**PROSPECTUS**

*Initial Public Offering* August 1, 2012

ARGENT ENERGY TRUST

# $212,300,000
# 21,230,000 Units

This prospectus qualifies the distribution of 21,230,000 trust units ("**Units**") of Argent Energy Trust (the "**Trust**") to be issued pursuant to the terms of an Underwriting Agreement (as defined herein) at a price of $10.00 per Unit (the "**Offering**").

The Trust is an unincorporated limited purpose open-ended trust established under the laws of the Province of Alberta. The Trust intends to qualify as a "mutual fund trust" under the *Income Tax Act* (Canada) (the "**Tax Act**"). The Trust will not be a "SIFT trust" (as defined in the Tax Act), provided that the Trust complies at all times with its investment restrictions, which preclude the Trust from holding any "non-portfolio property" (as defined in the Tax Act).

The Trust's objective is to create stable, consistent returns for investors through the indirect acquisition and development of oil and natural gas reserves and production with low-risk exploitation potential, located primarily in the United States (the "**U.S.**"), and to pay out a portion of available cash to holders of Units ("**Unitholders**") on a monthly basis. See "Undertaking of the Trust".

The Trust owns all of the issued and outstanding shares of Argent Energy (Canada) Holdings Inc. ("**Can Holdco**"), an Alberta corporation, which in turn owns all of the issued and outstanding shares of Argent Energy (US) Holdings Inc. ("**US Opco**"), a Delaware corporation. US Opco was formed for the purpose of acquiring assets in accordance with the strategy of the Trust. See "Funding, Acquisition and Related Transactions – Structure Following Closing".

US Opco has entered into a purchase and sale agreement dated May 23, 2012, as amended on June 11, 2012 and July 12, 2012 (as amended, the "**Purchase and Sale Agreement**") with Denali Oil & Gas Partners II, LP and Denali Oil & Gas Partners III, LLC (collectively, "**Denali**") to acquire the Denali Assets (as defined herein) located primarily in South Texas (the "**Acquisition**"). The Denali Assets are oil and natural gas properties, covering approximately 117,273 net acres, consisting of producing wells and exploitation and development opportunities. See "Funding, Acquisition and Related Transactions – Acquisition – Purchase and Sale Agreement".

The purchase price for the Denali Assets (excluding the Deep Rights (as defined herein)) is US$166.7 million, subject to certain closing adjustments and net of US$36.6 million that will be paid to Denali by the Trust on closing of the Offering, which amount will be held in escrow by Denali and applied to US Opco's capital expenditures and general and administrative expenses on the Denali Assets for the 24 month period following closing of the Offering. In addition, pursuant to the Deferred Payment Obligation (as defined herein) in the Purchase and Sale Agreement, US Opco is required to pay Denali an aggregate of US$18 million over a three year period commencing January 1, 2013 in respect of the Deep Rights. US Opco will also be obligated to pay an additional US$30 million for additional interests in the Deep Rights upon the occurrence of certain events. See "Funding, Acquisition and Related Transactions – Acquisition – Purchase and Sale Agreement – Deep Rights". The Acquisition will have an effective date of January 1, 2012. The purchase price for the Acquisition will be funded from the net proceeds of the Offering and an advance under the Credit Facilities (as defined herein) to be established by US Opco. It is a condition under the Purchase and Sale Agreement that the closing of the Acquisition occurs concurrently with the closing of the Offering and the closing of the Credit Facilities. See "Use of Proceeds", "Undertaking of the Trust – Credit Facilities" and "Funding, Acquisition and Related Transactions – Acquisition – Purchase and Sale Agreement".

The Trust intends to make monthly distributions of a portion of its available cash to Unitholders. The Trust expects that the initial monthly cash distribution rate will be $0.0875 per Unit. The initial cash distribution, which will be for the period from and including the date of closing of the Offering to August 31, 2012, is expected to be paid on September 24, 2012 to Unitholders of record on August 31, 2012 and is estimated to be $0.0621 per Unit (assuming that the closing of the Offering occurs on August 10, 2012). The distribution of cash to Unitholders is not assured. See "Description of the Trust – Distributions" and "Risk Factors".

**There is currently no market through which the Units may be sold and purchasers may not be able to resell Units purchased under this prospectus, which may affect the pricing of the Units in the secondary market, the transparency and availability of trading prices, the liquidity of the Units and the extent of issuer regulation. The TSX has conditionally approved the listing of the Units under the symbol "AET.UN". Listing is subject to the Trust fulfilling all the requirements of the TSX on or before October 23, 2012, including distribution of the Units to a minimum number of public securityholders. An investment in the Units is speculative and is subject to a number of risks that should be considered by a prospective purchaser. The Trust's business is subject to the risks normally encountered in the U.S. oil and natural gas industry and the Trust's early stage of development. See "Risk Factors".**

## Price: $10.00 per Unit

| | Price to Public(1) | Underwriters' Fee(2) | Net Proceeds to the Trust(3) |
|---|---|---|---|
| Per Unit | $10.00 | $0.60 | $9.40 |
| Total Offering(4) | $212,300,000 | $12,673,200 | $199,626,800 |

**Notes:**

(1) The offering price of the Units to be issued pursuant to the Offering has been determined by negotiation between Argent Energy Ltd. (the "**Administrator**") (on behalf of the Trust) and the Underwriters (as defined herein). No third-party valuation of the Units was obtained in determining the offering price.

(2) The Trust has agreed to pay a fee to the Underwriters in the amount of $0.60 per Unit issued pursuant to the Offering. No fee will be paid in respect of the 108,000 Units subscribed for by directors and officers of the Administrator.

(3) Before deducting expenses of the Offering, estimated at approximately $3.0 million, of which approximately $1.5 million will be paid from proceeds raised in the Initial Private Placements (as defined herein). The remaining expenses of the Offering of approximately $1.5 million, together with the Underwriters' fee, will be paid by the Trust from the proceeds of the Offering.

(4) The Underwriters have been granted an over-allotment option (the "**Over-Allotment Option**") by the Trust, exercisable in whole or in part, from time to time, for a period of 30 days from closing of the Offering to purchase up to 3,184,500 additional Units on the same terms as the Units sold under the Offering, to cover over-allotments, if any, and for market stabilization purposes. If the Over-Allotment Option is exercised in full, the total Price to Public, Underwriters' Fee and Net Proceeds to the Trust in respect of the Offering will be $244,145,000, $14,583,900 and $229,561,100, respectively. This prospectus qualifies the grant of the Over-Allotment Option and the distribution of the additional Units issuable upon the exercise of the Over-Allotment Option. A purchaser who acquires Units forming part of the Underwriters' over-allocation position acquires such Units under this prospectus, regardless of whether the over-allocation position is ultimately filled through the exercise of

the Over-Allotment Option or secondary market purchases. See “Plan of Distribution”. The net proceeds to be received by the Trust pursuant to the exercise of the Over-Allotment Option are expected to be provided to US Opco in the same manner as the net proceeds of the Offering. If the Over-Allotment Option is exercised for net proceeds of at least $25 million, US Opco will acquire the Denali Reserved Interest for US$20 million in accordance with the Purchase and Sale Agreement, with the remaining proceeds to be used to reduce the amount outstanding under the Credit Facilities and for general corporate purposes. If the Over-Allotment Option is exercised for net proceeds of less than $25 million, the proceeds will be used to reduce the amount outstanding under the Credit Facilities and for general corporate purposes. See “Funding, Acquisition and Related Transactions” and “Use of Proceeds”.

The following table sets out the number of Units that may be issuable under the Offering pursuant to the Over-Allotment Option.

| Underwriters’ Position | Maximum Size or Number of Securities Available | Exercise Period | Exercise Price |
|---|---|---|---|
| Over-Allotment Option | Option to acquire up to 3,184,500 additional Units | For a period of 30 days after closing of the Offering | $10.00 per Unit |

Scotia Capital Inc., CIBC World Markets Inc., RBC Dominion Securities Inc., BMO Nesbitt Burns Inc., TD Securities Inc., Canaccord Genuity Corp., National Bank Financial Inc., Acumen Capital Finance Partners Limited, AltaCorp Capital Inc., Cormark Securities Inc., Desjardins Securities Inc., Dundee Securities Ltd., FirstEnergy Capital Corp. and GMP Securities L.P. (collectively, the “**Underwriters**”), as principals, conditionally offer the Units qualified under this prospectus, subject to prior sale, if, as and when issued, sold and delivered by the Trust to, and accepted by, the Underwriters in accordance with the conditions contained in the Underwriting Agreement referred to under “Plan of Distribution” and subject to the approval of certain legal matters on behalf of the Trust, Can Holdco and the Administrator by Bennett Jones LLP, on behalf of US Opco by Vinson & Elkins L.L.P. and on behalf of the Underwriters by Blake, Cassels & Graydon LLP.

**An affiliate of Scotia Capital Inc. has committed to make certain credit facilities available to US Opco on closing of the Offering. Accordingly, under applicable securities laws, the Trust may be considered a “connected issuer” to such Underwriter. See “Credit Facilities” and “Relationship Between the Trust and An Underwriter”.**

In connection with the Offering, the Underwriters may over-allocate or effect transactions that stabilize the market price of the Units at levels other than those which otherwise might prevail on the open market. **The Underwriters may offer the Units at a price lower than that stated above. Any such reduction in price will not affect the proceeds received by the Trust. See “Plan of Distribution”**.

Subscriptions for Units comprising the Offering will be received subject to rejection or allotment in whole or in part and the right is reserved to close the subscription books at any time without notice. A book-entry only certificate representing the Units will be issued in registered form to CDS Clearing and Depository Services Inc. or its nominee (“**CDS**”), and will be deposited with CDS on the date of closing of the Offering, which is expected to occur on or about August 10, 2012, or such later date as the Trust and the Underwriters may agree, but in any event not later than August 31, 2012. A purchaser of Units comprising the Offering will receive only a customer confirmation from the registered dealer which is a CDS participant and from or through which the Units are purchased. See “Plan of Distribution”. The Units comprising the Offering are to be taken up by the Underwriters, if at all, on or before a date not later than 42 days after the date of the receipt for the final prospectus.

A return on an investment in the Units is not comparable to the return on an investment in a fixed-income security. The recovery by Unitholders of their initial investment is at risk, and the anticipated return on that investment is based on many performance assumptions. Although the Trust intends to make monthly distributions to Unitholders of a portion of its available cash, those cash distributions may be reduced or suspended. The actual amount of cash distributed to Unitholders will depend on numerous factors including: (i) the operational and financial performance of the Trust and its subsidiaries (including fluctuations in the market price and quantity of oil, natural gas and NGLs (as defined herein) production); (ii) fluctuations in the costs to produce oil, natural gas and NGLs, including royalty burdens, and to administer and manage the Trust and its subsidiaries; (iii) the amount of cash required or retained for debt service or repayment; (iv) the amount of cash required to fund capital expenditures and working capital requirements; (v) foreign currency exchange rates and interest rates; and (vi) hedging activities undertaken by subsidiaries of the Trust from time to time. In addition, the market value of the Units may decline if the Trust is unable to meet its cash distribution targets in the future, which decline may be significant. See “Risk Factors”.

It is important for purchasers of Units to consider the particular risk factors that may affect the industry in which they are investing, and therefore the stability of the distributions that Unitholders receive. See, for example, "Risks Relating to the Business and Operations of the Trust and its Subsidiaries" under the section "Risk Factors". That section also describes the Trust's assessment of those risk factors, as well as the potential consequences to a Unitholder if a risk should occur.

The return from an investment in Units may consist of both a return on investment (including taxable dividends) and a return of capital. The composition of that return may change over time, thus affecting the after-tax return to Unitholders. Returns on investment are generally taxed as ordinary income (subject to the taxation regime governing taxable dividends) in the hands of a Unitholder who is resident in Canada for purposes of the Tax Act. Returns of capital are generally tax-deferred for a Unitholder who is resident in Canada for purposes of the Tax Act and reduce the Unitholder's adjusted cost base in the Unit for purposes of the Tax Act. The Canadian income tax considerations discussed in this prospectus only apply to Unitholders who are resident in Canada for tax purposes. See "Canadian Federal Income Tax Considerations".

TABLE OF CONTENTS

## NOTICE TO INVESTORS

### About this Prospectus

A Unitholder should rely only on the information contained in this prospectus and should not rely on some parts of this prospectus to the exclusion of others. The Trust and the Underwriters have not authorized anyone to provide investors with additional or different information. The Trust and the Underwriters are not offering to sell the Units in any jurisdictions where an offer or sale is not permitted. The information contained in this prospectus is accurate only as of the date of this prospectus, regardless of the time of delivery of this prospectus or any sale of the Units. The Trust's business, financial condition, results of operations and prospects may have changed since the date of this prospectus.

For investors outside of Canada, neither the Trust nor any of the Underwriters have done anything that would permit the Offering or possession or distribution of this prospectus in any jurisdiction where action for that purpose is required, other than in Canada. Investors are required to inform themselves about, and to observe any restrictions relating to, the Offering and the distribution of the Units and this prospectus.

Unless the context otherwise requires, the disclosure contained in this prospectus assumes that: (i) the steps described under "Funding, Acquisition and Related Transactions" have been completed and that, as a result, US Opco holds the Denali Assets; and (ii) the Over-Allotment Option has not been exercised. For an explanation of certain terms and abbreviations used in this prospectus and not otherwise defined, reference is made to the "Glossary" and "Notice to Investors – Abbreviations and Conversions".

All production, reserves and well information with respect to the Denali Assets in this prospectus, unless otherwise stated, represent the gross interest (operated and non-operated) in respect of such production, reserves or wells, as applicable, before deduction of royalties and without including any royalty interests received from third parties, in accordance with NI 51-101. See "Reserves and Other Oil and Gas Information – Notes and Definitions" for additional information.

In this prospectus, unless otherwise indicated, all dollar amounts are expressed in Canadian dollars. References to "$" or "C$" are to Canadian dollars and references to "US$" or "U.S. dollars" are to United States dollars.

### Eligibility for Investment

In the opinion of Bennett Jones LLP, counsel to the Trust, and Blake, Cassels & Graydon LLP, counsel to the Underwriters, based on the current provisions of the Tax Act and the regulations thereunder, and subject to the provisions of any particular plan, provided that the Trust qualifies at all times as a mutual fund trust (as defined in the Tax Act), the Units will be a qualified investment for trusts governed by a registered retirement savings plan ("**RRSP**"), registered education savings plan, registered retirement income fund ("**RRIF**"), deferred profit sharing plan, registered disability savings plan or tax-free savings account ("**TFSA**").

The Units will not be a prohibited investment for an RRSP, RRIF or TFSA provided that the holder of the RRSP, RRIF or TFSA, for the purposes of the Tax Act, deals at arm's length with the Trust and does not have a significant interest in the Trust or a corporation, partnership or trust with which the Trust does not deal at arm's length. Generally, a holder will have a significant interest in the Trust if the holder and/or persons not dealing at arm's length with the holder own, directly or indirectly, 10% or more of the fair market value of the Units. Holders to whom Units otherwise would be prohibited investments as described above should consult their own tax advisors, including with respect to any potential relief under an undated "comfort letter" of the Department of Finance provided by it in 2012 to the Joint Committee on Taxation of the Canadian Bar Association and the Canadian Institute of Chartered Accountants.

### Forward-Looking Statements

Certain statements and information contained in this prospectus constitute forward-looking statements and forward-looking information (collectively, "**forward-looking statements**") and the Trust cautions investors about important factors that could cause the Trust's actual results to differ materially from those projected in any forward-looking statements included in this prospectus. Any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as “will likely result”, “are expected to”, “expects”, “will continue”, “is anticipated”, “anticipates”, “believes”, “estimated”, “intends”, “plans”, “forecast”, “projection” and “outlook”) are not historical facts and may be forward-looking statements and may involve estimates, assumptions and uncertainties which could cause actual results or outcomes to differ materially from those expressed 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 prospectus should not be unduly relied upon. These statements speak only as of the date of this prospectus. In addition, this prospectus may contain forward-looking statements attributed to third party industry sources. Accordingly, any such statements are qualified in their entirety by reference to, and are accompanied by, the information and factors discussed throughout this prospectus.

In particular and without limitation, this prospectus contains forward-looking statements pertaining to the following:

- oil, natural gas and NGLs production volumes, including expectations regarding the ability to increase certain existing production based on development drilling and potential production from the Eagle Ford Shale oil formation;
- projections of market prices for oil, natural gas and NGLs as well as exploration, development and production costs;
- supply and demand fundamentals for oil, natural gas and NGLs;
- expectations regarding the ability to raise capital and to continually add reserves through acquisitions, exploration and development;
- realization of anticipated benefits of acquisitions or dispositions, including from the Acquisition and, if applicable, the acquisition of the Denali Reserved Interest;
- plans for, and results of, exploration, exploitation and development activities;
- growth strategy and opportunities, including future acquisitions;
- treatment under governmental regulatory regimes and tax laws;
- capital expenditure programs and sources of funding;
- plans for, and results of, the implementation of a rolling hedging program;
- estimated well parameters, well economics and total drilling opportunities in regards to the Denali Assets;
- the intentions of the Trust to maintain a prudent debt to EBITDA ratio;
- continued drilling by the operator of the leaseholds pertaining to the Denali Reserved Interest and Management’s expectation that such drilling may increase production and/or the amount of the Denali Production Payment;
- the timing for and cost of additional development drilling and the timing for, and levels of, increases to production and reserves;
- the location of future drilling opportunities, including in the Austin Chalk and Eagle Ford Shale oil formations;
- the implementation of the Trust’s development plan and the anticipated results associated therewith;
- the intentions of the Trust to create a balanced commodity profile;
- anticipated general and administrative costs, operating expenses, and expected drilling and completion costs;
- the Reserve Life Index of assets and properties acquired by the Trust’s subsidiaries, and the development risk and exploitation potential of assets and properties acquired by the Trust’s subsidiaries, including the Denali Assets;

- estimates of abandonment, disconnection and reclamation costs;
- status of the Trust as a "mutual fund trust" and not as a "SIFT trust" for purposes of the Tax Act, and the taxability of the Trust and its subsidiaries;
- estimates of the distributable cash of, and estimates of cash flow available for distribution by, the Trust, including assumptions regarding the revenue and expense items relating thereto;
- the payment and stability of cash distributions by the Trust, including the amount and timing of payment of cash distributions, including the initial cash distribution;
- the taxation of distributions received by Unitholders that are resident in Canada for purposes of the Tax Act;
- the impact of Canadian and U.S. federal income taxation on the availability of cash for distribution by the Trust;
- access to credit facilities, including the Credit Facilities, related borrowing base capacity and interest costs and the termination of the Bridge Facility upon the occurrence of certain events;
- the amount and use of the net proceeds from the Offering;
- the exercise of the Over-Allotment Option and the use of the net proceeds therefrom;
- the exercise of a put option (as described herein) by Denali in respect of the Deep Rights;
- the Asset Disposition and the use of proceeds therefrom;
- the Acquisition, including timing for completion, sources of funding, adjustments to the purchase price, escrow conditions and satisfaction of conditions to closing;
- the implementation and terms of the DRIP and PURP (as such terms are defined herein);
- the provision of certain technical and administrative services by Aston Hill;
- the retention of certain contractors and field personnel by US Opco; and
- executive compensation arrangements.

