successful production ramp-up profile to nameplate production for Hangingstone Project 1 and market conditions allow for further development and project funding is secured.

Other Thermal Oil Exploration Areas

Following are descriptions of Athabasca's other thermal oil exploration areas. Athabasca is reviewing its development scenarios for these areas and has pared back activity and funding in relation to these areas for the immediate future. It

will continue certain limited technical and technological progression within its thermal oil exploration areas and continue to assess partnership and project funding strategies and to monitor when market conditions allow for future development of these assets.

Dover West Assets

Athabasca has a 100% working interest in its Dover West assets, which contain resources in the Dover West Sands and in the Dover West Carbonates. The Dover West assets are located within the Athabasca oil sands fairway in northeastern Alberta approximately 90 kilometres northwest of the city of Fort McMurray. As at December 31, 2015, the Dover West assets were comprised of a large contiguous land base of approximately 233,000 acres.

The Dover West assets are located in a geologically unique area which contains three primary bitumen reservoirs. The bitumen reservoirs are contained within the McMurray Formation and the Wabiskaw member of the Clearwater Formation (the Dover West Sands), and within the Leduc and Cooking Lake Formations of the Devonian Woodbend Group (the Dover West Carbonates).

Dover West Sands

The regulatory application for the Dover West Sands Project 1 was submitted to the ERCB (now the AER) in December 2011. The application process was prolonged as Athabasca was focused on a SOC that had been filed by the FMFN in relation to the Dover Oil Sands Project and as such the Dover West Sands Project 1 regulatory application was not progressed by Athabasca during this time period pending closure of the SOC (which took approximately 2 years). During the intervening period, Athabasca has been assessing the development timeline of the Dover West Sands Project 1. Given the change in global commodity prices has affected the ability to finance projects in the near term and the considerable uncertainty in regulatory and royalty regimes and the present shift in focus to Athabasca's Hangingstone asset area in the immediate future, a decision regarding proceeding with the regulatory application has not yet been taken but it is likely that management will advance the regulatory application during 2016. Due to the uncertainty around the status of the Dover West Sands Project 1 regulatory application the Probable Reserves reported for the year ending December 31, 2014 have been converted by the Independent Evaluators back to Contingent Resources for the year ending December 31, 2015. While management believes that the Dover West Sands are an attractive and viable long-term development opportunity, it is not expected that Athabasca will fully develop the Dover West Sands without first securing another suitable means of financing.

Dover West Carbonates

In management's opinion, the testing performed in Dover West Carbonates suggests that multiple recovery processes, such as SAGD, CSS or TAGD, may be suitable for use in this reservoir. The technical viability of CSS has been demonstrated successfully in carbonate reservoirs, however, testing would be required within the Dover West Carbonates to validate the technical viability in the Dover West Carbonates. Athabasca believes TAGD could become a superior in-situ recovery process for the Dover West Leduc Carbonates reservoir characteristics; however, at present the TAGD recovery process is defined as Experimental Technology. Athabasca continues to expend limited resources in determining the optimal development and production methods for the Dover West Carbonates.

In 2011, Athabasca conducted a steam injection test in the Dover West Carbonates. This test supported steam injection as a viable recovery process for the Dover West Carbonates. Since 2011, Athabasca has also been conducting a TAGD field test which has demonstrated the ability of TAGD to heat the reservoir through thermal conduction and to produce bitumen via gravity drainage. In 2015, Athabasca completed the fourth production cycle of the TAGD field test. This fourth production cycle provided additional information that can be used to improve the design of a future TAGD Pilot and Demonstration Project in the Dover West Carbonates. This test was considered to have been successful by Athabasca's management. Due to the demonstrated success of the TAGD field test and limited value in continuing to operate the test, Athabasca terminated the field test in the third quarter of 2015.

In October of 2011, Athabasca submitted a regulatory application in respect of the TAGD Pilot and Demonstration Project with a production capacity of up to 6,000 bbl/d to further evaluate bitumen recovery using TAGD. The regulatory application was approved by both the AER and Alberta Environment in 2013. The pilot stage of the TAGD

Pilot and Demonstration Project is intended to evaluate the recovery factor and energy balance. The demonstration stage of the TAGD Pilot and Demonstration Project is intended to demonstrate the commercial viability of the TAGD process.

Athabasca also continues to progress its TAGD heater technology at Athabasca's HAF which was completed in 2013. The HAF consists of a building enclosing a deviated well which is used for heater assembly and a horizontal well which is used for heater testing. Athabasca is currently testing its second prototype heater and has now accumulated over 25,000 hours of prototype operation, at times beyond the design basis, without a failure as at December 31, 2015. Patents have been applied for both in Canada and the United States by Athabasca in respect of all aspects of the heater technology, the HAF and the heater assembly process.

The timing of the first commercial development in the Dover West Carbonates will be dependent on the performance of the TAGD Pilot and Demonstration Project, the receipt of the required regulatory approvals, securing funding for the project and market conditions.

Birch assets

Athabasca holds a 100% working interest in the Birch assets. The Birch assets are located within the Athabasca oil sands fairway of northeastern Alberta, approximately 95 kilometres northwest of the city of Fort McMurray. The Birch assets comprise an extensive contiguous land base of approximately 447,000 acres.

The Birch resources will be produced using SAGD technology which has been successfully implemented in the ramp up of Hangingstone Project 1 during 2015. The production of the Birch resources is contingent upon the completion of the first phase of the Birch Project which is presently planned to be on stream in 2024 with a capacity of 12,000 bbl/d. The second phase of the Birch Project will have a capacity of 40,000 bbl/d. Three subsequent 40,000 bbl/d phases will follow to the ultimate approximate capacity of 170,000 bbl/d.

A field development plan has been developed for the Birch Project but an environmental impact assessment application has not been submitted. Management presently does not expect to proceed with the Birch Project without a suitable means of financing and economic conditions allow for its development.

Grosmont assets

The Grosmont assets are located within the Athabasca oil sands fairway of northeastern Alberta. Athabasca has a 50% working interest in the Grosmont assets of approximately 113,000 net acres. On November 7, 2008, Athabasca entered into a joint venture with ZAM Ventures Alberta Inc. with respect to the Grosmont assets. Athabasca, which is the operator of the joint venture, and ZAM Ventures Alberta Inc., each hold a 50% interest in the joint venture. ZAM Ventures Alberta Inc. is a family investment entity advised by Ziff Brothers Investments, L.L.C., and is an affiliate of ZAM Investments Luxembourg, s.á.r.l.

The resources at Grosmont are contained in carbonate reservoirs. While other operators may be pursuing development of the Grosmont formation, these reservoirs have not been commercially developed by industry to date. Athabasca has not prepared a development plan or timeline for the Grosmont assets and does not intend to develop these assets at present.

Specialized Skill and Knowledge

Athabasca employs individuals with various professional skills in the course of pursuing its business plan. These professional skills include, but are not limited to, geology, geophysics, engineering, financial and business skills. Drawing on significant experience in the oil and gas business, Athabasca believes its management team has a demonstrated track record of bringing together all of the key components to a successful exploration and production company: strong technical skills; expertise in planning and financial controls; the ability to execute on business development opportunities; capital markets expertise; and an entrepreneurial spirit that allows Athabasca to effectively identify, evaluate and execute on value added initiatives.

Personnel

As at December 31, 2015, Athabasca had 167 employees (comprised of 112 head office and 55 field employees).

INDEPENDENT RESERVES EVALUATIONS

Reserves Classifications

The reserves estimates presented in the Independent Reports are based upon the definitions and guidelines contained in the COGE Handbook. A summary of those definitions is set forth below:

Reserves Categories

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

- analysis of drilling, geological, geophysical, and engineering data;
- the use of established technology; and
- specified economic conditions, which are generally accepted as being reasonable and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates. The following terms when used herein have the following meanings:

- “**Proved Reserves**” are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated Proved Reserves.
- “**Probable Reserves**” are those additional reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved Reserves plus Probable Reserves.

Other criteria that must be met for the classification of reserves are provided in the COGE Handbook.

Development and Production Status

Each of the Reserves categories (Proved Reserves and Probable Reserves) may be divided into “developed” and “undeveloped” categories:

- “**Developed reserves**” are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.
 - “**Developed producing reserves**” are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
 - “**Developed non-producing reserves**” are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

- “**Undeveloped reserves**” are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (Proved Reserves or Probable Reserves) to which they are assigned.

Levels of Certainty for Reported Reserves

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

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated Proved Reserves; and
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved Reserves plus Probable Reserves.

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

Independent Reports

Athabasca engaged the Independent Evaluators to prepare the Independent Reports, which are independent assessments and evaluations of Athabasca’s bitumen, light crude oil and medium crude oil, tight oil, conventional natural gas, shale gas and NGL reserves effective as at December 31, 2015.

The reserve estimates set out below reflect Athabasca’s 100% working interests (as at December 31, 2015) in the Hangingstone assets and its interests in the Light Oil assets.

The information set forth below relating to Athabasca’s reserves constitutes forward-looking information, which is subject to certain risks and uncertainties. See “Forward-Looking Statements” for additional information.

The effective date of the information provided below is December 31, 2015. The preparation date of the GLJ Report was February 1, 2016. The preparation date of the D&M Report was February 25, 2016. The preparation and disclosure of the reported reserve estimates are the responsibility of Athabasca’s management. The Independent Evaluators’ responsibilities are to express opinions on the bitumen, light crude oil and medium crude oil, tight oil, conventional natural gas, shale gas and NGL reserves including the associated estimated net present values, based upon their respective evaluations. The Independent Evaluators carried out their evaluations in accordance with standards established by the Canadian Securities Administrators in NI 51-101. Those standards require that the bitumen, light crude oil and medium crude oil, shale oil, conventional natural gas, shale gas and NGL reserves be prepared in accordance with the COGE Handbook. Athabasca’s properties are located in the Province of Alberta and are described under the heading “*Description of Athabasca’s Business*”.

GLJ’s Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor and D&M’s Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor are each set forth in Schedule “C” to this Annual Information Form. Athabasca’s Report of Management and Directors on Oil and Gas Disclosure in the form of National Instrument 51-101F3 is set forth in Schedule “B” to this Annual Information Form.

The evaluation procedures employed by GLJ and D&M are in compliance with standards contained in the COGE Handbook.

The Independent Reports do not take into account taxes or other amounts that may be payable in the future by Athabasca pursuant to new or existing provincial and federal laws and regulations (including without limitation the *Climate Change and Emissions Management Act* (Alberta) and the *Specified Gas Emitters Regulation*) that restrict or otherwise regulate GHG emissions.

The estimates of reserves and future net revenue for individual properties that are contained in this Annual Information Form may not reflect the same confidence level as estimates of reserves and future net revenue for all of Athabasca's properties, due to the effects of aggregation.

Management Commentary on Assumptions

Reserve Estimates

As at December 31, 2015, Athabasca's bitumen reserves were contained in the Hangingstone assets. Proved Reserves were assigned by D&M to Hangingstone Project 1, and Probable Reserves were assigned by D&M to the Hangingstone Expansion.

Athabasca's light crude oil and medium crude oil, tight oil, conventional natural gas, shale gas and NGL reserves are located in the Light Oil assets. Both Proved Reserves and Probable Reserves have been assigned by GLJ to Athabasca's Light Oil assets.

Set out below is a summary of Athabasca's reserves, as well as the estimated value of future net revenue of Athabasca from the reserves, as at December 31, 2015, as evaluated by GLJ in the GLJ Report, and as evaluated by D&M in the D&M Report. The pricing used in the forecast price evaluations for all assets is set forth below under "*GLJ Price Forecast*".

All evaluations of future net revenue are after the deduction of royalties, development costs, production costs and abandonment and reclamation costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenues contained in the following tables do not represent the fair market value of Athabasca's reserves. There is no assurance that the forecast price assumptions that have been estimated by GLJ will be realized and variances could be material. Other assumptions have been made by GLJ and D&M and qualifications relating to costs and other matters are included in the GLJ Report and D&M Report. The recovery and reserves estimates of Athabasca's properties described herein are estimates only. The actual reserves of Athabasca's properties may be greater or less than those calculated.

Summary of Reserves Data – Forecast Prices and Costs as of December 31, 2015⁽¹⁾⁽²⁾

Reserves Category	Bitumen		Tight Oil		Conventional Natural Gas	
	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)
PROVED RESERVES						
Developed Producing	50,734	46,393	2,348	1,841	258	240
Developed Non-Producing	0	0	624	545	1,085	1,021
Undeveloped	44,369	35,507	7,156	5,870	314	292
TOTAL PROVED RESERVES	95,103	81,900	10,128	8,256	1,657	1,553
TOTAL PROBABLE RESERVES	129,819	101,236	15,022	11,334	545	505
TOTAL PROVED PLUS PROBABLE RESERVES	224,922	183,136	25,150	19,590	2,202	2,058

Reserves Category	Shale Gas		Natural Gas Liquids		Oil Equivalent	
	Gross (MMcf)	Net (MMcf)	Gross (Mbbls)	Net (Mbbls)	Gross (Mboe)	Net (Mboe)
PROVED RESERVES						
Developed Producing	18,417	17,059	808	605	57,002	51,723
Developed Non-Producing	3,280	3,107	131	97	1,483	1,329
Undeveloped	60,016	56,958	1,857	1,456	63,437	52,375
TOTAL PROVED RESERVES	81,713	77,124	2,796	2,158	121,922	105,427
TOTAL PROBABLE RESERVES	111,403	103,498	4,923	3,804	168,421	133,708
TOTAL PROVED PLUS PROBABLE RESERVES	193,116	180,622	7,719	5,962	290,343	239,135

For notes please see the notes following the “Reconciliation of Reserves by Principal Product Type” table.

Summary of Net Present Values of Future Net Revenue – Forecast Prices and Costs as of December 31, 2015⁽¹⁾⁽²⁾⁽³⁾⁽⁷⁾

RESERVES CATEGORY	Before Income Tax Discounted at (%/year)					After Income Taxes Discounted at (%/year)					Unit Value Before Income Tax at 10% Discount/ Year	
	0% (M\$)	5% (M\$)	10% (M\$)	15% (M\$)	20% (M\$)	0% (M\$)	5% (M\$)	10% (M\$)	15% (M\$)	20% (M\$)	(\$/boe)	(\$/Mcf)
PROVED RESERVES												
Developed Producing	1,118,900	806,479	614,057	485,178	394,230	1,118,900	806,479	614,057	485,178	394,230	11.87	1.98
Developed Non-Producing	22,738	21,226	19,879	18,685	17,625	22,738	21,226	19,879	18,685	17,625	14.96	2.49
Undeveloped	1,189,181	564,623	285,576	149,712	78,156	1,189,181	564,623	285,576	149,712	78,156	5.45	0.91
TOTAL PROVED RESERVES	2,330,819	1,392,328	919,512	653,575	490,011	2,330,819	1,392,328	919,512	653,575	490,011	8.72	1.45
TOTAL PROBABLE RESERVES	4,949,916	1,955,087	947,834	539,605	343,639	3,643,221	1,487,584	760,046	456,560	303,930	7.09	1.18
TOTAL PROVED PLUS PROBABLE RESERVES	7,280,734	3,347,414	1,867,346	1,193,180	833,650	5,974,040	2,879,911	1,679,557	1,110,135	793,940	7.81	1.3

For notes please see the notes following the “Reconciliation of Reserves by Principal Product Type” table.

Future Net Revenue (Undiscounted) – Forecast Prices and Cost as of December 31, 2015⁽¹⁾⁽²⁾⁽³⁾⁽⁷⁾

Reserves Category	Revenue (M\$)	Royalties (M\$)	Operating Costs (M\$)	Development Costs (M\$)	Abandonment and Reclamation Costs (M\$)	Future Net Revenue Before Future Income Tax Expenses (M\$)	Future Income Tax Expenses (M\$)	Future Net Revenue After Future Income Tax Expenses (M\$)
PROVED RESERVES	7,526,646	1,181,373	2,785,295	1,141,336	87,824	2,330,819	-	2,330,819
PROBABLE RESERVES	14,258,005	3,133,204	3,811,729	2,241,848	121,308	4,949,916	1,306,694	3,643,221
Proved Plus Probable RESERVES	21,784,652	4,314,577	6,597,024	3,383,184	209,132	7,280,734	1,306,694	5,974,040

For notes please see the notes following the “Reconciliation of Reserves by Principal Product Type” table.

Future Net Revenue by Product Type– Forecast Prices and Costs as of December 31, 2015⁽¹⁾⁽²⁾⁽³⁾⁽⁴⁾⁽⁵⁾⁽⁸⁾

RESERVES CATEGORY	Product Type	Future Net Revenue Before Income Taxes (Discounted at 10%/Year)		
		M\$	\$/bbl	\$/Mcfe
PROVED RESERVES	Bitumen	711,245	8.68	1.45
	Tight Oil	51,831	14.64	2.44
	Conventional Natural Gas	1,344	4.58	0.76
	Shale Gas	155,091	7.88	1.31
	TOTAL	919,512	8.72	1.45
PROVED PLUS PROBABLE RESERVES	Bitumen	1,276,603	6.97	1.16
	Tight Oil	109,412	14.33	2.39
	Conventional Natural Gas	2,025	5.18	0.86
	Shale Gas	479,306	9.99	1.67
	TOTAL	1,867,346	7.81	1.30

For notes please see the notes following the “Reconciliation of Reserves by Principal Product Type” table.

Reconciliation of Reserves by Principal Product Type – Forecast Prices and Costs as of December 31, 2015⁽¹⁾⁽²⁾⁽⁶⁾⁽⁹⁾

The following table sets forth a reconciliation of the changes of Athabasca’s reserves estimates, before royalties, of bitumen, light crude oil and medium crude oil, tight oil, conventional natural gas, shale gas and NGL as at December 31, 2015, compared to such reserves as at December 31, 2014, based on the forecast price and cost assumptions that are described in Note 1 below.

FACTORS	Bitumen			Light Crude Oil and Medium Crude Oil		
	Gross Proved Reserves (MMbbls)	Gross Probable Reserves (MMbbls)	Gross Proved Plus Probable Reserves (MMbbls)	Gross Proved Reserves (MMbbls)	Gross Probable Reserves (MMbbls)	Gross Proved Plus Probable Reserves (MMbbls)
December 31, 2014	51.4	261.3	312.7	3.5	10.8	14.3
Product Type Transfers	0.0	0.0	0.0	(3.2)	(10.4)	(13.6)
Adjusted December 31, 2014	51.4	261.3	312.7	0.3	0.5	0.7
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0
Extensions and Improved Recovery	0.0	0.0	0.0	0.0	0.0	0.0
Technical Revisions	44.4	(131.4)	(87.1)	(0.3)	(0.5)	(0.7)
Acquisitions	0.0	0.0	0.0	0.0	0.0	0.0
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	0.0	0.0	0.0	0.0	0.0	0.0
Production	(0.7)	0.0	(0.7)	0.0	0.0	0.0
December 31, 2015	95.1	129.8	224.9	0.0	0.0	0.0

FACTORS	Conventional Natural Gas			Natural Gas Liquids		
	Gross Proved Reserves (Bcf)	Gross Probable Reserves (Bcf)	Gross Proved Plus Probable Reserves (Bcf)	Gross Proved Reserves (MMbbls)	Gross Probable Reserves (MMbbls)	Gross Proved Plus Probable Reserves (MMbbls)
December 31, 2014	19.2	55.6	74.8	2.2	7.8	10.0
Product Type Transfers	(10.6)	(33.4)	(44.0)	0.0	(0.0)	(0.0)
Adjusted December 31, 2014	8.6	22.1	30.8	2.2	7.8	10.0
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0
Extensions and Improved Recovery	0.0	0.0	0.0	1.1	0.4	1.6
Technical Revisions	(6.8)	(21.6)	(28.4)	(0.3)	(2.9)	(3.2)
Acquisitions	0.0	0.0	0.0	0.0	0.0	0.0
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	0.0	0.0	0.0	(0.0)	(0.4)	(0.4)
Production	(0.1)	0.0	(0.1)	(0.2)	0.0	(0.2)
December 31, 2015	1.7	0.5	2.2	2.8	4.9	7.7

FACTORS	Tight Oil			Shale Gas		
	Gross Proved Reserves (MMbbls)	Gross Probable Reserves (MMbbls)	Gross Proved Plus Probable Reserves (MMbbls)	Gross Proved Reserves (Bcf)	Gross Probable Reserves (Bcf)	Gross Proved Plus Probable Reserves (Bcf)
December 31, 2014	0.0	0.0	0.0	16.1	60.9	77.0
Product Type Transfers	3.2	10.4	13.6	10.6	33.4	44.0
Adjusted December 31, 2014	3.2	10.4	13.6	26.6	94.3	121.0
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0
Extensions and Improved Recovery	7.4	0.1	7.5	57.1	0.6	57.7
Technical Revisions	0.3	4.5	4.9	4.3	21.1	25.4
Acquisitions	0.0	0.0	0.0	0.0	0.0	0.0
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	0.0	0.0	0.0	(0.2)	(4.6)	(4.8)
Production	(0.8)	0.0	(0.8)	(6.1)	0.0	(6.1)
December 31, 2015	10.1	15.0	25.1	81.7	111.4	193.1

FACTORS	Oil Equivalent		
	Gross Proved Reserves (MMboe)	Gross Probable Reserves (MMboe)	Gross Proved Plus Probable Reserves (MMboe)
December 31, 2014	63.0	299.3	362.3
Product Type Transfers	0.0	(0.0)	(0.0)
Adjusted December 31, 2014	63.0	299.3	362.3
Discoveries	0.0	0.0	0.0
Extensions and Improved Recovery	18.0	0.6	18.6
Technical Revisions	43.7	(130.3)	(86.6)
Acquisitions	0.0	0.0	0.0
Dispositions	0.0	0.0	0.0
Economic Factors	(0.0)	(1.2)	(1.2)
Production	(2.8)	0.0	(2.8)
December 31, 2015	121.9	168.4	290.3

Notes:

- (1) Based on the Independent Reports. Future net revenue estimates were calculated by GLJ and D&M using the pricing assumptions set forth below under “GLJ Price Forecast” to ensure for consistency and in accordance with the COGE Handbook.
- (2) Totals may not add due to rounding
- (3) All evaluations of future net revenue are after the deduction of royalties, development costs, production costs and abandonment and reclamation costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. For further detail on what is and isn’t included in abandonment and reclamation costs, please see the “*Abandonment and Reclamation Obligations for Properties with Reserves*”.
- (4) Unit values based on Athabasca’s net reserves.
- (5) Other revenue and costs not related to a specific product type have been allocated proportionately across product types.
- (6) Product type transfers occurred with respect to light crude oil and medium crude oil product and conventional natural gas product to the tight oil and shale gas categories respectively due to re-classification of product types under NI 51-101 which came into effect July 1, 2015
- (7) The estimated tax burden included in the after-tax net present values of the Company’s oil and gas properties is reflected at the corporate consolidation level and does not consider tax planning or provide an estimate of the tax burden at the business entity level which may be significantly different.
- (8) Including by-products but excluding solution gas.
- (9) Infill drilling is included in the Extensions and Improved Recovery Category.

GLJ Price Forecast

The price forecasts that formed the basis for the revenue projections and net present value estimates that are contained herein are based on GLJ’s January 1, 2016 pricing models. A summary of applicable selected price forecasts is set forth below.

Year	Inflation	Bank of Canada Average Noon Exchange Rate	WTI Oil at Cushing Oklahoma Current	Light Sweet Crude Oil (40° API, 0.3%S) at Edmonton Current	WCS Stream Quality at Hardisty Current	Midwest price at Chicago Current	AECO/NIT Spot Current	Natural Gas Liquids Edmonton		
								Pentanes Plus	Propane	Butane
	%	(\$US/\$Cdn)	(\$US/bbl)	(\$Cdn/bbl)	(\$Cdn/bbl)	(\$USD/MMBtu)	(\$Cdn/MMBtu)	(\$Cdn/bbl)	(\$Cdn/bbl)	(\$Cdn/bbl)
2016	2.00	0.725	44.00	55.86	42.26	2.70	2.76	60.79	9.58	41.90
2017	2.00	0.750	52.00	64.00	51.20	3.20	3.27	68.48	16.00	48.00
2018	2.00	0.775	58.00	68.39	55.39	3.40	3.45	73.17	20.52	51.29
2019	2.00	0.800	64.00	73.75	60.84	3.60	3.63	78.91	25.81	55.31
2020	2.00	0.825	70.00	78.79	66.18	3.80	3.81	84.30	27.58	59.09
2021	2.00	0.850	75.00	82.35	70.00	4.00	3.90	88.12	28.82	61.76
2022	2.00	0.850	80.00	88.24	75.88	4.20	4.10	94.41	30.88	66.18
2023	2.00	0.850	85.00	94.12	81.41	4.40	4.30	100.71	32.94	70.59
2024	2.00	0.850	87.88	96.48	84.90	4.60	4.50	103.24	33.77	72.36
2025	2.00	0.850	89.63	98.41	86.60	4.70	4.60	105.30	34.44	73.81
2026+	Escalated oil, gas and product prices at 2.0% per year thereafter.									

The weighted average realized sales prices for Athabasca for the year ended December 31, 2015 were \$19.16/bbl for bitumen, \$52.71/bbl for tight oil, \$3.34/Mcf for conventional natural gas, \$26.13/bbl for NGL, and \$2.74/Mcf for shale gas.

Undeveloped Reserves

44.4 MMbbl of the probable reserves that were attributable to the Hangingstone assets in the December 31, 2014 Independent Reports were converted to proved undeveloped reserves in the December 31, 2015 Independent Reports. This was due to the Hangingstone environmental impact assessment being deemed to be technically complete by the AER on October 19, 2015, and the existence of 3D seismic and development level delineation drilling density in the areas adjacent to the Hangingstone Project 1 area. The probable undeveloped reserves of bitumen attributed to the Hangingstone Expansion would transition to proved developed reserves with the sanctioning, construction, commissioning and start-up of the Hangingstone Expansion.

Once proved and/or probable undeveloped reserves are identified in respect of Athabasca's Light Oil assets, they are generally scheduled into Athabasca's development plans. Athabasca plans to develop the proved and probable undeveloped reserves that have been attributed to its Light Oil assets within the next five years. Athabasca's undeveloped bitumen reserves, which are considered to be longer term opportunities, are expected to be developed over a period of time exceeding two years. For additional information regarding the anticipated development of, the Hangingstone Expansion which is the project that has undeveloped bitumen reserves attributed to it, see "*Description of Athabasca's Business – Thermal Oil Division*".

A number of factors that could result in delayed or cancelled development plans are as follows:

- changing economic conditions (e.g. due to pricing, operating and capital expenditure fluctuations);
- changing technical conditions (e.g. production anomalies, such as water breakthrough or accelerated depletion);
- multi-zone developments (e.g. prospective formation completion may be delayed until the initial completion is no longer economic);
- availability and allocation of capital based on other opportunities available to Athabasca in any given year;
- a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization;
- surface access issues (e.g. landowner issues, weather conditions and receipt of required regulatory approvals); and

- Changes in the legal & regulatory framework applicable to the assets (rendering it uneconomic, difficult or impossible to proceed with development).

The following tables set out the volumes of proved undeveloped reserves and probable undeveloped reserves that were attributed for each of Athabasca's product types for each of Athabasca's most recent three financial years and in the aggregate before that time using forecast prices and costs:

Proved Undeveloped Reserves⁽¹⁾⁽²⁾⁽³⁾

	Light Crude Oil & Medium Crude Oil		Conventional Natural Gas (Bcf)		Natural Gas Liquids (MMbbl)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end
2013	0.9	1.3	3.8	22.0	0.3	1.5
2014	0.1	0.3	3.8	10.4	1.3	1.7
2015	0.0	0.0	0.0	0.3	0.8	1.9

	Tight Oil (MMbbl)		Bitumen (MMbbl)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end
2013	0.3	0.7	0.0	51.1
2014	0.6	1.2	0.0	0.0
2015	5.5	7.2	0.0	44.4

	Shale Gas (Bcf)		Oil Equivalent (MMbbl)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end
2013	1.8	3.6	2.4	58.9
2014	8.2	11.9	4.0	6.9
2015	43.3	60.0	13.5	63.4

Probable Undeveloped Reserves⁽¹⁾⁽²⁾⁽³⁾

	Light & Medium Oil (MMbbl)		Conventional Natural Gas (Bcf)		Natural Gas Liquids (MMbbl)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end
2013	1.0	1.4	14.3	42.3	1.3	3.6
2014	0.1	0.5	5.7	52.2	3.2	7.6
2015	0.0	0.0	0.0	0.1	1.2	4.6

	Tight Oil (MMbbl)		Bitumen (MMbbl)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end
2013	0.0	0.0	107.5	398.7
2014	9.5	9.6	0.0	261.3
2015	4.9	14.0	0.0	129.8

	Shale Gas (MMcf)		Oil Equivalent (MMbbl)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end
2013	2.0	9.4	35.4	120.2
2014	50.9	59.7	22.2	297.7
2015	37.8	103.2	12.4	165.6

Notes:

- (1) A portion of the decrease in total at year end for light crude oil and medium crude oil and conventional natural gas in 2015 is attributable to product type changes to tight oil and shale gas respectively, under NI 51-101 effective July 1, 2015.
- (2) "First Attributed" refers to reserves first attributed at year-end of the corresponding fiscal year.
- (3) Based on the Independent Reports.

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserves estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserves estimates and the present worth of the future net revenue therefrom. See "*Risk Factors –Uncertainties Associated with Estimating Reserve and Resource Volumes*".

As circumstances change and additional data becomes available, reserve estimates may also change. Estimates made are reviewed and revised, either upward or downward, as warranted by new information. Revisions may be required as a result of a number of factors that are beyond Athabasca's control, including, among others, product pricing, economic conditions, access to markets, changes to royalty and tax regimes, governmental restrictions, changing operating and capital costs, surface access issues, the receipt of regulatory approvals, availability of services and

processing facilities and technical issues affecting well performance. Although every reasonable effort is made to ensure that reserves estimates are accurate, reserve estimation is an inferential science and revisions to reserve estimates based upon the foregoing factors may be either positive or negative.

Abandonment and Reclamation Obligations For Properties with Reserves

In connection with Athabasca's operations, Athabasca will incur abandonment and reclamation costs for surface leases, wells, facilities and pipelines. Athabasca budgets for and recognizes as a liability the estimated present value of the future decommissioning liabilities associated with its property, plant and equipment. Athabasca's overall abandonment and reclamation costs include all costs associated with the process of restoring a property that has been disturbed by oil and gas activities to the standard imposed by the applicable government or regulatory authorities. These costs were estimated using amongst other things, Athabasca's experience conducting abandonment and reclamation programs, previous actual costs incurred and published industry information. Athabasca reviews suspended or standing wells for reactivation, recompletion or sale and conduct systematic abandonment programs for those wells that do not meet its criteria. A portion of Athabasca's liability issues are retired every year and facilities are decommissioned when all the wells producing to them have been abandoned. All of Athabasca's liability reduction programs take into account seasonal access, high priority and stakeholder issues, and opportunities for multi-location programs to reduce costs. There are no unusually significant abandonment and reclamation costs associated with our properties with attributed reserves. See "Other Oil and Gas Information – Properties with no Attributable Reserves - Liege Area Abandonment and Reclamation Obligations" for a discussion of certain abandonment and reclamation liabilities associated with properties with no attributed reserves.

The future net revenues disclosed in this Annual Information Form are based on the Independent Reports and do not contain an allowance for abandonment and reclamation costs for facilities, pipelines or wells without reserves. The future net revenue disclosures by the Independent Reports however did include reclamation and abandonment costs associated with future development wells & infrastructure which are not included in the Company's consolidated financial statements. The Independent Reports deducted an aggregate of \$209 million (undiscounted) and \$13 million (10% discount) for abandonment and reclamation costs of wells with proved and probable reserves.

As at December 31, 2015, Management estimates there was \$275.9 million (undiscounted) and \$69.8 million (10% discount) in total reclamation and abandonment costs associated with the existing 404 net wells (approximate) and the associated sites, facilities and pipelines for which it expects to incur abandonment and reclamation costs in the Company's Light Oil and Thermal Oil Divisions.

Future Development Costs⁽¹⁾

The following table sets forth the undiscounted development costs deducted in the estimation of future net revenue attributable to each of the following reserves categories contained in the Independent Reports.

Year	Total Proved Reserves Future Development Costs Using Forecast Prices and Costs (M\$)	Total Proved Plus Probable Reserves Future Development Costs Using Forecast Prices and Costs (M\$)
2016	78,349	78,349
2017	175,446	268,981
2018	75,518	262,081
2019	54,637	204,730
2020	21,741	243,994
Total for all remaining years	735,644	2,325,050
Total Undiscounted	1,141,336	3,383,184

Note:

(1) Totals may not add due to rounding.

Athabasca expects that existing cash and short term investments, the remaining Promissory Note, future proceeds upon closing the Murphy Transaction, the Kaybob Carry Commitment, cash flow from operations, the amounts available under the undrawn Amended Credit Facility, the delayed draw portion of its Term Loans or other available debt financing and potential access to additional external financing will be sufficient to fund the above future development costs. External financing could include additional debt financing, joint ventures, project financing, proceeds from asset dispositions or equity financing, subject to the terms and conditions of the Note Indenture, the Amended Credit Facility and Term Loans. There can be no guarantee, however, that sufficient funds will be available on terms acceptable to Athabasca or on a timely basis, or that Athabasca will allocate funding to develop all of its reserves. Failure to develop its reserves would have a negative impact on Athabasca's future net revenue. The costs of future external financing are not included in the reserves and future net revenue estimates and would also reduce future net revenue, the extent to which would depend upon the sources of external financing that are utilized.

OTHER OIL AND GAS INFORMATION

Oil & Gas Properties

As at December 31, 2015, Athabasca held approximately 1,724,240 net acres of mineral resource leases and permits, including over 1.24 million net acres of oil sands leases and permits in the Athabasca region of northeastern Alberta and over 483,650 net acres of petroleum and natural gas leases in northwestern Alberta. See "*General Development of the Business – Thermal Oil Division*" and "*General Development of the Business – Light Oil Division*". Athabasca's oil sands leases and permits are large and generally contiguous, which management expects will allow for scale efficiency and simpler development planning.

As at December 31, 2015, Athabasca had an interest in approximately 147.00 Gross Wells (143.18 Net Wells), as set forth below, all of which are located in Alberta:

	Producing		Non-Producing ⁽³⁾		Total	
	Gross Wells ⁽¹⁾	Net Wells ⁽²⁾	Gross Wells ⁽¹⁾	Net Wells ⁽²⁾	Gross Wells ⁽¹⁾	Net Wells ⁽²⁾
Bitumen	21.00	21.00	5.00	5.00	26.00	26.00
Crude Oil Wells	38.00	38.00	18.00	18.00	56.00	56.00
Natural Gas Wells	27.00	24.18	38.00	37.00	65.00	61.18
TOTAL	86.00	83.18	61.00	60.00	147.00	143.18

Notes:

- (1) "**Gross Wells**" means the total number of producing or non-producing bitumen, oil or gas wells in which Athabasca had an interest as of December 31, 2015.
- (2) "**Net Wells**" means the aggregate number of producing or non-producing bitumen, oil or gas wells obtained by multiplying each Gross Well by Athabasca's percentage working interest therein.
- (3) "**Non-Producing**" wells include stratigraphic test wells, wells awaiting completion as at December 31, 2015, and wells that are capable of production but were not producing as at December 31, 2015, due to facility limitations related to water handling or that were awaiting artificial lift or were waiting to be tied-in. All non-producing wells considered to be capable of producing are located near existing transportation infrastructure. Athabasca has not included the following type of wells in its Non-Producing well count above: wells that Athabasca has an interest in that are suspended or permanently shut-in in the Liege area either due to a lack of existing functional proximate transportation infrastructure or a permanent shut-in order issued by the AER, its HAF, water source, steam injection, disposal wells or wells that have been abandoned.

Oil sands leases in the Athabasca oil sands area carry a primary term of 15 years with an additional 2 year extension, and petroleum and natural gas leases carry a primary term of 5 years, after which time the leases can be continued if certain activity and/or production levels are satisfied. Oil sands permits have a primary term of 5 years and petroleum and natural gas licenses have a primary term of 4 years. Depending on the level of activity and/or production, both oil sands permits and petroleum and natural gas licenses can be converted into leases at the end of their primary terms. A vast majority of Athabasca's oil sands reserves and resources are held under oil sands leases (15 year initial terms),

and those lands held under oil sands permits have met all requirements to convert to leases at the end of their initial terms.

Properties with No Attributed Reserves

The following table is a summary of properties in which Athabasca has an interest to which no reserves have been attributed, and also the number of net acres for which Athabasca's rights to explore, develop or exploit will, absent further action, expire within one year, as at December 31, 2015:

	Gross Acres ⁽¹⁾⁽²⁾	Net Acres ⁽¹⁾⁽²⁾	Net Acres Expiring Within One Year ⁽¹⁾⁽²⁾
Alberta.....	1,376,873	1,195,240	14,400
Total.....	1,376,873	1,195,240	14,400

Notes:

- (1) "Gross" means the total area of properties in which Athabasca has a working interest. "Net" means the total area in which Athabasca has an interest multiplied by the working interest owned by Athabasca.
- (2) Excludes certain non-oil sands acreage held by Athabasca in formations under and adjacent to the same surface area as Athabasca's oil sands leases. Athabasca measures its land acreage based on the leases, licenses and permits granted by the Crown, as specified within the applicable legal documentation.

No capital expenditures were approved for the development of the Light Oil Exploration areas as part of Athabasca's 2016 capital budget. As a result the Company expects the following expiries to occur during 2016: Grande Prairie area – approximately 2,880 net acres, Sawn Lake- approximately 8,960 net acres, Rycroft- approximately 1,920 net acres and Rainbow Lake-approximately 640 net acres.

Uncertainties associated with Development of Oil Sands and Carbonates Assets

In respect of Athabasca's Dover West Carbonates assets, the recovery of bitumen using SAGD, CSS and TAGD processes is uncertain. The SAGD bitumen recovery process is mature in the clastics but relatively immature in carbonates. All of the commercially successful SAGD recovery projects developed to date in Alberta have targeted clastic reservoirs. There are, however, no developed successful commercial projects that use either SAGD, CSS or TAGD to recover bitumen from carbonates.

There can be no assurance that Athabasca's operations will produce bitumen at the expected levels or on schedule. This is particularly true in respect of Athabasca's carbonate bitumen assets (Dover West Carbonates and Grosmont assets). SAGD, CSS and TAGD are in their initial stages of testing and have not been used in a commercial carbonates project and SAGD is not currently being actively developed for application to an analogue reservoir within the vicinity of Athabasca's asset areas.

Athabasca's ability to develop its bitumen resources that are located in carbonate reservoirs on a commercially viable scale is contingent upon one or more of the following events occurring: Athabasca adapting existing SAGD or CSS technology such that it can be successfully used to exploit its carbonate reservoirs; or, Athabasca developing or acquiring new technology, such as TAGD, that can be used to successfully exploit its carbonate reservoirs. There can be no assurance that existing technologies will prove to be viable for the commercial exploitation of bitumen located in Athabasca's carbonate reservoirs, that existing technologies can be modified in such a manner as to be made to be viable for the commercial exploitation of bitumen located in Athabasca's carbonate reservoirs, or that new technologies, such as TAGD, will be developed or acquired by Athabasca that will be viable for the commercial exploitation of bitumen located in its carbonate reservoirs. The development of such recovery processes will involve significant capital expenditures and a lengthy time to project payout, and project payout is not assured.

In addition, should Athabasca encounter the existence of adverse reservoir conditions during the development of its oil sands or carbonates assets, ultimate bitumen recovery levels achieved by Athabasca utilizing SAGD, CSS and/or TAGD recovery processes may be negatively affected. Such adverse reservoir conditions could include, but are not

limited to, the following: regional poor quality geological features; depleted or partially depleted associated gas caps due to prior gas production; the existence of bottom or top water, inter-formation water, or other thief zones; or the absence of an overlying cap rock. TAGD technology also requires a significant amount of electricity to provide power to the downhole conduction heaters.

Impairment Conducted in 2015

In the fourth quarter of 2015, given continued deterioration in commodity prices and the value of the Light Oil assets implied by the Murphy Transaction and recent federal and provincial governance initiatives surrounding climate change and pipeline development which could impact the long-term development of thermal oil projects, Athabasca determined that indicators of impairment were present over all its oil and gas assets. In response, Athabasca performed an impairment test on each of its cash generating units. The impairment tests resulted in an impairment loss relating to Athabasca's Light Oil assets and its Dover West assets. For further details relating to this impairment loss, please see Athabasca's Consolidated Financial Statements and Management Discussion & Analysis as at December 31, 2015.

Liege Area Abandonment and Reclamation Obligations

In November 2010, Athabasca acquired 259 shut-in gas wells from Perpetual Energy Inc. in the Liege area, which were located in proximity to its oil sands assets including oil sand assets that were part of the PetroChina Transaction. These wells were the subject of a permanent gas over bitumen shut-in order issued by the ERCB (now AER) pursuant to shut-in orders *ERCB 2011-035* and *ERCB 2011-002*. 61 of these wells are now operated by other companies. Athabasca has assumed the responsibility for its proportionate share of any abandonment and reclamation associated with the remaining 198 wells. Other items also acquired as part of the transaction and for which Athabasca is now responsible for the associated environmental liability include gas plants, gathering pipelines, several compressor stations, boosters, camps, airstrips and storage areas. Athabasca has budgeted approximately \$40 million over the next 6 years for the abandonment and reclamation of the remaining assets in the Liege area.

Tax Horizon

For the fiscal year ended December 31, 2015, the Company paid no income tax. The Company does not expect to pay Canadian income taxes during the next five years. This estimate would be affected by, among other factors, the Company's other business activities such as any joint venture arrangements or asset sales. Changes in these factors from estimates used by the Company could result in the Company paying income taxes earlier or later than expected. For additional information concerning the Company's tax horizon see "*Risk Factors – Income Tax Matters*".

Costs Incurred During the Year Ended December 31, 2015

Division	Proved Property Acquisition Costs MM(\$)	Unproved Property Acquisition Costs MM(\$)	Exploration Costs MM(\$)	Development Costs MM(\$)
Light Oil	-	\$ 13.2	-	\$ 176.0
Thermal Oil	-	-	\$ 13.4	\$101.2
Total	-	\$ 13.2	\$ 13.4	\$ 277.2

Exploration and Development Activities

The following table summarizes the gross and net exploratory and development wells that were completed by Athabasca during the year ended December 31, 2015:

	Exploratory		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil wells	-	-	-	-	-	-
Bitumen wells	-	-	-	-	-	-
Gas wells	9	9	5	5	14	14
Service wells	-	-	-	-	-	-
Stratigraphic test wells	2	2	-	-	2	2
Dry holes	-	-	-	-	-	-
Total	11	11	5	5	16	16

For a description of the Company's current and likely exploration and development activities see "*Description of Athabasca's Business*".

Production Estimates⁽¹⁾

The following table sets out the volumes of Athabasca's working interest production estimated by GLJ and D&M for the year ending December 31, 2016, which is reflected in the estimates of future net revenue disclosed in the tables contained under the headings "*Summary of Net Present Values of Future Net Revenue – Forecast Prices and Costs as of December 31, 2015*", "*Future Net Revenue (Undiscounted) – Forecast Prices and Costs as of December 31, 2015*" and "*Future Net Revenue by Product Type– Forecast Prices and Costs as of December 31, 2015*".

Reserve Category	Bitumen (bbl/d)	Conventional Natural Gas (Mcf/d)	NGLs (bbl/d)	Tight Oil (bbl/d)	Shale Gas (Mcf/d)	Oil Equivalent (Boe/d)
Gross Proved Reserves						
Hangingstone Assets	12,000	-	-	-	-	12,000
Other Properties	-	260	594	1,705	14,638	4,781
Total Gross Proved Reserves	12,000	260	594	1,705	14,638	16,781

Reserve Category	Bitumen (bbl/d)	Conventional Natural Gas (Mcf/d)	NGLs (bbl/d)	Tight Oil (bbl/d)	Shale Gas (Mcf/d)	Oil Equivalent (Boe/d)
Gross Probable Reserves						
Hangingstone Assets	-	-	-	-	-	-
Other Properties	-	8	98	374	3,125	994
Total Gross Probable Reserves	0	8	98	374	3,125	994

Reserve Category	Bitumen (bbl/d)	Conventional Natural Gas (Mcf/d)	NGLs (bbl/d)	Tight Oil (bbl/d)	Shale Gas (Mcf/d)	Oil Equivalent (Boe/d)
Gross Proved + Probable Reserves						
Hangingstone Assets	12,000	-	-	-	-	12,000
Other Properties	-	268	907	3,719	25,814	8,973
Total Gross Proved + Probable Reserves	12,000	268	907	3,719	25,814	20,973

Note:

(1) Totals may not add due to rounding.

The Hangingstone assets are estimated to account for greater than 20% of Athabasca's 2016 production volumes. As is shown above, estimated 2016 production volumes for the Hangingstone assets are 12,000 boe/d on a Gross Proved Reserves basis and 12,000 boe/d on a Gross Proved plus Probable Reserves basis.

The above production estimates are as at December 31, 2015. Closing of the Murphy Transaction will affect Light Oil production estimates for Athabasca for 2016 for the Kaybob and Simonette asset areas. See "*General Development of the Business- Recent Significant Transactions*".

Production History

The following table sets forth on a quarterly basis for the year ended December 31, 2015, certain information in respect of production, product prices received, royalties paid, production costs and the resulting netbacks.

	Quarter Ended 2015				Year Ended Dec. 31, 2015
	Mar. 31	June 30	Sept. 30	Dec. 31	
Average Daily Production ⁽¹⁾					
Bitumen (bbls/d)	-	17	2,110	5,702	1,973
Tight Oil (bbls/d)	2,366	1,930	1,696	2,350	2,084
Natural Gas (Mcf/d)	521	366	282	273	360
NGLs (bbls/d)	564	735	754	511	641
Shale Gas (Mcf/d)	17,490	16,874	15,295	17,563	16,802
Total (Boe/d)	5,932	5,556	7,156	11,536	7,560
Average Prices Received					
Bitumen (\$/bbl)	0	0	15.42	20.95	19.16
Tight Oil (\$/bbl)	47.55	63.47	53.11	48.77	52.71
Natural Gas (\$/Mcf)	3.45	3.65	3.00	3.10	3.34
NGLs (\$/bbl)	24.92	28.81	23.43	27.63	26.13
Shale Gas (\$/Mcf)	2.84	2.73	2.83	2.58	2.74
Total (\$/boe)	30.02	34.40	25.77	25.51	28.01
Royalties Paid					
Bitumen (\$/bbl)	-	-	(0.05)	(0.35)	(0.25)
Tight Oil (\$/bbl)	(5.45)	(4.77)	(5.56)	(4.28)	(4.99)
Natural Gas (\$/Mcf)	0.37	(0.26)	(0.33)	(0.22)	(0.04)
NGLs (\$/bbl)	(5.30)	(7.56)	(5.09)	(4.26)	(5.67)
Shale Gas (\$/Mcf)	0.01	0.33	0.25	0.13	0.18
Total (\$/boe)	(2.61)	(1.67)	(1.34)	(1.04)	(1.53)
Production Costs ⁽²⁾					
Bitumen (\$/bbl)	-	(73,902.43)	(119.86)	(68.08)	(116.88)
Tight Oil (\$/bbl)	(14.34)	(14.93)	(14.30)	(15.53)	(14.81)
Natural Gas (\$/Mcf)	(2.38)	(2.47)	(2.38)	(2.50)	(2.43)
NGLs (\$/bbl)	(14.13)	(15.02)	(14.29)	(15.12)	(14.63)
Shale Gas (\$/Mcf)	(2.36)	(2.49)	(2.38)	(2.53)	(2.44)
Total (\$/boe)	(14.24)	(241.03)	(45.42)	(41.40)	(41.38)
Netback Received ⁽³⁾					
Bitumen (\$/bbl)	-	(73,902.43)	(104.49)	(47.48)	(97.97)
Tight Oil (\$/bbl)	27.76	43.76	33.25	28.96	32.92
Natural Gas (\$/Mcf)	1.44	0.92	0.28	0.37	0.88
NGLs (\$/bbl)	5.50	6.23	4.05	8.25	5.83
Shale Gas (\$/Mcf)	0.49	0.57	0.70	0.17	0.48
Total (\$/boe)	13.18	(208.30)	(20.99)	(16.93)	(14.90)

Notes:

- (1) Production by activity month and is before deduction of royalties and capitalized sales volumes.
- (2) For wells producing multiple products, production costs have been allocated based on barrels of oil equivalent.
- (3) Netbacks are calculated by subtracting royalties and operating and transportation costs from revenues.

The following table sets forth the average daily production from each of the Company's producing fields for the year ended December 31, 2015:

	Bitumen (bbls/d)	Tight Oil (bbls/d)	Natural Gas (Mcf/d)	NGLs (bbls/d)	Shale Gas (Mcf/d)	Oil Equivalent (boe/d)
Hangingsstone Area	1,973	-	-	-	-	1,973
Kaybob Area	-	1,612	-	563	13,295	6,364
Simonette Area	-	472	315	78	3,507	1,187
Light Oil Exploration Areas	-	-	45	1	-	8
Total	1,973	2,084	360	641	16,802	7,559

Environmental Considerations

The environmental issues and stakeholder concerns to be managed by Athabasca in developing its assets are similar to those currently being managed by other oil and gas companies, and by communities, and encompass the health of local and regional residents and employees, surface disturbance on the terrestrial ecosystem, effects on traditional land use and historical resources, local and regional air quality, GHG emissions, water quality, monitoring seismic activity levels, health of the aquatic ecosystem in rivers and cumulative effects on wildlife populations and aquatic resources. Athabasca has committed to both site-specific and regional monitoring programs to track the effects of its projects and the cumulative effects of regional development on environmental components and ecosystems.

Athabasca is committed to operating its projects to achieve compliance with applicable statutes, regulations, codes, regulatory approvals and, to the extent practicable, government guidelines. Where the applicable laws are not clear or do not address all environmental concerns, management intends to apply appropriate internal standards and guidelines to address such concerns. In addition to complying with applicable statutes, regulations, codes and regulatory approvals and exercising due diligence, Athabasca strives to continuously improve its operations to address environmental concerns.