With respect to forward-looking statements contained in this prospectus, assumptions have been made regarding, among other things:

- future prices for oil, natural gas and NGLs, including, in respect of the estimated cash flow available for distribution, the future pricing assumptions listed in the notes to the table in the sections entitled "Offering Summary – Summary of Distributable Cash" and "Summary of Distributable Cash";
- in respect of the estimated cash flow available for distribution, those other assumptions listed in the notes to the table in the sections entitled "Offering Summary – Summary of Distributable Cash" and "Summary of Distributable Cash";
- future currency exchange rates;
- the ability of the Trust's subsidiaries to obtain qualified staff and equipment in a timely and cost-efficient manner;
- the ability of Aston Hill to provide necessary technical and administrative services to the Trust and the Administrator pursuant to the Services Agreement;
- the regulatory framework governing taxes and environmental matters in the U.S.;
- the ability of the Trust's subsidiaries to successfully market future oil, natural gas and NGLs production;
- the Trust's subsidiaries' future production levels;
- the applicability of technologies for recovery and production of the Trust's subsidiaries' oil, natural gas and NGLs reserves;
- geological and engineering estimates in respect of the Trust's subsidiaries' reserves and production;
- the recoverability of the Trust's subsidiaries' reserves;
- future capital expenditures to be made by the Trust's subsidiaries and the Trust's ability to obtain financing on acceptable terms for capital projects and future acquisitions;

- future sources of funding for the capital programs of and future acquisitions by the Trust's subsidiaries;
- the intentions of the Administrator Directors with respect to the executive compensation plans and corporate governance programs described herein;
- the impact of competition on the Trust;
- the deductibility of interest payments on the US Opco Notes;
- the impact of Canadian and U.S. federal income taxes on cash available for distribution by the Trust and its subsidiaries;
- the willingness of Unitholders resident in the United States to provide certifications with regard to qualification for exemptions from withholding tax; and
- the Trust's status as a "mutual fund trust" and not as a "SIFT trust" for purposes of the Tax Act.

The Trust's actual results could differ materially from those anticipated in forward-looking statements as a result of the risk factors set forth below and included elsewhere in this prospectus:

- failure to realize the anticipated benefits from the Acquisition, future acquisitions and dispositions and, if applicable, the acquisition of the Denali Reserved Interest;
- incorrect assessments of the value of acquisitions, including the Acquisition, and, if applicable, the acquisition of the Denali Reserved Interest, and the likelihood of success of exploitation and development programs;
- failure to achieve the anticipated benefits of the planned drilling program;
- volatility of market prices for oil, natural gas and NGLs and marketing and hedging activities related thereto;
- risks related to the exploration, development and production of oil, natural gas and NGLs reserves;
- volatility of costs of development, operations and maintenance of properties;
- risks which may create liabilities to the Trust or its subsidiaries in excess of the Trust's insurance coverage;
- general economic, market and business conditions;
- current global financial conditions, including fluctuations in interest rates, foreign exchange rates, inflation and commodity prices and stock market volatility;
- uncertainties associated with estimating oil, natural gas and NGLs reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped or underdeveloped lands and skilled personnel;
- geological, technical, drilling and processing problems, including the availability of equipment and access to properties;
- environmental risks and hazards;
- changes in tax laws and incentive programs relating to the oil and natural gas industry;
- certain financing transactions among the Trust and its subsidiaries being treated as equity rather than debt for U.S. federal income tax purposes;
- changes in government regulations or increased scrutiny by governmental agencies;
- failure to obtain regulatory, industry partner and third party consents and approvals where required;
- failure to engage or retain key personnel;
- conflicts of interest involving directors and officers of the Administrator;

- conflicts of interest involving Aston Hill and the Trust as a result of the Services Agreement;
- claims made in respect of the properties or assets of the Trust and its subsidiaries;
- potential losses which would stem from any disruptions in production or infrastructure performance, including work stoppages or other labour difficulties, or disruptions in the transportation network on which the Trust's subsidiaries will be reliant;
- discretion in the use of the net proceeds of the Offering;
- failure of the Trust's subsidiaries to meet specific requirements of their leases or agreements;
- failure to accurately estimate abandonment and reclamation costs;
- the inability to obtain financing on acceptable terms;
- failure of third parties' reviews, reports and projections to be accurate;
- reliance on Aston Hill for the provision of certain technical and administrative services pursuant to the Services Agreement;
- failure by US Opco to maintain or achieve increased production and the resulting adverse effect on cash flow to US Opco;
- failure to complete the Asset Disposition;
- title defects in the properties in which the Trust invests and/or undisclosed liabilities, including environmental liabilities, associated with such properties, including the Acquisition; and
- other factors discussed under "Risk Factors".

Since actual results or outcomes could differ materially from those expressed in any forward-looking statements made by or on behalf of the Trust, investors should not place undue reliance on any such forward-looking statements. Statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. Further, any forward-looking statement is made only as of the date of this prospectus, and neither the Trust nor the Underwriters undertake any obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events, except as required by applicable securities laws. New factors emerge from time to time, and it is not possible for Management to predict all of these factors or to assess in advance the impact of each such factor on the Trust's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. The forward-looking statements contained in this prospectus are presented to assist potential purchasers in making a decision to invest in the Units and should not be relied upon for any other purpose.

**The forward-looking statements contained in this prospectus are expressly qualified by the foregoing cautionary statements and are made as of the date of this prospectus. Neither the Trust nor the Underwriters undertake any obligation to publicly update or revise any forward-looking statements, except as required by applicable securities laws. Investors should read this entire prospectus and consult their own professional advisors to ascertain and assess the income tax, legal, risks and other aspects of their investment in the Units.**

**International Financial Reporting Standards**

The Canadian Accounting Standards Board requires that all Canadian publicly accountable enterprises transition from Canadian generally accepted accounting principles in effect prior to January 1, 2011 to Canadian generally accepted accounting principles for publicly accountable enterprises (being International Financial Reporting Standards as adopted by the Canadian Accounting Standards Board) ("**IFRS**") for interim and annual reporting periods for fiscal years beginning on or after January 1, 2011. Accordingly, the Trust prepares its consolidated financial statements in accordance with IFRS. In addition, the Operating Statements Containing Gross Revenues, Royalties and Production Taxes and Operating Expenses for the Denali Assets have been prepared using accounting policies that are permitted by IFRS, with such accounting policies applying to those line items as if such line items were presented as part of a complete set of financial statements. See "Exemptions from Certain Disclosure Requirements".

**Non-IFRS Financial Measures**

In addition to using financial measures prescribed by IFRS, references are made in this prospectus to "distributable cash", "cash flow available for distribution", "netback", "yield", "debt to EBITDA" and "internal rate of return", or "IRR", which are measures that do not have any standardized meaning as prescribed by IFRS and are not presented in the financial statements of the Trust or the operating statements for the Denali Assets. Accordingly, the Trust's use of such terms may not be comparable to similarly defined measures presented by other entities.

References to "distributable cash" and "cash flow available for distribution" are to distributable cash and cash flow available for distribution to Unitholders in accordance with the distribution policies of the Trust described in this prospectus. Distributable cash and cash flow available for distribution are measures commonly used by the trust sector as indicators of financial performance and Management believes that prospective investors may consider the cash distributed by the Trust relative to the price of the Units when assessing an investment in Units.

"Netback" is equal to oil, natural gas and NGLs sales revenue less royalties, transportation costs, production taxes and operating expenses. Management considers netback important as it is a measure of profitability and reflects the quality of production. Management uses this non-IFRS measurement for its own performance measures and to provide Unitholders and potential investors with a measurement of the Trust's efficiency and its ability to fund a portion of its future growth expenditures.

Cash-on-cash "yield" as used in this prospectus is calculated by dividing the annualized distribution anticipated to be paid per Unit by the offering price of the Units hereunder. Cash-on-cash yield is a measure commonly used in the trust sector as an indicator of financial performance and Management believes that prospective investors may consider yield when assessing an investment in Units. Investors are cautioned, however, that distributions do not represent a "yield" in the traditional sense and are not comparable to bonds or other fixed income securities, where investors are entitled to a full return of the principal amount of debt on maturity in addition to a return on investment through interest payments at a predetermined level. Distributions can represent a blend of return on investment of Unitholders' initial investment and a return of capital on Unitholders' initial investment. See "Risk Factors – Risks Relating to the Trust's Structure and Ownership of Units".

References to "debt to EBITDA" refer to net debt as a proportion of annualized EBITDA of the Trust. Net debt is defined as bank debt plus any other long-term debt of the Trust, adjusted for working capital but excluding from working capital derivative contracts and future income tax balances. EBITDA is defined as earnings before interest, income taxes, depreciation, amortization, other non-cash expenses such as unrealized foreign exchange gains or losses and asset impairment, and any unusual non-operating one-time items such as acquisition costs. The debt to EBITDA ratio will be used by Management to assess the Trust's leverage and the continuing appropriateness of its distribution and capital investment levels in light of its ability to generate cash to finance its operations.

References to "internal rate of return", or "IRR", are to the discount rate at which the net present value of the expected cash flows of an investment is equal to zero. IRR is a measure generally used to assess capital investment and will be used by Management to assess US Opco's ability to generate a return on investment.

**Market and Industry Data**

Certain market and industry data contained in this prospectus is based upon information from government or other independent industry publications and reports or based on estimates derived from such publications and reports. Government and industry publications and reports do not guarantee the accuracy or completeness of their information. While Management believes this data to be reliable, market and industry data is subject to variations and cannot be verified with complete certainty due to limits on the availability and reliability of raw data, the voluntary nature of the data gathering process and other limitations and uncertainties inherent in any statistical survey. Accordingly, the accuracy, currency and completeness of this information cannot be guaranteed. Neither the Trust nor any of the Underwriters have independently verified any of the data from third party sources referred to in this prospectus or ascertained the underlying assumptions relied upon by such sources.

**Trademarks**

The Administrator intends to apply for trademark registration of the name "Argent Energy". Management believes that failure to obtain trademark registration of that name will not prevent it from being used by the Trust, the Administrator, or their subsidiaries.

**Abbreviations and Conversions**

In this prospectus, the following abbreviations have the meanings set forth below:

| | | | |
|---|---|---|---|
| API | American Petroleum Institute | Mcf | thousand cubic feet |
| bbl and bbls | barrel and barrels, each barrel representing 34.972 Imperial gallons or 42 U.S. gallons | Mcf/d | thousand cubic feet per day |
| | | Mcfe | thousand cubic feet of natural gas equivalent |
| | | Mcfe/d | thousand cubic feet of natural gas equivalent per day |
| bbls/d | barrels per day | MMbbls | millions of barrels |
| Bboe | billions of barrels of oil equivalent | MMboe | millions of barrels of oil equivalent |
| Bcf | billion cubic feet | MMBtu | million British thermal units |
| Bcfe | billion cubic feet equivalent | MMcf | million cubic feet |
| boe | barrels of oil equivalent | MMcf/d | million cubic feet per day |
| boe/d | barrels of oil equivalent per day | psi | pounds per square inch |
| Btu | British thermal unit | Tcf | trillion cubic feet |
| gpm | gallons per minute | Tcfe | trillion cubic feet of natural gas equivalent |
| kW | thousand watts | M | thousand |
| Mbbls | thousands of barrels | MM | million |
| Mboe | thousands of barrels of oil equivalent | | |

The following table sets forth certain standard conversions between Standard Imperial Units and 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 | 6.293 |
| feet | metres | 0.305 |
| metres | feet | 3.281 |
| miles | kilometers | 1.609 |
| kilometers | miles | 0.621 |
| acres | hectares | 0.405 |
| hectares | acres | 2.471 |

Disclosure provided in this prospectus for barrels of oil equivalent (boe) and thousand cubic feet of gas equivalent (Mcfe) may be misleading, particularly if used in isolation. A boe conversion ratio of six Mcf to one bbl and a Mcfe conversion ratio of one bbl to six Mcf are based on an energy equivalency conversion method primarily applicable at the burner tip and do not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalency conversion ratio of six to one, utilizing a boe conversion ratio of six Mcf to one bbl and a Mcfe conversion ratio of one bbl to six Mcf may be misleading as an indication of value.

## Exchange Rate Data

The following table sets forth, for the periods indicated, the high, low, average and period-end noon spot rates of exchange for one U.S. dollar, expressed in Canadian dollars, as published by the Bank of Canada.

| | Three Months Ended March 31 | | Year Ended December 31 | | |
|---|---|---|---|---|---|
| | 2012 | 2011 | 2011 | 2010 | 2009 |
| | (C$) | (C$) | (C$) | (C$) | (C$) |
| Highest rate during the period | 1.0272 | 1.0022 | 1.0604 | 1.0778 | 1.3000 |
| Lowest rate during the period | 0.9849 | 0.9686 | 0.9449 | 0.9946 | 1.0292 |
| Average noon spot rate for the period(1) | 1.0013 | 0.9857 | 0.9891 | 1.0299 | 1.1420 |
| Rate at the end of the period | 0.9975 | 0.9696 | 1.0162 | 0.9946 | 1.0466 |

**Note:**

(1) Determined by averaging the rates on the last business day of each month during the respective period.

On July 30, 2012, the noon rate of exchange posted by the Bank of Canada for conversion of U.S. dollars into Canadian dollars was US$1.00 equals C$1.0033**.**

## OFFERING SUMMARY

***The following is a summary of the principal features of the Trust and the Offering and should be read together with the more detailed information and financial data and statements contained elsewhere in this prospectus. Reference is made to the "Glossary" and "Notice to Investors – Abbreviations and Conversions" for the meanings of certain defined terms and abbreviations.***

**Offering:** 21,230,000 Units.

**Offering Price:** $10.00 per Unit.

**Amount:** $212,300,000.

**Over-Allotment Option:** The Underwriters have been granted the Over-Allotment Option exercisable in whole or in part, from time to time, for a period of 30 days from closing of the Offering to purchase up to 3,184,500 additional Units on the same terms as the Units sold under the Offering, to cover over-allotments, if any, and for market stabilization purposes. See "Plan of Distribution".

**Units:** Each Unit represents an equal, undivided beneficial interest in the Trust and ranks equally with all of the other Units without discrimination, preference or priority. Each Unit entitles the holder to one vote at all meetings of Unitholders, to participate equally with respect to any and all distributions by the Trust and, on liquidation or termination of the Trust, to participate equally with respect to the distribution of the remaining assets of the Trust after payment of the Trust's debts, liabilities and liquidation or termination expenses. See "Description of the Trust".

**Use of Proceeds:** The net proceeds to the Trust from the Offering will be approximately $198.1 million (approximately $228.1 million if the Over-Allotment Option is exercised in full) after deducting the fees payable to the Underwriters of approximately $12.7 million (approximately $14.6 million if the Over-Allotment Option is exercised in full) and the expenses of the Offering estimated to be approximately $3.0 million, of which approximately $1.5 million will be paid from proceeds raised in the Initial Private Placements.

The Trust will provide the net proceeds of the Offering to US Opco. US Opco will use those proceeds, plus an advance of approximately US$5.8 million under the Credit Facilities, to fund the purchase price of the Acquisition. The purchase price for the Denali Assets (excluding the Deep Rights) is US$166.7 million, subject to certain closing adjustments and net of US$36.6 million that will be paid to Denali by the Trust on closing of the Offering, which amount will be held in escrow by Denali and applied to US Opco's capital expenditures and general and administrative expenses on the Denali Assets for the 24 month period following closing of the Offering. See "Funding, Acquisition and Related Transactions". Following completion of the Offering and the Acquisition, the Trust will continue to pursue the objective and strategies set out under the heading "Undertaking of the Trust – Objective and Strategies of the Trust".

After the closing of the Offering and the Acquisition, the Trust anticipates that approximately US$5.8 million will have been initially drawn under the Credit Facilities to partially fund the Acquisition, and that approximately US$9.7

million will be available for borrowing under the Credit Facilities. The Trust's capital expenditure program for the remainder of 2012 is approximately US$13.6 million based on an August 10, 2012 closing date for the Acquisition, which will be funded from the amounts held in escrow by Denali.

The net proceeds to be received by the Trust pursuant to the exercise of the Over-Allotment Option, if exercised, are expected to be provided to US Opco in the same manner as the net proceeds of the Offering. If the Over-Allotment Option is exercised for net proceeds of at least $25 million, US Opco will acquire the Denali Reserved Interest for US$20 million in accordance with the Purchase and Sale Agreement, with the remaining proceeds to be used to reduce the amount outstanding under the Credit Facilities and for general corporate purposes. If the Over-Allotment Option is exercised for net proceeds of less than $25 million, the proceeds will be used to reduce the amount outstanding under the Credit Facilities and for general corporate purposes. See "Use of Proceeds" for a tabular presentation of the use of proceeds and "Funding, Acquisition and Related Transactions – Acquisition – Purchase and Sale Agreement – Denali Reserved Interest".

**Distribution Policy of the Trust:** The Trust intends to make monthly distributions to Unitholders of record as of the close of business on the last business day in Calgary, Alberta of each month, which are expected to be paid to Unitholders on or about the 23rd day of the following month or, if not a business day, the next business day thereafter. The amount of cash to be distributed per month per Unit will be determined by the Administrator Directors, taking into consideration the overall distribution policy of the Trust and after consideration of the Trust's net monthly cash receipts less estimated amounts required for the payment of expenses and other obligations of the Trust, cash redemptions of Units and the satisfaction of any tax liability. The Trust expects that the initial monthly cash distribution rate will be $0.0875 per Unit. The initial cash distribution, which will be for the period from and including the date of closing of the Offering to August 31, 2012, is expected to be paid on September 24, 2012 to Unitholders of record on August 31, 2012 and is estimated to be $0.0621 per Unit (assuming that closing of the Offering occurs on August 10, 2012). See "Description of the Trust – Distributions".

**Distribution Reinvestment Plan of the Trust:** Following completion of the Offering and subject to the receipt of all necessary regulatory approvals, the Trust intends to adopt a distribution reinvestment plan (the "**DRIP**"). The DRIP will allow eligible Unitholders to elect to have their monthly cash distributions reinvested in additional Units on the applicable distribution payment date at a purchase price to be determined in accordance with the terms of the DRIP. Unitholders who do not enroll in the DRIP will receive the regular cash distributions. See "Description of the Trust – Distribution Reinvestment Plan".