DIVIDENDS

The Company has not declared or paid any cash dividends on its Common Shares in any of the three most recently completed financial years. The Company does not currently anticipate paying any cash dividends on its Common Shares in the foreseeable future but will review that policy from time to time as circumstances warrant. The Company currently intends to retain future earnings, if any, for future operations, expansion and debt repayment. Any decision to declare and pay dividends in the future will be made at the discretion of the Board and will depend on, among other things, the Company's results of operations, current and anticipated cash requirements and surplus, financial condition, solvency tests imposed by corporate law, contractual restrictions and financing agreement covenants, including those contained in the Note Indenture, Amended Credit Facility and the Term Loans and other factors that the Board may deem relevant.

Under the terms of the Note Indenture, Amended Credit Facility and the Term Loans, the Company and certain of its subsidiaries are prohibited from making certain restricted payments, including the payment of dividends, unless at the time of and immediately after giving effect to such a proposed restricted payment, certain financial tests (as set forth in the respective applicable agreements) are met, and no default or event of default under the Note Indenture, Amended Credit Facility or Term Loans, as applicable, has occurred and is continuing.

DESCRIPTION OF CAPITAL STRUCTURE

General

The Company's authorized share capital consists of an unlimited number of Common Shares without nominal or par value, an unlimited number of first preferred shares, issuable in series, and an unlimited number of second preferred

shares, issuable in series, each of which are described below. The Company has also issued the Senior Secured Notes and has the ability to utilize the Amended Credit Facility and Term Loans that are described below.

As at December 31, 2015, 404,299,592 Common Shares were issued and outstanding and no first preferred shares or second preferred shares were issued and outstanding. In addition, 9,942,905 Stock Options and 8,365,500 RSUs (2010 and 2015), 1,260,500 Performance Awards and 663,082 DSUs were issued and outstanding on December 31, 2015.

Common Shares

Each Common Share entitles the holder thereof to: (a) vote at any meeting of Shareholders of the Company; (b) receive any dividend on the Common Shares declared by the Company; and (c) receive the remaining property of the Company upon dissolution. For a description of the Company's dividend policy, see "*Dividends*".

First Preferred Shares

Subject to the filing of articles of amendment in accordance with the ABCA, the Board may at any time and from time to time issue first preferred shares in one or more series, each series to consist of such number of shares as may, before the issuance thereof, be determined by the Board. Subject to the filing of articles of amendment in accordance with the ABCA, the Board may from time to time fix, before issuance, the designation, rights, privileges, restrictions and conditions attaching to each series of first preferred shares including, without limiting the generality of the foregoing: the amount, if any, specified as being payable preferentially to such series on a Distribution (as defined below); the extent, if any, of further participation on a Distribution; voting rights, if any; and dividend rights (including whether such dividends are preferential, cumulative or non-cumulative), if any.

In the event of the voluntary or involuntary liquidation, dissolution or winding up of the Company, or any other distribution of its assets among its Shareholders for the purpose of winding up its affairs (such event referred to herein as a "**Distribution**"), holders of each series of first preferred shares shall be entitled, in priority to holders of Common Shares, second preferred shares and any other shares of the Company ranking junior to the first preferred shares from time to time with respect to payment on a Distribution, to be paid rateably with holders of each other series of first preferred shares the amount, if any, specified as being payable preferentially to the holders of such series on a Distribution.

The holders of each series of first preferred shares shall be entitled, in priority to holders of Common Shares, second preferred shares and any other shares of the Company ranking junior to the first preferred shares from time to time with respect to the payment of dividends, to be paid rateably with holders of each other series of first preferred shares, the amount of accumulated dividends, if any, specified as being payable preferentially to the holders of such series.

Under the terms of the Note Indenture, Amended Credit Facility and the Term Loans, the Company is prohibited from issuing preferred shares, unless certain financial tests (as set forth in the respective applicable agreements) are met, and no default or event of default under the Note Indenture, Amended Credit Facility or Term Loans, as applicable, has occurred and is continuing.

Second Preferred Shares

Subject to the filing of articles of amendment in accordance with the ABCA, the Board may at any time and from time to time issue second preferred shares in one or more series, each series to consist of such number of shares as may, before the issuance thereof, be determined by the Board. Subject to the filing of articles of amendment in accordance with the ABCA, the Board may from time to time fix, before issuance, the designation, rights, privileges, restrictions and conditions attaching to each series of second preferred shares including, without limiting the generality of the foregoing: the amount, if any, specified as being payable preferentially to such series on a Distribution; the extent, if any, of further participation on a Distribution; voting rights, if any; and dividend rights (including whether such dividends are preferential, cumulative or non-cumulative), if any.

In the event of a Distribution, holders of each series of second preferred shares shall be entitled, subject to the preference accorded to holders of first preferred shares but in priority to holders of Common Shares and any other shares of the Company ranking junior to the second preferred shares from time to time with respect to payment on a Distribution, to be paid rateably with holders of each other series of second preferred shares the amount, if any, specified as being payable preferentially to the holders of such series on a Distribution.

The holders of each series of second preferred shares shall be entitled, subject to the preference accorded to the holders of first preferred shares but in priority to holders of Common Shares and any other shares of the Company ranking junior to the second preferred shares from time to time with respect to the payment of dividends, to be paid rateably with holders of each other series of second preferred shares, the amount of accumulated dividends, if any, specified as being payable preferentially to the holders of such series.

Shareholder Rights Plan

Effective April 8, 2010 (the “**Effective Date**”), the Company adopted the Rights Plan, which was originally approved by Shareholders at a special meeting held on April 21, 2015 and was subsequently amended and restated by the Shareholders at the annual general and special meeting that was held on May 10, 2012 (the “**Amended Rights Plan**”). Pursuant to the Amended Rights Plan, the Shareholders also approved an extension to the term of the Amended Rights Plan until the close of business on the first business day following the annual general meeting of the Shareholders to be held in 2018, unless at such meeting the Shareholders reconfirm the Amended Rights Plan for an additional period of time or the Amended Rights Plan is otherwise terminated in accordance with its terms prior thereto.

The objectives of the Amended Rights Plan are to provide adequate time for the Board and Shareholders to assess an unsolicited take-over bid for the Company, to provide the Board with sufficient time to explore and develop alternatives for maximizing Shareholder value if a take-over bid is made, and to provide Shareholders with an equal opportunity to participate in a take-over bid. The Amended Rights Plan encourages a potential acquirer who makes a take-over bid to proceed either by way of a “Permitted Bid” (as defined in the Amended Rights Plan), which generally requires a take-over bid to satisfy certain minimum standards designed to promote fairness, or with the concurrence of the Board. If a take-over bid fails to meet these minimum standards, the Amended Rights Plan provides that holders of Common Shares, other than the acquirer, will be able to purchase additional Common Shares at a significant discount to market, thus exposing the acquirer to substantial dilution of its holdings.

Pursuant to the Amended Rights Plan, effective on the Effective Date, one right (“**Right**”) was issued and attached to each outstanding Common Share and one Right is also issued and attached to each Common Share issued after the Effective Date. If a person, or a group acting jointly or in concert, acquires (other than pursuant to an exemption available under the Amended Rights Plan including by way of a Permitted Bid) beneficial ownership of 20 percent or more of the Common Shares, Rights (other than those held by such acquiring person) will permit the holder to purchase that number of Common Shares having an aggregate market price (determined in accordance with the Amended Rights Plan) equal to two times the exercise price of the Rights for an amount in cash equal to the exercise price. The exercise price of the Rights is \$100.00 per Right.

A copy of the Amended Rights Plan is available on the Company’s SEDAR profile at www.sedar.com.

Senior Secured Notes

On November 19, 2012, the Company completed a private placement offering of \$550 million aggregate principal amount of senior secured second lien notes, which bear interest at 7.50% per annum and mature on November 19, 2017 (the “**Senior Secured Notes**”). The Company is required to pay interest on the Senior Secured Notes at a rate of 7.50% per year on May 19 and November 19 of each year. The Senior Secured Notes mature on November 19, 2017. At any time on or after November 19, 2014, the Company may redeem the Senior Secured Notes at the following redemption prices plus accrued and unpaid interest on the Senior Secured Notes that are redeemed, to the applicable redemption date, if redeemed during the 12-month period beginning on November 19th of each of the following years: 2014 – 107.50%, 2015 – 103.75%, 2016 and thereafter – 100.00%.

If the Company undergoes certain kinds of changes of control, it is required to offer to repurchase the Senior Secured Notes from holders at a purchase price equal to 101% of the principal amount of the Senior Secured Notes plus accrued and unpaid interest, if any, to, but not including, the date of repurchase.

The Senior Secured Notes are guaranteed on senior secured basis by the Company's material subsidiaries. The Senior Secured Notes and the guarantees are secured by second-priority security interests (subject to certain liens that are permitted pursuant to the terms of the Note Indenture) in substantially all of the assets of the Company and the guarantors, with the exception of certain assets that are excluded pursuant to the terms of the Note Indenture. The Senior Secured Notes are also subject to the terms of a collateral agent and intercreditor agreement among the Company, the guarantors, the Indenture Trustee and the Collateral Agent dated November 19, 2012 (the "**Collateral Agent Agreement**").

Subject to certain exceptions and qualifications which are set forth in the Note Indenture, the Senior Secured Notes limit the ability of the Company and certain of its subsidiaries that are considered to be "restricted subsidiaries" pursuant to the Note Indenture ("**Restricted Subsidiaries**") to, among other things: make restricted payments; incur additional indebtedness; issue disqualified or preferred stock; create or permit liens to exist; create or permit to exist restrictions on the ability of the Restricted Subsidiaries to make payments and distributions; make certain dispositions and transfers of assets; engage in amalgamations, mergers or consolidations; and engage in certain transactions with affiliates.

A copy of the Note Indenture is available on the Company's SEDAR profile at www.sedar.com

Senior Secured Term Loans

On May 7, 2014, Athabasca entered into a credit agreement providing for a US\$225 million term loan which was fully funded at closing and an additional US\$50 million committed delayed draw term loan which the Company may draw at its option at any time up until May 7, 2016, subject to compliance with certain conditions precedent and covenants (the "**Term Loans**"). Borrowings under the Term Loans bear interest at a floating rate based on LIBOR plus 7.25%, subject to a LIBOR floor of 1.00%. The Company also incurs standby fees on the undrawn portion of the US\$50 million delayed draw term loan equal to 1.00% per annum. The Term Loans will amortize in equal quarterly installments in an aggregate annual amount equal to 1.00% of the original principal amount with the balance payable on May 7, 2019 or on May 19, 2017 if the Company has not redeemed or refinanced the Senior Secured Notes prior to that date.

Athabasca has the option to redeem the Term Loans at a price of 102% for the 12-month period beginning May 7, 2015, 101% for the 12-month period beginning May 7, 2016 and at par thereafter.

The Term Loans are guaranteed on a senior secured first lien basis by the Company's material subsidiaries. The Term Loans and the guarantees are secured by first priority security interests (subject to certain liens that are permitted pursuant to the terms of the Term Loan Credit Agreement) in substantially all of the assets of the Company and the guarantors, with the exception of certain assets that are excluded pursuant to the terms of the Term Loan Credit Agreement. The Term Loans are also subject to the terms of the Collateral Agent Agreement.

Subject to certain exceptions and qualifications which are set forth in the Term Loans, the Term Loans limit the ability of the Company and certain of its subsidiaries that are considered to be "restricted subsidiaries" pursuant to the Term Loan Credit Agreement ("**Restricted Subsidiaries**") to, among other things: make restricted payments; incur additional indebtedness; issue disqualified or preferred stock; create or permit liens to exist; create or permit to exist restrictions on the ability of the Restricted Subsidiaries to make payments and distributions; make certain dispositions and transfers of assets; engage in amalgamations, mergers or consolidations; and engage in certain transactions with affiliates.

The Term Loans are also subject to certain financial covenants including: a requirement to maintain a minimum ratio of adjusted consolidated net tangible assets (including the present value of total proved and probable reserves) to total debt of 3.5 times; and, beginning with the March 31, 2015 quarter-end, if the aggregate of unrestricted cash, cash equivalents and short term investments do not exceed the amount of outstanding total debt, the maintenance of a

minimum ratio of the present value of proved reserves discounted at 10% to net first lien debt of 1.5 times is required. As at December 31, 2015, Athabasca was in compliance with all of the covenants related to the Term Loans.

Pursuant to an agreement dated May 7, 2014 between the lenders under the Amended Credit facility and the holders of the Term Loans, it was agreed that the Amended Credit Facility ranks in priority to the Term Loans.

Revolving Senior Secured Credit Facility

On May 7, 2014, concurrent with entering into the Term Loans, the Company entered into a \$125 million amended and restated credit agreement with a syndicate of financial institutions to replace the 2013 Credit Facilities. The amended and restated credit facility (the “**Amended Credit Facility**”) is available on a revolving basis until April 30, 2017. The Amended Credit Facility may be extended subject to lender consent and provided the term of the facility does not exceed three years from the date of extension.

Amounts borrowed under the Credit Facility bear interest at a floating rate based on the applicable Canadian prime rate, US base rate, LIBOR or bankers' acceptance rate, plus a margin of between 1.00% and 4.00% depending on the type of borrowing and the Company's indebtedness to consolidated cash flow ratio. Athabasca pays issuance fees for letters of credit between 2.0% and 4.0% depending on the type of borrowing and the Company's indebtedness. The Company incurs a standby fee on the undrawn portion of the Amended Credit Facility of between 0.50% and 1.00% based on the Company's indebtedness to consolidated cash flow ratio. For the year ended December 31, 2015, the Company paid a rate of between 2.67% and 4.0% for letters of credit and a rate of 1.00% on the undrawn portion of the Amended Credit Facility (December 31, 2014 - 1.00%). As of December 31, 2015, Athabasca had \$7.3 million in letters of credit secured by the Amended Credit Facility (December 31, 2014 - \$0.5 million) and no amounts had been drawn under the Amended Credit Facility (December 31, 2014 - \$ nil). If drawn, the Amended Credit Facility is collateralized by a first priority security interest on all present and after acquired property of the Company and is effectively senior in priority to the Term Loans and the Senior Secured Second Lien Notes. In the first quarter of 2016, Athabasca issued an additional letter of credit for \$89.9 million in respect of financial assurance provisions associated with the Company's pipeline transportation commitments, reducing the remaining capacity of the Amended Credit Facility to \$27.8 million.

The is subject to substantially the same covenants as the Notes and Term Loans plus, among others, the requirement to maintain a minimum tangible net worth based on the Company's shareholders' equity. The Company amended its tangible net worth covenant from a minimum of \$2,750 million to \$1,700 million. As at December 31, 2015, the Company's shareholders' equity was \$2,413 million (December 31, 2014 - \$3,164 million). As at December 31, 2015, Athabasca was in compliance with all of the Amended Credit Facility covenants.

The Amended Credit Facility is guaranteed on a senior secured first lien basis by the Company's material subsidiaries. The Amended Credit Facility and the guarantees are secured by first-priority security interests (subject to certain liens that are permitted pursuant to the terms of the Amended and Restated Credit Agreement) in substantially all of the assets of the Company and the guarantors, with the exception of certain assets that are excluded pursuant to the terms of the Amended and Restated Credit Agreement. The Amended Credit Facility is also subject to the terms of the Collateral Agent Agreement.

Subject to certain exceptions and qualifications which are set forth in the Amended and Restated Credit Agreement, the Amended Credit Facility limits the ability of the Company and the Restricted Subsidiaries to, among other things: make restricted payments; incur additional indebtedness; issue disqualified or preferred stock; create or permit liens to exist; create or permit to exist restrictions on the ability of the Restricted Subsidiaries to make payments and distributions; make certain dispositions and transfers of assets; engage in amalgamations, mergers or consolidations; and engage in certain transactions with affiliates.

Pursuant to an agreement dated May 7, 2014 between the lenders under the Amended Credit Facility and the holders of the Term Loans, it was agreed that the Amended Credit Facility ranks in priority to the Term Loans.

CREDIT RATINGS

The following information relating to the Company's credit ratings is provided as it relates to the Company's financing costs, liquidity and cost of operations. Specifically, credit ratings impact the Company's ability to obtain short-term and long-term financing and the cost of such financings. Changes in the Company's current credit ratings by the rating agencies, particularly downgrades below the current ratings or negative changes in the ratings outlooks, could adversely affect the Company's cost of borrowing and/or access to sources of liquidity and capital. In addition, changes in credit ratings may affect the Company's ability to: (a) enter into, or the associated costs of entering into hedging transactions or other ordinary course contracts on acceptable terms and may require the Company to post additional collateral under certain of its contracts; and (b) enter into and maintain ordinary course contracts with customers and suppliers on acceptable terms.

The Company has been assigned corporate credit ratings of B(low) with a negative trend by DBRS and CCC+ with a "Stable" trend by S&P. The corporate credit rating focuses on a borrower's capacity and ability to meet its financial commitments as they come due.

The Senior Secured Notes have been assigned credit ratings of B(low) by DBRS and B by S&P.

DBRS and S&P provide credit ratings of debt securities for commercial entities. A credit rating generally provides an indication of the risk that the borrower will not fulfill its full obligations in a timely manner with respect to both interest and principal commitments.

DBRS' credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. A reference to "high" or "low" reflects the relative strength within the rating category, while the absence of either a "high" or "low" designation indicates the rating is placed in the middle category. According to DBRS, the "negative" trend helps give investors an understanding of DBRS' opinion regarding the outlook for the rating.

S&P's credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. The ratings from AA to CCC may be modified by the addition of a plus (+) or a minus (-) sign to show relative standing within the major rating categories. In addition, S&P may add a rating outlook of "positive", "negative" or "stable" which assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years).

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. Credit ratings are not recommendations to purchase, hold or sell securities and do not address the market price or suitability of a specific security for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant. A rating can be revised, suspended or withdrawn at any time by the rating agency.

The Company paid a fee for service to both DBRS and S&P to provide ratings in respect of the offering of the Senior Secured Notes. No service fees other than annual maintenance fees in respect of the existing credit ratings were paid by the Company to these organizations during the last two years.

MARKET FOR SECURITIES

Trading Price and Volume

The Common Shares have been listed and posted for trading on the TSX under the symbol "ATH" since April 8, 2010. The following table sets forth the price range and trading volume for the Common Shares on the TSX as reported by the TSX for the periods indicated.

	Price Range		Volume
	High \$/share	Low \$/share	
2016			
March (1 to 9)	\$1.34	\$0.91	18,912,121
February	\$1.58	\$0.93	26,618,525
January	\$1.95	\$1.16	39,379,153
2015			
December	\$1.74	\$1.44	29,200,308
November	\$1.84	\$1.33	24,433,682
October	\$1.88	\$1.18	17,650,538
September	\$1.54	\$1.16	17,378,325
August	\$1.65	\$1.16	23,480,011
July	\$2.03	\$1.32	25,815,660
June	\$2.24	\$1.98	16,477,421
May	\$2.29	\$1.96	26,558,029
April	\$2.58	\$2.10	26,369,967
March	\$2.24	\$1.61	33,433,736
February	\$2.37	\$1.89	37,915,918
January	\$2.68	\$1.70	40,605,665

Prior Sales

The following is a description of securities of the Company that were issued in the financial year ended December 31, 2015 that are not listed or quoted on a marketplace:

- the Company granted an aggregate of 519,580 2010 RSUs to acquire an aggregate of 519,580 Common Shares, each with an exercise price of \$0.10. the Company also granted an aggregate of 2,996,150 2015 RSUs to acquire an aggregate of 2,996,150 Common Shares, each with no exercise price;
- the Company granted an aggregate of 2,792,800 Stock Options to acquire an aggregate of 2,792,800 Common Shares with a weighted average exercise price of \$2.02;
- the Company granted an aggregate of 1,429,500 Performance Awards; and
- the Company granted an aggregate of 633,082 Deferred Share Units;

ESCROWED COMMON SHARES AND COMMON SHARES SUBJECT TO A CONTRACTUAL RESTRICTION ON TRANSFER

As at December 31, 2015, the Common Shares of the Company that continued to be held in trust to the Company's knowledge were immaterial, representing less than 0.01% of the Company's issued and outstanding Common Shares.

DIRECTORS AND OFFICERS

As at the date of filing of this Annual Information Form, the names, provinces and countries of residence, positions held with the Company, and principal occupation of the directors and executive officers of the Company during the past five years are set out below, and in the case of directors, the period each has served as a director of the Company is also set forth below.

Name and Place of Residence	Office	Principal Occupation	Director Since
Ronald J. Eckhardt ⁽³⁾⁽⁴⁾ Alberta, Canada	Chairman	Mr. Eckhardt is currently retired. Prior thereto, Executive Vice President, North American Operations of Talisman Energy Inc. from October 2003 to September 2009.	April 1, 2012
Marshall McRae ⁽²⁾⁽⁴⁾ Alberta, Canada	Director	Mr. McRae has been an independent financial and management consultant since August 2009. Prior thereto, Mr. McRae was Chief Financial Officer of CCS Inc., administrator of CCS Income Trust and its successor corporation, CCS Corporation since August 2002. . Mr. McRae is a director and the Chair of the audit committee of Gibson Energy Inc. and a director of Black Diamond Group Limited. Mr. McRae served as interim Executive Vice President and CFO of Black Diamond Group Limited from October 16, 2013 to August 8, 2014 and as its Executive Vice President to December 31, 2014.	October 30, 2009
Peter Sametz ⁽²⁾⁽³⁾ Alberta, Canada	Director	Chief Executive Officer of Alberta Steam and Power Corp. since February 2013, a private company focused on provision of steam and power to the oil and gas industry. Prior thereto, Interim Chief Executive Officer from February 2012 to December 2012, President, Chief Operating Officer and a director from May 2010 to January 2012 and Executive Vice President and Chief Operating Officer from 2005 to 2010 of Connacher Oil and Gas Limited, a bitumen exploration, a development and production company listed on the TSX. Also currently a director of Gemini Corporation since October 2013.	March 14, 2014
Carlos Fierro ⁽²⁾ Washington, D.C., U.S.A	Director	Mr. Fierro is an independent investor and serves on public and private corporate boards. From September 2008 to June 2013, Mr. Fierro was the Managing Director and Global Head of the Natural Resources Group for Barclays PLC. Prior thereto, Mr. Fierro spent 11 years at Lehman Brothers, where his last role was the Global Head of the National Resources Group. Before joining Lehman Brothers, Mr. Fierro was a transactional lawyer with Baker Botts LLP., where he practiced corporate, M&A and securities law.	January 7, 2015

Name and Place of Residence	Office	Principal Occupation	Director Since
Paul G. Haggis ⁽⁴⁾ Alberta, Canada	Director	Mr. Haggis is currently the Chairman of Alberta Enterprise Corporation (a private Alberta Crown Corporation). He also currently sits on the board of Advantage Oil and Gas Ltd. Mr. Haggis has extensive experience in the institutional investment industry, including as CEO of Ontario Municipal Employees Retirement System from September 2003 to March 2007; Interim Chief Executive Officer of the Public Sector Pension Investment Board during 2003; Executive Vice-President, Development and Chief Credit Officer of Manulife Financial in 2002; and as CEO of Alberta Treasury Branches from 1996 to 2001. Mr. Haggis is also an advisor to the board of the Insurance Corporation of British Columbia (ICBC) and was the former chair of the ICBC's Investment Committee.	January 7, 2015
Bryan Begley	Director	Mr. Begley is currently a Managing Director and Partner at 1901 Partners, a private equity firm formed in 2014 to make private investments in the energy sector. From 2007 to 2014, Mr. Begley served as a Managing Director of ZBI Ventures, LLC, a private equity firm focused on the energy sector. Prior to joining ZBI Ventures, Mr. Begley was a Partner at MckInsey & Co. in the Houston and Dallas offices where he advised clients across the global energy sector. He began his career as an engineer with Phillips Petroleum Company.	March 10, 2016
Rob Broen ⁽³⁾ Alberta, Canada	Director, President & Chief Executive Officer	Director, President and Chief Executive Officer of the Company since April 21, 2015. Prior thereto, Chief Operating Officer of the Company since October 12, 2013. Prior thereto, Senior Vice President, Light Oil of the Company from November 26, 2012 to October 12, 2013. Prior thereto, Senior Vice-President, North American Shale at Talisman Energy Inc. from April 2012 to November 2012. Prior thereto, President and a director of Talisman Energy USA Inc. from 2009 to April 2012.	April 21, 2015
Kim Anderson Alberta, Canada	Chief Financial Officer	Chief Financial Officer of the Company since February 18, 2014. Prior thereto, Chief Financial Officer of KANATA Energy Group Ltd. from January 9, 2013 until February 14, 2014. Prior thereto, held various roles at Provident Energy Ltd. between June 2009 and April 2012, including Vice President, Finance & Investor Relations, Director, Finance & Investor Relations, Director, Finance & Information Services and Director, Finance Midstream.	N/A
Anne Schenkenberger Alberta, Canada	Vice President, General Counsel and Corporate Secretary	Vice President, General Counsel and Corporate Secretary of the Company since August 18, 2010. Prior thereto, General Counsel and Corporate Secretary of the Company from May 2008 to August 18, 2010. Prior thereto, legal counsel at ConocoPhillips Canada, a subsidiary of ConocoPhillips from April 2000 to April 2008.	N/A

Name and Place of Residence	Office	Principal Occupation	Director Since
Blair Hockley Alberta, Canada	Vice President, Thermal Oil	Vice President, Thermal Oil of the Company since April 1, 2015. Prior thereto Vice President, Hangingstone Asset since November 16, 2014. Prior thereto was the Asset Director of the Hangingstone Asset from March 1 2011, prior thereto was the Development Manager of the Hangingstone Asset from November 15, 2010. Prior thereto was the Insitu Integration Manager at Shell Canada from March 2009. Prior thereto was the Lead Project Engineer at Shell Canada from July 2008.	N/A
Kevin Smith Alberta, Canada	Vice President, Light Oil	Vice President, Light Oil of the Company since January 6, 2014. Prior thereto, Business Unit, Vice President at Encana Corporation from October 2008 until November 2013.	N/A
Matthew Taylor Alberta, Canada	Vice President, Capital Markets and Communications	Vice President, Capital Markets and Communications of the Company since May 4, 2014. Prior thereto was the Director of Energy Equity Research at National Bank from July 2010 to April 2014. Prior thereto held positions in equity research and investment banking at GMP Securities and CIBC World Markets from August 2007 to June 2010.	N/A
Rod Sousa Alberta, Canada	Vice President, Corporate Development	Vice President, Corporate Development of the Company since November 16, 2015. Prior thereto, Managing Director & Head of TD Energy Advisors in investment banking sector from July 2010. Prior thereto Managing Director and President of Ross Smith Sousa Energy Advisors between 2008 and 2010. Prior thereto held positions at Scotia Waterous between 1999 and 2008.	N/A

Notes:

- (1) The Company's directors hold office for a term expiring at the conclusion of the next annual meeting of Shareholders of the Company, or until their successors are elected or appointed pursuant to the ABCA, and are eligible for re-election. The Company's officers are appointed by and serve at the discretion of the Board.
- (2) Member of the Audit Committee. Mr. McRae is the Chairman of the Audit Committee.
- (3) Member of the Reserves Committee. Mr. Eckhardt is the Chairman of the Reserves Committee.
- (4) Member of the Compensation and Governance Committee. Mr. Haggis is the Chairman of the Compensation and Governance Committee.
- (5) The information set forth above is current as at the date of the filing of this Annual Information Form (March 10, 2016).
- (6) Mr. Thomas Buchanan and Mr. Gary Dundas stepped down from the Company's Board on the date of filing of this Annual Information Form, consequently they are not included in the current list of directors set forth above.