**Distribution Policy of the Trust Subsidiaries:** US Opco intends to adopt a policy to distribute its distributable cash to the extent determined prudent by the directors of US Opco. In addition to monthly payments made by US Opco to the Trust on the US Opco Notes, distributions will be made on a monthly basis to Can Holdco in the form of dividends and return of capital on the US Opco Shares held by Can Holdco and Can Holdco will make corresponding distributions to the Trust. US Opco and Can Holdco may, in addition, make distributions at any other time, which will also be distributed to the Trust. Capital and other expenditures, including amounts to enable the Trust to stabilize monthly distributions based on anticipated future distributable cash, may be financed by the Credit Facilities, other borrowings or additional capital contributions to US Opco. See "Description of Can Holdco" and "Description of US Opco".

| | |
|---|---|
| | **The Administrator Directors, on behalf of the Trust, and the boards of directors of US Opco and Can Holdco, each have considerable discretion in determining the amount of cash distributions. Cash flow available for distribution to Unitholders is not guaranteed and will fluctuate with, among other things, commodity price volatility and the performance of subsidiaries of the Trust, initially including results from the Denali Assets. See "Risk Factors".** |
| **Governance of the Trust:** | Computershare Trust Company of Canada is the Trustee of the Trust. The Trust Indenture provides that Unitholders may replace the Trustee by Ordinary Resolution at any time. The Trust Indenture also empowers the Trustee to delegate much of the responsibility regarding the operations and governance of the Trust, which it has done pursuant to the Administrative Services Agreement with the Administrator. The Administrative Services Agreement provides for the reimbursement, on an "at cost" basis, to the Administrator for all of its reasonable expenses incurred in respect thereof. No fees are payable by the Trust to the Administrator. The Voting Agreement will provide that Unitholders will be entitled to elect all of the Administrator Directors. See "Trustee, Directors and Management – The Trust", "Description of the Trust", "Administration of the Trust – Administrative Services Agreement" and "Voting Agreement". |
| **Administration of the Trust:** | The Trust and the Administrator will enter into the Services Agreement with Aston Hill, pursuant to which Aston Hill will perform certain technical and administrative services that may be required by the Administrator, on behalf of the Trust. The Services Agreement provides for the recovery by Aston Hill of its direct costs incurred in providing the services under the Services Agreement plus an annual overhead allocation based on the enterprise value of the Trust from time to time. See "Administration of the Trust – Services Agreement with Aston Hill". |
| **Committees of the Administrator Directors:** | The Administrator Directors have formed the following committees with chairpersons and members as set out below:<br><br>Audit Committee – William D. Robertson (Chairman), Scott Butler and Glen C. Schmidt.<br><br>Governance, Nomination & Compensation Committee – John Brussa (Chairman) and Scott Butler.<br><br>Reserves & Environment, Health & Safety Committee – Glen C. Schmidt (Chairman), Richard Louden and William D. Robertson.<br><br>See "Trustee, Directors and Management" and "Corporate Governance". |
| **Canadian Federal Income Tax Considerations:** | **There are important tax consequences to an investment in the Units. See "Canadian Federal Income Tax Considerations".** A Unitholder resident in Canada will generally be required to include in computing income from property for a taxation year that portion of the net income of the Trust, including interest, taxable dividends and net realized taxable capital gains, that is paid or becomes payable to the Unitholder in the year (whether in cash or in Units). Taxable dividends in respect of which the appropriate designations are made by Can Holdco and the Trust may benefit from the enhanced dividend tax credit available in respect of eligible dividends for Unitholders who are individuals resident in Canada. |

The non-taxable half of any net realized capital gains of the Trust that is paid or becomes payable to a Unitholder in a taxation year will not be included in computing the Unitholder's income for the year. Distributions by the Trust in excess of the Unitholder's share of the net income and net realized capital gains generally will not be included in such Unitholder's income for the year. However, such an amount (other than an amount received as proceeds of disposition on the redemption of Units) will reduce the adjusted cost base of the Units held by the Unitholder. To the extent that the adjusted cost base of a Unit held as capital property would otherwise be less than zero, the Unitholder will be deemed to have realized a capital gain equal to the negative amount. A Unitholder who disposes of Units held as capital property (on a redemption or otherwise) will realize a capital gain (or capital loss) to the extent that the proceeds of disposition exceed (or are less than) the adjusted cost base of the Units and any reasonable costs of disposition. Each prospective purchaser should satisfy itself as to the tax consequences of an investment in Units by obtaining tax advice from its tax advisor. See "Canadian Federal Income Tax Considerations".

**Risk Factors:**

**These securities are considered to be speculative due to the nature of the Trust's business and its formative stage of development.** The Trust was formed to participate through its subsidiaries in the oil and natural gas industry by acquiring principally existing producing properties located primarily in the U.S., and by exploiting the reserves associated with these properties. The Trust plans to pursue these objectives by working with industry partners and by developing its own internally generated prospects, the success of which cannot be assured. The Trust and its subsidiaries have no business history or history of earnings.

There are additional risks associated with an investment in the Units relating to the Trust's prospects for success, including:

- not achieving the anticipated benefits of the Acquisition;
- an incorrect assessment of value of the Acquisition;
- failure by US Opco, as operator of the Denali Assets, to maintain or achieve increased production and the resulting adverse effect on cash flow to US Opco;
- reliance on third party operators, including in respect of the Denali Reserved Interest, if applicable;
- title to oil and natural gas properties and undisclosed liabilities, including environmental liabilities, associated with such properties;
- declines in oil, NGLs and natural gas prices;
- the Trust's inability to guarantee distributions;
- future indebtedness and fluctuations in interest rates;
- access to the capital necessary to acquire and exploit additional assets;
- reliance on Aston Hill for the provision of technical and administrative services pursuant to the Services Agreement;
- conflicts of interest involving directors and officers of the Administrator;

- conflicts of interest involving Aston Hill and the Trust as a result of the Services Agreement;
- competition from other oil and natural gas companies for qualified staff, assets and services;
- potential liability for damages arising during operations, including environmental damages;
- changes in legislation and regulations (including tax and environmental laws and regulations) which may adversely affect the Trust or Unitholders;
- income tax matters in the U.S. and Canada (including the Trust ceasing to qualify as a mutual fund trust, becoming a SIFT trust, a change in the SIFT Rules, withholding tax, or the potential non-deductibility of interest on the US Opco Notes or of certain expenditures relating to the development or production of oil or natural gas under U.S. tax rules);
- changes in foreign exchange rates between the U.S. and Canadian dollars;
- reduced or limited availability of oil, natural gas and NGLs markets;
- dilution resulting from sales of additional Units;
- a market not developing for its Units;
- decline in the overall global economy; and
- issues with respect to enforcing indemnities in favour of the Trust.

Many of these factors are beyond the control of the Trust. In assessing the risks of an investment in the Units, potential investors should realize that they are relying on the experience, judgment, discretion, integrity and good faith of Management and the Administrator Directors. An investment in the Units is suitable for only those investors who are willing to risk a loss of their entire investment and who can afford to lose their entire investment. Investors should consult their own professional advisors to assess the income tax, legal and other aspects of an investment in Units. See “Risk Factors”.

## PROSPECTUS SUMMARY

***The following is a summary of the principal features of the Trust and the Offering and should be read together with the more detailed information and financial data and statements appearing elsewhere in this prospectus. Reference is made to the "Glossary" and "Notice to Investors – Abbreviations and Conversions" for the meanings of certain defined terms and abbreviations.***

### Investment Highlights

Management believes that an investment in the Units provides investors with a unique combination of investment opportunities, including:

***Attractive cash yield paid monthly***

The Trust intends to make monthly cash distributions to Unitholders, initially at a rate of \$0.0875 per Unit, implying an initial annualized cash-on-cash yield, based on the purchase price of a Unit hereunder, of approximately 10.5%. See "Description of the Trust – Distributions" and "Summary of Distributable Cash".

***Sustainable distribution profile***

The Denali Assets consist of long-life reserves with a proved plus probable Reserve Life Index of 21 years and a proved Reserve Life Index of nine years, which makes the assets well suited for a yield-focused entity with an objective of delivering stable and consistent distributions to Unitholders. The low-risk drilling opportunities and the balanced commodity profile created from ownership of the Denali Assets are expected to enhance the stability of distributions from the Trust. Management intends to implement a rolling hedging program that will reduce the Trust's commodity price exposure for up to 36 months and may also implement foreign exchange and interest rate hedges as opportunities arise, thereby further enhancing the stability of distributions. See "Undertaking of the Trust – Objective and Strategies of the Trust", and "Funding, Acquisition and Related Transactions – Acquisition".

***High quality assets with balanced commodity exposure***

The Trust's initial assets are of high quality and the Trust intends to develop such assets with a view to creating a balanced commodity profile. Working interest production before royalties for the month of May 2012 in respect of the Denali Assets averaged 1,543 boe/d with an additional 90 bbls/d of oil temporarily shut-in (due to a leaking plug which has since been repaired), resulting in production weighted approximately 21% to oil, 77% to natural gas and 2% to NGLs. The total proved plus probable reserves volumes as set forth in the Sproule Reserve Report are weighted approximately 30% to oil, 66% to natural gas and 4% to NGLs, resulting in reserves values weighted approximately 61% to oil, 31% to natural gas and 8% to NGLs. Management believes the Trust's balanced commodity profile will provide Management with the flexibility to focus the Trust's capital investments towards those opportunities which meet the Trust's disciplined investment criteria at any given time with the objective of maximizing value to Unitholders. In addition, the close proximity of the Denali Assets to refineries along the Gulf Coast of Texas provides favourable pricing for the related marketing contracts.

The Denali Assets consist of varying working interests in 1,755 oil and natural gas leases covering approximately 143,765 gross (117,273 net) acres and an interest in 61 operated wells and eight non-operated wells. The Denali Assets include interests in: (i) the Austin Chalk and Eagle Ford Shale oil formations; (ii) the South Texas natural gas assets, including the South Escobas Field; and (iii) the Deep Rights. The development plan included in the Sproule Reserve Report and expected to be carried out by US Opco is anticipated to increase the proportion of oil produced in the near term. See "Funding, Acquisition and Related Transactions – Acquisition."

The Austin Chalk and Eagle Ford Shale oil formations are in one of the most active chalk and shale plays, respectively, in the United States. The Austin Chalk oil formation has been developed and producing since the 1920s, with over 150,000 wells drilled and cumulative production of over 2.5 Bboe to date, with an estimated one billion barrels of oil yet to be developed. The Austin Chalk oil formation produces light oil and is being aggressively developed by horizontal drilling (often dual) and open hole completion. Since discovery in 2008 the Eagle Ford Shale oil formation has also been aggressively developed, due in part to technological advances in horizontal drilling and multi-stage fracturing, thereby enhancing the permeability and deliverability of this tight shale and allowing access to its high quality light oil. Production from the Eagle Ford Shale oil formation has steadily increased from 131,000 bbls produced and 26 drilling permits granted in 2008 to over 30 million bbls produced and 2,826 drilling permits granted in 2011. Numerous operators are currently drilling in the Eagle Ford Shale oil formation and the total rig count is over 200 rigs. The overall recovery potential of the Eagle Ford Shale oil formation has not yet been conclusively determined, although it is believed to contain 21 Tcf of natural gas and 3 billion bbls of oil, suggesting significant potential growth in production and reserves. The Austin Chalk oil formation demonstrates high initial decline rates followed by long, slow decline rates for approximately 30 years, which is typical of tight gas, chalk or shale resource plays, and a similar decline rate is expected by Management for the Eagle Ford Shale oil formation. The historical and forward-looking information in this paragraph is sourced from reports prepared by the U.S. Energy Information Administration, the United States Geological Society and the Texas Railroad Commission (the "**RRC**").

The Denali South Texas natural gas assets are standard deltaic Wilcox formations with conventional production. The South Escobas Field has produced 21.7 Bcfe from 10 wells since discovery in January 2008. Management believes these natural gas assets would require modest investment to maintain relatively flat production over the next few years. The average operating cost of Denali gas production in the first quarter of 2012 was approximately US$0.80/Mcfe.

***Control over operations by experienced operating team***

The Trust, through US Opco, will operate approximately 96% of the current production from the Denali Assets. This will allow the Trust to efficiently manage operations and to prudently allocate capital on a timely basis to the most profitable opportunities. This high percentage of operatorship will also allow the Trust to be more involved with overall field operation design and execution as well as choose service providers. This is expected to help ensure the most current and appropriate technologies and practices will be used. The Trust will also have a high degree of control over tie-in locations and product transportation options which is expected to aid in controlling costs and ensuring new production is brought on in a timely and cost effective manner. Additionally, operatorship allows the Trust to better source and control acquisition opportunities and act upon them directly; as well as source and directly negotiate with potential joint venture partners.

The operating team of Denali, being led by Richard Louden and John Elzner, will be joining US Opco upon closing of the Acquisition, and will operate the Denali Assets. The Denali operating team has an average of over 30 years of experience in the upstream oil and natural gas industry and has worked together as active drillers and operators in Texas for the past nine years, building three successful energy companies. The operating team has drilled over 85 wells with Denali, with a drilling success rate of 81%. From this program, they have added reserves of 30.3 MMboe on net capital expenditures of US$262 million, with no lost time incidents involving their personnel. The operating team's focus on reducing costs has resulted in direct operating costs excluding workovers in respect of the Denali Assets for the three month period ended March 31, 2012 being US$0.57/Mcf for the natural gas assets and US$3.14/boe for the oil assets, for an average of US$3.35/boe for both oil and natural gas assets. Prior to founding Denali, the operating team worked together at Coastal Oil & Gas Corp. and El Paso Production Company, where, in the South Texas business unit alone, they drilled over 500 wells, adding reserves of over 1.0 Tcfe. The Denali team currently consists of 17 technical and administrative personnel and eight field personnel, including seven field contractors, five administrative contractors and one technical contractor, all of whom will join US Opco following closing of the Offering.

***Large inventory of low-risk exploitation opportunities***

The Denali Assets offer significant low-risk drilling, recompletion and optimization opportunities. The Sproule Reserve Report indicates that Denali has 14 gross (9.7 net) proved undeveloped drilling locations in the Austin Chalk oil formation at locations offsetting Denali's current producing wells in Fayette and Gonzales Counties, Texas. In addition, Sproule has determined there are 13 gross (8.9 net) probable drilling locations in the Austin Chalk oil formation. Management believes additional acreage with drilling potential in the Austin Chalk oil formation will become available for lease over the next few years, potentially providing the Trust with the opportunity to expand on this drilling program. There are a total of 15 gross (8.1 net) natural gas wells to be drilled on Denali's South Escobas acreage as per the development plan in the Sproule Reserve Report. In addition to the 8.1 net natural gas wells reflected in the Sproule Reserve Report, Management believes there are an additional 4.2 net natural gas wells that may be drilled in future years on acreage that is held by production. In the current context of historically low natural gas prices, the current development plan is to defer drilling all but one of the natural gas wells until at least 2014. See "Funding, Acquisition and Related Transactions – Acquisition".

***Eagle Ford Shale light oil upside***

Operators are successfully drilling and completing oil wells in the Eagle Ford Shale oil formation near the Denali Assets in Fayette and Gonzales Counties, Texas, which consist of approximately 29,000 gross (23,500 net) acres. These results are encouraging for the Eagle Ford Shale oil formation, which underlay the Austin Chalk oil formation included in the Denali Assets. The Eagle Ford Shale oil formation is consistently evident on the well logs of existing Denali Austin Chalk wells in Fayette and Gonzales Counties, Texas, which further supports the development potential of the Denali Assets. The Sproule Reserve Report has attributed to the Eagle Ford Shale oil formation, eight gross (7.7 net) probable drilling locations and 1.8 MMboe of gross probable reserves relating to 1,280 net acres out of the acreage of the Denali Assets located in Fayette and Gonzales Counties, Texas. In addition to the 1,280 net acres, the Deep Rights relating to the Eagle Ford Shale oil formation under the remainder of Denali's Austin Chalk assets (22,220 net acres) are offset, to a large extent, by recent successful drilling activity by third parties. This drilling activity includes twenty-four Eagle Ford Shale horizontal wells which have been drilled within 5 miles of Denali's acreage in Fayette and Gonzales Counties, Texas with an average initial production rate of over 925 boe/d. Twenty-nine additional wells have either been permitted to drill, are in the process of being drilled, or are being completed in this area. South and southeast of Denali's acreage in Gonzales County, Magnum Hunter Resources Inc. has drilled and completed 11 wells with an average 24 hour initial production rate of 1,331 boe/d and average flowing tubing pressure of 1,917 psi (RRC, 2011 and 2012). The two wells of Magnum Hunter Resources Inc. that are in the closest proximity to Denali's acreage have produced 85,100 boe in 13 months and 77,300 boe in 18 months, respectively (RRC, 2012). Magnum Hunter Resources Inc. has been permitted to drill ten additional wells in this area. In addition, to the south of Denali's acreage in Gonzales County, Tidal Petroleum, Inc. has drilled and completed a well that had a 24 hour initial production rate of 361 boe/d and flowing pressure of 700 psi (RRC, 2012). Tidal Petroleum, Inc. has also been permitted to drill three additional wells in this area. Immediately east of Denali's acreage in Fayette and Gonzales Counties, GeoResources Inc. has drilled and completed nine wells with an average 24 hour initial production of 705 boe/d and average flowing pressure of 2020 psi (RRC, 2011 and 2012). GeoResources Inc. has 13 additional wells that have either been permitted to drill, are in the process of being drilled, or are being completed. Also immediately adjacent to Denali's acreage in Gonzales County, Zaza Energy Corporation (in a joint venture with Hess Corporation) has drilled a well which realized a 24 hour initial production rate of 291 boe/d with 556 psi flowing pressure (RRC, 2012) and has been permitted to drill an additional well in this area. To the northeast of Denali's acreage in Fayette County, Weber Energy Corporation has drilled two short lateral horizontal Eagle Ford Shale wells, which have a combined lateral length of approximately 4,765 feet and tested a total of 610 boe/d with average flowing tubing pressure of 520 psi (RRC, 2011). These wells have produced 52,500 boe in the first 6 months of production reporting (RRC, 2012). Sanchez Oil & Gas Corp. has also been permitted to drill two wells, one of which was spud in June 2012.

Management believes production from wells drilled by third parties in the Eagle Ford Shale oil formation may be indicative of possible production that can be achieved by US Opco on its properties and that there is sufficient production data from nearby wells to conclude the undeveloped acreage in Fayette and Gonzales Counties, Texas, is commercial to drill. However, at this stage of development, Management cannot accurately predict the quantity of reserves per well or the anticipated production levels from such wells. Management also believes at least 15,000 net acres of the Deep Rights acreage in Fayette and Gonzales Counties, Texas, is prospective for the Eagle Ford Shale oil formation at current drilling costs and oil prices. Management expects that drilling in the Eagle Ford Shale oil formation will be on 160 acre well spacing, which would provide approximately 95 net prospective Eagle Ford Shale drilling locations on the Denali Assets.

*Visible low-cost production growth*

Management expects that following closing of the Offering the Trust will spend in aggregate approximately US$13.6 million during the remainder of 2012 based on an August 10, 2012 closing date for the Acquisition and US$33.8 million in 2013 in connection with its capital program on the Denali Assets, of which, pursuant to the Purchase and Sale Agreement, Denali will be obligated to fund an aggregate of US$35.6 million of US Opco's capital expenditures on the Denali Assets for the 24 month period following closing of the Offering using a portion of the amount that will be paid by the Trust to Denali on closing of the Offering and held in escrow. Based on the Sproule Reserve Report and the development plan reflected therein, the production rate is expected to double on a boe basis within two years. Based on the Sproule Reserve Report, Management expects favourable drilling, completion and tie-in costs of approximately US$18.32 per boe in 2012 and approximately US$15.72 per boe in 2013 for the 2013 drilling program, which is expected to result in incremental production before declines of approximately 693 boe/d for the period from July to December 2012 and approximately 1,410 boe/d for 2013.

US Opco expects to drill approximately six (3.7 net) new wells from July, 2012 to the end of 2012 and approximately six (six net) new wells during 2013 on the Denali Assets. According to the development plan in the Sproule Reserve Report, five of the proposed Austin Chalk locations and one of the Eagle Ford Shale locations are scheduled for development in the latter half of 2012. In addition, one of the Austin Chalk, four of the Eagle Ford Shale development locations and one of the Escobas area development locations are scheduled for development in 2013.

*Opportunities for growth in distributions*

The Trust provides investors with opportunities for potential growth in distributions: (i) through the low-risk drilling program developed by Management designed to fully exploit the Denali Assets over the next seven years; (ii) through the possibility of future drilling in the Deep Rights acquired pursuant to the Purchase and Sale Agreement; (iii) from the exposure to future increases, if any, in natural gas prices provided by natural gas production from the Denali Assets; and (iv) through other accretive acquisition opportunities, if such become available.

*Opportunities for future acquisitions*

Management believes that there are numerous opportunities for future acquisitions in Texas and elsewhere within the U.S. based on the large number of oil and natural gas fields in both absolute and relative terms, the mature nature of the many producing fields in the U.S., and relatively low operating costs. In particular, Management believes the following factors result in significant opportunities in the U.S., as compared to Canada, for future acquisitions:

- the U.S. has an abundant supply of producing oil and natural gas fields that are available for purchase, due to more fields in general as well as a more varied ownership profile, including private individuals and non-industry participants;
- the U.S. has a well developed and experienced oil and natural gas industry resulting in many mature oil and natural gas fields that are well suited for a trust structure, including assets with predictable production profiles and long-life reserves. In addition, the mature nature of the oil and natural gas fields and the use of only legacy development techniques often mean that these fields are candidates for new oilfield technology and production and completion techniques, including horizontal wells, multiple hydraulic fracturing and co-mingled production, which can improve primary recoveries and overall economics. These fields are also suitable candidates for secondary recovery techniques, such as waterflooding; and
- operating costs tend to be relatively low due to year-round access, higher density in-fill drilling, oilfield services competition and the presence of local operators. In addition, proximity to markets and available transportation infrastructure helps to lower transportation costs and increase realized prices.

***Experienced and committed leadership team***

The Administrator has a strong management team and Board with a varied background in engineering, operations, geosciences, finance and oil and natural gas acquisitions and divestitures. Management has on average over 25 years of experience in the oil and natural gas industry and has been senior management of small, medium and large oil and natural gas companies, including yield-focused oil and natural gas income trusts. The Board has extensive experience in the oil and natural gas industry particularly with respect to income and royalty trusts. The members of the Board have a broad range of experience in the fields of accounting, finance and corporate governance. See “Corporate Governance”.

***Tax efficient structure***

The Trust intends to qualify as a “mutual fund trust” under the Tax Act, but will not be a “SIFT trust” (as defined in the Tax Act) and will not be subject to any taxes under the SIFT Rules, provided that the Trust complies at all times with the investment restrictions set forth in the Trust Indenture, which preclude the Trust from holding any “non-portfolio property” (as defined in the Tax Act). Management anticipates that the Trust will distribute its taxable income each year to Unitholders and therefore does not expect taxes to be payable by the Trust in Canada. The Canadian tax treatment of the Trust is not available to yield-focused oil and natural gas entities with Canadian assets. See “Canadian Federal Income Tax Considerations”.

**The Trust and its Subsidiaries**

The Trust is an unincorporated limited purpose open-ended trust established under the laws of the Province of Alberta on January 31, 2012 by the Trust Indenture. The Trust intends to qualify as a “mutual fund trust” under the Tax Act. The Trust has been established to initially indirectly acquire the Denali Assets through its direct and indirect interests in Can Holdco and US Opco. The Trust will, on closing or immediately following closing of the Offering, also hold the US Opco Notes. See “Description of the Trust”.

The Administrator, a wholly-owned subsidiary of the Administrator Shareholder, is a corporation formed under the laws of the Province of Alberta on June 9, 2011 and is the administrator of the Trust. See “Administration of the Trust – Administrative Services Agreement”.

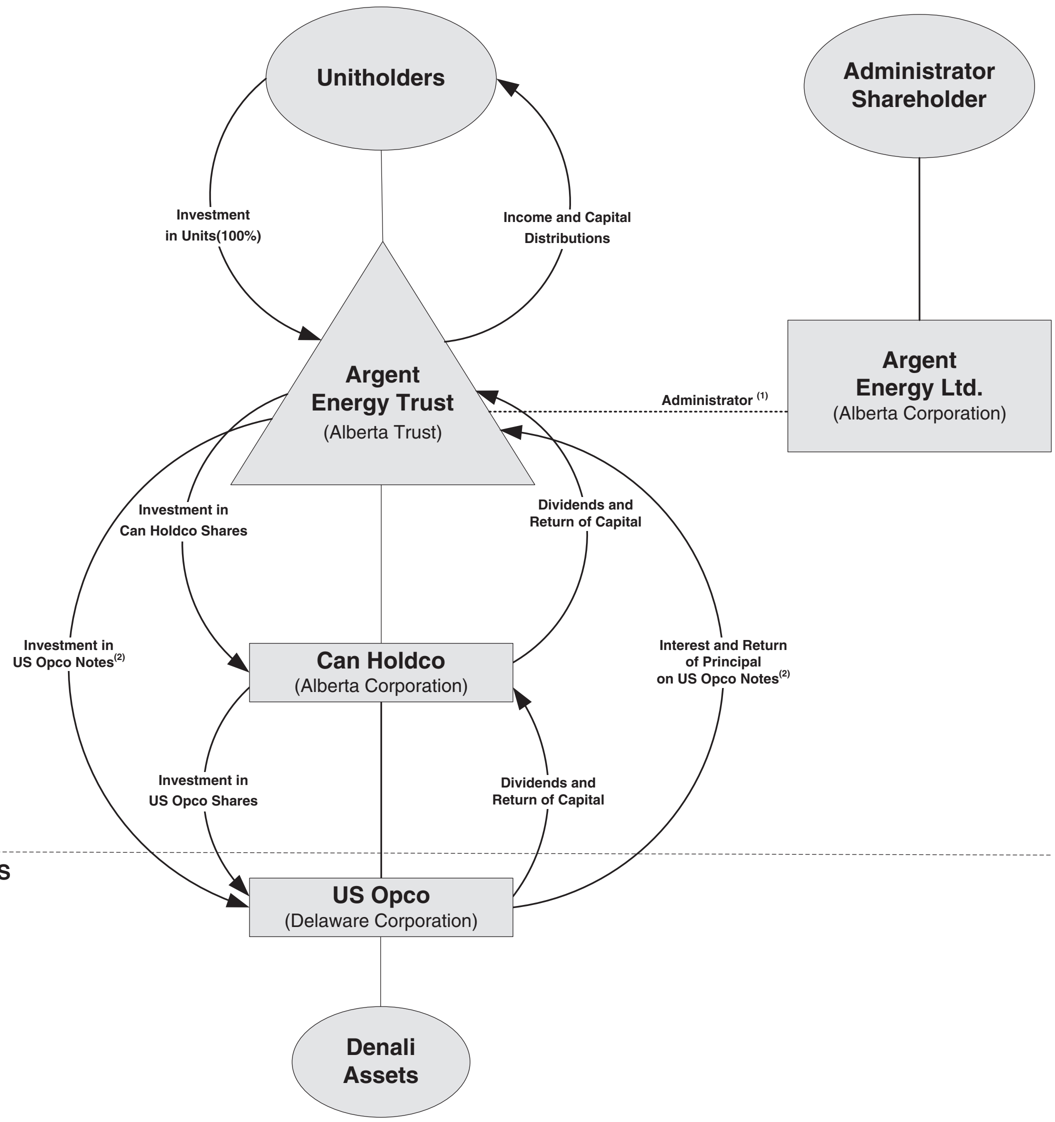
Can Holdco is a corporation formed under the laws of the Province of Alberta on May 4, 2012 to acquire and hold on closing of the Offering all of the issued and outstanding shares of US Opco. See “Description of Can Holdco”.

US Opco is a corporation formed under the laws of the State of Delaware on May 4, 2012 to acquire the Denali Assets. See “Description of US Opco”.

The Trust has been established to initially indirectly hold an interest in US Opco. US Opco has been created to engage in the acquisition and development of oil and natural gas reserves and production with low-risk exploitation potential, including the Denali Assets. The assets of the Trust will therefore be directly owned and operated by US Opco.

## Structure Following Closing

The following chart illustrates the structure of the Trust following completion of the Offering and the indirect investment by the Trust in US Opco and related transactions (as described in more detail in "Funding, Acquisition and Related Transactions"). All subsidiaries of the Trust will be directly or indirectly wholly-owned by the Trust. All of the shares of the Administrator are owned by the Administrator Shareholder and are subject to the terms of the Voting Agreement. See "Voting Agreement".




**Notes:**

(1) Pursuant to the terms of the Administrative Services Agreement, the Administrator will perform all administrative, operational and investment services that are or may be required or advisable, from time to time, for the Trust. The Administrator and the Trust will also enter into the Services Agreement with Aston Hill, pursuant to which Aston Hill will provide certain technical and administrative services that are or may be required or advisable, from time to time, for the Administrator on behalf of the Trust. See "Administration of the Trust – Administrative Services Agreement" and "Administration of the Trust – Services Agreement with Aston Hill".

(2) The US Opco Notes will initially be issued to Can Holdco and will be distributed by Can Holdco to the Trust concurrently with or immediately following the closing of the Offering. As a result, interest and principal on the US Opco Notes will be paid by US Opco directly to the Trust instead of to Can Holdco.

**Undertaking of the Trust**

The Trust is a recently formed energy trust created to provide investors with a publicly traded, oil and natural gas focused, distribution-producing investment, with favourable Canadian income tax treatment relative to taxable Canadian corporations. The strategy of the Trust is to acquire, exploit and develop, indirectly through US Opco, long-life crude oil and natural gas reserves, including the Denali Assets, in established producing basins located primarily in the U.S. The Trust's focus is the ownership and development, indirectly through US Opco, of producing crude oil and natural gas properties with low-risk exploitation potential. The Trust does not intend to engage in high-risk exploration activities. The Trust intends to make monthly distributions of a portion of its available cash to Unitholders and US Opco intends to use the remainder of available cash (which is not ultimately distributed to the Trust) to fund growth through additional acquisitions and capital expenditures.

US Opco entered into the Purchase and Sale Agreement with Denali on May 23, 2012, as amended on June 11, 2012 and July 12, 2012, pursuant to which it will acquire the Denali Assets.

The purchase price for the Denali Assets (excluding the Deep Rights) is US$166.7 million, subject to certain closing adjustments and net of US$36.6 million to be paid by the Trust to Denali on closing of the Offering and which amount will be held in escrow by Denali and applied to US Opco's capital expenditures and general and administrative expenses on the Denali Assets for the 24 month period following closing of the Offering. In addition, pursuant to the Deferred Payment Obligation in the Purchase and Sale Agreement, US Opco is required to pay Denali an aggregate of US$18 million over a three year period commencing January 1, 2013 in respect of the Deep Rights. US Opco will also be obligated to pay an additional US$30 million for additional interests in the Deep Rights upon the occurrence of certain events. See "Funding, Acquisition and Related Transactions – Acquisition – Purchase and Sale Agreement – Deep Rights". The purchase price for the Acquisition will be funded from the net proceeds of the Offering and an advance under the Credit Facilities to be established by US Opco. The Acquisition will have an effective date of January 1, 2012. It is a condition under the Purchase and Sale Agreement that the closing of the Acquisition occurs concurrently with the closing of the Offering and the closing of the Credit Facilities. See "Funding, Acquisition and Related Transactions – Acquisition – Purchase and Sale Agreement", "Use of Proceeds" and "Undertaking of the Trust – Credit Facilities".

The net proceeds to be received by the Trust pursuant to the exercise of the Over-Allotment Option, if exercised, are expected to be provided to US Opco in the same manner as the net proceeds of the Offering. If the Over-Allotment Option is exercised for net proceeds of at least $25 million, US Opco will acquire the Denali Reserved Interest for US$20 million in accordance with the Purchase and Sale Agreement, with the remaining proceeds to be used to reduce the amount outstanding under the Credit Facilities and for general corporate purposes. If the Over-Allotment Option is exercised for net proceeds of less than $25 million, the proceeds will be used to reduce the amount outstanding under the Credit Facilities and for general corporate purposes. See "Use of Proceeds" for a tabular presentation of the use of proceeds and "Funding, Acquisition and Related Transactions – Acquisition – Purchase and Sale Agreement – Denali Reserved Interest".

The Trust intends to qualify as a "mutual fund trust" and not be a "SIFT trust", each as defined in the Tax Act. The SIFT Rules tax certain income earned by a SIFT trust as if it were a corporation and treat certain distributions received by unitholders of a SIFT trust as taxable dividends. The Trust will not be a SIFT trust, provided that the Trust complies at all times with the investment restrictions set forth in the Trust Indenture, which preclude the Trust from holding any "non-portfolio property" (as defined in the Tax Act). Similar restrictions are included in the articles of Can Holdco and US Opco. If the SIFT Rules were to apply to the Trust, they might have an adverse impact on the Trust, including on the amount of distributions received by Unitholders and/or the value of the Units. The Administrator will be responsible for monitoring the Trust's investments and holdings of property to ensure the Trust is not at any time a SIFT trust and does not hold any "non-portfolio property". See "Description of the Trust – General", "Undertaking of the Trust", "Risk Factors" and "Canadian Federal Income Tax Considerations".

**Objective and Strategies of the Trust**

The objective of the Trust is to create stable, consistent returns for investors through the acquisition and development of oil and natural gas reserves and production with low-risk exploitation potential, located primarily in the U.S., and to pay out a portion of available cash to Unitholders on a monthly basis. The Trust believes it can achieve this objective through:

- ***Prudent and Disciplined Capital Investment*** – The Trust will maintain a focus on full cycle economics expected to be generated by all of its capital investments, without reliance upon the expectation of increased commodity prices. US Opco will pursue a prudent capital program in respect of the Denali Assets in order to provide cost-effective production growth having regard to commodity prices and other operational considerations. US Opco intends to allocate its capital prudently over all of US Opco's properties, balancing the need for production maintenance and cash flow generation with new production growth and reserves additions for long term value enhancement. The Trust will focus on increasing net asset value per Unit when making development and exploitation capital investments and acquisitions. All projects will undergo a capital ranking exercise by Management that, in combination with US Opco's overall objectives and strategies, will determine the optimal investment, development and drilling plans.
- ***Accretive Growth*** – The Trust will focus on prudent growth through a combination of internally generated opportunities (with disciplined capital ranking) and accretive acquisitions. At times in the oil and natural gas business it is more cost effective to access new reserves through exploitation of internal opportunities, while at other times it is more cost effective to acquire production and reserves from third parties. The Trust intends to invest its capital in a manner it believes will generate the highest full cycle returns to Unitholders over time. In all cases, the objective of the investments will be to focus on growth which is accretive to Unitholders. Management is experienced in both exploitation and acquisitions of reserves.
- ***Financially Conservative*** – Management believes that prudent utilization of debt can contribute to distribution stability and increased returns to Unitholders. Leverage will generally be maintained at a level appropriate for projected commodity prices and the ability of the Trust (through US Opco) to repay indebtedness without negatively impacting returns to Unitholders. The Trust intends to maintain a prudent debt to EBITDA ratio that will generally not exceed 1.5 times debt to EBITDA. The Trust may temporarily exceed this parameter, particularly in the case of acquisitions, provided that Management has a plan to return this ratio to the preferred range in the short term. Upon closing of the Offering, Management expects the debt to EBITDA (based on the 2012 financial year) ratio to be approximately 0.3 times.

The Trust will utilize a number of strategies intended to achieve its objective, including, in particular:

- ***Asset Location*** – The Trust intends to target its investments on assets primarily located on-shore in the U.S. near its initial operating properties, being the Denali Assets. Management believes that oil and natural gas assets located in the U.S. have certain favourable characteristics compared to Canada, including:
  - There are more discrete oil and natural gas assets in the U.S., a significant percentage of which are held by private or non-industry participants. As a result, Management believes that there are more opportunities for the acquisition of suitably sized assets in the U.S. than in Canada.
  - Operating costs of oil and natural gas assets in the U.S. are generally lower than operating costs for comparable oil and natural gas assets in Canada for a variety of reasons. Firstly, there is year-round access to properties in many parts of the U.S., while in Canada many assets can only be accessed during one of the winter or summer seasons. Secondly, there is generally more competition among service providers in the U.S. as compared to Canada, often resulting in lower service costs. Thirdly, oil and natural gas production in the U.S. tends to be closer to markets, often resulting in lower transportation costs and higher netbacks.
- ***Investment In Long-Life Assets*** – The Trust intends to focus on long-life oil and natural gas assets. These types of assets typically have lower risk development and exploitation potential and a longer reserve life which provides a natural hedge against short term commodity price cycles.

- ***Control Over Capital Expenditures*** – The Trust intends to focus its investments on properties where it has a material degree of control over the pace and degree of capital spending. The Trust will manage its assets as one portfolio, regardless of location and will prioritize its capital investment opportunities accordingly.
- ***Development and Exploitation*** – The Trust intends to focus on the development and exploitation of its properties. Although the Trust may undertake other activities which may technically qualify as exploration, the Trust does not intend to engage in high-risk exploration activities.
- ***Commodity Balance*** – The Trust does not expect to favour oil over natural gas or vice versa in the long-term. However, in the current context of historically low natural gas prices, the current development plan is to defer drilling all but one of the natural gas wells until at least 2014. On balance, the Trust will invest in those opportunities which meet its disciplined investment criteria, having regard to various factors including commodity prices, quality of assets in terms of reserves, production and operating costs, availability of operatorship, and associated operational risks and opportunities.
- ***Hedging Strategy*** – As part of the Trust's risk management strategy, Management plans to use financial instruments to reduce its commodity price exposure. Management intends to implement a rolling hedging program that would reduce the Trust's exposure to changes in commodity prices for up to 36 months. The Trust expects to hedge: (i) up to 70% of US Opco's after royalty forecasted production 12 months forward; (ii) up to 60% of US Opco's after royalty forecasted production 24 months forward; and (iii) up to 50% of US Opco's after royalty forecasted production 36 months forward. The amount and types of hedges will be dependent on, among other things, the Trust's debt level, anticipated capital expenditures, anticipated distributions and market conditions. The purpose of the hedging program is to reduce volatility in cash flows, protect acquisition economics, and to maintain stability of cash distributions to Unitholders. The Trust may also hedge its foreign exchange and interest rate exposure.