As at December 31, 2015, the directors and executive officers of the Company, as a group, beneficially owned, controlled or directed, directly or indirectly, an aggregate of 2,666,551 Common Shares, representing 0.6% of the issued and outstanding Common Shares (not including any Common Shares issuable pursuant to the exercise of the issued and outstanding Stock Options, RSUs, Performance Awards or DSUs). As at March 10, 2016, the directors and executive officers of the Company, as a group, beneficially owned, controlled or directed, directly or indirectly, an aggregate of 735,707 Common Shares, representing 0.2% of the issued and outstanding Common Shares (not including any Common Shares issuable pursuant to the exercise of the issued and outstanding Stock Options, RSUs, Performance Awards or DSUs).

Corporate Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Other than as disclosed below, to the knowledge of the Company, no current director or executive officer of the Company has, within the last ten years prior to the date of this document, been a director, chief executive officer or

chief financial officer of any issuer (including the Company) that: (a) while the person was acting in the capacity as director, chief executive officer or chief financial officer, was the subject of a cease trade or similar order or an order that denied the company access to any exemption under securities legislation, that was in effect for a period of more than thirty (30) consecutive days; or (b) was subject to an order that resulted, after the director or executive officer ceased to be a director, chief executive officer or chief financial officer of an issuer, in the issuer being the subject of a cease trade or similar order or an order that denied the relevant issuer access to any exemption under securities legislation, for a period of more than thirty (30) consecutive days, which resulted from an event that occurred while that person was acting as a director, chief executive officer or chief financial officer of the issuer.

To the knowledge of the Company, other than as disclosed below, no current director or executive officer or security-holder holding a sufficient number of securities of the Company to affect materially the control of the Company has, within the last ten years prior to the date of this document, been a director or executive officer of any company (including the Company) that, while such person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement for compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

In addition, no current director or executive officer or security-holder holding a sufficient number of securities of the Company to affect materially the control of the Company has, within the last ten years prior to the date of this document, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, officer or security-holder.

To the knowledge of the Company, no current director or executive officer or security-holder holding a sufficient number of securities of the Company to affect materially the control of the Company has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Certain of the directors and officers of the Company are engaged in, and may continue to be engaged in, other activities in the oil and natural gas industry from time to time. As a result of these and other activities, certain directors and officers of the Company may become subject to conflicts of interest from time to time. The ABCA provides that in the event that an officer or director is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or material transaction or proposed material contract or proposed material transaction, such officer or director shall disclose the nature and extent of his or her interest and shall refrain from voting to approve such contract or transaction, unless otherwise provided under the ABCA. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the ABCA.

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

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

There were no legal proceedings that the Company is or was a party to, or that any of the Company's property is or was the subject of, during the most recently completed financial year, that were or are material to the Company, and there are no such material legal proceedings that the Company knows to be contemplated. For the purposes of the foregoing, a legal proceeding is not considered to be "material" by the Company if it involves a claim for damages and the amount involved, exclusive of interest and costs, does not exceed 10% of the Company's current assets, provided that if any proceeding presents in large degree the same legal and factual issues as other proceedings pending

or known to be contemplated, the Company has included the amount involved in the other proceedings in computing the percentage.

Regulatory Actions

During the year ended December 31, 2015, there were: (a) no penalties or sanctions imposed against the Company by a court relating to securities legislation or by a securities regulatory authority; (b) no other penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decision; and (c) no settlement agreements entered into by the Company with a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of any director or executive officer of the Company, any person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of the outstanding Common Shares, or any associate or affiliate of any of such persons or companies, in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or is reasonably expected to materially affect the Company or a subsidiary of the Company.

TRANSFER AGENTS AND REGISTRARS

Computershare Trust Company of Canada at its office in Calgary, is the transfer agent and registrar for the Common Shares.

MATERIAL CONTRACTS

As at December 31, 2015, the following were the only material contracts, other than those contracts entered into in the ordinary course of business, which the Company or any of its subsidiaries has entered into within the most recently completed financial year, or before the most recently completed financial year and which were still in effect as of December 31, 2015:

- the Note Indenture;
- the Rights Plan referred to under the heading “*Description of Capital Structure – Shareholder Rights Plan*”.
- The Murphy Purchase and Sale Agreement (entered into January 27, 2016). See “*The Murphy Transaction*” under the heading “*General Development of the Business - Recent Significant Transactions*”.

Copies of these material contracts are available for review on the Company’s SEDAR profile at www.sedar.com.

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada and Alberta, all of which should be carefully considered by investors in the oil and gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in Alberta.

Pricing and Marketing

Oil

In Canada, the producers of oil are entitled to negotiate sales contracts directly with oil purchasers, which results in the market determining the price of oil. Worldwide supply and demand factors primarily determine oil prices; however, prices are also influenced by regional market and transportation issues. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the supply/demand balance and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export license from the NEB. The NEB is currently undergoing a consultation process to update the regulations governing the issuance of export licenses. The updating process is necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act* (Canada) (the "**Prosperity Act**") which received Royal Assent on June 29, 2012. In this transitory period, the NEB has issued, and is currently following an "Interim Memorandum of Guidance concerning Oil and Gas Export Applications and Gas Import Applications" under Part VI of the *National Energy Board Act* (Canada).

Natural Gas

Canada's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system, at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange, Intercontinental Exchange or the New York Mercantile Exchange in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m³/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 40 years) or for a larger quantity requires an exporter to obtain an export license from the NEB.

The North American Free Trade Agreement

The North American Free Trade Agreement ("NAFTA") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply.

All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports. NAFTA contemplates the reduction

of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects, crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of 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 and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are carved out of the working interest owner's interest, from time to time, through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

The federal government has signaled it will, *inter alia*, phase out subsidies for the oil and gas industry, which include only allowing the use of the Canadian Exploration Expenses tax deduction in cases of successful exploration, implementing more stringent reviews for pipelines, and establishing a pan-Canadian framework for combating climate change within 90 days of the 2015 Paris Climate Conference which concluded on December 12, 2015. These changes could affect earnings of companies operating in the oil and natural gas industry.

Alberta

On January 29, 2016, the Government of Alberta released and accepted the Royalty Review Advisory Panel's recommendations, which outlined the implementation of a "Modernized Royalty Framework" for Alberta (the "MRF"). The MRF will take effect on January 1, 2017. Wells drilled prior to January 1, 2017 will continue to be governed by the current "Alberta Royalty Framework" for a period of 10 years until January 1, 2027. The MRF is structured in three phases: (i) Pre-Payout, (ii) Mid-Life, and (iii) Mature. During the Pre-Payout phase, a fixed 5% royalty will apply until the well reaches payout. Well payout occurs when the cumulative revenue from a well is equal to the Drilling and Completion Cost Allowance (determined by a formula that approximates drilling and completion costs for wells based on depth, length and historical costs). The new royalty rate will be payable on gross revenue generated from all production streams (oil, gas, and natural gas liquids), eliminating the need to label a well as "oil" or "gas". Post-payout, the Mid-Life phase will apply a higher royalty rate than the Pre-Payout phase. While the metrics for calculating the Mid-Life phase royalty have yet to be released, the rate will be determined based on commodity prices and are intended, on average, to yield the same internal rate of return as under the current Alberta Royalty Framework. In the Mature phase, once a well reaches the tail end of its cycle and production falls below a Maturity Threshold, currently estimated to be 20 bbl/d for oil and 200 mcf/d for gas, the royalty rate will move to a sliding scale (based on volume and price) with a minimum royalty rate of 5%. The downward adjustment of the royalty rate in the Mature phase is intended to account for the higher per-unit fixed cost involved in operating an older well. Details of the MRF, including the applicable royalty rates and formulas, are scheduled to be released by March 31, 2016.

Oil sands projects are also subject to Alberta's royalty regime. The MRF does not change the oil sands royalty framework, however, the method and figures by which the royalties are calculated will be released to the public. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1% - 9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil at Cushing, Oklahoma. Rates are 1% when the market price

of oil is less than or equal to \$55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at \$120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1% - 9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above \$55 up to 40% when oil is priced at \$120 or higher.

Currently, producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, at a rate of \$3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced.

Royalties, for wells drilled prior to January 1, 2017 are paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the "Alberta Royalty Framework" until January 1, 2027. Royalty rates for conventional oil are set by a single sliding rate formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 40%. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula with the maximum royalty payable under the royalty regime set at 36%.

Producers of oil and natural gas from freehold lands in Alberta are required to pay freehold mineral tax. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the *Freehold Mineral Rights Tax Act* (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is 4% of revenues reported from fee simple mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program (the "**IETP**") has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "**Emerging Resource and Technologies Initiative**"). These initiatives apply to wells drilled before January 1, 2017, for a 10 year period, until January 1, 2027. Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;
- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;
- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and
- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

While the MRF eliminates the various royalty credits and incentives, outlined above, for wells drilled after December 31, 2016, the Government of Alberta has committed to creating cost allowance programs for both enhanced oil recovery schemes and higher risk experimental drilling. Details of these programs are scheduled to be released simultaneously with the finalization of the MRF, prior to March 31, 2016.

Land Tenure

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licenses, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Private ownership of oil and natural gas also exists in such provinces and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Alberta has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license. Alberta has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses issued after January 1, 2009 at the conclusion of the primary term of the lease or license.

Production and Operation Regulations

The oil and natural gas industry in Canada is highly regulated and subject to significant control by provincial regulators. Regulatory approval is required for, among other things, the drilling of oil and natural gas wells, construction and operation of facilities, the storage, injection and disposal of substances and the abandonment and reclamation of well-sites. In order to conduct oil and gas operations and remain in good standing with the applicable provincial regulator, we must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance with such legislation, regulations, orders, directives or other directions can be costly and a breach of the same may result in fines or other sanctions.

Environmental Regulation

The oil and natural gas industry is currently subject to regulation pursuant to a variety of provincial and federal environmental legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, 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, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability and the imposition of material fines and penalties.

Federal

Pursuant to the *Prosperity Act*, the Government of Canada amended or repealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime that came in to force on July 6, 2012. The changes to the environmental legislation under the *Prosperity Act* are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

Alberta

The Alberta Energy Regulator (the "**AER**") is the single regulator responsible for all energy development in Alberta. The AER ensures the safe, efficient, orderly, and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind a single regulator is an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. The following frameworks, plans and policies form the basis of Alberta's Integrated Resource Management System ("IRMS"). The IRMS method to natural resource management sets out to engage and consult with stakeholders and the public. While the AER is the primary regulator for energy development, several governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, the AER, the Alberta Environmental Monitoring, Evaluation and Reporting Agency, the Policy Management Office, the Aboriginal Consultation Office, and the Land Use Secretariat.

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage 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 seven 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.

Proclaimed in force in Alberta on October 1, 2009, the *Alberta Land Stewardship Act* (the "**ALSA**") provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established under the ALSA are deemed to be legislative instruments equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas 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, licenses, registrations, approvals and authorizations 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 set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**") which came into force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeastern corner of Alberta that is approximately 93,212 square kilometres in size. The region includes a substantial portion of the Athabasca oil sands area, which contains approximately 82% of the province's oil sands resources and much of the Cold Lake oil sands area.

LARP establishes six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and gas companies with pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and provincial recreation areas will include a restriction that prohibits surface access. In contrast, oil sands companies' tenure has been (or will be) cancelled in conservation areas and no new oil sands tenure will be issued. While new oil sands tenure will be issued in provincial recreation areas, new and existing oil sands tenure will prohibit surface access.

In July 2014, the Government of Alberta approved the South Saskatchewan Regional Plan ("**SSRP**") which came into force on September 1, 2014. The SSRP is the second regional plan developed under the ALUF. The SSRP covers approximately 83,764 square kilometres and includes 44% of the provincial population.

The SSRP creates four new and four expanded conservation areas, and two new and six expanded provincial parks and recreational areas. Similar to LARP, the SSRP will honour existing petroleum and natural gas tenure in conservation and provincial recreational areas. However, any new petroleum and natural gas tenures sold in conservation areas, provincial parks, and recreational areas will prohibit surface access. However, oil and gas companies must minimize impacts of activities on the natural landscape, historic resources, wildlife, fish and vegetation when exploring, developing and extracting the resources. Freehold mineral rights will not be subject to this restriction.

Liability Management Rating Programs

Alberta

In Alberta, the AER implements the Licensee Liability Rating Program (the "**AB LLR Program**"). The AB LLR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. Alberta's *Oil and Gas Conservation Act* establishes an orphan fund (the "**Orphan Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program if a licensee or working interest participant ("**WIP**") becomes defunct. The Orphan Fund is funded by licensees in the AB LLR Program through a levy administered by the AER. The AB LLR Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licensees and prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The AB LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the AER.

Made effective in three phases, from May 1, 2013 to August 1, 2015, the AER implemented important changes to the AB LLR Program (the "**Changes**") that resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security. The Changes affect the deemed parameters and costs used in the formula that calculates the ratio of deemed liabilities to deemed assets under the AB LLR Program, increasing a licensee's deemed liabilities and rendering the industry average netback factor more sensitive to asset value fluctuations. The Changes stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

The AER implemented the inactive well compliance program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under *Directive 013: Suspension Requirements for Wells* ("**Directive 013**"). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within 5 years. As of April 1, 2015, each licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with *Directive 020: Well Abandonment*. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission system.

Climate Change Regulation

Federal

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulatory environment of the oil and natural gas industry in Canada. Such regulations, surveyed below, impose certain costs and risks on the industry.

The Government of Canada is a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and a participant to the Copenhagen Accord (a non-binding agreement created by the UNFCCC which represents a broad political consensus and reinforces commitments to reducing greenhouse gas ("**GHG**") emissions). On January 29, 2010, Canada inscribed in the Copenhagen Accord its 2020 economy-wide target of a 17% reduction of GHG emissions from 2005 levels. This target is aligned with the United States target. In a report dated October 2013, the federal government stated that this target represents a significant challenge in light of strong economic growth (Canada's economy is projected to be approximately 31% larger in 2020 compared to 2005 levels).

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets, for application to regulated sectors on a facility-specific basis, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated

Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors. The federal government indicates that it is taking a sector-by-sector regulatory approach to reducing GHG emissions and is working on regulations for other sectors. Representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. In June 2012, the second US-Canada Clean Energy Dialogue Action Plan was released. The plan renewed efforts to enhance bilateral collaboration on the development of clean energy technologies to reduce GHG emissions.

On December 12, 2015, the UNFCCC adopted the Paris Agreement, to which Canada is a participant. The Paris Agreement mandates that all countries must work together to limit global temperature rise resulting from GHG emissions to a goal of less than 2° Celsius and to pursue efforts to limit below 1.5° Celsius, through implementing successive nationally determined contributions. Technical details remain unreleased, but the Government of Canada is expected to announce a plan within 90 days of the Paris Agreement, which will significantly increase Canada's GHG emission reduction targets.

Alberta

As part of its efforts to reduce GHG emissions, Alberta introduced legislation to address GHG emissions: the *Climate Change and Emissions Management Act* (the "**CCEMA**") enacted on December 4, 2003 and amended through the *Climate Change and Emissions Management Amendment Act*, which received royal assent on November 4, 2008. The accompanying regulations include the *Specified Gas Emitters Regulation* ("**SGER**"), which imposes GHG limits, and the *Specified Gas Reporting Regulation*, which imposes GHG emissions reporting requirements. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions. The SGER applies to facilities emitting more than 100,000 tonnes of GHGs in 2003 or any subsequent year ("**Regulated Emitters**"), and requires reductions in GHG emissions intensity (e.g. the quantity of GHG emissions per unit of production) from emissions intensity baselines established in accordance with the SGER.

On June 25, 2015, the Government of Alberta renewed the SGER for a period of two years with significant amendments while Alberta's newly formed Climate Advisory Panel conducted a comprehensive review of the province's climate change policy. In 2015, Regulated Emitters are required to reduce their emissions intensity by 2% from their baseline in the fourth year of commercial operation, 4% of their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year, 10% of their baseline in the eighth year, and 12% of their baseline in the ninth or subsequent years. These reduction targets will increase, meaning that Regulated Emitters in their ninth or subsequent years of commercial operation must reduce their emissions intensity from their baseline by 15% in 2016 and 20% in 2017.

Regulated Emitters can meet their emissions intensity targets through a combination of the following: (1) producing its products with lower carbon inputs, (2) purchasing emissions offset credits from non-regulated emitters (generated through activities that result in emissions reductions in accordance with established protocols), (3) purchasing emissions performance credits from other Regulated Emitters that earned credits through the reduction of their emissions below the 100,000 tonne threshold, (4) cogeneration compliance adjustments, and (5) by contributing to the Climate Change and Emissions Management Fund (the "**Fund**"). Contributions to the Fund are made at a rate of \$15 per tonne of GHG emissions, increasing to a rate of \$20 per tonne of GHG emissions in 2016 and \$30 per tonne of GHG emissions in 2017. Proceeds from the Fund are directed at testing and implementing new technologies for greening energy production.

On November 22, 2015, as a result of the Climate Advisory Panel's Climate Leadership report, the Government of Alberta announced its Climate Leadership Plan which proposes to introduce a carbon tax on all emitters. An economy-wide levy \$30 per tonne of GHG emissions will be phased in, starting in January 2017 at \$20 per tonne, and increasing to \$30 per tonne in January 2018 relative to a performance standard which is yet to be determined. An oil sands specific approach was proposed to replace the \$30 per tonne of GHG emissions to further reduce emissions and promote carbon competitiveness rather than rewarding past intensity levels. A 100 megatonne per year limit for GHG emissions was proposed for oil sands operations, which currently emit roughly 70 megatonnes per year. This cap exempts new upgrading and cogeneration facilities, which are allocated a separate 10 megatonne limit. The existing SGER will be replaced for large industrial facilities with a Carbon Competitiveness Regulation ("**CCR**"), in which sector specific output-based carbon allocations will be used to ensure competitiveness.

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed \$1.24 billion over 15 years to fund two large-scale carbon capture and storage projects that will begin commercializing the technology on the scale needed to be successful. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*. It 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.

INTEREST OF EXPERTS

Names of Experts

The only persons or companies who are named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under NI 51-102 by the Company during, or relating to the Company's most recently completed financial year, and whose profession or business gives authority to the report, valuation, statement or opinion made by the person or company, are GLJ and D&M (collectively, the "**Experts**"), Athabasca's independent engineering evaluators, and Ernst & Young LLP, the Company's auditors.

Interests of Experts

There were no registered or beneficial interests, direct or indirect, in any securities or other property of the Company or of one of its associates or affiliates: (a) held by an Expert or by the "designated professionals" (as defined in Form 51-102F2 to NI 51-102) of such Expert, when such Expert prepared the report, valuation, statement or opinion referred to herein as having been prepared by such Expert; (b) received by an Expert or by the "designated professionals" of such Expert, after the time specified above; or (c) to be received by an Expert or by the "designated professionals" of such Expert; except in each case for the ownership of Common Shares, which in respect of each Expert and such Expert's "designated professionals", as a group, has at all relevant times represented less than one percent of the outstanding Common Shares. In addition, none of the Experts, and no director, officer or employee of any of the Experts, is or is expected to be elected, appointed or employed as a director, officer or employee of the Company or of any associate or affiliate of the Company.

Ernst & Young LLP is independent within the meaning of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta.

RISK FACTORS

An investment in the Common Shares involves a substantial degree of risk and is highly speculative due to the nature of Athabasca's business and its stage of development. As a result, investors should consider investing in the Common Shares only if they can afford to lose their entire investment. Investors should carefully consider the risks described below and the other information contained in this Annual Information Form before making a decision to buy Common Shares.

If any of the following risks or other risks occur Athabasca's business, prospects, financial condition, results of operations and cash flows could be materially adversely impacted. In that case, the trading price of the Common Shares could decline and investors could lose all or part of their investment in the Common Shares. There is no assurance that risk management steps taken by Athabasca will avoid future loss due to the occurrence of the risk factors described below or other unforeseen risks.

Risks Relating to Athabasca's Business

Weakness in the Oil and Gas Industry

Recent market events and conditions, including global excess oil and natural gas supply, recent actions taken by the Organization of the Petroleum Exporting Countries ("**OPEC**"), slowing growth in China and other emerging economies, market volatility and disruptions in Asia, and sovereign debt levels in various countries, have caused

significant weakness and volatility in commodity prices. These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by the recent changes in government at a federal level and, in case of Alberta, the provincial level and the resultant uncertainty surrounding regulatory, tax and royalty changes that may be implemented by the new governments. In addition, the inability to get the necessary approvals to build pipelines and other facilities to provide better access to markets for the oil and gas industry in western Canada has led to additional uncertainty and reduced confidence in the oil and gas industry in western Canada. Lower commodity prices may also affect the volume and value of Athabasca's reserves especially as certain reserves become uneconomic. In addition, lower commodity prices have restricted, and are anticipated to continue to restrict, Athabasca's cash flow resulting in a reduced capital expenditure budget. As a result, Athabasca may not be able to replace its production with additional reserves and both Athabasca's production and reserves could be reduced on a year over year basis. Any decrease in value of Athabasca's reserves may reduce the borrowing base under its credit facilities, which, depending on the level of Athabasca's indebtedness, could result in Athabasca having to repay a portion of its indebtedness. Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, Athabasca may have difficulty raising additional funds or if it is able to do so, it may be on unfavourable and highly dilutive terms. If these conditions persist, Athabasca's cash flow may not be sufficient to continue to fund its operations and to satisfy its obligations when due and Athabasca's ability to continue as a going concern and discharge its obligations will require additional equity or debt financing and/or proceeds from asset sales. There can be no assurance that such equity or debt financing will be available on terms that are satisfactory to Athabasca or at all. Similarly, there can be no assurance that Athabasca will be able to realize any or sufficient proceeds from asset sales to discharge its obligations and continue as a going concern.

Fluctuations in Prices, Markets and Marketing

Numerous factors beyond Athabasca's control do, and will continue to, affect the marketability and price of oil and natural gas acquired or discovered by Athabasca. Athabasca's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets or contract for the delivery of crude oil by rail. Deliverability uncertainties related to the distance Athabasca's reserves are from pipelines, railway lines, processing and storage facilities, operational problems affecting pipelines, railway lines and facilities as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect Athabasca.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of Athabasca. These factors include economic conditions in the United States, Canada, Europe, China and emerging markets, the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply and demand of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and Athabasca's ability to access such markets. Oil prices are expected to remain volatile and may decline in the near future as a result of global excess supply due to the increased growth of shale oil production in the United States, the decline in global demand for exported crude oil commodities, and OPEC's recent decisions pertaining to the oil production of OPEC member countries, among other factors. A material decline in prices could result in a reduction of Athabasca's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of Athabasca's reserves. Athabasca might also elect not to produce from certain wells at lower prices.

All these factors could result in a material decrease in Athabasca's expected net production revenue and a reduction in its oil and natural gas acquisition, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on Athabasca's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on Athabasca's business, financial condition, results of operations and prospects.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions, sanctions imposed on certain oil producing nations by other countries and ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause

disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

Any prolonged period of low crude oil and/or natural gas prices could result in a decision by Athabasca to suspend or slow development activities, to suspend or slow the construction or expansion of bitumen recovery, crude oil and/or natural gas projects, or (following the commencement of production) to suspend or reduce production levels. Any of such actions could have a material adverse effect on Athabasca's results of operations and financial condition.

Athabasca conducts an assessment of the carrying value of its assets to the extent required by International Financial Reporting Standards. If commodity prices decline, the carrying value of Athabasca's assets could be subject to downward revision, and Athabasca's earnings could be adversely affected.

See also "*Weakness in the Oil and Gas Industry*".

General Economic Conditions, Business Environment and Other Risks

The business of Athabasca is subject to general economic conditions. Adverse changes in general economic and market conditions could negatively impact demand for crude oil, bitumen and bitumen blend, natural gas, revenue, operating costs, results of financing efforts, timing and extent of capital expenditures or credit risk and counterparty risk. Volatility in crude oil, bitumen blend, natural gas, SCO and other diluent prices, fluctuations in interest rates, product supply and demand fundamentals, market competition, labour market supplies, risks associated with technology, risks of a widespread pandemic, Athabasca's ability to generate sufficient cash flow from operations to meet its current and future obligations, Athabasca's ability to access external sources of debt and equity capital, general economic and business conditions, Athabasca's ability to make capital investments and the amounts of capital investments, risks associated with potential future lawsuits and regulations, assessments and audits (including income tax) against Athabasca and its subsidiaries, political and economic conditions in the geographic regions in which Athabasca and its subsidiaries operate, difficulty in obtaining necessary regulatory approvals, a significant decline in Athabasca's reputation, and such other risks and uncertainties, could individually or in the aggregate have a material adverse impact on Athabasca's business, prospects, financial condition, results of operation or cash flows. Challenging market conditions and the health of the economy as a whole may have a material adverse effect on Athabasca's business, financial condition, liquidity and results of operations. There can be no assurance that any risk management steps taken by Athabasca with the objective of mitigating the foregoing risks will avoid future loss due to the occurrence of such risks.

Global Financial Markets

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels have caused significant volatility in commodity prices. These events and conditions have caused a decrease in confidence in the broader United States and global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and are likely to continue to impact the performance of the global economy going forward. Worldwide crude oil commodity prices are expected to remain volatile for the near future as a result of global excess supply, recent actions taken by OPEC and ongoing global credit and liquidity concerns. This volatility may affect Athabasca's ability to obtain equity or debt financing on acceptable terms.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

Athabasca considers acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and Athabasca's ability to realize the anticipated growth opportunities and

synergies from combining the acquired businesses and operations with those of Athabasca. The integration of acquired businesses may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, certain assets may be periodically disposed of so Athabasca can focus its efforts and resources more efficiently. Depending on the state of the market for such assets, certain assets of Athabasca, if disposed of, may realize less than their carrying value on the financial statements of Athabasca.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase Athabasca's costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that Athabasca is ultimately able to produce from its reserves.

Due to recent seismic activity reported in the Fox Creek area of Alberta, the Alberta Energy Regulator has announced new seismic monitoring and reporting requirements for hydraulic fracturing operators in the Duvernay Zone in the Fox Creek area. These requirements include, among others, an assessment of the potential for seismicity prior to operations, the implementation of a response plan to address potential events, and the suspension of operations if a seismic event above a particular threshold occurs. The Alberta Energy Regulator continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary.

Extent of, and Cost of Compliance with, Government Regulation

The oil and gas industry in Canada, including the oil sands industry, operates under federal and provincial statutes and regulations governing such matters as land tenure, prices, royalties, production rates, environmental protection controls, the export of crude oil, natural gas and other products, as well as other matters. The industry is also subject to regulation by governments in such matters as the awarding or acquisition of exploration and production rights, oil sands, petroleum, natural gas or other interests, the imposition of specific drilling obligations, control over the development and abandonment of oil and natural gas properties (including restrictions on production) and possible expropriation or cancellation of lease and permit rights. The regulatory scheme as it relates to oil sands, and the recovery and marketing of bitumen or bitumen by-products from oil sands, is somewhat different from that related to conventional oil and gas in general.

Government regulations may be changed from time to time in response to economic or political conditions. The exercise of discretion by governmental authorities under existing statutes or regulations, the implementation of new statutes or regulations or the modification of existing statutes or regulations affecting the crude oil and natural gas industry could impact the markets for crude oil and natural gas, delay or stop the development of Athabasca's projects, delay or increase Athabasca's costs, either of which may have a material adverse effect on Athabasca's business, financial condition, results of operations and prospects.

In order to conduct oil and gas operations, Athabasca will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that Athabasca will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, Athabasca's business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

Royalty Regimes

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of Athabasca's projects. An increase in royalties would reduce Athabasca's earnings and could make future capital investments, or Athabasca's operations, less economic. On January 29, 2016, the Government of Alberta adopted a new royalty regime which will take effect on January 1, 2017. Details of this new regime are scheduled to be finalized and released before March 31, 2016. See "*Industry Conditions - Royalties and Incentives*".

Substantial Capital Requirements and Liquidity Risk

Substantial capital expenditures will be required to fund the exploration and development of Athabasca's Thermal Oil assets and Light Oil assets. Athabasca's 2016 capital and operating budgets are intended to be funded with existing cash and short term investments, the remaining Promissory Note, proceeds of the Murphy Transaction, the Kaybob Carry Commitment, cash flow from operations, the Amended Credit Facility, Term Loans or other debt financing. Beyond 2016, Athabasca will require additional capital to maintain its pace of development. Currently, management intends that Athabasca will fund its activities and other requirements beyond 2016 through some combination of existing cash and short term investments, the remaining Promissory Note, proceeds of the Murphy Transaction, the Kaybob Carry Commitment, cash flow from operations, the Amended Credit Facility, Term Loans or other external financing options including debt financing, equity issuances and possible future joint venture arrangements to the extent permitted by the Amended Credit Facility, Term Loans and Note Indenture. However, there can be no assurance that the cash that may be generated from Athabasca's operations and/or the other sources of financing, including the ability to raise additional capital through debt financing or refinancing, will be available or sufficient to meet Athabasca's requirements, or if external sources of funding are available, that they will be available on terms that are acceptable to Athabasca. Athabasca's ability to obtain the required capital will depend on, among other factors, the overall state of the capital markets, interest rates, royalty rates, and investor demand for investments in the energy industry and Athabasca's securities in particular. Additionally, asset divestments are subject to certain limitations in terms of how Athabasca is permitted to allocate the proceeds pursuant to the terms of the Amended Credit Facility, Term Loans and Note Indenture.

The inability to access sufficient capital for Athabasca's operations and other requirements could result in, among other things, the default of Athabasca under the Amended Credit Facility, Terms Loans and/or the Note Indenture and the inability of Athabasca to conduct exploration and development programs in respect of certain or all of its assets. Any of these results could have a material adverse effect on Athabasca's financial condition, results of operations and prospects.

Additional Funding Requirements

Athabasca's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and from time to time, Athabasca may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. There is risk that if the economy and banking industry experiences unexpected and/or prolonged deterioration, Athabasca's access to additional financing may be affected.

Because of global economic volatility, Athabasca may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause Athabasca to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If Athabasca's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect Athabasca's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, Athabasca's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of Athabasca's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Failure to obtain any financing necessary for Athabasca's capital expenditure plans may result in a delay in development or production on Athabasca's properties.

The Murphy Transaction

Athabasca or Murphy may not satisfy the required pre-closing conditions or acquire required regulatory approvals or there may be a delay in the satisfaction of required pre-closing conditions or acquiring of required regulatory approvals which may impact timing of closing of the Murphy Transaction or closing may not occur at all. Post-closing, Athabasca will be dependent upon Murphy as operator of the Kaybob assets and as its joint venture participant in the Kaybob and Placid assets. Athabasca is dependent upon Murphy's willingness and ability to satisfy its obligations in relation to the payment of the purchase price and the Kaybob Carry Commitment and any partial or complete failure to do so by Murphy may have an adverse financial impact upon Athabasca. Athabasca may not realize the expected benefit or any benefit at all, financial or otherwise from the Murphy Transaction.

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars. The Canadian dollar/United States dollar exchange rate, which fluctuates over time, consequently affects the price received by the Canadian producers of oil and natural gas. Recently, the Canadian dollar has decreased materially in value against the United States dollar. Material decreases in the value of the Canadian dollar positively affect commodity prices valued in United States dollars thereby increasing Athabasca's production revenues. Future Canadian/U.S. dollar exchange rates could accordingly affect the future value of Athabasca's resources as determined by independent evaluators.

Athabasca has incurred current United States denominated debt and may incur further US denominated debt in future which may result in exposure for Athabasca to the aforementioned fluctuations in currency exchange rates. In addition, Athabasca may in the future incur indebtedness at variable rates of interest that expose Athabasca to additional interest rate risk. If interest rates increase, Athabasca's debt service obligations on such variable rate indebtedness would increase even though the amount borrowed remains the same, and Athabasca's net income and cash flows would decrease. This could result in a reduced amount available to fund Athabasca's exploration and development activities, and could negatively impact the market price of the Common Shares. To the extent that Athabasca engages in risk management activities related to foreign exchange rates or interest rates, there is a credit risk associated with counterparties with whom Athabasca may contract.

Climate Change

Athabasca's exploration and production facilities and other operations and activities emit greenhouse gases which may require Athabasca to comply with GHG emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the *United Nations Framework Convention on Climate Change* (the "UNFCCC") and a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in GHG emissions from 2005 levels by 2020; however, these GHG emission reduction targets are not binding. Some of Athabasca's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. As a result of the UNFCCC adopting the Paris Agreement on December 12, 2015, to which Canada was a participant, the Government of Canada is expected to announce a plan to further reduce its GHG emission reduction targets by March 11, 2016. The direct or indirect costs of compliance with these regulations may have a material adverse effect on Athabasca's business, financial condition, results of operations and prospects. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is not possible to predict the impact on Athabasca and its operations and financial condition. Environmental legislation regulating carbon fuel standards in jurisdictions that import crude and synthetic crude oil in the United States could result in increased costs and/or reduced revenue for oil sands companies such as Athabasca. For example, both California and the United States federal government have passed legislation which, in some circumstances, considers the lifecycle GHG emissions of purchased fuel and which may negatively affect the marketing of bitumen, bitumen blend or SCO, or require the purchase of emissions credits in order to effect sales in such jurisdictions. See "*Industry Conditions - Climate Change Regulation*".

Amended Credit Facility, Term Loans and Senior Secured Notes

Athabasca currently has the Amended Credit Facility, the Term Loans and the Senior Secured Notes (collectively the “**Secured Debt**”). Athabasca is required to comply with covenants under the Secured Debt which include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding and in the event that Athabasca does not comply with these covenants, Athabasca’s access to capital could be restricted or repayment could be required. Events beyond Athabasca’s control may contribute to the failure of Athabasca to comply with such covenants. A failure to comply with covenants could result in the default under all or any of the Amended Credit Facility, the Term Loans or the Senior Secured Notes which could result in Athabasca being required to repay amounts owing thereunder. Even if Athabasca is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to Athabasca. If Athabasca is unable to repay amounts owing under any or all of the Amended Credit Facility, the Term Loans or the Senior Secured Notes, the lenders under the Amended Credit Facility, the Term Loans or the Senior Secured Notes as applicable, could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of Athabasca’s indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Secured Debt may impose operating and financial restrictions on Athabasca that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to Athabasca’s securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into amalgamations, mergers, take-over bids or disposition of assets, among others.

If Athabasca experiences a Change of Control (as such term is defined in the Note Indenture, Amended and Restated Credit Agreement or the Term Loan Credit Agreement, as the context requires), Athabasca may be required to make an offer to repurchase all of the outstanding Senior Secured Notes prior to their maturity at 101% of their principal amount and the Term Loans at par value, plus accrued and unpaid interest if any, to, but not including, the purchase date. Additionally, under each of the Amended Credit Facility and the Term Loans, a Change of Control (as defined in the Amended and Restated Credit Agreement or the Term Loan Credit Agreement, as applicable) may permit the lenders to accelerate the maturity of borrowings under such facilities, terminate their commitments to lend and require repayment of amounts drawn under the Amended Credit Facility. Athabasca may not have sufficient funds or be able to arrange for additional financing at the time of the Change of Control to make the required repurchase of the Senior Secured Notes and repay any of Athabasca’s other indebtedness that may also become due. As a result, Athabasca may require additional financing from third parties to fund any such purchases, and it may be unable to obtain financing on satisfactory terms or at all. Further, Athabasca’s ability to repurchase the Senior Secured Notes may also be limited by law.

Geopolitical Risks

Political events throughout the world that cause disruptions in the supply of oil continuously affect the marketability and price of oil and natural gas acquired or discovered by Athabasca. Conflicts, or conversely, peaceful developments, arising outside of Canada have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of Athabasca’s net production revenue. In addition, Athabasca’s oil and natural gas properties, wells and facilities could be the subject of a terrorist attack. If any of Athabasca’s properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on Athabasca’s business, financial condition, results of operations and prospects. Athabasca does not have insurance to protect against the risk from terrorism.

Uncertainties Associated with Estimating Reserves and Resource Volumes

GLJ and D&M have completed geological evaluations of Athabasca’s properties effective as of December 31, 2015. See “*Independent Reserves Evaluations*” and “*Schedule A- Contingent Resource Estimates*”. There are numerous uncertainties inherent in estimating the quantities of reserves and resources attributable to Athabasca’s assets and the future cash flows attributed to such reserves and resources, including many factors beyond Athabasca’s control, and no assurance can be given that the indicated level of reserves and resources will be realized. The reserves, resource and associated cash flow information set forth in this document are estimates only.

In general, estimates of recoverable reserves and resources are based upon a number of factors and assumptions made as of the date on which the reserves and resource estimates were determined, such as geological and engineering estimates, historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, and the assumed effects of regulation by governmental agencies, estimates of future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of reserves and resources are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable bitumen, crude oil and natural gas and the classification of such reserves and resources based on risk of recovery prepared by different engineers or by the same engineers at different times may vary substantially.

Estimates with respect to reserves and resources that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves and resources, rather than upon actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves and resources based upon production history will result in variations, which may be material, in the estimated reserves and resources. Reserves and resource estimates may require revision based on actual production experience. Such figures have been determined based upon assumed oil and natural gas prices and operating costs. Market fluctuations of oil prices may render uneconomic the recovery of certain grades of bitumen. Moreover, short term factors relating to oil sands reserves and resources may impair the profitability of Athabasca's projects in any particular period.

In accordance with applicable securities laws, GLJ and D&M have used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production revenues, taxes, development and operating expenditures and cash flows associated with Athabasca's reserves will vary from the estimates contained in the evaluations, and such variations could be material. The evaluations are based in part on the assumed success of activities Athabasca intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom and contained in the evaluations will be reduced to the extent that such activities do not achieve the level of success assumed in the evaluations. The evaluations are effective as of a specific effective date and have not been updated and thus do not reflect changes in Athabasca's reserves since that date.

There is no certainty that any of Athabasca's assets will produce any portion of the volumes currently classified by the Independent Evaluators as "Proved Reserves", "Probable Reserves" or "Contingent Resources".

Operational Dependence

Other companies operate some of the assets in which Athabasca has an interest. Athabasca has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect Athabasca's financial performance. Athabasca's return on assets operated by others depends upon a number of factors that may be outside of Athabasca's control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

In addition, due to the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which Athabasca has an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which Athabasca has an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations Athabasca may be required to satisfy such obligations and to seek recourse from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, Athabasca potentially becoming subject to additional liabilities relating to such assets and Athabasca having difficulty collecting revenue

due from such operators. Any of these factors could materially adversely affect Athabasca's financial and operational results.

Future Acquisition and Joint Venture Activities May Have Adverse Effects

Athabasca may consider the acquisition of additional companies or assets in Athabasca's industry or enter into joint venture arrangements. There can be no assurance that suitable acquisition candidates or joint venture partners will be identified or that related agreements will be entered into on favourable terms. There may be additional risks associated with entering into joint venture arrangements with foreign state-owned entities ("SOE") which may affect the ability to proceed with or finalize a joint venture transaction, including but not limited to the evolving legal, regulatory & compliance regime in Canada relating to dealings with SOE's, the foreign legal regime to which the SOE and any proposed transaction may be subject and the political climate where the SOE is based (see also "*Risk Factors - Geopolitical Risks*" and "*Risk Factors - Global Financial Markets*").

The acquisition of oil and natural gas companies and assets is subject to substantial risks, including the failure to identify material problems during due diligence, the risk of over-paying for assets, and the inability to arrange financing for an acquisition as may be required or desired. Further, the integration and consolidation of acquisitions and joint venture arrangements requires substantial human, financial and other resources and, ultimately, Athabasca's acquisitions and joint venture arrangements may not be successfully integrated. There can be no assurances that any future acquisitions or joint venture arrangements will perform as expected or that the returns from such acquisitions or joint venture arrangements will support the indebtedness incurred to acquire them or the capital expenditures needed to develop them.

Crude Oil and Natural Gas Exploration, Development and Production

Crude oil and natural gas exploration involves a high degree of risk and there is no assurance that expenditures made by Athabasca on exploration will result in new discoveries of crude oil or natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

Future crude oil and gas exploration may involve unprofitable efforts, from dry wells, as well as from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completing (including hydraulic fracturing) and operating costs. In addition, drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents and shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Status and Stage of Development

The Hangingstone Projects, the Light Oil assets and are all currently in the relatively early stages of their development schedules, and all of Athabasca's other assets are currently in the early stages of exploration or development. There is a risk that one or all of the Hangingstone Projects, the Dover West assets or any other proposed commercial development of Athabasca's assets, including in the Light Oil assets, will not be completed on time or within the applicable capital cost estimates or at all. Additionally, there is a risk that one or all of the Hangingstone Projects, the Dover West assets or any other proposed commercial development of Athabasca's assets, including in the Light Oil assets, may have delays, interruption of operations or increased costs due to many factors, including, without limitation: breakdown or failure of equipment or processes; construction performance falling below expected levels of output or efficiency; design errors; contractor or operator errors; non-performance by third-party contractors; labour disputes, disruptions or declines in productivity; increases in materials or labour costs; inability to attract sufficient numbers of qualified workers; delays in obtaining or conditions imposed by, regulatory approvals; changes in project

scope; violation of permit requirements; disruption in the supply of energy and other inputs, including natural gas and diluents; and catastrophic events such as fires, earthquakes, storms or explosions.

Given the stage of development of the Hangingstone Projects, the Light Oil assets and of the Dover West assets, various changes are likely to be made prior to completion. See “*Description of Athabasca’s Business*” for detailed descriptions of the various regulatory applications that have previously been submitted in respect of Athabasca’s various thermal oil assets. No commercial development applications for regulatory approval of Athabasca’s Thermal Oil assets (other than those described in “*Description of Athabasca’s Business*”) have been submitted. The information contained herein, including, without limitation, resource and economic evaluations, is conditional upon receipt of all regulatory approvals and no material changes being made to Athabasca’s various projects or to the scope of any of the projects. Changes and revisions to the concepts for Hangingstone Project 1, the Hangingstone Expansion, Dover West Sands Project 1 and the TAGD Pilot and Demonstration Project, which may be material both in terms of design, timing and cost, are also virtually certain to occur.

There is no assurance that any of Athabasca’s oil sands properties will commence production, generate earnings, operate profitably or provide a return on investment in the future.

In addition to the foregoing, there is also a risk that some or all of Athabasca’s other assets may not be developed on a timely basis or at all. Numerous factors, many of which are beyond Athabasca’s control, could impact Athabasca’s ability to further explore and develop Athabasca’s other assets and the timing thereof, including the risk factors set forth in this Annual Information Form.

Development Schedules and Cost Over-Runs

Historically, oil sands projects have experienced capital cost over-runs due to a variety of factors. Prior to the onset of the most recent global financial crisis, the large number of existing and planned bitumen recovery and upgrading projects in the Athabasca oil sands area of northeast Alberta had created a strong demand for, and in some cases shortages of, the labour, goods and services that are required to complete and operate these types of projects. As the North American and world economies continue to improve and the demand for commodities continues to recover, these conditions could again materialize in the Athabasca oil sands area. Similarly, strong crude oil and natural gas prices may result in increased competition for, and shortages of, the labour, goods and services that are required to complete and operate bitumen recovery projects and crude oil and natural gas operations.

Although Athabasca is defining its schedule for developing its oil sands, crude oil and natural gas resources (including obtaining regulatory approvals), and commencing and completing the construction of certain projects (including the Hangingstone Projects), there is no assurance that the development and project schedules will proceed as planned. Any delays in the development and project schedules could be material and could adversely affect Athabasca’s results of operations and financial condition.

Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. Additionally, there is a risk that Athabasca’s future projects may have delays, interruption of operations or increased costs. Athabasca’s ability to execute projects, and the performance of such projects, depends upon numerous factors beyond Athabasca’s control, including:

- an inability to obtain adequate financing, or financing on terms satisfactory to Athabasca;
- shortages of, or delays in obtaining qualified labour, equipment, materials or services;
- labour disputes, disruptions or declines in productivity;
- changes in the scope of the project or increases in the amount or cost of materials or labour;
- contractor or operator errors in design or construction and non-performance by, or financial failure of, third party contractors;
- breakdown or failure of equipment or processes including facility performance falling below expected levels of output or efficiency;
- delays in obtaining, or conditions imposed by, regulatory approvals;
- reservoir performance;
- challenges to Athabasca’s proprietary technology and/or that of Athabasca’s suppliers or licensors;

- transportation or construction accidents, disruption or delays in availability of transportation services or adverse weather conditions affecting construction or transportation;
- unforeseen site surface or subsurface conditions;
- the availability of, and the ability to acquire, water supplies needed for drilling, or Athabasca's ability to dispose of water used or removed from strata at reasonable costs and within applicable environmental regulations;
- disruption in the supply of energy;
- catastrophic events such as fires, earthquakes, storms or explosions;
- the availability of processing capacity;
- the availability of storage capacity;
- the availability of alternative fuel sources;
- the effects of inclement weather including delays or suspension of operations;
- the availability of drilling and related equipment;
- unexpected cost increases;
- transportation or operations accidents or other accidental events;
- currency fluctuations;
- changes in regulations; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, Athabasca could be unable to execute projects on time, on budget or at all or the projects may not perform to Athabasca's expectations or as required by regulatory approvals.

The cost to construct projects for the development of Athabasca's oil sands resources has not been fixed and remains dependent on many factors, some of which are beyond Athabasca's control. There is no assurance that the current construction and operation schedules will proceed as planned without any delays or cost over-runs. Any delays may increase the costs of those projects, which could result in the need for additional capital, and there can be no assurance that such capital will be available on acceptable terms or at all.

Gathering and Processing Facilities, Pipeline Systems and Rail

Athabasca delivers its products through gathering and processing facilities and pipeline systems some of which it does not own and by rail. The amount of oil and natural gas that Athabasca can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines, and in particular the processing facilities, could result in Athabasca's inability to realize the full economic potential of its production or in a reduction of the price offered for Athabasca's production. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect Athabasca's production, operations and financial results. Furthermore, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm Athabasca's business and, in turn, Athabasca's financial condition, results of operations and cash flows. The federal government has signaled that it plans to review the National Energy Board approval process for large projects. This may cause the timeframe for project approvals to increase for current and future applications.

Following major accidents in Lac-Mégantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. In June 2015, as a result of these recommendations, the Government of Canada passed the Safe and Accountable Rail Act which increased insurance obligations on the shipment of crude oil by rail, imposed a per tonne levy of \$1.65 on crude oil shipped by rail to compensate victims and for environmental cleanup in the event of a railway accident. In addition to this legislation, new regulations have implemented the TC-117 standard for all rail tank cars carrying flammable liquids which formalized the commitment to retrofit, and eventually phase out DOT-

111 tank cars carrying crude oil. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and add additional costs to the transportation of crude oil by rail.

A portion of Athabasca's production may, from time to time be processed through facilities owned by third parties and over which Athabasca does not have control. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a materially adverse effect on Athabasca's ability to process its production and deliver the same for sale.

Environmental Considerations

The operations of Athabasca are, and will continue to be, affected in varying degrees by federal and provincial statutes and regulations regarding the protection of the environment. Should there be changes to existing statutes or regulations, Athabasca's competitive position within the oil sands and petroleum and natural gas industries may be adversely affected, as many industry players have greater resources than Athabasca.

No assurance can be given that future environmental approvals, laws or regulations will not adversely impact Athabasca's ability to develop and operate its oil sands or light oil projects or increase or maintain production or will not increase unit costs of production, or to realize other business opportunities from its exploration leases and permits. Equipment from suppliers which can meet future emission standards may not be available on an economic or timely basis and other methods of reducing emissions to required levels 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 such emissions or require, directly or indirectly, reductions in such emissions produced by energy industry participants, which Athabasca may be unable to mitigate.

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with environmental 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. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require Athabasca to incur costs to remedy such discharge. Although Athabasca believes that it is in material compliance with current applicable environmental legislation no assurance can be given 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 have a material adverse effect on Athabasca's business, financial condition, results of operations and prospects.

Claims Made by Aboriginal Peoples

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. Claims by aboriginal peoples or groups could, among other things, delay or prevent the exploration or development of Athabasca's properties, which in turn could have a material adverse effect on Athabasca's business, financial condition, results of operations and prospects.