**Credit Facilities**

US Opco has received a commitment for the Credit Facilities and expects to establish the Credit Facilities concurrently with the closing of the Offering and the Acquisition. After the closing of the Offering and the Acquisition, Management anticipates that approximately US$5.8 million will have been initially drawn under the Credit Facilities to partially fund the Acquisition, and approximately US$9.7 million will be available for borrowing under the Credit Facilities.

Management expects available credit under the Operating Facility to increase commensurate with the growth of the borrowing base. See "Credit Facilities", "Use of Proceeds" and "Consolidated Capitalization".

**Acquisition**

Pursuant to the Purchase and Sale Agreement, US Opco will acquire the Denali Assets, which include interests in: (i) the Austin Chalk and Eagle Ford Shale oil formations; (ii) the South Texas natural gas assets, including the South Escobas Field; and (iii) the Deep Rights. If the Over-Allotment Option is exercised for net proceeds of at least $25 million, US Opco is also required to use a portion of the net proceeds it receives from the Trust pursuant to the exercise of the Over-Allotment Option to acquire the Denali Reserved Interest.

***Purchase and Sale Agreement***

US Opco has entered into the Purchase and Sale Agreement pursuant to which it will acquire the Denali Assets. The Purchase and Sale Agreement establishes a January 1, 2012 effective date for the Acquisition.

The purchase price for the Denali Assets (excluding the Deep Rights) is US$166.7 million, subject to certain closing adjustments and net of US$36.6 million that will be paid by the Trust to Denali on closing of the Offering, which amount will be held in escrow by Denali to be applied to US Opco's capital expenditures and general and administrative expenses on the Denali Assets for the 24 month period following closing of the Offering. The escrow funds are required to be released to US Opco within one business day of US Opco providing the escrow agent with a certificate confirming that capital expenditures or general and administrative expenses have been incurred by US Opco with respect to the Denali Assets. Any funds remaining in escrow at the expiration of the 24 month period will be distributed to US Opco. The purchase price will be funded from the net proceeds of the Offering and an advance under the Credit Facilities to be established by US Opco. In connection with the Purchase and Sale Agreement, Denali has agreed to provide certain technical, operational and administrative support to US Opco for a period of up to three years, pursuant to which Denali will be reimbursed for direct costs and will receive consideration of US$100/month. The foregoing services and related compensation will be provided pursuant to the Transition Services Agreement to be entered into by US Opco and Denali prior to the closing of the Acquisition. During the term of the Transition Services Agreement, the operatorship of certain Denali Assets will be transferred from Denali to US Opco.

The Purchase and Sale Agreement includes representations and warranties from Denali in relation to, among other things, its authority and power to transact, the validity and enforceability of the agreement against Denali, litigation affecting the Denali Assets, certain environmental matters and certain information and statements relating to Denali and the Denali Assets contained in this prospectus. The Purchase and Sale Agreement provides that Denali will convey the Denali Assets to US Opco subject to all existing royalties, burdens, liens, encumbrances and surface rights, and without any warranty of title except in relation to matters caused by, through or under Denali. Representations and warranties will generally survive for a period of twelve months following the closing of the Acquisition.

The Purchase and Sale Agreement provides for Denali to indemnify and hold US Opco harmless from and against any and all claims caused by, resulting from or incidental to any breach or default by Denali of any of its representations or warranties in the agreement or any of its covenants or obligations under such agreement, provided that Denali will generally not be required to indemnify US Opco for certain individual claims less than US$250,000 and will generally only be required to indemnify US Opco for certain claims to the extent the aggregate amount of claims exceeds US$1,500,000, up to an aggregate limit of 100% of the purchase price. Purchasers are encouraged to review the terms of the Purchase and Sale Agreement for a complete description of representations, warranties and indemnities (and related limitations). The Purchase and Sale Agreement will be available at www.sedar.com. See “Material Contracts”.

Denali is not a promoter and is not a signatory to this prospectus. Purchasers of Units under this prospectus will not have a direct statutory right of action against Denali for any misrepresentations in this prospectus. Unitholders’ sole indirect remedy against Denali for any misrepresentations in this prospectus resulting from certain information and statements relating to the Denali Assets provided by Denali to the Trust for use in the prospectus will be through US Opco exercising its rights under the Purchase and Sale Agreement to claim for indemnification in respect of a breach of the representations and warranties in that agreement by Denali, subject to the limitations described above. There can be no assurance of recovery by US Opco from Denali for breaches of Denali’s representations and warranties in the Purchase and Sale Agreement. See “Risk Factors”.

Completion of the Acquisition contemplated by the Purchase and Sale Agreement is conditional upon, among other things, the closing of the Offering, the closing of the Credit Facilities, and other customary conditions. US Opco is entitled to waive certain closing conditions and elect to complete the transactions contemplated by the Purchase and Sale Agreement. It is also a condition to the Purchase and Sale Agreement that US Opco enter into an operating agreement with a party qualified to operate the Denali Assets, which condition is anticipated to be satisfied by entering into the Transition Services Agreement. The Purchase and Sale Agreement may be terminated by either US Opco or Denali if the closing of the Acquisition does not occur on or before August 31, 2012. See “Use of Proceeds” and “Funding, Acquisition and Related Transactions”.

*Deep Rights*

Pursuant to the Purchase and Sale Agreement, upon closing of the Acquisition and in exchange for future payments, US Opco will be assigned a 75% net revenue interest in oil and natural gas leasehold rights below the Austin

Chalk oil formation in specified undeveloped leases covering approximately 22,220 net acres in the Fayette and Gonzales Counties, Texas (the "**Deep Rights**"). The Deep Rights consist primarily of interests in the Eagle Ford Shale oil formation. US Opco is responsible for 100% of the costs associated with the Deep Rights. US Opco will be required to pay to Denali US$5.0 million on January 1, 2013, US$6.0 million on January 1, 2014, and US$7.0 million on January 1, 2015 in respect of its 75% net revenue interest in the Deep Rights (collectively, the "**Deferred Payment Obligation**"). US Opco will have no obligation to drill or develop any part of the Deep Rights.

The Deep Rights will be subject to a retained overriding royalty interest (the "**Deep Rights ORRI**") and after certain well costs have been recovered by US Opco from production proceeds, either a net working interest or an additional overriding royalty interest in favour of Denali as discussed below. The Deep Rights ORRI currently equals approximately 4% of gross revenue from the Deep Rights, being (i) 25% of revenue from all oil, natural gas and associated hydrocarbons produced, saved and sold from the Deep Rights by US Opco less (ii) the amount of any burdens, including royalties, taxes and downstream costs, affecting the Deep Rights (such burden currently averaging approximately 21%). For each well drilled by US Opco in the Deep Rights, Denali will have the option, on a well by well basis, after certain well costs have been recovered by US Opco from production proceeds to cause US Opco to assign to Denali either (i) an additional 7.5% net working interest in such well or (ii) an additional 3.0% overriding royalty interest with respect to such well (all such foregoing rights, together with the Deep Rights ORRI, collectively referred to as the "**Denali Deep Rights Interests**").

During the period commencing on the first anniversary of the closing of the Offering and for three years from such date (the "**Put Period**"), Denali will have the right to require US Opco to acquire 100% of the Denali Deep Rights Interests for US$30 million (the "**Put Amount**"), which put right will be triggered upon the first to occur of the following:

1. market capitalization of the Trust (based on a ten day volume weighted average trading price) exceeding 130% of the market capitalization of the Trust immediately following the closing of the Offering (based on the initial public offering price of $10.00 per Unit) and, if applicable, the exercise of the Over-Allotment Option;
2. the Trust's debt to EBITDA ratio (using debt as of the end of the most recently reported quarterly reporting period to annualized consolidated EBITDA, calculated by multiplying EBITDA from such quarter by four) falling below 0.4 at the end of any quarterly reporting period;
3. the Trust completing acquisitions, other than the Acquisition, for an aggregate purchase consideration of greater than $125 million; or
4. the Trust completing one or more equity financings following the closing of the Offering and any exercise of the Over-Allotment Option, for an aggregate amount exceeding $125 million.

If none of the foregoing triggering events have occurred during the Put Period, upon the expiration of the Put Period, Denali will have the option to require the Trust to purchase 100% of the Denali Deep Rights Interests and all of its rights to such interests for the Put Amount. US Opco is required to pay the Put Amount within 60 calendar days of the put option being exercised by Denali. In addition, US Opco has the option to pay the Put Amount at any time after closing of the Offering to fully acquire or extinguish the Denali Deep Rights Interests. In the event US Opco pays the Put Amount prior to the payment in full of the Deferred Payment Obligation, any unpaid portion of such amounts will remain outstanding and continue to be an obligation of US Opco until payment thereof. Upon payment of the Put Amount, all right, title and interest in the Denali Deep Rights Interests will be transferred to US Opco and Denali will cease to have any interest in the Deep Rights.

*The Denali Reserved Interest*

In December 2009, Denali assigned leases covering approximately 77,000 net acres in Wilson and Gonzales Counties, Texas to an affiliate of Forest Oil Corporation. In connection with the assignment of such leases, Denali reserved a production payment (the "**Denali Production Payment**") and an overriding royalty interest (the "**Denali ORRI**" and, together with the Denali Production Payment, the "**Denali Reserved Interest**") in respect of the leases that had been assigned.

Pursuant to the Purchase and Sale Agreement, if the Over-Allotment Option is exercised for net proceeds of at least $25 million, US Opco is required to use a portion of the net proceeds it receives pursuant to the exercise of the Over-Allotment Option to acquire the Denali Reserved Interest for US$20 million.

The Denali Production Payment is a production payment currently equal to approximately 4% of gross revenue, being 25% of all gross oil, natural gas and associated hydrocarbons produced, saved and sold from such leases, less the amount of any royalty and overriding royalty burdens on the leases (such burden currently averaging approximately 21%). The Denali Production Payment terminates the first day of the month following the month when the quantity of production attributable to such payment equals 2,500,000 boe (representing approximately 62,500,000 gross boe). In addition, with respect to any reserves that may exist after the production of 74,062,500 boe on a 100% basis from all of the leases, Denali becomes entitled to the Denali ORRI, which is currently equal to approximately 4% of gross revenue, being 25% of all gross oil, natural gas and associated hydrocarbons produced, saved and sold from such leases, less the amount of any royalty and overriding royalty burdens on such leases (such burden currently averaging approximately 21%). From inception to June 30, 2012, Denali has received aggregate payments of US$1,825,967 and the quantity of production attributable to the Denali Production Payment was 19,672 boe.

As of June 30, 2012, 27 horizontal wells have been drilled on the leases subject to the Denali Reserved Interest. For the month of June, gross production before royalties averaged approximately 2,430 boe/d, resulting in production after royalties attributable to the Denali Production Payment of approximately 97 boe/d net to Denali. Pursuant to the Denali Reserved Interest Agreement, Denali is responsible for its net share of all applicable taxes and any downstream costs affecting such leases. For the six-month period ended June 30, 2012, Denali received US$1,099,307 in connection with the Denali Production Payment. Management expects the operator to continue to drill on the leases subject to the Denali Reserved Interest which may increase production and result in a higher Denali Production Payment.

See "Funding, Acquisition and Related Transactions – Acquisition – Purchase and Sale Agreement – Denali Reserved Interest" and "Use of Proceeds".

***The Denali Assets***

The Denali Assets are located in Zapata, Duval, Brooks, Webb, Lavaca, Houston, Atascosa, Robertson, Wilson, Fayette, Gonzales, and Zavala Counties, Texas and Warren County, Mississippi. The Denali Assets consist of varying working interests in 1,755 oil and natural gas leases covering approximately 143,765 gross acres (117,273 net acres) and an interest in 61 operated wells and eight non-operated wells. The Denali Assets include interests in: (i) the Austin Chalk and Eagle Ford Shale oil formations; (ii) the South Texas natural gas assets, including the South Escobas Field; and (iii) the Deep Rights. Working interest production before royalties for the month of May 2012 in respect of the Denali Assets averaged approximately 1,543 boe/d with an additional 90 bbls/d of oil from the Jendrzey well temporarily shut-in due to a leaking plug, which has since been repaired. With the Jendrzey well back on, production is weighted approximately 21% to oil, 77% to natural gas and 2% to NGLs. The total proved plus probable reserves volumes of the Denali Assets as set forth in the Sproule Reserve Report are weighted approximately 30% to oil, 66% to natural gas and 4% to NGLs, resulting in reserves values weighted approximately 61% to oil, 31% to natural gas and 8% to NGLs.

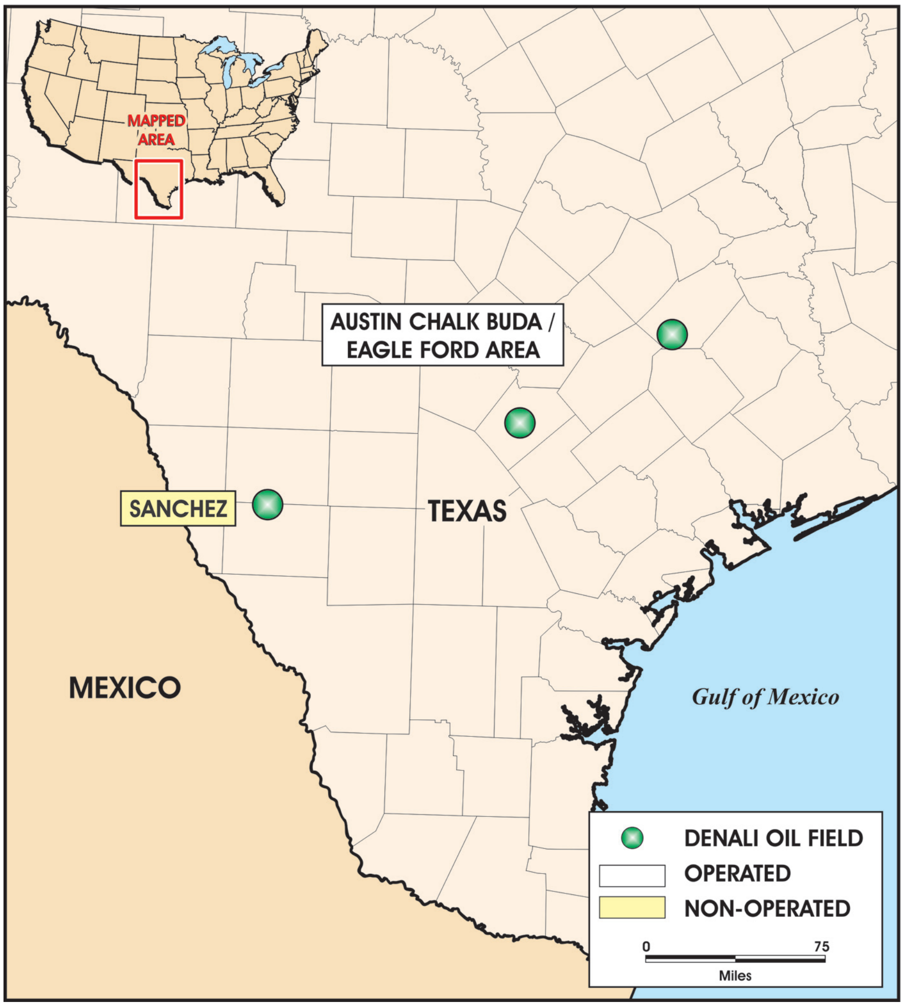
According to the Sproule Reserve Report, the Austin Chalk and Eagle Ford Shale formations account for approximately 37% of the proved plus probable reserves and approximately 72% of the net present value of future net revenue, discounted at 10%, of the Denali Assets. The South Texas natural gas assets account for the remaining 63% of the proved plus probable reserves and approximately 28% of the net present value of future net revenue, discounted at 10%, of the Denali Assets. The Austin Chalk and Eagle Ford Shale oil formations consist primarily of oil, and the South Texas natural gas assets consist primarily of natural gas. The acreage in Warren County, Mississippi consists of approximately 8,000 net acres of undeveloped leasehold, which Management has no current intention of developing.

In respect of the Denali Assets, US Opco's total estimated asset retirement obligation for 47.1 net wells is estimated at US$2.1 million undiscounted (approximately US$0.9 million discounted at 10%) and includes the abandonment and reclamation of wells to which no reserves have been assigned. In respect of the Denali Assets, US Opco anticipates incurring approximately US$450,000 (the remainder of 2012 – US$270,000; 2013 – US$90,000; 2014 – US$90,000) of its identified abandonment and reclamation costs during the next three years. See “Reserves and Other Oil and Gas Information – Abandonment and Reclamation Costs”.

***Austin Chalk and Eagle Ford Shale Oil Assets***

The Denali Assets located in the Austin Chalk and Eagle Ford Shale formation, which target primarily oil, are shown on the locator map below.

**Denali Assets Located in the Austin Chalk and Eagle Ford Shale Formation**




The Denali Assets include interests in approximately 35,700 gross (26,000 net) acres in the Austin Chalk and Eagle Ford Shale oil formation. The majority of these interests are operated by Denali with approximately 29,000 gross (23,500 net) acres of leasehold interests in Fayette and Gonzales Counties, Texas, on which Denali has drilled and operates six horizontal oil wells. The Denali Assets include an additional 1,704 gross (1,495 net) acres of leasehold interests in Wilson County, Texas, on which Denali has drilled and operates two horizontal oil wells.

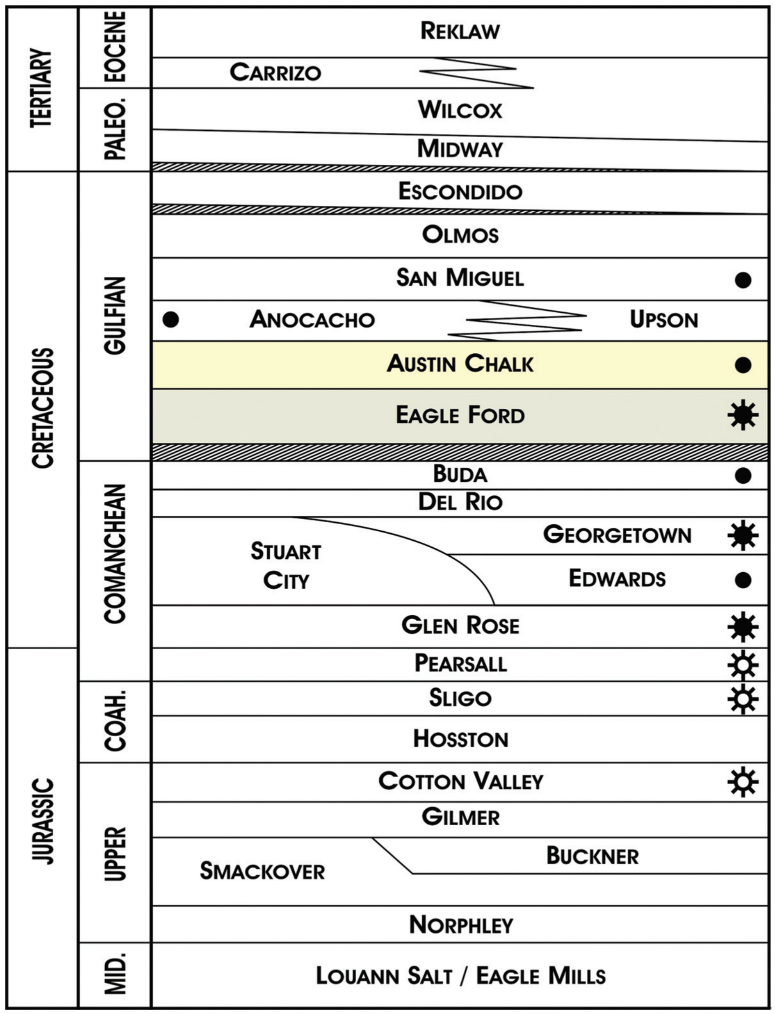
The Denali Assets also include a non-operated interest in 5,056 gross (990 net) acres in Zavala County, Texas. This acreage is operated by Sanchez Oil & Gas Corp., and includes two producing horizontal oil wells in the Austin Chalk oil formation and one producing horizontal oil well in the Eagle Ford Shale oil formation.