Bitumen Recovery Processes

The recovery of bitumen using SAGD, CSS and TAGD processes is subject to uncertainty. The SAGD bitumen recovery process is mature in the clastics but relatively immature in carbonates. All of the commercially successful SAGD recovery projects developed to date in Alberta have targeted clastic reservoirs. There are, however, no developed successful commercial projects that use TAGD or CSS to recover bitumen from carbonates.

There can be no assurance that Athabasca's operations will produce bitumen at the expected levels or on schedule. This is particularly true in respect of Athabasca's carbonate bitumen resources (Dover West Carbonates and Grosmont assets). SAGD, CSS and TAGD are in their initial stages of testing and have not been used in a commercial carbonates project and SAGD is not currently being actively developed for application to an analogue reservoir within the vicinity of Athabasca's asset areas.

The successful development of Athabasca's carbonate reservoirs depends on, among other things, the successful development and application of SAGD, CSS or TAGD or other recovery processes to the subject reservoirs. Presently, there exists a large range in the expected recoverable volumes, the lower end of which may not be economically viable. Some risks associated with the utilization of SAGD, CSS and/or TAGD recovery in carbonate reservoirs are: (a) the possibility of unexpected steam channeling (if SAGD is applied) which would increase steam requirements resulting in increased costs and potentially reduced economically recoverable bitumen volumes; (b) uncertainty regarding the ability to efficiently drain the matrix porosity; (c) potential for mechanical operating problems due to the production of fines which could cause wellbore plugging and reduced bitumen production rates and potential interruption of surface production operations; and (d) uncertainty as to whether the technologies may be economically applied on a commercial scale. The development of the Dover West Carbonates would involve significant capital expenditures and a lengthy time to project payout, and project payout is not assured. If pilot and/or demonstration projects do not demonstrate potential commerciality in the subject reservoir, then Athabasca's Dover West Carbonates Projects may not proceed and this may occur only after significant expenditures have been incurred by Athabasca. With respect to Athabasca's Grosmont assets, the asset is currently uneconomic based upon the application of CSS technology currently being field tested by competitors in an analogous reservoir and no contingent resource volumes have been booked for this area.

Athabasca's ability to develop its bitumen resources that are located in carbonate reservoirs on a commercially viable scale is contingent upon one or more of the following events occurring: Athabasca adapting existing SAGD technology such that it can be successfully used to exploit its carbonate reservoirs; or, Athabasca developing or acquiring new technology, such as TAGD, that can be used to successfully exploit its carbonate reservoirs. There can be no assurance that existing technologies will prove to be viable for the commercial exploitation of bitumen located in Athabasca's carbonate reservoirs, that existing technologies can be modified in such a manner as to be made to be viable for the commercial exploitation of bitumen located in Athabasca's carbonate reservoirs, or that new technologies, such as TAGD, will be developed or acquired by Athabasca that will be viable for the commercial exploitation of bitumen located in its carbonate reservoirs. The development of such recovery processes will involve significant capital expenditures and a lengthy time to project payout, and project payout is not assured.

In addition, should Athabasca encounter the existence of adverse reservoir conditions during the development of its oil sands or carbonates projects, ultimate bitumen recovery levels achieved by Athabasca utilizing the SAGD, CSS and/or TAGD recovery processes may be negatively affected. Such adverse reservoir conditions could include, but are not limited to, the following: regional poor quality geological features; depleted or partially depleted associated gas caps due to prior gas production; the existence of bottom or top water, inter-formation water, or other thief zones; or the absence of an overlying cap rock. TAGD technology also requires a significant amount of electricity to provide power to the downhole conduction heaters.

Any of these events could have a material adverse impact on the future operating activities conducted at, and the economic performance of, Athabasca's projects, which in turn could have a material adverse impact on Athabasca's results of operations and financial condition thereby adversely affecting the value and trading price of the Common Shares.

Reliance on, Competition for, Loss of, and Failure to Attract Key Personnel

The design, development and construction of, and commencement of operations at each of Athabasca's oil sands and light oil projects will require experienced executive, management and technical personnel and operational employees and contractors with expertise in a wide range of areas. There can be no assurance that all of the required employees with the necessary expertise will be available. It is likely that other oil sands and light oil projects or expansions will proceed in the same time frame as Athabasca's projects and Athabasca's projects will compete with these other projects for experienced employees and such competition may result in increases to compensation paid to such personnel or a lack of qualified personnel.

Any inability on the part of Athabasca to attract and retain qualified personnel, may delay or interrupt the design, development and construction of, and commencement of operations of such projects. Sustained delays or interruptions could have a material adverse effect on Athabasca's projects, and on the financial condition and performance of Athabasca. In addition, rising personnel costs would adversely impact the costs associated with the design, development and construction of, and commencement of operations at Athabasca's projects, which could be significant and material.

Athabasca's success depends in large measure on certain key personnel. The loss of or changes in the services provided by such key personnel may have a material adverse effect on its business, financial condition, results of operations and prospects. Athabasca does not have any key person insurance in effect. The contributions of the existing management team to Athabasca's immediate and near term operations are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that Athabasca will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of management of Athabasca.

Pipeline Transportation Contract Covenants

Athabasca has contracts for pipeline transportation in place with third parties which contain certain financial assurance covenants. Depending upon Athabasca's capitalization, liquidity position and state of operational performance at certain times, Athabasca may not be in a position to comply with the financial assurance covenants contained within these agreements, which may require Athabasca to provide security to the third parties it has contracted with including, but not limited to, letters of credit.

Availability of Drilling Equipment and Access

Oil and gas exploration and development activities (including those for bitumen from oil sands) are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to Athabasca and may delay exploration and development activities. There can be no assurance that sufficient drilling and completion equipment, services and supplies will be available when needed. Shortages could delay Athabasca's proposed exploration, development and sales activities. If the demand for, and wage rates of, qualified rig crews rise in the drilling industry then the oil industry may experience shortages of qualified personnel to operate drilling rigs. This could delay and increase the costs of Athabasca's drilling operations. One or more of these events could have a material adverse effect on Athabasca's results of operations and financial condition.

Operating Costs

The operating costs of the projects undertaken by Athabasca will be significant components of the cost of production of the products produced by such projects. Those operating costs may vary considerably during the operating period. The principal factors which could affect operating costs include, without limitation: the amount and cost of labour to operate the projects; the cost of chemicals; the actual SOR required to operate Athabasca's oil sands projects; the cost of natural gas, diluent and electricity; the cost of complying with regulatory approvals; the maintenance cost of the facilities; the cost to process product, the cost to transport sales products and the cost to dispose of certain by-products; and the cost of insurance and taxes. Unexpected increases in operating costs may result in decreased earnings, which may in turn have a material adverse effect on Athabasca's results of operations and financial condition.

Diluent, Natural Gas and Utility Supply and Costs

Extracting bitumen using SAGD, CSS or TAGD technology in order to sell bitumen blend requires considerable quantities of natural gas and diluent. Natural gas is used as an energy input, primarily to produce steam from water at the in-situ extraction site. The amount of steam required to extract one barrel of oil is commonly referred to as the steam-oil-ratio (or SOR). A higher SOR indicates that more steam is required, and therefore more natural gas. Natural gas is currently plentiful in the Athabasca region. Diluent is used to create bitumen blend, which has a lower viscosity than bitumen and is able to flow in a pipeline to markets. Condensate, a by-product of natural gas processing, is currently the diluent preferred by bitumen producers. However, the current demand for condensate in the Athabasca

region for use as diluent exceeds regional supply. An alternative diluent to condensate is SCO. SCO is currently plentiful in the Athabasca region, but under current market conditions the operating netback realized for a SCO bitumen blend is less than for a condensate bitumen blend.

Athabasca's ability to sell bitumen blend profitably will be dependent on, among other things, the cost of natural gas and the cost of diluent. As production of non-upgraded bitumen increases in the Athabasca region, so will the demand for natural gas and diluent. As the demand for natural gas and diluent increases, the availability of these products may decrease and cost of these products may increase. If Athabasca is unable to source a stable supply of natural gas and/or diluent at economic prices, one or more of Athabasca's projects may become uneconomic, which could have a material adverse effect on Athabasca's results of operations and financial condition.

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

In the case of extracting bitumen using TAGD technology, a significant amount of electricity to provide power to the downhole conduction heaters would be required.

Cost of New Technologies

The petroleum industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before Athabasca. There can be no assurance that Athabasca will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilized by Athabasca or implemented in the future may become obsolete. In such case, Athabasca's business, financial condition and results of operations could be affected adversely and materially. If Athabasca is unable to utilize the most advanced commercially available technology, its business, financial condition and results of operations could also be adversely affected in a material way.

Alternatives to and Changing Demand for Petroleum Products

Full conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and energy generation devices could reduce the demand for oil, natural gas and other liquid hydrocarbons. Athabasca cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on Athabasca's business, financial condition, results of operations and cash flows.

Gas Over Bitumen

Some of Athabasca's oil sands leases contain producing and shut-in natural gas wells owned by third parties that may penetrate, or otherwise result in the applicable petroleum and natural gas zones coming into communication with, Athabasca's bitumen resources. In October 2009, the ERCB ordered the interim shut-in of 297 intervals associated with 158 gas wells largely in the Dover West area to mitigate potential future risk to bitumen recovery in the area. On December 15, 2011, pursuant to Order 11-002, the ERCB shut-in these, as well as other wells. There are also natural gas zones in several of Athabasca's asset areas that do not currently contain producing or shut-in natural gas wells. There is a risk that if the production of natural gas from these zones penetrates or otherwise comes into communication with Athabasca's bitumen resources, there may be a loss of steam or steam chamber pressure during the SAGD bitumen extraction process, which could adversely affect Athabasca's ability to recover bitumen using SAGD technology. No assurance can be provided that the production or potential production of natural gas overlying bitumen resources on Athabasca's oil sands leases will not pose a risk to Athabasca's ability to recover the bitumen resources on these properties using SAGD technology, and such risk could have a material adverse effect on Athabasca's business, financial condition, liquidity and results of operations.

Liability Management

The Province of Alberta has developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes of the ratio of Athabasca's deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. See "*Industry Conditions*".

Income Tax Matters

Income tax provisions, including current and future income tax assets and liabilities in Athabasca's financial statements, and income tax filing positions require estimates and interpretations of federal and provincial income tax rules and regulations, and judgments as to their interpretation and application to Athabasca's specific situation. In addition, there can be no assurance that the Canada Revenue Agency or a provincial or other tax agency will agree with Athabasca's tax filing positions or will not change its administrative practices to the detriment of Athabasca or its Shareholders and creditors. Athabasca's business and operations are complex and Athabasca has executed a number of significant financings, acquisitions, dispositions, reorganizations, joint ventures and business combinations over the course of its history. The computation of income taxes payable as a result of these transactions involves many complex factors as well as Athabasca's interpretation of and compliance with relevant tax legislation and regulations. While Athabasca believes that its tax filing positions are supportable under applicable law, a number of Athabasca's tax filing positions are or may be the subject of review by taxation authorities. Therefore, it is possible that additional taxes could be payable by Athabasca and the ultimate value of Athabasca's income tax assets and liabilities could change in the future and that such additional taxes and changes to such amounts could be materially adverse to Athabasca.

Abandonment and Reclamation Costs

Estimates of Athabasca's abandonment and reclamation costs will be a function of regulatory requirements existing at the time that the estimates are made, which are subject to change in the future. In addition, the value of the salvaged equipment may be more or less than the abandonment and reclamation costs. Consequently, the estimates may or may not accurately reflect these future costs. In addition, in the future Athabasca or the operator of Athabasca's projects may determine it prudent, or 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 result in a material increase in the cost of Athabasca's projects.

Exploration, Development and Production Risks

Athabasca's exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, but not limited to, fire, explosion, blowouts, cratering, sour gas releases and spills and other environmental hazards. These typical risks and hazards could result in substantial damage to wells, production facilities, other property and the environment or personal injury.

Particularly, Athabasca may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to Athabasca. SAGD and other in-situ exploration and production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on Athabasca's business, financial condition, results of operations and prospects.

As is standard industry practice, Athabasca is not fully insured against all of these risks, nor are all such risks insurable. Although Athabasca maintains liability insurance in an amount that it considers consistent with industry practice, the

liabilities associated with certain risks could exceed policy limits, in which event Athabasca could incur significant costs.

In addition to the foregoing, recovering bitumen from oil sands and upgrading the recovered bitumen into a diluent-bitumen blend product, a synthetic crude-bitumen blend product or other products involves particular risks and uncertainties. Athabasca's projects will be susceptible to loss of production, slowdowns, or restrictions on its ability to produce higher value products due to the interdependence of its component systems. Severe climatic conditions can cause reduced production and in some situations result in higher costs.

Management Estimates and Assumptions

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

Long Term Reliance on Third Parties

Athabasca will be obliged to enter into long term arrangements with third parties in order to construct and operate the Hangingstone Projects, The Dover West Sands Project 1, The TAGD pilot and Demonstration Project and any other bitumen recovery, crude oil or natural gas development project that it may propose to undertake. Such arrangements may include engineering, equipment procurement and construction contracts, long term maintenance contracts for key equipment, contracts for shipping bitumen, bitumen products, crude oil or natural gas to market, and contracts for services of a constant or recurring nature. Athabasca will be dependent on the ability of these third parties to perform their obligations in a timely, cost efficient, reliable and effective manner. There is no assurance that such arrangements can be made on a cost-effective basis or that Athabasca will not be obliged to fund the creation of necessary resources, which could increase Athabasca's operating costs and thereby adversely affect Athabasca's results of operations and financial condition.

Reliance on Third Party Infrastructure

The projects that Athabasca may propose to undertake, will depend on certain infrastructure owned and operated by third parties, including without limitation: pipelines for the transportation of feedstocks to the project, and petroleum products to be sold by the project; pipelines for the transportation of natural gas; the availability of and access to processing capacity, electricity transmission systems for the provision and/or sale of electricity; and roads, bridges and highways for the transportation of heavy loads in the project areas. The failure of any or all of these third parties to provide an adequate supply of such services in a timely, cost efficient, reliable and effective manner could negatively impact the operation of the project or projects affected, and thereby adversely affect Athabasca's results of operations and financial condition.

Seasonality

The level of activity in the Canadian oilsands industry is influenced by seasonal weather patterns. 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. In addition, certain oil and natural gas producing areas (including most of the areas in which Athabasca operates) are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in

these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding decreases in the demand for the goods and services of Athabasca.

Hedging Risks

The nature of Athabasca's operations will result in exposure to fluctuations in commodity prices. Athabasca may use financial instruments and physical delivery contracts to hedge its exposure to these risks. In addition, Athabasca has previously and may in future enter into hedging arrangements to act as a risk control mechanism with respect to foreign denominated debt incurred by Athabasca. If Athabasca engages in hedging it will be exposed to credit related losses in the event of non-performance by counterparties to the financial instruments. In addition, if product prices increase above those levels specified in any future hedging agreements, Athabasca could lose the cost of floors or a fixed price could limit Athabasca from receiving the full benefit of commodity price increases. If Athabasca enters into hedging arrangements, it may suffer financial loss if it is unable to commence operations on schedule, production falls short of the hedged volumes or prices fall significantly lower than projected, there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement, the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements, a sudden unexpected event materially impacts oil and natural gas prices, or it unable to produce sufficient quantities of bitumen, crude oil or natural gas to fulfill its obligations. If currency exchange rates result in a stronger-performing Canadian dollar relative to previously incurred foreign denominated debt, this may result in Athabasca incurring financial loss as a result of the financial hedging arrangements it has in place.

Athabasca may also hedge its exposure to the costs of inputs to a project, such as natural gas, electricity or diluent. If the prices of these inputs fall below the levels specified in any future hedging agreements, Athabasca could lose the cost of ceilings or a fixed price could limit it from receiving the full benefit of commodity price decreases.

Internal Controls

Effective internal controls are necessary for Athabasca to provide reliable financial reports and to help prevent fraud. Although Athabasca undertakes a number of procedures in order to help ensure the reliability of its financial reports, including those imposed on it under Canadian securities laws, Athabasca cannot be certain that such measures will ensure that Athabasca will maintain adequate control over financial processes and reporting. Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm Athabasca's results of operations or cause it to fail to meet its reporting obligations. If Athabasca or its independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in Athabasca's consolidated financial statements and harm the trading price of the Common Shares.

Insurance Risks

Athabasca's involvement in the exploration for and development of oil, natural gas and bitumen properties may result in Athabasca becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although Athabasca maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. Athabasca's property, business interruption and liability insurance is subject to deductibles, limits and exclusions, and may not provide sufficient coverage for these and other insurable risks. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, Athabasca may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to Athabasca. The occurrence of a significant event that Athabasca is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on Athabasca's business, financial condition, results of operations and prospects. Further, there can be no assurance that such insurance will continue to be offered on an economically feasible basis, that all events that could give rise to a loss or liability are insurable, or that the amounts of insurance (net of applicable deductibles) will at all times be sufficient to cover each and every loss or claim that may occur involving the assets or operations of Athabasca.

Litigation Risks

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

Effect of Competition on Athabasca

The Canadian and international petroleum industry is highly competitive in all aspects, including the exploration for, and the development of, new sources of supply, the acquisition of resource interests, access to third party infrastructure and the distribution and marketing of petroleum products. Athabasca will compete with other bitumen producers, and competes with producers of crude oil, natural gas and SCO. Some of the conventional producers that Athabasca competes with have lower operating costs than Athabasca and many of them have greater resources than Athabasca. Certain of Athabasca's competitors may have greater resources to source, attract, and retain the personnel, materials and services that Athabasca will require to conduct its operations. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers.

A number of companies other than Athabasca have announced plans to enter the oil sands business and begin production of bitumen, or expand existing operations. Expansion of existing operations and the development of new projects could materially increase the supply of bitumen or synthetic crude oil and other competing crude oil products in the marketplace and could materially increase the costs of inputs such as natural gas, diluent, labour, equipment, materials or services. Depending on the levels of future demand, increased supplies could have a negative impact on prices of bitumen and, accordingly, Athabasca's results of operations and cash flow.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise. The actual interest of Athabasca in properties may, accordingly vary from Athabasca's records. If a title defect does exist, it is possible that Athabasca may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on Athabasca's business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes which affect Athabasca's title to the oil and natural gas properties Athabasca controls that could impair Athabasca's activities on them and result in a reduction of the revenue received by Athabasca.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, Athabasca may disclose confidential information relating to the business, operations or affairs of Athabasca. Although confidentiality agreements are generally signed by third parties prior to the disclosure of confidential information, a breach could put Athabasca at competitive risk and may cause significant damage to its business. The harm to Athabasca's business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, Athabasca will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Forward-Looking Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on Athabasca's forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks

and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate. See “Forward Looking Statements”.

Expansion into New Activities

The operations and expertise of Athabasca’s management are currently focused primarily on oil and gas production, exploration and development in the Western Canada Sedimentary Basin. In the future Athabasca may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase Athabasca’s exposure to one or more existing risk factors, which may in turn result in Athabasca’s future operational and financial conditions being adversely affected.

Risks Related to the Common Shares

Volatile Market Price for Common Shares

The market price for Common Shares may be volatile and subject to wide fluctuations in response to numerous factors, many of which are beyond Athabasca’s control, including the following: (a) actual or anticipated fluctuations in Athabasca’s quarterly results of operations; (b) actual or anticipated changes in crude oil, bitumen blend, natural gas, SCO and other diluent prices; (c) recommendations by securities research analysts; (d) changes in the economic performance or market valuations of other companies that investors deem comparable to Athabasca; (e) addition or departure of Athabasca’s executive officers and other key personnel; (f) release or expiration of lock-up or other transfer restrictions on outstanding Common Shares; (g) sales or perceived sales of additional Common Shares; (h) significant acquisitions or business combinations, strategic partnerships, joint ventures or capital commitments by or involving Athabasca or its competitors; and (i) news reports relating to trends, concerns, technological or competitive developments, regulatory changes and other related issues in Athabasca’s industry or target markets.

Financial markets have experienced significant price and volume fluctuations in the last several years that have particularly affected the market prices of equity securities of companies and that have, in many cases, been unrelated to the operating performance, underlying asset values or prospects of such companies. Accordingly, the market price of the Common Shares may decline even if Athabasca’s operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause decreases in asset values that are deemed to be other than temporary, which may result in impairment losses. As well, certain institutional investors may base their investment decisions on consideration of Athabasca’s environmental, governance and social practices and performance against such institutions’ respective investment guidelines and criteria, and failure to meet such criteria may result in a limited or no investment in the Common Shares by those institutions, which could adversely affect the trading price of the Common Shares. There can be no assurance that continuing fluctuations in the price and volume of publicly traded equity securities will not occur. If such increased levels of volatility and market turmoil continue, Athabasca’s operations could be adversely impacted and the trading price of the Common Shares may be adversely affected.

Issuance of Additional Securities

The Board may issue an unlimited number of Common Shares, without any vote or action by Athabasca’s Shareholders, subject to the rules of the TSX or such other stock exchange on which Athabasca’s securities may be listed from time to time. Athabasca may make future acquisitions or enter into financings or other transactions involving the issuance of securities. In addition, pursuant to the Stock Option Plan, the Performance Plan and the 2015 RSU Plan, Athabasca may issue Stock Options and RSUs exercisable to acquire up to 10% of the number of Common Shares outstanding at any given time. If Athabasca issues any additional Common Shares, the percentage ownership of existing Shareholders will be reduced and diluted.

Dividend Policy

Other than the Special Dividend, Athabasca has never declared or paid any cash dividends on its Common Shares. Athabasca does not currently anticipate paying any cash dividends on its Common Shares in the foreseeable future but will review that policy from time to time as circumstances warrant. Athabasca currently intends to retain future earnings, if any, for future operations, expansion and debt repayment. Any decision to declare and pay dividends in the future will be made at the discretion of the Board and will depend on, among other things, Athabasca's results of operations, current and anticipated cash requirements and surplus, financial condition, contractual restrictions and financing agreement covenants, including those contained in the Amended and Restated Credit Agreement, Term Loan Credit Agreement and Note Indenture, and other factors that the Board may deem relevant. For a description of the restrictions that are contained in the Credit Agreement and Note Indenture that relate to Athabasca's ability to pay dividends, please see "*Dividends*" above.

As a result of the foregoing factors, purchasers of Common Shares may not receive any return on an investment in Common Shares unless they sell such Common Shares for a price greater than that which they paid for it.

AUDIT COMMITTEE INFORMATION

National Instrument 52-110 *Audit Committees* of the Canadian Securities Administrators ("**NI 52-110**") requires the Company to disclose annually in its Annual Information Form certain information concerning the constitution of its Audit Committee and its relationship with its independent auditor.

Audit Committee Mandate and Terms of Reference for Chair

The Board has adopted a written mandate for the Audit Committee, which sets out the Audit Committee's responsibilities. The mandate states that the Audit Committee's primary purpose is to assist the Board in fulfilling its oversight responsibilities with respect to: the integrity of the Company's annual and quarterly financial statements to be provided to Shareholders and regulatory bodies; the Company's compliance with accounting and finance-based legal and regulatory requirements; the external auditor's qualifications, independence and compensation, and communicating with the external auditor; the system of internal accounting and financial reporting controls that management has established; the performance of the external audit process and of the external auditor; financial policies and strategies, including the Company's capital structure; financial risk management practices; and transactions or circumstances which could materially affect the financial profile of the Company. A copy of the mandate of the Audit Committee is attached to this Annual Information Form as Schedule "D".

Composition of the Audit Committee and Relevant Education and Experience

As at the date of filing of this Annual Information Form, the Audit Committee consists of Messrs. Marshall McRae (chair), Pete Sametz and Carlos Fierro. Each of the members of the Audit Committee is considered "independent" and "financially literate" within the meaning of NI 52-110.

Mr. McRae has been an independent financial and management consultant since August 2009. Prior thereto, Mr. McRae was Chief Financial Officer of CCS Inc., administrator of CCS Income Trust and its successor corporation, CCS Corporation since August 2002. Mr. McRae has over 30 years of experience in senior operating and financial management positions with a number of publicly traded and private companies, including CCS Inc., Versacold Corporation and Mark's Work Wearhouse Limited. Mr. McRae is a director and the Chair of the audit committee of Gibson Energy Inc. and a director of Black Diamond Group Limited. Mr. McRae served as interim Executive Vice President and CFO of Black Diamond Group Limited from October 16, 2013 to August 8, 2014 and as its Executive Vice President to December 31, 2014. Mr. McRae obtained a Bachelor of Commerce degree, with Distinction, from the University of Calgary in 1979, and a Chartered Accountant designation from the Institute of Chartered Accountants of Alberta in 1981.

Mr. Sametz is presently a director of Gemini Corporation since October 2013. He is also the Chief Executive Officer of Alberta Steam and Power Corp. since February 2013, a private company focused on provision of steam and power to the oil and gas industry. Prior thereto, Interim Chief Executive Officer from February 2012 to December 2012,

President, Chief Operating Officer and a director from May 2010 to January 2012 and Executive Vice President and Chief Operating Officer from 2005 to 2010 of Connacher Oil and Gas Limited, a bitumen exploration, development and production company listed on the TSX. Mr. Sametz obtained a Bachelor of Engineering (Mech.) degree with High Distinction from Carleton University in 1979. He is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA) and the Institute of Corporate Directors (ICD).

Mr. Fierro is an independent investor and serves on public and private corporate boards. From September 2008 to June 2013, Mr. Fierro was a Managing Director and the Global Head of the Natural Resources Group for Barclays PLC. Prior thereto, Mr. Fierro spent 11 years at Lehman Brothers, where his last role was the Global Head of the Natural Resources Group. Before joining Lehman Brothers, Mr. Fierro was a transactional lawyer with Baker Botts LLP., where he practiced corporate, M&A and securities law. Mr. Fierro obtained a Bachelor of Arts degree from the University of Notre Dame in 1983 and a Juris Doctor (J.D.) from Harvard University in 1986.

The Company believes that each of the members of the Audit Committee possesses: (a) an understanding of the accounting principles used by the Company to prepare its financial statements; (b) the ability to assess the general application of such accounting principles in connection with the accounting for estimates, accruals and reserves; (c) experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the Company's financial statements, or experience actively supervising one or more individuals engaged in such activities; and (d) an understanding of internal controls and procedures for financial reporting.

Audit Committee Oversight

At no time since the commencement of the Company's most recently completed financial year has a recommendation of the Audit Committee to nominate or compensate an external auditor not been adopted by the Board.

Pre-Approval Policies and Procedures for the Engagement of Non-Audit Services

The Audit Committee must pre-approve and disclose, as required, the retention of the external auditor for non-audit services to be provided to the Company or any of its subsidiaries that is permitted under applicable law. In the discretion of the Audit Committee, it may annually delegate to one or more of its independent members or to management the authority to grant pre-approvals for the provision of non-audit services; subject to, in the case of any such delegation to management, the subsequent ratification by the Audit Committee.

External Audit Service Fees

The following table summarizes the fees paid by the Company to its auditors, Ernst & Young LLP, for external audit and other services during the periods indicated.

Nature of Services	Fees Paid to Auditor in Year Ended December 31, 2015 (\$)	Fees Paid to Auditor in Year Ended December 31, 2014 (\$)
Audit Fees ⁽¹⁾	449,510	463,480
Audit-Related Fees ⁽²⁾	19,490	-
Tax Fees ⁽³⁾	238,610	193,684
All Other Fees ⁽⁴⁾	73,160	90,038
Total	780,770	747,202

Notes:

- (1) "Audit Fees" include fees necessary to perform the annual audit and quarterly reviews of the Company's financial statements. Audit Fees also include audit or other attest services required by legislation or regulation, such as comfort letters, consents, reviews of securities filings and statutory audits.

- (2) **“Audit-Related Fees”** include services that are traditionally performed by the auditor. These audit-related services include fees for accounting consultations on International Financial Reporting Standards matters, accounting consultations on proposed transactions, internal control reviews and audit or attest services not required by legislation or regulation.
- (3) **“Tax Fees”** include fees for all tax services other than those included in “Audit Fees” and “Audit-Related Fees”. This category includes fees for tax compliance, tax planning and tax advice. Tax planning and tax advice includes assistance with tax audits and appeals, tax advice related to mergers and acquisitions, and requests for rulings or technical advice from tax authorities.
- (4) **“All Other Fees”** include all other non-audit services. The amounts shown in All Other Fees for the years ended December 31, 2014 and December 31, 2015 represent surcharges, outlays and subscription fees for a tax research tool.

ADDITIONAL INFORMATION

Additional information relating to the Company can be found on SEDAR at www.sedar.com. Additional information, including directors’ and officers’ remuneration and indebtedness, principal holders of securities and securities authorized for issuance under the Company’s equity compensation plans, is contained in the Information Circular for the Company’s most recent annual meeting of securityholders that involved the election of directors. Additional financial information about Athabasca is provided in the Company’s financial statements and management’s discussion and analysis for the year ended December 31, 2015, which may be found on SEDAR at www.sedar.com

SCHEDULE “A”

SUPPLEMENTAL DISCLOSURE- CONTINGENT RESOURCE ESTIMATES

Athabasca has engaged D&M and GLJ to prepare Contingent Resource evaluations of its Hangingstone, Dover West Sands and Birch assets, all of which are located in the Province of Alberta. All of Athabasca's Contingent Resources have been evaluated in accordance with NI 51-101. D&M's Report on Contingent Resources Data by Independent Qualified Reserves Evaluator or Auditor and GLJ's Report on Reserves Data, Contingent Resources Data by Independent Qualified Reserves Evaluator or Auditor are set forth in Schedule “C” to this Annual Information Form.

Quantities of Contingent Resources may be estimated using low estimate (high certainty), Best Estimate (most likely) and high estimate (low certainty) cases. In this Annual Information Form, Athabasca has reported its Contingent Resources using the Best Estimate case, which is considered to be the best estimate of the quantity of Contingent Resources that may actually be recovered. All of the Company's Contingent Resources disclosed herein are classified under the product type of bitumen resources. It should not be assumed that the estimates of recovery, production and net revenue that are reflected in the table that is provided below represent the fair market value of Athabasca's bitumen resources. There is no assurance that the forecast prices and cost assumptions will be realized and variances could be material and there is no guarantee that the estimated resources will be recovered or produced. Actual resources may be greater than or less than the estimates provided herein. There is no certainty that it will be commercially viable for Athabasca to produce any portion of the Contingent Resources on any of its properties.

The Contingent Resources estimates presented in the Independent Reports are based upon the definitions and guidelines contained in the COGE Handbook. A summary of the applicable definitions is set forth below:

“**Best Estimate**” is a classification of estimated resources described in the COGE Handbook as being 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 a 50% probability (P50) that the quantities actually recovered will equal or exceed the Best Estimate.

“**chance of development**” means the estimated probability that, once discovered, a known accumulation will be commercially developed.

“**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 such factors as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as “Contingent Resources” the estimated discovered recoverable quantities associated with a project in the early evaluation stage.

“**Economic**” means those Contingent Resources that are currently economically recoverable based on the same fiscal conditions used in the assessment of reserves.

“**risk**ed” means the applicable reported volumes or revenues have been risked (or adjusted) based on the chance of commerciality of such resources in accordance with the COGE Handbook. In accordance with the COGE Handbook for contingent resources, the chance of commerciality is solely based on the chance of development based on all contingencies required for the re-classification of the contingent resources as reserves being resolved. Therefore risked reported volumes and values of contingent resources reflect the risking (or adjustment) of such volumes or values based on the chance of development of such resources.

“**unrisk**ed” means applicable reported volumes or values of resources have not been risked (or adjusted) based on the chance of commerciality of such resources. In accordance with the COGE Handbook for contingent resources, the chance of commerciality is solely based on the chance of development based on all contingencies required for the re-classification of the contingent resources as reserves being resolved. Therefore unrisked reported volumes and values of contingent resources do not reflect the risking (or adjustment) of such volumes or values based on the chance of development of such resources.

Contingent resources may be divided into the following project maturity sub-classes:

“Development Pending” is assigned to Contingent Resources for a particular project where resolution of the final conditions for development is being actively pursued (high chance of development).

“Development On Hold” is assigned to Contingent Resources for a particular project where there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator.

“Development Unclassified” is assigned to Contingent Resources for a particular project where evaluation is incomplete and there is ongoing activity to resolve any risks or uncertainties or which require significant further appraisal to clarify potential for development and where contingencies have yet to be defined.

“Development Not Viable” is assigned to Contingent Resources for a particular project where no further data acquisition or evaluation is currently planned and there is a low chance of development.

Other Terms not defined in this Schedule “A” have the meaning ascribed to such terms under “*Glossary of Defined Terms*” in the main body of this Annual Information Form.

The following table sets forth: (a) the unrisked Best Estimate Contingent Resources; (b) the risked Best Estimate Contingent Resources; and (c) the associated risked future net revenue (before income taxes) estimates for the Contingent Resources calculated by GLJ and D&M. The evaluation procedures employed by GLJ and D&M are in accordance with the standards set forth in the COGE Handbook. The price forecasts that formed the basis for the net present value estimates that are contained herein were based on GLJ’s January 1, 2015 pricing models set forth below under “*Forecast Prices & Costs Used in Contingent Resource Estimates*”. There is no assurance that the forecast price and cost assumptions used will be realized and variances could be material. See “*Forward Looking Statements*” in this Annual Information Form.

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

Summary of Unrisked and Risked Contingent Resources and Risked Net Present Value of Future Net Revenue (Best Estimate Contingent Resources)^(1,2,3,4,5,6,7,8,9,10)

Bitumen Resources Project Maturity Sub-Class	Working Interest (%)	Gross Unrisked Best Estimate Contingent Resources (MMboe)	Chance of Development (%)	Gross Risked Best Estimate Contingent Resources ⁽¹⁾ (MMboe)	Net Risked Best Estimate Contingent Resources (MMboe)	Risked Net Present Value Of Future Net Revenue Before Income Tax Discounted at (%/year)				
						0%	5%	10%	15%	20%
						(MM\$)	(MM\$)	(MM\$)	(MM\$)	(MM\$)
Thermal Oil Assets										
Hangingsstone Development Pending	100	271	89	242	188	8,708	1,824	443	83	-28
Hangingsstone Development On Hold	100	479	70	335	260	12,063	2,526	613	115	-39
Hangingsstone Development Unclassified	100	40	25	10	7	347	73	18	3	-1
Dover West Sands Development On Hold	100	101	77	78	68	908	301	65	-28	-63
Dover West Sands Development Unclassified	100	2894	54	1,563	1,317	31,779	6,436	1,215	40	-203
Birch Development On Hold	100	1441	70	1,009	775	37,950	7,559	1,758	411	60
Birch Development Unclassified	100	674	46	310	239	11,678	2,326	541	126	19

Notes:

- (1) See definitions for “Contingent Resources”, “Best Estimate”, “risked”, “unrisked”, “Development Pending”, “Development On Hold” and “Development Unclassified” above.

- (2) The volumes of Contingent Resources in this table were calculated at the outlet of the proposed extraction plant.
- (3) There is no certainty that it will be commercially viable to produce any portion of the Contingent Resources.
- (4) The Contingent Resource estimates set out in the table reflect, as at December 31, 2015, Athabasca's 100% working interest in the Hangingstone, Birch and Dover West Sands assets.
- (5) Based on the estimates contained in the GLJ Report or the D&M Report dated effective as of December 31, 2015, but calculated by each of GLJ and D&M using GLJ's pricing forecasts for consistency and in accordance with the COGE Handbook.
- (6) Totals may not add due to rounding.
- (7) Gross unrisks Contingent Resource volumes have been included here to provide a comparison with the Company's Contingent Resources disclosure from previous years in which risking was not included.
- (8) All of the Company's Contingent Resources are of the bitumen product type.
- (9) All evaluations of future revenue are after the deduction of royalties, development costs, production costs and well abandonment and reclamation costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses.
- (10) The estimates of Contingent Resources (Best Estimate) and future net revenue for individual properties may not reflect the same confidence levels as estimates of Contingent Resources (Best Estimate) and future net revenues for all properties, due to the effects of aggregation.

Forecast Prices & Costs Used in Contingent Resource Estimates

Year	Inflation	Bank of Canada Average Noon Exchange Rate	WTI Oil at Cushing Oklahoma Current	Light Sweet Crude Oil (40° API, 0.3%S) at Edmonton Current	WCS Stream Quality at Hardisty Current	Midwest price at Chicago Current	AECO/NIT Spot Current	Natural Gas Liquids Edmonton		
								Pentanes Plus	Propane	Butane
	%	(\$US/\$Cdn)	(\$US/bbl)	(\$Cdn/bbl)	(\$Cdn/bbl)	(\$USD/MMBtu)	(\$Cdn/MMBtu)	(\$Cdn/bbl)	(\$Cdn/bbl)	(\$Cdn/bbl)
2016	2.00	0.725	44.00	55.86	42.26	2.70	2.76	60.79	9.58	41.90
2017	2.00	0.750	52.00	64.00	51.20	3.20	3.27	68.48	16.00	48.00
2018	2.00	0.775	58.00	68.39	55.39	3.40	3.45	73.17	20.52	51.29
2019	2.00	0.800	64.00	73.75	60.84	3.60	3.63	78.91	25.81	55.31
2020	2.00	0.825	70.00	78.79	66.18	3.80	3.81	84.30	27.58	59.09
2021	2.00	0.850	75.00	82.35	70.00	4.00	3.90	88.12	28.82	61.76
2022	2.00	0.850	80.00	88.24	75.88	4.20	4.10	94.41	30.88	66.18
2023	2.00	0.850	85.00	94.12	81.41	4.40	4.30	100.71	32.94	70.59
2024	2.00	0.850	87.88	96.48	84.90	4.60	4.50	103.24	33.77	72.36
2025	2.00	0.850	89.63	98.41	86.60	4.70	4.60	105.30	34.44	73.81

2026+ Escalated oil, gas and product prices at 2.0% per year thereafter.

Description of Hangingstone Contingent Resources

The Contingent Resources assigned to Athabasca's Hangingstone assets assume that such resources will be produced using SAGD technology which has been successfully implemented in the ramp up of Hangingstone Project 1 during 2015. The production of the Hangingstone resources is contingent upon the completion of the Hangingstone Expansion Project 2B and Project 3, for which first oil is forecast for 2022 and 2024 respectively (for full description of the Hangingstone Expansion refer to "*Description of Athabasca's Business – Thermal Oil Division – Hangingstone assets – Hangingstone Expansion*"). The environmental impact assessment for this Hangingstone Expansion was deemed to be technically complete by the AER on October 19, 2015. The infrastructure already in place to support the Hangingstone Expansion includes the access road to the Central Production Facility, the diluent import pipeline, the dilbit sales pipeline to Cheecham Terminal and the gas import pipeline. Water source and disposal wells have been identified for the Hangingstone Expansion and are described in the environmental impact assessment. The construction of the associated water wells and pipelines will be part of the Hangingstone Expansion project.

Based on the development plan proposed by the Company, the total Best Estimate capital cost of first commercial production in 2022 at the completion of Hangingstone Expansion Project 2B is estimated at approximately \$813 million (unrisks, undiscounted).

The contingences identified for the development of the Hangingstone Contingent Resources are:

- Regulatory Approval – the environmental impact assessment was deemed to be technically complete by the AER on October 19, 2015, but there are still five SOC's outstanding. Athabasca is pursuing resolution of these SOC's with the SOC holders and expects to resolve them in 2016.
- Corporate Commitment – the Hangingstone Expansion is not expected to be sanctioned by the Board until Hangingstone Project 1 has demonstrated a successful production ramp-up to nameplate production, market conditions allow for further development and project funding is secured.

In accordance with the COGE Handbook, Hangingstone Contingent Resources have been divided into the sub-classes of Development Pending, Development on Hold and Development Unclassified.

The Hangingstone risked Best Estimate Contingent Resource volumes identified as Development Pending in the above table have been determined to be Economic by the Independent Evaluator. A development plan is in place and FEED has been completed on Hangingstone Project 2B. There is 3D seismic and development level delineation drilling density in these areas. First steam is planned for 2021 subject to project sanctioning. The duration of Hangingstone Project 1 from regulatory approval to first steam was two and a half years. Athabasca will execute the Hangingstone Expansion with the same proven execution strategy and facility design utilized for Hangingstone Project 1, consequently Athabasca does not need to do further work on the Hangingstone Expansion until 2018 to maintain a reasonable expectation of reaching first steam in 2021. The chance of development of these resources is estimated to be approximately 90% given their proximity to the existing HS CPF and the level of existing delineation but subject to market conditions and securing a suitable means of financing.

The Hangingstone risked Best Estimate Contingent Resource volumes identified as Development On Hold in the above table have been determined to be Economic by the Independent Evaluator. These resources have adequate delineation to support resource classification and an investment decision and a development plan is in place. Incremental delineation will be completed in future to support execution in line with standard staged development project execution. These resources are considered to be Development On Hold rather than Development Pending as Athabasca has chosen not to develop them until after development of the Development Pending Contingent Resources. The chance of development of these Contingent Resources is estimated to be 70% given that they are geographically further from the HS CPF than the Development Pending Contingent Resources, they have a lower level of delineation and their development is subject to required regulatory approvals, market conditions, securing a suitable means of financing and corporate commitment to proceed.

The Hangingstone risked Best Estimate Contingent Resource volumes identified as Development Unclassified in the above table have been determined to be Economic by the Independent Evaluator. These Contingent Resources are considered to be Development Unclassified rather than Development Pending or Development on Hold as there is a lower level of delineation in this area and they are located physically furthest from the HS CPF. The delineation conducted to date is sufficient to prepare the development strategy consistent with a project evaluation scenario status of pre-development. Based on the COGE Handbook, a pre-development study is considered an intermediate step in the development of a project evaluation scenario. The level of economic analysis is sufficient to assess development options and overall project viability, but is insufficient for a final investment decision. For these resources, additional delineation to refine pad layouts and successful execution of the project will be required in order to advance these assets to a project evaluation scenario status of development. The chance of development of these Contingent Resources is estimated to be 25% due to their physical location and delineation level and their development is subject to required regulatory approvals, market conditions, securing a suitable means of financing and corporate commitment to proceed.

The positive factors relevant to the Contingent Resource estimates for Hangingstone include:

- Using established technology which has been successfully implemented in Hangingstone Project 1.
- The environmental impact assessment has been deemed technically complete by the AER.
- A development plan is in place for all phases of the asset for the full lifecycle of the project (however, for the Contingent Resources in the Development Unclassified project maturity sub-class, the development plan is based on a pre-development study).
- The reservoir has been defined across the asset using delineation drilling as well as 2D and 3D seismic. The level of delineation supports the risks assigned to the different project maturity sub-classes. As development

progresses in Hangingstone, incremental delineation across the asset may result in changes to the project maturity sub-classes and to the assigned risks.

- Existing infrastructure supporting development of the Contingent Resources including an access road to the HS CPF, the diluent import pipeline, the dilbit sales pipeline from the HS CPF to the Enbridge Cheecham terminal and the gas import pipeline. All pipelines are sized to transport the respective products to support 80,000 bbl/d of bitumen production.
- Pipeline capacity to take up to 80,000 bbl/d of bitumen to Edmonton.
- Water source and disposal wells are identified.
- A salt zone suitable to build caverns used to process water treatment waste have been located and tested adjacent to the HS CPF. The regulatory ownership rights for the salt zones have been secured that support the lifecycle requirements of the Hangingstone asset.

The negative factors relevant to the Contingent Resource estimates for Hangingstone include:

- Economic sensitivity to future oil pricing.
- Uncertainty regarding regulatory regimes in Alberta.
- Ability to access project funding.
- Potential lack of pipeline capacity beyond Edmonton to access bitumen markets.
- Resource scarcity attributable to a number of other oil sands projects being developed in the area in the same timeframe.

See also "*Risk Factors*" in this Annual Information Form.

Description of Dover West Sands Contingent Resources

The estimates of Contingent Resources assigned to Athabasca's Dover West Sands assets assume that such resources will be produced using SAGD technology. There are adequate analogues in the area and reservoir studies to confirm that SAGD is applicable to the Dover West reservoir. Athabasca will leverage the experience gained in successfully delivering and ramping up Hangingstone Project 1 during 2015 to deliver the Dover West Sands Project 1. The commencement of production from the Dover West Sands resources is contingent upon the commissioning and completion of the 12,000 bbl/d Dover West Sands Project 1 for which first oil is forecast in 2022. If commissioned and completed, the second phase of the Dover West Sands Project is expected to have a capacity of 40,000 bbl/d with first oil expected in 2025. If commissioned and completed, six subsequent 40,000 bbl/d phases may follow at two yearly intervals to the expected ultimate approximate capacity of 290,000 bbl/d.

The regulatory application for the Dover West Sands Project 1 was submitted to the ERCB (now the AER) in December 2011. The application process was prolonged as Athabasca was focused on an SOC that had been filed by the FMFN in relation to the Dover Oil Sands Project of which Athabasca was a 40% owner at the time and as such the Dover West Sands Project 1 regulatory application was not progressed by Athabasca during this time period pending closure of the SOC (which took approximately 2 years). During the intervening period, Athabasca has been assessing the development timeline of the Dover West Sands Project 1. Given the change in global commodity prices has affected the ability to finance projects in the near term, the considerable uncertainty in regulatory and royalty regimes and Athabasca's focus on its Hangingstone Project 1 in the immediate future, a decision regarding proceeding with the regulatory application has not yet been taken, although management does expect to advance the Dover West Sands regulatory application towards approval during 2016. Due to this uncertainty 87 MMboe of Probable Reserves (which had previously been allocated in the GLJ independent report effective December 31, 2014), were re-classified as Contingent Resources in the Independent Reports.

The only infrastructure already in place to support the Dover West Sands Project 1 is an access road.

Based on the development plan proposed by the Company, the total Best Estimate capital cost of first commercial production in 2022 for Dover West Sands Project 1 is estimated at approximately \$615 million (unrisked, undiscounted).

The contingences identified for the development of the Dover West Sands Contingent Resources are:

- Regulatory Approval – an application has been filed but approval has not yet been granted.
- Corporate Commitment – the Dover West Sands project is not expected to be sanctioned by the Board until market conditions allow and project funding is secured.
- Delineation – development level delineation has only been achieved in the Development On Hold area of the reservoir. Further delineation is required in the Development Unclassified area before a final investment decision can be made

In accordance with the in the COGE Handbook, Dover West Sands Contingent Resources have been divided into the sub-classes of Development On Hold and Development Unclassified.

The Dover West Sands risked Best Estimate Contingent Resource volumes identified as Development On Hold in the above table have been determined to be Economic by the Independent Evaluator. These resources will be produced via the Dover West Sands Project 1 for which a development plan is in place and FEED has been completed. There is 3D seismic and development level delineation drilling density in these areas. These resources are considered to be Development On Hold rather than Development Pending as Athabasca does not yet have regulatory approval and, due to the current economic climate, Athabasca does not expect to produce these resources before 2022. The duration of Hangingstone Project 1 from regulatory approval to first steam was approximately two and a half years. Athabasca will execute the Dover West Sands Project 1 with the same execution strategy and facility design utilized for Hangingstone Project 1, consequently Athabasca does not need to do further work on the Dover West Sands Phase 1 project until 2019 to maintain a reasonable expectation of reaching first steam in 2022. The chance of development of these Contingent Resources is estimated to be 77% due to uncertainties related to the regulatory application status, securing a suitable means of financing, market conditions and corporate commitment to proceed.

The Dover West Sands risked Best Estimate Contingent Resource volumes identified as Development Unclassified in the above table have been determined to be Economic by the Independent Evaluator. These Contingent Resources are considered to be Development Unclassified rather than Development Pending or Development on Hold as there is a lower level of delineation in these areas and they are located physically further from the proposed Dover West Sands Project 1 central processing area. The delineation conducted to date is sufficient to prepare the development strategy consistent with a project evaluation scenario status of pre-development. Based on the COGE Handbook, a pre-development study is considered an intermediate step in the development of a project evaluation scenario. The level of economic analysis is sufficient to assess development options and overall project viability, but is insufficient for a final investment decision. For these resources, additional delineation to refine pad layouts and successful execution of the project will be required in order to advance these assets to a project evaluation scenario status of development. The chance of development of these Contingent Resources is estimated to be 54% due to their physical location, delineation level, required regulatory approvals, market conditions, securing a suitable means of financing and corporate commitment to proceed.

The positive factors relevant to the Contingent Resource estimates for Dover West Sands include:

- Using established technology which is being successfully implemented in Hangingstone Project 1.
- The regulatory application has been submitted for Dover West Sands Project 1.
- A development plan is in place for all phases of the assets (however, for the Contingent Resources in the Development Unclassified project maturity sub-class, the development plan is based on a pre-development study) for the full lifecycle and FEED has been completed for Dover West Sands Project 1.
- The reservoir has been defined across the asset using delineation drilling as well as 2D and 3D seismic. The level of delineation supports the risks assigned to the different project maturity sub-classes. As development progresses in Dover West Sands, incremental delineation across the asset may result in changes to the project maturity sub-classes and to the assigned risks.
- Water source and disposal wells identified for Dover West Sands Project 1.

The negative factors relevant to the Contingent Resource estimates for Dover West Sands include:

- Economic sensitivity to future oil pricing.
- Minimal existing infrastructure.
- Uncertainty regarding regulatory regimes in Alberta.

- Ability to access project funding.
- Potential lack of pipeline capacity to access bitumen markets.
- Resource scarcity attributable to a number of other oil sands projects being developed in the area in the same timeframe.

See also "*Risk Factors*" in this Annual Information Form.

Description of Birch Contingent Resources

The Contingent Resources assigned to Athabasca's Birch assets assume that the resources will be produced using SAGD technology. There are adequate analogues in the area and reservoir studies to confirm that SAGD is applicable to the Birch reservoir. Athabasca will leverage the experience gained in successfully delivering and ramping up the Hangingstone Project 1 during 2015 to deliver the Birch project. The production of the Birch resources is contingent upon the completion of the first phase of the Birch Project which, if commissioned, is planned to be on stream in 2024 with a capacity of 12,000 bbl/d. If commissioned and completed, the second phase of the Birch Project is expected to have a capacity of 40,000 bbl/d with first oil expected in 2027. If commissioned and completed, three subsequent 40,000 bbl/d phases are expected to follow at two yearly intervals to the expected ultimate approximate capacity of 170,000 bbl/d.

A field development plan has been developed for Birch but an environmental impact assessment application has not been submitted.

There is currently no infrastructure in place to support the Birch Project.