The Denali Assets provide drilling opportunities in the Austin Chalk oil formation as well as in the rapidly developing Eagle Ford Shale oil formation. There are numerous other potential drilling targets included in the Denali Assets, including the Buda, Edwards and Pearsall Shale formations. All of these drilling targets will be subject to future evaluation across Denali's leasehold other than approximately 76,300 net acres of rights below the Buda formation reserved by Denali in leases in Wilson and Atascosa Counties, Texas, which leases are expected to be sold to a third party on September 10, 2012 for a net purchase price of approximately US$7.5 million (the "**Asset Disposition**") pursuant to a purchase and sale agreement dated effective July 1, 2012 (the "**Asset Purchase Agreement**"). The Asset Purchase Agreement is subject to customary closing conditions. All amounts owing under the Bridge Facility will become payable upon the earlier of the closing of the Asset Disposition and October 15, 2012, at which time the Bridge Facility will be terminated. See "Risk Factors".

*Geology of the Austin Chalk and Eagle Ford Shale Formations*

The Austin Chalk formation is an upper cretaceous geologic formation which runs from the border of Mexico across South Texas and into Louisiana. Its geology consists of a finely grained limestone comprised of recrystalized, fossiliferous, interbedded chalks and marls. The depths of the deposition of the Austin Chalk formation occurred in approximately 250 metres or 820 feet of water. Volcanic ash layers present in the Austin Chalk formation result in there being several different reservoir targets within the formation. In the specific area of Denali's acreage in Fayette and Gonzales Counties, there are two distinct targets within the Austin Chalk formation which are designated as the Upper Austin Chalk and the Lower Austin Chalk. The Upper Austin Chalk is the primary target of Denali's wells.

As a result of the Austin Chalk formation having very small pore spaces, it has very low or no matrix permeability. When the Austin Chalk formation is naturally fractured it is permeable and productive and generally no commercial fracturing is required. These instances of permeability and productivity occur where the chalk is densely fractured. The Austin Chalk formation is considered a typical basin centered type oil and natural gas play with natural gas being produced down dip at deeper depths and graduating updip into an oil leg. The following stratigraphic chart sets forth the main formations included in Fayette and Gonzales Counties, Texas.




Oil and natural gas were first discovered in the Austin Chalk formation in the 1920s but drilling rates were highest in the late 1970s when oil prices increased. Increased oil prices resulted in a boom of vertical shallow drilling, principally in the Pearsall and Giddings Fields in South Texas. Because better wells result when the well bore encounters the presence of natural fractures, the vertical wells drilled during this era would often miss the vertical fractures and result in marginal wells or dry holes. In the late 1980s, a second oil boom in the productive Austin Chalk formation occurred with the advent of horizontal drilling technology. Horizontal well bores at that time were typically a length of 1,500 feet to 3,500 feet and increased the probability of encountering multiple vertical fractures resulting in better drilling economics.

Denali acquired the majority of its acreage in the Austin Chalk formation in 2008 and 2009. Horizontal drilling technology now makes it possible to drill horizontally at a length of 6,000 feet or longer, thereby improving the drilling economics of the play as longer horizontals have a higher probability of encountering more oil productive fractures. Also, the acreage acquired by Denali sits on top of the productive Eagle Ford Shale oil formation as well as the productive Austin Chalk oil formation. US Opco intends to drill 27 gross (18.6 net) wells in the Austin Chalk formation, with eight gross (5.6 net) wells planned in 2012 and one gross (1.0 net) well in 2013.

The Eagle Ford Shale is a formation of cretaceous sediment resting between the Austin Chalk and the Buda Lime formations at a depth of approximately 5,500 to 11,000 feet. It is considered to be the "source rock", or the original source of hydrocarbons that are contained in the Austin Chalk formation above it. As a hydrocarbon producing formation, the Eagle Ford Shale formation is of significant importance due to its capability of producing not only natural gas but more oil than is typically identified in other traditional shale plays. It contains a high carbonate shale percentage, upwards of 70% in South Texas, which makes it more brittle and amenable to hydraulic fracturing. The shale play trends across Texas from the Mexican border up into East Texas, is roughly 50 miles wide and 400 miles long, with an average thickness of 250 feet.

The Eagle Ford Shale formation is still at a relatively early stage of development. Numerous operators are currently drilling in the field and the total rig count is over 200 rigs. As the number of wells has increased, operators have improved their use of technology, drilling the wells at lower costs while increasing production rates and recoverable reserves. In Management's view, these improvements have made the Eagle Ford Shale formation one of the most commercial fields in the United States and it is expected that further optimization will result as additional drilling occurs. Management currently has one gross (0.9 net) well planned for 2012 and four gross (4.0 net) wells planned for 2013 in the Eagle Ford Shale formation.

In Management's view, the pervasive areal extent of both the Austin Chalk and the Eagle Ford Shale formations make them attractive resource plays. The porosity of the Austin Chalk formation provides an ample reservoir for oil. The unique fracture swarms provide the required permeability within the Austin Chalk formation and are ideally suited to horizontal drilling which can access these multiple fracture zones. The Eagle Ford Shale oil formation is a tighter and lower permeability formation than the Austin Chalk oil formation and has been generally overlooked for years due to the difficulty in exploiting this type of reservoir. However, by virtue of horizontal drilling combined with high pressure, multi-fracturing completion techniques, the Eagle Ford Shale oil formation has recently become a valuable and profitable resource play.

*Production and Operations*

Production from the Austin Chalk and Eagle Ford Shale formations for the month of May 2012, averaged approximately 287 boe/d to Denali's working interest before royalties (231 net boe/d after royalties production), with an additional 90 bbls/d of oil from the Jendrzey well temporarily shut-in due to a leaking plug, which has since been repaired. The majority of this production is from horizontal wells operated by Denali in the Austin Chalk oil formation.

Denali operates eight horizontal oil wells in the Austin Chalk oil formation, all of which have been drilled since 2010. Six of these wells are located on Denali's large acreage block in Fayette and Gonzales Counties and two are located in Wilson County. Denali has a 100% working interest in six of the wells and a 77% and 72% working interest in the remaining two wells, respectively. In addition, Denali has a non-operated interest in two horizontal wells in the Austin Chalk oil formation and one horizontal well in the Eagle Ford Shale formation on acreage in Zavala County, operated by Sanchez Oil & Gas Corp.

*Marketing*

Oil from all but one of Denali's operated wells is sold on a month to month contract to Gulfmark Energy, Inc. with oil from the remaining well being sold on a month to month contract to Eastex Crude Company. These oil contracts achieve favourable pricing due to the close proximity of these wells to the refineries on the Gulf Coast of Texas. Historically, pricing has approached the WTI index but since January 1, 2012 has met or exceeded the WTI index for all the wells. From October 1, 2011 to April 30, 2012, the Denali contract with Gulfmark Energy, Inc. for the wells in the Fayette and Gonzales Counties, Texas has averaged a price of US$103.45/bbl versus the US$99.19/bbl average price for WTI during this period.

In Fayette and Gonzales Counties, Texas, Denali also has a natural gas marketing and NGLs sharing contract with DCP Midstream, L.P. ("**DCP**"). DCP maintains a wet system tied into an NGLs processing facility. The natural gas produced from these wells has a high Btu content (1,400-1,800 Btu) and is rich in NGLs (9-14 gpm). As a result of the NGLs, the wellhead price per Mcf was in excess of the NYMEX price of natural gas, resulting in an uplift in the economics of this area. Denali's average price received for the three months ended March 31, 2012 was US$48.11/bbl for the NGLs component and US$2.32/Mcf for the natural gas component, for a blended wellhead price of US$14.41/Mcf, compared to an average NYMEX natural gas settlement price of US$2.74/MMBtu for the same period.

*Exploitation Opportunities in the Austin Chalk and Eagle Ford Shale Oil Formations*

The wells that Management intends to drill in the Austin Chalk oil formation are at an average vertical depth of 7,800 feet and are expected to have an additional horizontal length averaging 6,000 feet. These wells produce from naturally occurring fractures that occur randomly along the horizontal well path. The wells are completed open hole and do not require fracture stimulation. Spacing is typically 640 acres per well.

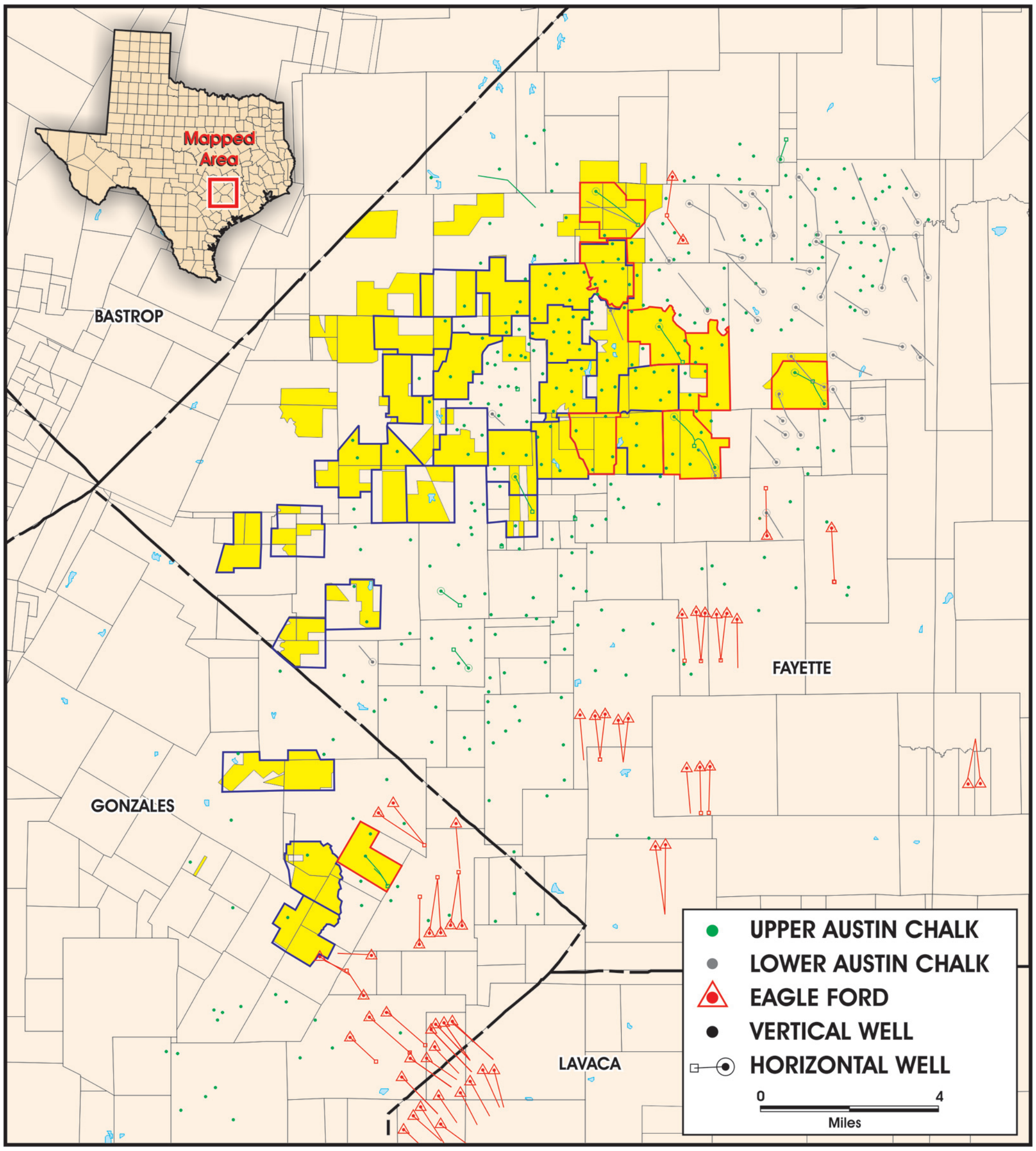
The Sproule Reserve Report includes 14 proved undeveloped drilling locations in the Austin Chalk oil formation (9.7 net), offsetting current production in Fayette and Gonzales Counties, Texas. In addition, the Sproule Reserve Report identified 13 probable drilling locations (8.9 net) in the Austin Chalk oil formation. Management believes additional acreage with drilling potential in the Austin Chalk oil formation will become available for lease over the next few years which will provide US Opco with additional drilling opportunities.

On June 10, 2012, Denali completed the drilling and tie-in of one (one net) of the proved undeveloped drilling locations in the Austin Chalk oil formation in Fayette County, named the Ivy-1H well. Denali completed a 24 hour production flow test as required by the RRC, in which the final hour flow rates were calculated at 792 bbls/d of oil (43.6º API), 735 Mcf/d of natural gas, and 215 barrels of water per day, at an average pressure of 510 psi. This compares to an estimated initial production rate forecast in the Sproule Reserve Report for this well location of 325 boe/d. Total fluid recovery during this period was 752 bbls of oil, 369 Mcf of natural gas and 388 bbls of water. While no pressure transient analysis or well-test interpretation was carried out, there was no significant production or pressure decline during the test. While Management believes that the reference to this initial production rate is useful in confirming the presence of hydrocarbons, such rate is not determinative of the rate at which such well will continue to produce and decline thereafter nor is it indicative of the volume of hydrocarbons ultimately recoverable from such well. While such initial production rate is encouraging, investors are cautioned not to place undue reliance on such rate in calculating the aggregate production for the Trust. The long-term performance of the well may be greater or less than the initial production rate set out above. The well was shut-in after the production test to conduct a test of the casing integrity and to install a pumping unit. The casing was tested successfully to 1500 psi and the pumping unit was installed in early July. Accordingly, production with oil sales has recently commenced and is expected to ramp up over time.

In Fayette and Gonzales Counties, Texas, there are a number of operators drilling and completing wells in the Eagle Ford Shale oil formation near Denali's acreage. These include Magnum Hunter Resources Corp., GeoResources Inc., Zaza Energy Corporation (in partnership with Hess, Inc.) and Weber Energy Corporation.

The Sproule Reserve Report has attributed to the Eagle Ford Shale oil formation, eight gross (7.7 net) probable drilling locations and 1.8 MMboe of gross probable reserves relating to 1,280 net acres out of the Denali acreage located in Fayette and Gonzales Counties, Texas. In addition to the 1,280 net acres, the rights relating to the Eagle Ford Shale oil reservoir under the remainder of Denali's Austin Chalk assets (22,220 net acres) are offset by recent successful drilling activity by third parties.

**Oil Assets in Fayette and Gonzales Counties, Texas**




This drilling activity includes twenty-four Eagle Ford Shale horizontal wells which have been drilled within five miles of Denali's acreage in Fayette and Gonzales Counties, Texas with an average initial production rate of over 925 boe/d. Twenty-nine additional wells have either been permitted to drill, are in the process of being drilled, or are being completed in this area. South and southeast of Denali's acreage in Gonzales County, Magnum Hunter Resources Inc. has drilled and completed 11 wells with an average 24 hour initial production rate of 1,331 boe/d and average flowing tubing pressure of 1,917 psi (RRC, 2011 and 2012). The two wells of Magnum Hunter Resources Inc. that are in the closest proximity to Denali's acreage have produced 85,100 boe in 13 months and 77,300 boe in 18 months, respectively (RRC, 2012). Magnum Hunter Resources Inc. has been permitted to drill ten additional wells in this area.

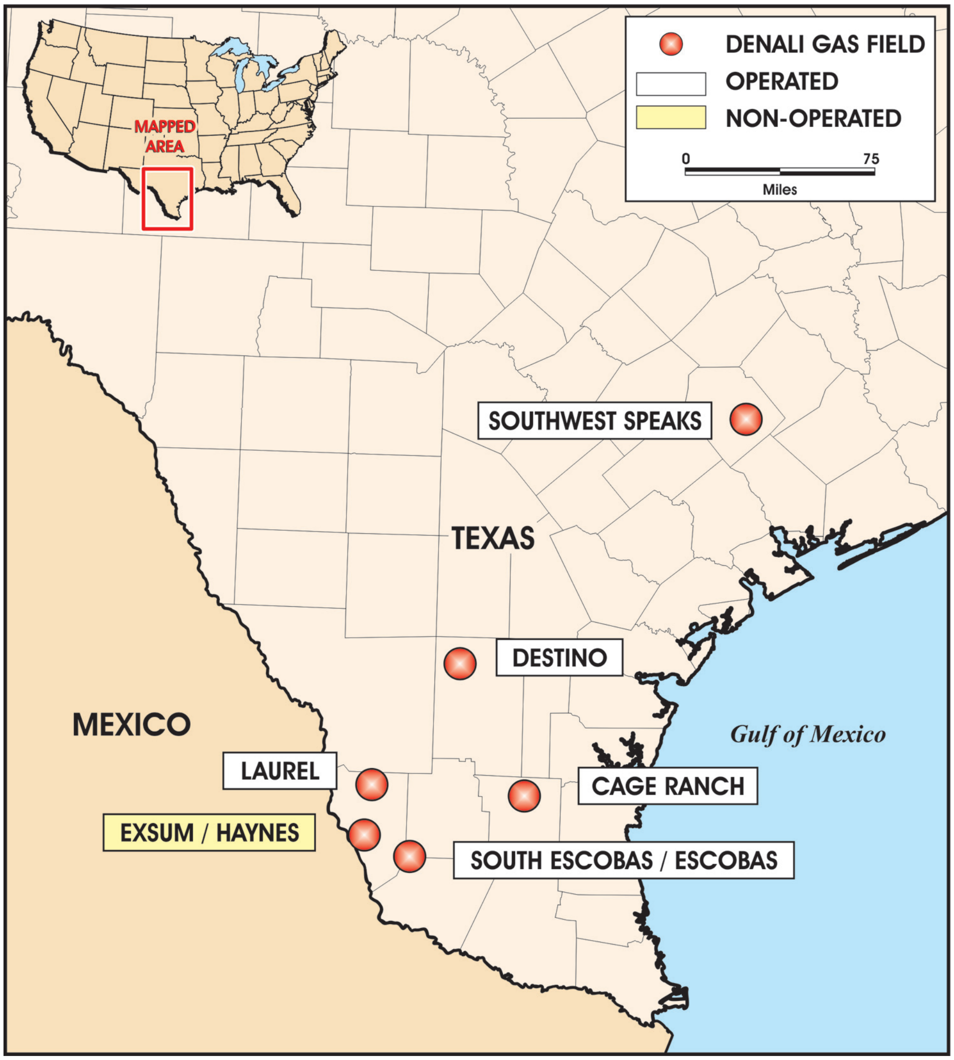
In addition, to the south of Denali's acreage in Gonzales County, Tidal Petroleum, Inc. has drilled and completed a well that had a 24 hour initial production rate of 361 boe/d and flowing pressure of 700 psi (RRC, 2012). Tidal Petroleum, Inc. has also been permitted to drill three additional wells in this area. Immediately east of Denali's acreage in Fayette and Gonzales Counties, GeoResources Inc. has drilled and completed nine wells with an average 24 hour initial production of 705 boe/d and average flowing pressure of 2,020 psi (RRC, 2011 and 2012). GeoResources Inc. has 13 additional wells that have either been permitted to drill, are in the process of being drilled, or are being completed. Also immediately adjacent to Denali's acreage in Gonzales County, Zaza Energy Corporation (in a joint venture with Hess Corporation) has drilled a well which realized a 24 hour initial production rate of 291 boe/d with 556 psi flowing pressure (RRC, 2012) and has been permitted to drill an additional well in this area. To the northeast of Denali's acreage in Fayette County, Weber Energy Corporation has drilled two short lateral horizontal Eagle Ford Shale wells, which have a combined lateral length of approximately 4,765 feet and tested a total of 610 boe/d with average flowing tubing pressure of 520 psi (RRC, 2011). These wells have produced 52,500 boe in the first 6 months of production reporting (RRC, 2012). Sanchez Oil & Gas Corp. has also been permitted to drill two wells, one of which was spud in June 2012.

Management believes production from wells drilled by third parties in the Eagle Ford Shale oil formation may be indicative of possible production that can be achieved by US Opco on its properties and that there is sufficient production data from nearby wells to conclude that the undeveloped acreage in Fayette and Gonzales Counties, Texas is commercial to drill. However, at this stage of development, Management cannot accurately predict the quantity of reserves per well or the anticipated production levels from such wells. Management also believes at least 15,000 net acres of the Deep Rights acreage in Fayette and Gonzales Counties, Texas, is prospective for the Eagle Ford Shale oil formation at current drilling costs and oil prices. Management expects that drilling in the Eagle Ford Shale oil formation will be on 160 acre well spacing, which would provide approximately 95 net prospective Eagle Ford Shale drilling locations on the Denali Assets.

***South Texas Natural Gas Assets***

The Denali natural gas assets in South Texas consist of 53 operated and five non-operated wells extending across 9,966 gross (5,768 net) acres. These assets are primarily natural gas weighted and are anchored by the South Escobas Field in Zapata County, Texas, where Denali operates 41 gross (29.6 net) wells. According to the Sproule Reserve Report, 28% of the net present value of future net revenue, discounted at 10%, of the Denali Assets are attributable to the South Texas natural gas assets, with approximately 84% of Denali's proved plus probable natural gas reserves located in the South Escobas Field and immediate vicinity. Denali's remaining South Texas natural gas assets, being those not located in the South Escobas Field, consist of 12 operated and five non-operated wells and, according to the Sproule Reserve Report, include approximately 16% of Denali's proved plus probable natural gas reserves. Most of these assets produce from the Wilcox/Lobo formations with some of the production from the Frio/Vicksburg formation. The Sproule Reserve Report has designated four proved (2.7 net) drilling locations accounting for 6.2 Bcfe of proved natural gas reserves. Management has identified an additional nine drilling locations (5.8 net) that are not economical at current natural gas prices.

**Location of Denali's South Texas Natural Gas**




*South Escobas Geology*

The South Escobas Field produces from the Wilcox formation in the southern portion of the downdip Wilcox trend of South Texas. The downdip Wilcox trend extends 150 miles and has produced over 3.5 Tcf to date. The South Escobas Field is one of a number of large natural gas fields in the Zapata delta area which is an ancestral depocenter of the Rio Grande River. Geologically, these type of depocenters can be viewed as mini-basins in which sediments pile up on the upper slope and eventually fail gravitationally, resulting in bedding slippage faults which move large sediment blocks downdip. Individual listric fault systems are favored as sites of optimum sand concentration. These listric growth faults with counter-regionally dipping fault blocks are recognized as the most effective traps of growth fault systems in this region.

Specifically, in the South Escobas Field, the Wilcox formation consists of a series of sands of the Eocene era that were deposited along the South Texas Gulf Coast and constitute the oldest of the thick sandstone/shale sequences within the Gulf Coast system. Sediments within the updip section were deposited primarily by fluvial processes. Downdip sediments were transported across the Wilcox fluvial plain and were deposited in huge deltaic systems. Some deltaic sediments were reworked and transported along the shore by marine processes and then redeposited on barrier bars and strand plains. Growth faults developed near the shorelines of several of the larger deltaic lobes where thick layers of sand were redeposited on previous sediments.

In terms of reservoir characteristics, the Wilcox formation is a tight, low permeability, consolidated, fine grained sandstone that requires fracture stimulation to yield commercial production rates. The reservoirs are over pressured allowing for a high amount of natural gas in place per acre. Further, it is common for reservoir quality to be best in the highest portion of each fault block as early natural gas migration helps preserve porosity and permeability.

Denali's discovery well, the Violeta Ranch #1, was drilled as an updip well to an old show well which was drilled in 1979 and abandoned after a series of mechanical failures. The Violeta Ranch #1 well is natural gas productive in the Hinnant 7 and Hinnant 5 sands and has produced over 3.0 Bcf since January 2008.

As additional wells were drilled, additional natural gas productive sands were encountered with completion depths ranging from 9,000 feet to 15,000 feet across multiple Wilcox sands (Hinnant, House, and Deep Wilcox). These sands have porosities which average 14.5% to 17% and require fracture stimulation with 100,000 to 300,000 pounds of proppant per zone. Thus, multiple sands (commonly, two to four vertically stacked sands) are perforated, fracture stimulated and then commingled prior to production. Typical well initial production rates are from 5,000 Mcf/d to 12,000 Mcf/d. There are no liquid hydrocarbons associated with this production.

*Production and Operations*

Production from the South Escobas Field for the month of May 2012, averaged approximately 968 boe/d to Denali's working interest before royalties (707 net boe/d after royalties production). Since Denali's initial discovery in January 2008, Denali has produced 21.7 Bcfe from this field from ten wells. Production from the other South Texas natural gas assets for the month of May 2012, was approximately 288 boe/d to Denali's working interest before royalties (217 net boe/d after royalties production). The average operating cost of Denali gas production in the first quarter of 2012 was approximately US$0.80/Mcfe.

Including the Violeta Ranch #1 discovery well, Denali has drilled a total of 10 gross (5.1 net) wells in South Escobas. In 2010, Denali acquired additional producing wells and acreage from a third party, bringing the total well count in South Escobas to 41 gross (29.6 net) wells, all of which are operated by Denali. In the South Escobas area, Denali has an interest in 6,853 gross (3,885 net) acres. At Escobas, Denali has central facilities to handle separation, dehydration and chemical treatment for any hydrogen sulfide content that may exist in order to meet pipeline specifications.

*Marketing*

Denali's South Escobas natural gas is under a contract to Kinder Morgan Tejas Pipeline, LLC ("**Kinder Morgan**") until April 30, 2013 and on a month to month basis thereafter. The contract terms provide for a price that, after deducting charges for treating and gathering, has averaged approximately US$0.33/MMBtu less than NYMEX since January 2011. Natural gas from the South Escobas Field contains approximately 10% carbon dioxide which is removed in a treating facility on the Kinder Morgan system eliminating the need for Denali to own or maintain carbon dioxide treating facilities. Kinder Morgan currently has approximately 35,000 to 40,000 Mcf/d in open capacity. In the event that Kinder Morgan is unable to transport natural gas on its system, Denali has the ability to switch sales to the Energy Transfer Pipeline system which also has spare capacity and treating facilities under similar terms to the Kinder Morgan contract.

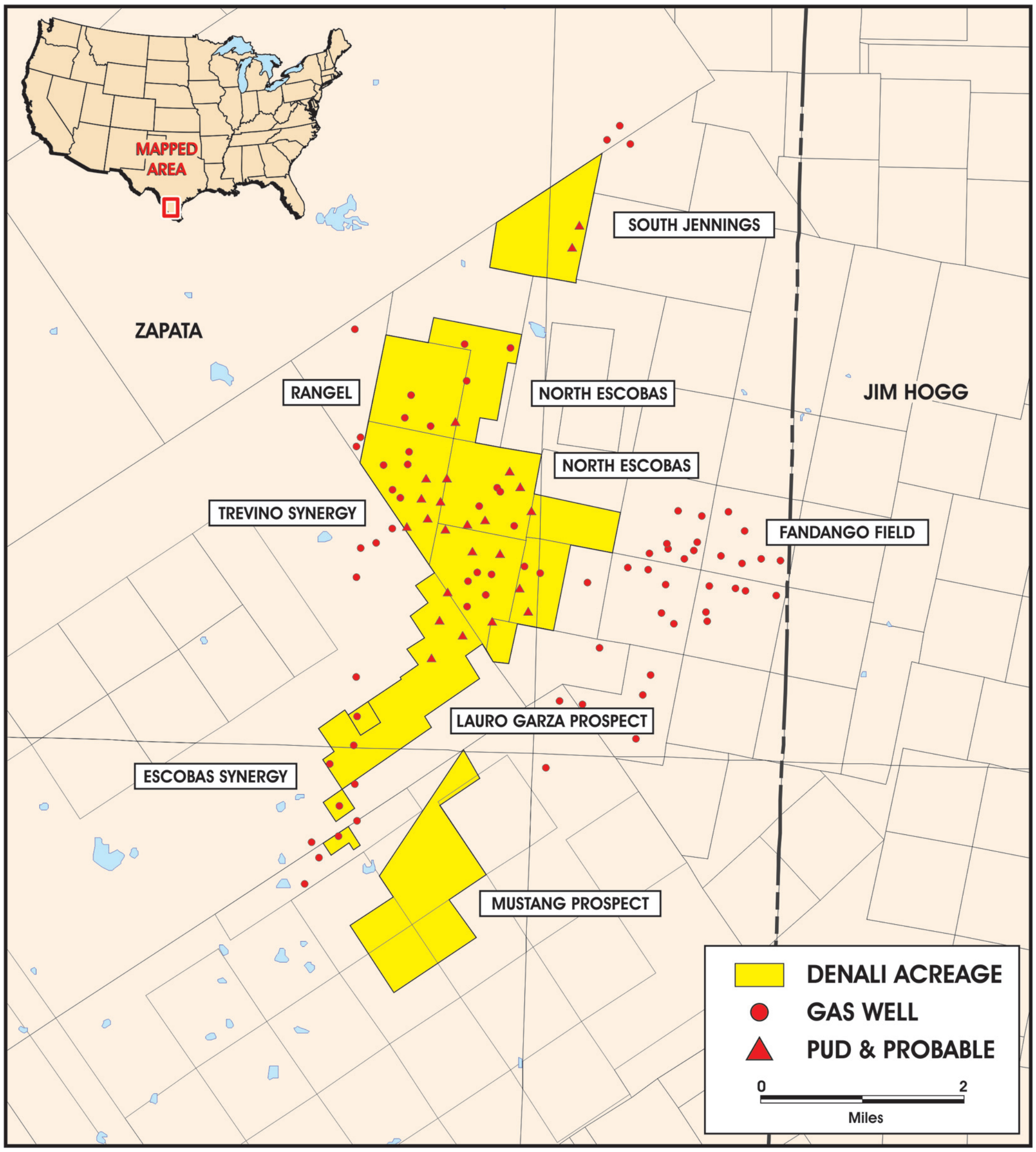
The production associated with the South Texas natural gas assets that is not located in the South Escobas Field is sold under various natural gas purchase agreements under a Houston Ship Channel Index pricing convention.

*Exploitation Opportunities in South Escobas and Adjacent Leases*

Subsequent to the Violeta Ranch #1 discovery well, Denali performed proprietary reprocessing on 114 square miles of 3-D data covering the South Escobas Field and its surrounding area. Reprocessing the 3-D data and a detailed field study led to further drilling successes and discoveries in additional reservoirs above and below the original targets of Denali's entry-well into the field. According to the Sproule Reserve Report, the South Escobas Field has 40.4 Bcfe proved plus probable reserves attributable to Denali's working interest before royalty. Also following the seismic reprocessing and field study, Denali purchased adjacent producing fields and open acreage yielding an additional 10.1 Bcfe proved plus probable reserves attributable to Denali's working interest before royalty.

There are a total of 15 gross (8.1 net) wells to be drilled on Denali's Escobas acreage as per the development plan in the Sproule Reserve Report. As a result of the historically low natural gas prices at this time, the current development plan is to defer drilling all but one of the natural gas wells until at least 2014. In addition to the 8.1 net wells reflected in the Sproule Reserve Report, Management believes there are an additional 4.2 net wells that may be drilled in future years on acreage that is held by production and can be drilled in future years.

**Leasehold Position for Denali's Assets at South Escobas and Surrounding Fields**



### Summary of Drilling Opportunities

The table below provides a summary of the drilling opportunities with respect to the Denali Assets:

| | Drilling Opportunities | | |
|---|---|---|---|
| | Eagle Ford Shale Oil | Austin Chalk Oil | South Texas Gas(6) |
| **Well Parameters(1)** | | | |
| Well Cost – Drill, Complete and Tie-in (US$M)(2) | 6,400 | 2,800 | 4,295 |
| Estimated Recoverable Reserves (Mboe)(3) | 236 | 195 | 769 |
| 30 Day Initial Production (boe/d) | 445 | 386 | 458 |
| **Well Economics(1)** | | | |
| Costs per boe of Reserves (US$/boe)(2) | 27.17 | 14.37 | 5.59 |
| Cost to Initial boe/d Production Rates (US$/boe/d) | 14,382 | 7,254 | 9,378 |
| Internal Rate of Return or IRR (%)(4)(5) | 24 | 228 | 62 |
| **Total Drilling Opportunities(1)** | | | |
| Drilling Locations | 8 | 27 | 19 |
| Capital (US$M)(2) | 51,200 | 75,600 | 81,600 |
| Incremental Reserves (Mboe)(6) | 1,854 | 5,238 | 14,611 |
| Incremental Reserves net to US Opco (Mboe)(6)(7) | 1,788 | 3,606 | 7,916 |

**Notes:**

(1) Estimates are 100% gross well interest, on a proved plus probable basis, before royalties based on the Sproule Reserve Report.

(2) Development costs presented in 2011 U.S. dollars.

(3) Technical reserves not subject to economic limits.

(4) IRR has been calculated using Sproule's December 31, 2011 price forecast and is the discount rate at which net present value is equal to zero.

(5) Values are an average of all locations.

(6) Reserves are subject to economic limits.

(7) Values are working interest before royalties.

### Summary of Reserves Associated with the Denali Assets

The summary of reserves data set forth below is based upon an evaluation by Sproule as set forth in the Sproule Reserve Report. A December 31, 2011 Sproule price forecast was used in the Sproule Reserve Report. The reserves data summarizes the oil, natural gas and NGLs reserves of the Denali Assets and the net present values of future net revenue for those reserves using forecast prices and costs. The Sproule Reserve Report does not include any data in respect of the Deep Rights and the Denali Reserved Interest. The reserves data complies with the requirements of NI 51-101. Actual oil, natural gas and NGLs reserves may be greater than or less than the estimates provided in the Sproule Reserve Report. See "Reserves and Other Oil and Gas Information" and "Risk Factors".

## Reserves Data
## as of December 31, 2011
## Forecast Prices and Costs

### *Summary of Reserves*

| Reserves Category | Light and Medium Oil Gross(1) (Mbbls) | Light and Medium Oil Net(1) (Mbbls) | Natural Gas Gross(1) (MMcf) | Natural Gas Net(1) (MMcf) | NGLs Gross(1) (Mbbls) | NGLs Net(1) (Mbbls) | Total Oil Equivalent Gross(1) (Mboe) | Total Oil Equivalent Net(1) (Mboe) |
|---|---|---|---|---|---|---|---|---|
| **Proved** | | | | | | | | |
| Developed Producing | 263.9 | 208.9 | 9,378 | 7,010 | 17.9 | 14.5 | 1,844.8 | 1,391.8 |
| Developed Non-Producing | 65.6 | 52.5 | 18 | 15 | 6.8 | 5.4 | 75.4 | 60.3 |
| Undeveloped | 1,013.1 | 831.1 | 22,639 | 16,483 | 208.7 | 171.2 | 4,995.0 | 3,749.6 |
| **Total Proved** | 1,342.6 | 1,092.5 | 32,034 | 23,508 | 233.4 | 191.1 | 6,915.2 | 5,201.7 |
| **Total Probable** | 3,498.6 | 2,831.7 | 30,959 | 23,301 | 371.2 | 304.2 | 9,029.7 | 7,019.4 |
| **Total Proved Plus Probable** | 4,841.2 | 3,924.2 | 62,994 | 46,809 | 604.6 | 495.3 | 15,944.8 | 12,221.1 |

* *Numbers may not add due to rounding.*

**Note:**

(1) Gross reserves represent the working interest share before deduction of any royalty obligations and without including any royalty interests. Net reserves represent the working interest share after deduction of royalty obligations, plus royalty interests in production or reserves.

### *Summary of Net Present Value of Future Net Revenue of Reserves*

| Reserves Category | Net Present Value of Future Net Revenue Before Income Taxes Discounted at (%/year)(2)(3) 0% (US$M) | 5% (US$M) | 10% (US$M) | 15% (US$M) | 20% (US$M) | Unit Value Before Income Tax Discounted at 10%/year Gross Reserves(1) (US$/boe) | Net Reserves(1) (US$/boe) |
|---|---|---|---|---|---|---|---|
| **Proved** | | | | | | | |
| Developed Producing | 34,010 | 28,759 | 25,285 | 22,799 | 20,917 | 13.71 | 18.17 |
| Developed Non-Producing | 3,909 | 3,449 | 3,086 | 2,792 | 2,550 | 40.93 | 51.16 |
| Undeveloped | 92,238 | 67,261 | 52,108 | 42,112 | 35,125 | 10.43 | 13.90 |
| **Total Proved** | 130,158 | 99,469 | 80,479 | 67,703 | 58,592 | 11.64 | 15.47 |
| **Total Probable** | 242,951 | 148,408 | 102,409 | 75,446 | 57,938 | 11.34 | 14.59 |
| **Total Proved Plus Probable** | 373,108 | 247,877 | 182,888 | 143,149 | 116,530 | 11.47 | 14.96 |

* *Numbers may not add due to rounding.*

**Notes:**

(1) Gross reserves represent the working interest share before deduction of any royalty obligations and without including any royalty interests. Net reserves represent the working interest share after deduction of royalty obligations, plus royalty interests in production or reserves.