Based on the development plan proposed by the Company, the total Best Estimate capital cost of first commercial production in 2024 for the Birch Project is estimated at approximately \$489 million (unrisked, undiscounted).

The contingences identified for the development of the Birch Contingent Resources are:

- Regulatory Approval – an application has not been filed for the Birch Project.
- Corporate Commitment – the Birch Project is not expected to be sanctioned by the Board until market conditions allow and project funding is secured.
- Delineation – development level delineation has only been achieved in the Development On Hold area of the Birch Project reservoir. Further delineation is required in the Development Unclassified area before a final investment decision can be made.
- Project Timing – the first phase of the Birch Project is not anticipated to start up until 2024 and significant spending is not anticipated before 2021.

In accordance with the COGE Handbook, Birch Contingent Resources have been divided into the sub-classes of Development on Hold and Development Unclassified.

The Birch risked Best Estimate Contingent Resource volumes identified as Development On Hold in the above table have been determined to be Economic by the Independent Evaluator. There is sufficient 3D seismic and delineation drilling density in these areas to support both application and development requirements and a development plan is in place. These resources are considered to be Development On Hold rather than Development Pending as Athabasca does not yet have regulatory approval and, due to the current economic climate, Athabasca does not expect to produce these resources before 2024. The duration of Hangingstone Project 1 from commencement of preparation of the regulatory application to first steam was four and a half years. Athabasca will execute the Birch Project with the same execution strategy and facility design utilized for Hangingstone Project 1, consequently Athabasca does not need to do further work on the Birch project until 2019 to maintain a reasonable expectation of reaching first steam in 2024. The chance of development of these Contingent Resources is estimated to be 70% due to uncertainties related to the regulatory approvals required, securing a suitable means of financing and corporate commitment to proceed.

The Birch risked Best Estimate Contingent Resource volumes identified as Development Unclassified in the above table have been determined to be Economic by the Independent Evaluator. These Contingent Resources are considered

to be Development Unclassified rather than Development Pending or Development on Hold as there is a lower level of delineation in these areas and they are located physically further from the proposed Birch Project central processing area. The delineation is sufficient to prepare the development strategy consistent with a project evaluation scenario status of pre-development. Based on the COGE Handbook, a pre-development study is considered an intermediate step in the development of a project evaluation scenario. The level of economic analysis is sufficient to assess development options and overall project viability, but is insufficient for a final investment decision. For these resources, additional delineation to refine pad layouts and successful execution of the project will be required in order to advance these assets to a project evaluation scenario status of development. The chance of development of these Contingent Resources is estimated to be 54% due to their physical location, delineation level, regulatory approvals required, securing a suitable means of financing and corporate commitment to proceed.

The positive factors relevant to the Contingent Resource estimates for the Birch Project include:

- Using established technology which is being successfully implemented in Hangingstone Project 1.
- A development plan is in place for all phases of the assets (however, for the Contingent Resources in the Development Unclassified project maturity sub-class, the development plan is based on a pre-development study) for the full lifecycle of the Birch Project.
- The reservoir has been defined across the asset using delineation drilling as well as 2D and 3D seismic. The level of delineation supports the risks assigned to the different project maturity sub-classes. As development progresses in Birch, incremental delineation across the asset may result in changes to the project maturity sub-classes and to the assigned risks.

The negative factors relevant to the Contingent Resource estimates for the Birch Project include:

- Economic sensitivity to future oil pricing.
- No existing infrastructure.
- Uncertainty regarding regulatory regimes in Alberta.
- Ability to access project funding.
- Potential lack of pipeline capacity to access bitumen markets.
- A regulatory application has not yet been submitted for the Birch Project.
- Resource scarcity attributable to a number of other oil sands projects being developed in the area in the same timeframe.

See also "*Risk Factors*" in this Annual Information Form.

Abandonment and Reclamation Costs

In the Independent Reports, D&M and GLJ have included an estimate of the costs to abandon and reclaim all existing and future wells, pipelines and major dedicated facilities associated with assessed Contingent Resources. No estimate of salvage value is netted against the estimated abandonment and reclamation costs. The estimate for abandonment and reclamation costs are based on the Company's estimation of costs to remediate, reclaim and abandon wells and facilities in which it has a working interest.

The Independent Reports include a Best Estimate for abandonment and reclamation costs (unrisked, undiscounted) of \$698 million at Hangingstone, \$4,121 million at Dover West Sands and \$2,094 million at Birch. Abandonment and reclamation costs in the Independent Reports represent all costs associated with the process of restoring the Company's properties (to which Contingent Resources have been allocated) which have been disturbed by oil and gas activities, to a standard imposed by applicable government or regulatory authorities. Abandonment and reclamation costs including all development drilling and all material dedicated gathering and processing facility expansions or builds required to enable production of the Contingent Resources, are included in the Independent Reports.

SCHEDULE "B"
FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Report of Management and Directors on Reserves Data and Other Information

Management of Athabasca Oil Corporation (the "**Company**") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data and includes, if disclosed in the statement required by item 1 of section 2.1 of NI 51-101, other information such as contingent resources data. Independent qualified reserves evaluators have evaluated the Company's reserves data and contingent resources data. The reports of the independent qualified reserves evaluators are presented will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the Board of Directors of the Company has:

- (a) reviewed the Company's procedures for providing information to 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 data and contingent resources data with management and the independent qualified reserves evaluators.

The Reserves Committee of the Board of Directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved:

- (a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data, contingent resources data and other oil and gas information;
- (b) the filing of Form 51-101F2 which is the reports the independent qualified reserves evaluators on the reserves data, contingent resources data, or prospective resources data; and
- (c) the content and filing of this report.

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

(signed) "Rob Broen"

Rob Broen
President & Chief Executive Officer

(signed) "Blair Hockley"

Blair Hockley
Vice President, Thermal Oil

(signed) "Ronald J. Eckhardt"

Ronald J. Eckhardt
Director

(signed) "Peter Sametz"

Peter Sametz
Director

Dated March 10, 2016

SCHEDULE "C"
FORM 51-101F2

**REPORTS ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR
AUDITOR**

AND

**REPORTS ON RESOURCES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATORS OR
AUDITORS**

FORM 51-101F2
REPORT ON RESERVES DATA, CONTINGENT RESOURCES DATA
BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Athabasca Oil Corporation (the "Corporation"):

1. We have evaluated the Corporation's reserves data and contingent resources data as at December 31, 2015. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2015, estimated using forecast prices and costs. The contingent resources data are risked estimates of volume of contingent resources and related risked net present value of future net revenue as at December 31, 2015, estimated using forecast prices and costs.
2. The reserves data and contingent resources data are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the reserves data and contingent resources data based on our evaluation.
3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).
4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data and contingent resources data are free of material misstatement. An evaluation also includes assessing whether the reserves data and contingent resources data are in accordance with principles and definitions presented in the COGE Handbook.
5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Corporation evaluated for the year ended December 31, 2015, and identifies the respective portions thereof that we have evaluated and reported on to the Corporation's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – M\$)			
			<u>Audited</u>	<u>Evaluated</u>	<u>Reviewed</u>	<u>Total</u>
GLJ Petroleum Consultants	12/31/2015	Canada	-	533,222	-	533,222

6. The following tables set forth the risked volume and risked net present value of future net revenue of contingent resources (before deduction of income taxes) attributed to contingent resources, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the Corporation's statement prepared in accordance with Form 51-101F1 and identifies the respective portions of the contingent resources data that we have evaluated and reported on to the Corporation's board of directors:

<u>Classification</u>	<u>Independent Qualified Reserves Evaluator or Audit</u>	<u>Effective Date of Evaluation Report</u>	<u>Location of Resources Other than Reserves (Country or Foreign Geographic Area)</u>	<u>Risked Volume (MMboe)</u>
Dover West				
Contingent Resources				
Development On Hold	GLJ Petroleum Consultants	12/31/2015	Canada	78
Development Unclassified	GLJ Petroleum Consultants	12/31/2015	Canada	1,563

7. In our opinion, the reserves data and contingent resources data, respectively, evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data and contingent resources data that we reviewed but did not audit or evaluate.
8. We have no responsibility to update our reports referred to in paragraphs 5 and 6 for events and circumstances occurring after the effective date of our reports.
9. Because the reserves data and contingent 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 Ltd., Calgary, Alberta, Canada, March 9, 2016

(signed) *Todd J. Ikeda*

Todd J. Ikeda, P. Eng.
Vice President

FORM 51-101F2
REPORT on RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Athabasca Oil Corporation (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2015. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as December 31, 2015, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.
3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).
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 the COGE Handbook.
5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using GLJ prices and DMCL estimated costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2015, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (before income tax, 10% discount rate)			
			<u>Audited</u> (MM\$)	<u>Evaluated</u> (MM\$)	<u>Reviewed</u> (MM\$)	<u>Total</u> (MM\$)
DeGolyer and MacNaughton Canada Limited	December 31, 2015	Canada	-	1,334	-	1,334

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. 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 5 for events and circumstances occurring after the effective date of our reports.

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

EXECUTED as to our report referred to above:

DeGolyer and MacNaughton Canada Limited, Calgary, Alberta, dated February 25, 2016.

DEGOLYER and MACNAUGHTON CANADA LIMITED

(signed) "*Nahla R. Boury*"

Nahla R. Boury, P. Eng.

FORM 51-101F2
REPORT ON CONTINGENT RESOURCES DATA
BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Athabasca Oil Corporation (the "Company"):

1. We have evaluated the Company's contingent resources data for the Hangingstone area as at December 31, 2015. The contingent resources data are risked estimates of volume of contingent resources and related risked net present value of future net revenue as at December 31, 2015, estimated using forecast prices and costs.
2. The contingent resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the contingent resources data based on our evaluation.
3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).
4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the contingent resources data are free of material misstatement. An evaluation also includes assessing whether the contingent resources data are in accordance with principles and definitions in the COGE Handbook.
5. The following table sets forth the risked volume and risked net present value of contingent resources (before deduction of income taxes) attributed to contingent resources, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the Company's statement prepared in accordance with Form 51-101F1 and identifies the respective portions of the contingent resources data that we have evaluated and reported on to the Company's management:

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Resources Other than Reserves	Risked Volume (Mbbbl)	Risked Net Present Value of Future Net Revenue ⁽¹⁾ (before income taxes, 10% discount rate)		
					Audited (MM\$)	Evaluated (MM\$)	Total (MM\$)
Development Pending Economic Contingent Resources (2C)	DeGolyer and MacNaughton Canada Limited	December 31, 2015	Canada	241,705	-	443	443
Development on Hold Economic Contingent Resources (2C)	DeGolyer and MacNaughton Canada Limited	December 31, 2015	Canada	334,808	-	613	613
Development Unclassified Economic Contingent Resources (2C)	DeGolyer and MacNaughton Canada Limited	December 31, 2015	Canada	9,626	-	18	18

Notes:

- (1) Estimated company share risked net present value of future net revenue are defined as Athabasca's participating interest in the Hangingstone area after deductions of royalties payable to others.

6. In our opinion, the contingent resources data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the contingent resources data that we reviewed but did not audit or evaluate.
7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.
8. Because the contingent resources data are based on judgments regarding future events, actual results will vary and the variations may be material.

EXECUTED as to our report referred to above:

DeGolyer and MacNaughton Canada Limited, Calgary, Alberta, dated February 25, 2016.

DEGOLYER and MACNAUGHTON CANADA LIMITED

(signed) "*Nahla R. Boury*"

Nahla R. Boury, P. Eng.

FORM 51-101F2
REPORT ON CONTINGENT RESOURCES DATA
BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Athabasca Oil Corporation (the "Company"):

1. We have evaluated the Company's contingent resources data for the Birch area as at December 31, 2015. The contingent resources data are risked estimates of volume of contingent resources and related risked net present value of future net revenue as at December 31, 2015, estimated using forecast prices and costs.
2. The contingent resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the contingent resources data based on our evaluation.
3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).
4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the contingent resources data are free of material misstatement. An evaluation also includes assessing whether the contingent resources data are in accordance with principles and definitions in the COGE Handbook.
5. The following table sets forth the risked volume and risked net present value of contingent resources (before deduction of income taxes) attributed to contingent resources, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the Company's statement prepared in accordance with Form 51-101F1 and identifies the respective portions of the contingent resources data that we have evaluated and reported on to the Company's management:

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Resources Other than Reserves	Risked Volume (Mbbbl)	Risked Net Present Value of Future Net Revenue ⁽¹⁾ (before income taxes, 10% discount rate)		
					Audited (MM\$)	Evaluated (MM\$)	Total (MM\$)
Development on Hold Economic Contingent Resources (2C)	DeGolyer and MacNaughton Canada Limited	December 31, 2015	Canada	1,008,734	-	1,759	1,759
Development Unclassified Economic Contingent Resources (2C)	DeGolyer and MacNaughton Canada Limited	December 31, 2015	Canada	310,414	-	541	541

Notes:

- (2) Estimated company share risked net present value of future net revenue are defined as Athabasca's participating interest in the Birch area after deductions of royalties payable to others.
6. In our opinion, the contingent resources data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the contingent resources data that we reviewed but did not audit or evaluate.

7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.
8. Because the contingent resources data are based on judgments regarding future events, actual results will vary and the variations may be material.

EXECUTED as to our report referred to above:

DeGolyer and MacNaughton Canada Limited, Calgary, Alberta, dated February 25, 2016.

DEGOLYER and MACNAUGHTON CANADA LIMITED

(signed) "*Nahla R. Boury*"

Nahla R. Boury, P. Eng.

SCHEDULE “D” AUDIT COMMITTEE MANDATE

The Audit Committee (**Committee**) of the board of directors (**Board**) of Athabasca Oil Corporation (**Company**) has the oversight responsibility and specific duties described below and shall comply with the requirements of applicable laws.

COMPOSITION

The Committee will be comprised of at least three directors or such greater number as the Board may determine from time to time. Except to the extent that the Board determines that an exemption contained in National Instrument 52-110 issued by the Canadian Securities Administrators or its successor instrument (**NI 52-110**) is available and determines to rely thereon, all Committee members will be independent within the meaning of NI 52-110.

All Committee members will be "financially literate" (as defined in NI 52-110) unless the Board determines that an exemption under NI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon.

Committee members will be appointed and removed by the Board. The Committee Chair will be appointed by the Board.

RESPONSIBILITIES

The Committee's primary purpose is to assist the Board in fulfilling its oversight responsibilities with respect to: (i) the integrity of annual and quarterly financial statements to be provided to the Company's shareholders and regulatory bodies; (ii) compliance with accounting and finance based legal and regulatory requirements; (iii) the external auditor's qualifications, independence and compensation, and communicating with the external auditor; (iv) the system of internal accounting and financial reporting controls that management has established; (v) performance of the external audit process and of the external auditor; (vi) financial policies; (vii) financial risk management practices; and (viii) transactions or circumstances which could materially affect the financial profile of the Company.

Management of the Company is responsible for preparing the quarterly and annual financial statements of the Company and for maintaining a system of risk assessment and internal controls to provide reasonable assurance that assets are safeguarded and that transactions are authorized, recorded and reported properly. The Committee is responsible for reviewing management's actions and has the authority to investigate any activity of the Company.

SPECIFIC DUTIES

The Committee will:

Audit Leadership

1. Have a clear understanding with the external auditor that it must maintain an open and transparent relationship with the Committee, and that the ultimate accountability of the external auditor is to the Committee, as representatives of the shareholders of the Company.
2. Provide an avenue for communication between each of the external auditor, financial and senior management and the Board. The Committee has the authority to communicate directly with the external auditors and financial and senior management.

Auditor Qualifications and Selection

3. Subject to required shareholder approval of the appointment of auditors of the Company, be solely responsible for recommending to the Board: (i) the external auditor for the purpose of preparing or issuing an auditor's report or performing other audit review or attest services for the Company; and (ii) the

compensation of the external auditor. The Committee is directly responsible for overseeing the work of the external auditor, including the resolution of disagreements between management and the external auditor regarding financial reporting and reviewing, considering and making a recommendation to the Board regarding a proposed discharge of the external auditor when circumstances warrant. In all circumstances the external auditor reports directly to the Committee. The Committee is entitled to adequate funding to compensate the external auditor for completing an audit and audit report or performing other audit, review or attest services.

4. Evaluate the external auditor's qualifications, performance and independence. Take all reasonable steps to ensure that the external auditor does not provide non-audit services that would disqualify it as independent under applicable law.
5. Review the experience and qualifications of the senior members of the external audit team and the quality control procedures of the external auditor. Ensure that the lead audit partner of the external auditor is replaced periodically, according to applicable law. Take all reasonable steps to ensure continuing independence of the external audit firm. Present the Committee's conclusions on auditor independence to the Board.
6. Review and approve policies for the Company's hiring of senior employees and former employees of the external auditor who were engaged on the Company's account and make recommendations to the Board for consideration.

Process

7. Pre-approve all audit services (which may include consent and comfort letters in connection with securities offerings). Pre-approve and disclose, as required, the retention of the external auditor for non-audit services to be provided to the Company or any of its subsidiaries permitted under applicable law. In the discretion of the Committee, annually delegate to one or more of its independent members the authority to grant pre-approvals. Approve all audit fees and terms and all non-audit fees.
8. Meet with the external auditor prior to the audit to review the scope and general extent of the external auditor's annual audit including: (i) the planning and staffing of the audit; and (ii) an explanation from the external auditor of the factors considered in determining the audit scope, including the major risk factors.
9. Require the external auditor to provide a timely report setting out: (i) all critical accounting policies, significant accounting judgments and practices to be used; (ii) all alternative treatments of financial information within International Financial Reporting Standards (**IFRS**) that have been discussed with management, ramifications of the use of such alternative disclosures and treatments and the treatment preferred by the external auditor; and (iii) other material written communications between the external auditor and management.
10. Take all reasonable steps to ensure that officers and directors or persons acting under their direction are aware that they are prohibited from coercing, manipulating, misleading or fraudulently influencing the external auditor when the person knew or should have known that the action could result in rendering the financial statements materially misleading.
11. Upon completion of the annual audit, review the following with management and the external auditor:
 - (a) The annual financial statements, including related notes and the Management's Discussion and Analysis of Financial Condition and Results of Operations (**MD&A**) of the Company for filing with applicable securities regulators and provision to shareholders, as required, as well as all annual earnings press releases before their public disclosure.
 - (b) The significant estimates and judgements and reporting principles, practices and procedures applied by the Company in preparing its financial statements, including any newly adopted accounting policies and the reasons for their adoption.

- (c) The results of the audit of the financial statements and whether any limitations were placed on the scope or nature of the audit procedures.
- (d) Significant changes to the audit plan, if any, and any serious disputes or difficulties with management encountered during the audit, including any problems or disagreements with management which, if not satisfactorily resolved, would have caused the external auditor to issue a non-standard report on the financial statements of the Company.
- (e) The cooperation received by the external auditor during its audit, including access to all requested records, data and information.
- (f) Any other matters not described above that are required to be communicated by the independent auditor to the Committee.

Financial Statements and Disclosure

- 12. At least quarterly, as part of the review of the annual and quarterly financial statements, receive an oral report from the Company's counsel concerning legal and regulatory matters that may have a material impact on the financial statements.
- 13. Based on discussions with management and the external auditor, in the Committee's discretion, recommend to the Board whether the annual financial statements and MD&A of the Company, together with any annual earnings press releases should be approved for filing with applicable securities regulators and provision to the Company's shareholders, as required, prior to their disclosure.
- 14. Review the general types and presentation format of information that it is appropriate for the Company to disclose in earnings news releases or other earnings guidance provided to analysts and rating agencies.
- 15. Review with management and the external auditor the quarterly financial statements and MD&A and quarterly earnings releases prior to their release and recommend to the Board for consideration the quarterly results, financial statements, MD&A and news releases prior to filing them with or furnishing them to the applicable securities regulators and prior to any public announcement of financial results for the periods covered, including a written report of the results of the external auditor's reviews of the quarterly financial statements, significant adjustments, new accounting policies, any disagreements between the external auditor and management and the impact on the financial statements of significant events, transactions or changes in accounting principles or estimates that potentially affect the quality of financial reporting.

Internal Control Supervision

- 16. As required by applicable law, review with management and the external auditor the Company's internal controls over financial reporting, any significant deficiencies or material weaknesses in their design or operation, any proposed major changes to them and any fraud involving management or other employees who have a significant role in the Company's internal controls over financial reporting.
- 17. Review with management, the Chief Financial Officer and the external auditor the methods used to establish and monitor the Company's policies with respect to unethical or illegal activities by employees that may have a material impact on the financial statements.
- 18. Meet with management and the external auditor to discuss any relevant significant recommendations that the external auditor may have, particularly those characterized as "material" or "serious". Review responses of management to any significant recommendations from the external auditor and receive follow-up reports on action taken concerning the recommendations.

19. Review with management and the external auditor any correspondence with regulators or government agencies and any employee complaints or published reports which raise material issues regarding the Company's financial statements or accounting policies of the Company (as required).
20. Review with management and the external auditor any off-balance sheet financing mechanisms, transactions or obligations of the Company.
21. Review with management and the external auditor any material related party transactions.
22. Review with the external auditor the quality of the Company's accounting personnel. This review may occur without the presence of management. Review with management the responsiveness of the external auditor to the needs of the Company.

Disclosure Controls and Procedures

23. Periodically assess and be satisfied with the adequacy of procedures in place for the review of public disclosure of financial information extracted or derived from the applicable financial statements (other than the annual and quarterly required filings) for the Company.

Financial Management

24. Regularly review current and expected future compliance with covenants under all financing agreements.
25. Annually review the instruments the Company and its subsidiaries are permitted to use for short-term investments of excess cash and, in the Committee's discretion, make recommendations to the Board for consideration.
26. Review the Company's compliance with required tax remittances and other deductions required by applicable law.

Financial Risk Management

27. Receive reports from management with respect to risk assessment, risk management and major financial risk exposures.
28. Discuss with management major financial risk exposures, including those arising from the Company's exposure to changes in interest rates, foreign currency exchange rates and credit. Review the management of these risks including any proposed hedging of the exposures. Review a summary report of the hedging activities including a summary of the hedge-related instruments
29. Discuss with management guidelines and policies with respect to financial risk assessment and financial risk management, including the processes management uses to assess and manage the Company's financial risk.
30. Annually review the insurance program including coverage for property damage, business interruption, liabilities, and directors and officers.
31. Review any other significant financial exposures of the Company to the risk of a material financial loss including tax audits or other activities.
32. Report to the Board on the financial risks of the Company and make recommendations to the Board for consideration.
33. Establish procedures (through approval of the relevant sections of the Code of Business Conduct) for: (i) the receipt, retention, and treatment of complaints received by the Company regarding accounting, internal

accounting and financial reporting controls, or auditing matters; and (ii) the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters.

34. Once or more annually, as the Committee decides, review and assess the Company's Code of Business Conduct and, in the Committee's discretion, recommend any changes to the Board for consideration.

Committee Reporting

35. Following each meeting of the Committee, report to the Board on the activities, findings and any recommendations of the Committee.
36. Report regularly to the Board and review with the Board any issues that arise with respect to the quality or integrity of the financial statements of the Company, compliance with applicable law and the performance and independence of the external auditor of the Company.
37. Annually review and approve the information regarding the Committee required to be disclosed in the Company's Annual Information Form and Committee's report for inclusion in the annual Proxy Circular.
38. Prepare any reports required to be prepared by the Committee under applicable law.

Committee Meetings

39. Meet at least four times annually and as many additional times as needed to carry out its duties effectively. The Committee may, on occasion and in appropriate circumstances, hold meetings by telephone conference call.
40. Meet in separate, non-management, closed sessions with the external auditor at each regularly scheduled meeting.
41. Meet in separate, non-management, in camera sessions at each regularly scheduled meeting.
42. Meet in separate, non-management, closed sessions with any other internal personnel or outside advisors, as needed or appropriate.
43. A quorum for meetings of the Committee will be a majority of its members and the rules for calling, holding, conducting and adjourning meetings of the Committee will be the same as those governing the Board.

Committee Governance

44. Once or more annually, as the Compensation and Governance Committee (**CG Committee**) decides, receive for consideration that Committee's evaluation of this Mandate and any recommended changes. Review and assess the CG Committee's recommended changes and make recommendations to the Board for consideration.

Advisors/Resources

45. Have the sole authority to retain, oversee, compensate and terminate independent advisors to assist the Committee in its activities.
46. Receive adequate funding from the Company for independent advisors and ordinary administrative expenses that are needed or appropriate for the Committee to carry out its duties.

Other

47. With the CG Committee, the Board and the Board Chair, respond to potential conflict of interest situations, as required.
48. Carry out any other appropriate duties and responsibilities assigned by the Board.
49. To honour the spirit and intent of applicable law as it evolves, authority to make minor technical amendments to this Mandate is delegated to the Secretary, who will report any amendments to the CG Committee at its next meeting.

STANDARDS OF LIABILITY

Nothing contained in this Mandate is intended to expand applicable standards of liability under statutory, regulatory or other legal requirements for the Board or members of the Committee. The purposes and responsibilities outlined in this Mandate are meant to serve as guidelines rather than inflexible rules and, subject to applicable law and the articles and bylaws of the Company, the Committee may adopt such additional procedures and standards, as it deems necessary from time to time to fulfill its responsibilities.

Approved: December 11, 2009

Revised: March 14, 2012
May 11, 2015