(2) Estimates of after-tax future net revenue are not presented because the Trust is not expected to be subject to any material income taxes in the U.S. or Canada.

(3) Reclamation costs were not deducted in estimating US Opco's future net revenue in this table. For a discussion on abandonment and reclamation costs see "Reserves and Other Oil and Gas Information – Abandonment and Reclamation Costs".

## Financial Information

The following table sets out financial information for the Denali Assets for the periods indicated.

The financial information set out below has been derived from the Operating Statements Containing Gross Revenues, Royalties and Production Taxes and Operating Expenses attached to this prospectus as Appendix B. Investors should read the financial information in conjunction with such operating statements and the accompanying notes. See "Summary of Distributable Cash" and "Risk Factors".

### Operating Statement Information

| | Three Months Ended March 31, 2012 US$ (unaudited) | Three Months Ended March 31, 2011 US$ (unaudited) | Year Ended December 31, 2011 US$ (audited) | Year Ended December 31, 2010 US$ (audited) | Year Ended December 31, 2009 US$ (audited) |
|---|---|---|---|---|---|
| Oil, Gas and NGLs Sales | 5,444,808 | 6,897,570 | 29,163,580 | 21,063,802 | 8,906,926 |
| Royalties and Production Taxes | (1,393,887) | (1,664,106) | (7,323,145) | (5,989,472) | (2,223,908) |
| Net Revenues | 4,050,921 | 5,233,464 | 21,840,435 | 15,074,330 | 6,683,018 |
| Operating Expenses | (756,041) | (1,557,870) | (5,386,952) | (2,933,882) | (2,272,075) |
| | 3,294,880 | 3,675,594 | 16,453,483 | 12,140,448 | 4,410,943 |

## Summary of Distributable Cash

The following summary has been prepared by Management on the basis of the information contained in this prospectus and its estimate of the expenses to be incurred by the Trust and its subsidiaries. This analysis may be considered a financial outlook. **The actual results of operations of the Trust and its subsidiaries and of the Denali Assets for any period, whether before or after closing of the Acquisition, will likely vary from the amounts set forth in the following analysis, and such variations may be material. See "Notice to Investors – Forward-Looking Statements" and "Risk Factors" for a discussion of the risks that could cause actual results to vary.**

The purpose of the following summary is to provide a reasonable estimate of what the cash flow available for distribution by the Trust will be for the 18-month period ending December 31, 2013 if the closing of the Offering and the completion of the transactions described under "Funding, Acquisition and Related Transactions" occurred on August 10, 2012, with an effective date of January 1, 2012, and should not be relied upon for any other purpose. This summary has been prepared using assumptions which reflect the Trust's and its subsidiaries' planned courses of action given Management's current expectations about the most probable set of economic conditions. The estimate is based on 2012 and 2013 production from the Denali Assets estimated in the Sproule Reserve Report and is adjusted for a variety of factors as described in the table below. See "Reserves and Other Oil and Gas Information". In forming these assumptions and estimates, Management relied on its knowledge of the oil and natural gas business, the development plan for the Denali Assets based on certain assumptions in the Sproule Reserve Report, certain tax assumptions as described in the prospectus, the Denali Assets' historical financial results and supplemental financial analysis. Further information related to the underlying assumptions is provided in the footnotes to the table for each reconciling item. Cash flow available for distribution does not have any standardized meaning as prescribed by IFRS and as a result such term is unlikely to be comparable to similar measures presented by other issuers. See "Notice to Investors – Non-IFRS Financial Measures".

**Estimated Cash Flow Available for Distribution From July 1, 2012 to December 31, 2013**

| | Amount ($M) |
|---|---|
| Revenue before royalties (US$)(1) | 92,324 |
| Less: Royalty interest (US$)(2) | (18,259) |
| Revenue after royalty interest (US$) | 74,065 |
| Less: Operating Expenses (US$)(3) | (4,571) |
| Production Taxes (US$)(4) | (4,361) |
| General and Administrative Expenses Related to Field Operations (US$)(5) | (3,206) |
| Federal and State Taxes (US$)(6) | (1,278) |
| Subtotal (US$) | 60,648 |
| Subtotal (C$)(7) | 62,333 |
| Less: General and Administrative Expenses Related to Trust and its affiliates (C$)(8) | (4,500) |
| Interest Costs on Bank Facility (C$ equivalent)(9) | (541) |
| Cash Flow Available for Distribution Before Capital Expenditures (C$)(10) | 57,293 |
| Capital Expenditures (US$)(11) | (18,431) |
| Deferred Payment Obligation (US$)(12) | (5,000) |
| Asset Disposition (US$)(13) | 7,500 |

**Notes:**

(1) Estimated revenue based on: (i) forecasted average production from the Sproule Reserve Report for the period from July 1, 2012 to December 31, 2013 of 2,992 boe/d (51% oil) for the total proved plus probable case, prior to royalty interests of approximately 20% of revenue on average after allowance for processing costs; and (ii) commodity prices based on forward strip prices as at July 11, 2012 of on average US$88.05/bbl WTI for oil and US$3.26/MMBtu NYMEX for natural gas.

(2) Royalty interest equal to approximately 20% of revenue on average after allowance for processing costs.

(3) Estimated operating expenses from the Sproule Reserve Report for the July 1, 2012 to December 31, 2013 period.

(4) Estimated production taxes are based on: (i) the assumptions in Note 1 above; and (ii) rates for production taxes reflected in the Sproule Reserve Report, being approximately 4.7%.

(5) Represents the aggregate of the estimated annual general and administrative expenses of US Opco, net of US$1.0 million that will be paid by the Trust to Denali on closing of the Offering and that will be held in escrow by Denali and applied to US Opco's general and administrative expenses for the twelve month period following closing of the Offering.

(6) Federal and state taxes represent the applicable Alternative Minimum Tax, at a rate of 20%, and Texas Margin Tax, at a rate of 1%, applied against qualifying net income after allowable deductions including interest, certain expenses, depreciation and/or capital cost allowances, and Dividend Withholding Tax, at a rate of 5% on the dividend portion of distributions from US Opco to Can Holdco.

(7) U.S. dollar netback converted to Canadian dollar equivalent based on average 18 month forward C$/US$ exchange rate of US$1.00 equals C$1.0278 as at July 11, 2012.

(8) Estimated general and administrative costs of the Trust are based on Management's estimate of salaries, rent, office supplies and administrative costs required to operate a public oil and gas entity of a similar size plus an initial overhead charge of $700,000 per year payable to Aston Hill pursuant to the Services Agreement. See "Administration of the Trust – Services Agreement with Aston Hill".

(9) Interest costs based on assumed initial advances of approximately C$9.2 million under the Credit Facilities and market interest at the closing of the Acquisition. Borrowings under the Credit Facilities will bear interest at a floating rate.

(10) The sensitivity of cash flow available for distribution before capital expenditures due to commodity price or exchange rate fluctuations for the 18 month period is estimated as follows: US$1/bbl change in WTI oil price equals approximately C$869,000; US$0.10/MMBtu change in NYMEX natural gas price equals approximately C$261,000; and $0.01 change in the C$/US$ exchange rate equals approximately C$608,000.

(11) Estimated capital expenditures plus abandonment and reclamation expenditures from the Sproule Reserve Report for the July 1, 2012 to December 31, 2013 period for the total proved plus probable case, net of an aggregate of US$29.1 million from the amount that will be paid by the Trust to Denali on closing of the Offering and that will be held in escrow by Denali and applied to US Opco's capital expenditures on the Denali Assets for the 24 month period following closing of the Offering. Capital expenditures are to be financed from both cash flow not distributed to Unitholders and advances under the Credit Facilities, if required.

(12) This is a non-recurring payment and relates to the payments in respect of the Deep Rights pursuant to the Purchase and Sale Agreement, which consists of payments of US$5.0 million payable on January 1, 2013; US$6.0 million payable on January 1, 2014; and US$7.0 million payable on January 1, 2015. See "Funding, Acquisition and Related Transactions – Acquisition – Purchase and Sale Agreement – Deep Rights."

(13) This is a non-recurring receipt of funds relating to the expected sale of approximately 76,300 net acres of rights below the Buda formation reserved by Denali in leases in Wilson and Atascosa Counties, Texas, which leases are expected to be sold to a third party on September 10, 2012 pursuant to the Asset Purchase Agreement. Closing of this transaction is subject to customary closing conditions. See "Risk Factors".

## GLOSSARY

In this prospectus, unless otherwise indicated or the context otherwise requires, the following terms shall have the indicated meanings. Certain other terms used in this prospectus 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. Words importing the singular include the plural and vice versa and words importing any gender include all genders. A reference to an agreement means the agreement as it may be amended, supplemented or restated from time to time.

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

"**Acquisition**" means the acquisition by US Opco of the Denali Assets from Denali;

"**Administrative Services Agreement**" means the administrative services agreement dated May 9, 2012 between the Trustee and the Administrator, pursuant to which the Administrator will agree to provide administrative services to the Trust and pursuant to which the Administrator will be delegated certain duties in connection with the governance of the Trust;

"**Administrator**" means Argent Energy Ltd., or such other party as may be appointed as administrator from time to time pursuant to the Administrative Services Agreement;

"**Administrator Directors**" means the directors of the Administrator from time to time;

"**Administrator Shareholder**" means Aston Hill Financial Management Ltd., a subsidiary of Aston Hill;

"**affiliate**" or "**associate**" has the meaning ascribed thereto in the *Securities Act* (Alberta), as amended from time to time;

"**Argent Group**" means the Trust and its direct and indirect subsidiaries, including Can Holdco and US Opco;

"**Asset Disposition**" means the proposed disposition of approximately 76,300 net acres of rights below the Buda formation reserved by Denali in leases in the Wilson and Atascosa Counties, Texas for a net purchase price of approximately US$7.5 million, the proceeds of which will be received by US Opco;

"**Asset Purchase Agreement**" means the purchase and sale agreement dated effective July 1, 2012 between Denali and a third party relating to the Asset Disposition;

"**Aston Hill**" means Aston Hill Financial Inc., a corporation formed pursuant to the laws of Alberta, the promoter of the Trust and the provider of certain technical and administrative services to the Administrator pursuant to the Services Agreement;

"**Board**" means all of the Administrator Directors;

"**Bridge Facility**" means the US$7,500,000 term credit facility to be established in favour of US Opco concurrently with the closing of the Offering and the Acquisition as described under "Credit Facilities";

"**business day**" means a day other than a Saturday, Sunday or a day on which the principal chartered banks located at Calgary, Alberta are not open for business;

"**Can Holdco**" means Argent Energy (Canada) Holdings Inc., a corporation formed pursuant to the laws of Alberta and a wholly-owned subsidiary of the Trust;

"**Can Holdco Shares**" means the common shares in the capital of Can Holdco;

"**CDS**" means CDS Clearing and Depository Services Inc.;

"**Code**" means the United States *Internal Revenue Code of 1986*, as amended;

"**Computershare**" means Computershare Trust Company of Canada;

"**CRA**" means the Canada Revenue Agency or any successor agency thereto;

"**Credit Facilities**" means, collectively, the Bridge Facility and the Operating Facility;

"**Deep Rights**" means the oil and natural gas leasehold rights below the Austin Chalk oil formation in specified undeveloped leases covering approximately 22,220 net acres in Fayette and Gonzales Counties, Texas, to be acquired by US Opco pursuant to the Purchase and Sale Agreement;

"**Deep Rights ORRI**" means the overriding royalty interest in respect of the Deep Rights retained by Denali, being (i) 25% of revenue from all oil, natural gas and associated hydrocarbons produced, saved and sold from the Deep Rights by US Opco less (ii) the amount of any burdens, including royalties, taxes and downstream costs, affecting the Deep Rights;

"**Deferred Payment Obligation**" means payments by US Opco to Denali equal to US$5.0 million payable on January 1, 2013, US$6.0 million payable on January 1, 2014, and US$7.0 million payable on January 1, 2015 in respect of the Deep Rights, pursuant to the Purchase and Sale Agreement;

"**Denali**" means, collectively, Denali Oil & Gas Partners II, LP, a Texas limited partnership, and Denali Oil & Gas Partners III, LLC, a Texas limited liability company;

"**Denali Assets**" means the 100% working interests currently owned by Denali, in various oil and natural gas leases located across 13 fields primarily located in South Texas, covering approximately 117,273 net acres and including the Deep Rights;

"**Denali Deep Rights Interests**" means, collectively, the Deep Rights ORRI and, after certain well costs have been recovered by US Opco, either (i) an additional 7.5% net working interest in each well drilled by US Opco in the Deep Rights, on a well by well basis, or (ii) an additional 3.0% overriding royalty interest with respect to any such well;

"**Denali Reserved Interest**" means, collectively, the production payment and overriding royalty interest reserved by Denali pursuant to the Denali Reserved Interest Agreement;

"**Denali Reserved Interest Agreement**" means the agreement dated December 1, 2009 establishing the Denali Reserved Interest in respect of certain leases covering approximately 80,000 net acres in the Wilson and Gonzales Counties, Texas;

"**DRIP**" means the distribution reinvestment plan that the Trust intends to adopt following completion of the Offering and subject to the receipt of all necessary regulatory approvals;

"**EBITDA**" means earnings before interest, income taxes, depreciation, amortization, other non-cash expenses such as unrealized foreign exchange gains or losses and asset impairment, and any unusual non-operating one-time items such as acquisition costs;

"**gross**" means:

(a) in relation to US Opco's interest in production or reserves, its "gross reserves", which are US Opco's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of US Opco;

(b) in relation to US Opco's interest in wells, the total number of wells in which US Opco has an interest; and

(c) in relation to US Opco's interest in properties, the total area of properties in which US Opco has an interest;

"**hydrocarbons**" means organic compounds containing a mixture of carbon and hydrogen;

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

"**Initial Private Placements**" means the issuance by the Trust, on a private placement basis, of an aggregate of 600,000 Units to the Administrator Directors, Management and certain other investors, including Aston Hill, at a price of $5.00 per Unit, for aggregate gross proceeds of $3,000,000;

"**IRS**" means the U.S. Internal Revenue Service;

"**LIBOR**" means the London Interbank Offered Rate;

"**Locked-up Unitholders**" means, collectively, all of the Unitholders that have entered into Lock-up Agreements;

"**Lock-up Agreements**" means the lock-up agreements to be entered into on the closing of the Offering between each the Locked-up Unitholders and Scotia Capital Inc., CIBC World Markets Inc. and RBC Dominion Securities Inc., on behalf of the Underwriters;

"**Management**" means the management of the Trust, being the officers of the Administrator;

"**net**" means:

(a) in relation to US Opco's interest in production or reserves, US Opco's working interest (operating or non-operating) share after deduction of royalty obligations, plus US Opco's royalty interests in production or reserves;

(b) in relation to US Opco's interest in wells, the number of wells obtained by aggregating US Opco's working interest in each of its gross wells; and

(c) in relation to US Opco's interest in a property, the total area in which US Opco has an interest multiplied by the working interest owned by US Opco;

"**NGL**" or "**NGLs**" means natural gas liquids, consisting of any one of ethane, propane, butane and other liquefied hydrocarbons or a combination thereof;

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

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

"**NYMEX**" means the New York Mercantile Exchange;

"**Offering**" means the distribution of Units pursuant to this prospectus;

"**Operating Facility**" means the US$8,000,000 extendible revolving term credit facility to be established in favour of US Opco concurrently with the closing of the Offering and the Acquisition as described under "Credit Facilities";

"**Ordinary Resolution**" means a resolution passed by more than 50% of the votes cast by those Unitholders entitled to vote on such resolution, whether cast in person or by proxy at a meeting of Unitholders at which a quorum was present, called (at least in part) for the purpose of approving such resolution, or a resolution approved in writing, in one or more counterparts, by holders of more than 50% of the votes represented by those Units entitled to be voted on such resolution;

"**Other Trust Securities**" means any type of securities of the Trust, other than Units, including notes (including Redemption Notes), options, rights, warrants or other securities convertible into or exercisable for Units or other securities of the Trust (including convertible debt securities, subscription receipts and installment receipts);

"**Over-Allotment Option**" means the option granted by the Trust to the Underwriters exercisable in whole or in part, from time to time for a period of 30 days from closing of the Offering, to purchase up to 3,184,500 additional Units from the Trust on the same terms as the Units sold under the Offering, to cover over-allotments, if any, and for market stabilization purposes;

"**Overhead Allocation**" has the meaning ascribed thereto under the heading "Administration of the Trust – Services Agreement with Aston Hill – Cost and Overhead Recovery";

"**person**" means and includes individuals, companies, corporations, limited partnerships, general partnerships, joint stock companies, limited liability companies, joint ventures, associations, trusts, banks, trust companies, pension funds, and other organizations, whether or not legal entities, and governments and agencies and political subdivisions thereof;

"**Purchase and Sale Agreement**" means the purchase and sale agreement entered into on May 23, 2012, as amended on June 11, 2012 and July 12, 2012, with an effective date of January 1, 2012 between US Opco and Denali, pursuant to which US Opco will acquire the Denali Assets;

"**PUR**" means a phantom unit right of the Trust, granted in accordance with the PURP;

"**PURP**" means the phantom unit rights plan of US Opco, as may be adopted by US Opco prior to the completion of the Offering;

"**Redemption Notes**" means subordinated unsecured promissory notes of the Trust that may be issued by the Trust in accordance with the Trust Indenture on a redemption of Units;

"**Redemption Price**" means the redemption price applicable to any redemption of Units by Unitholders as further described under "Description of the Trust – Redemption at the Option of Unitholders";

"**Registered Plans**" means, collectively, registered retirement savings plans, registered education savings plans, registered retirement income funds, deferred profit sharing plans, registered disability savings plans and tax-free savings accounts;

"**Reserve Life Index**" is a metric commonly used to estimate the useful life of producing oil and natural gas assets, which is calculated by dividing the reserves by the current average daily production on an annualized basis;

"**RRC**" means the Texas Railroad Commission;

"**RTU**" means a restricted trust unit of the Trust;

"**RTUP**" means the Restricted Trust Unit Plan of the Trust;

"**Services Agreement**" means the services agreement to be entered into between the Trust, the Administrator and Aston Hill, pursuant to which Aston Hill will provide certain technical and administrative services to the Trust and the Administrator;

"**SIFT Rules**" means the provisions of the Tax Act that apply to a SIFT trust or SIFT partnership;

"**SIFT trust**" means a specified investment flow-through trust as defined in subsection 122.1(1) of the Tax Act;

"**Special Resolution**" means a resolution passed by more than $66^2/_3$% of the votes cast by those Unitholders, entitled to vote on such resolution, whether cast in person or by proxy, at a meeting of Unitholders, at which a quorum was present, called (at least in part) for the purpose of approving such resolution, or a resolution approved in writing, in one or more counterparts, by holders of more than $66^2/_3$% of the votes represented by those Units, entitled to be voted on such resolution;

"**Sproule**" means Sproule Associates Limited, an independent firm of professional petroleum engineers, geologists, geophysicists and petrophysicists providing services within North America and internationally;

"**Sproule Reserve Report**" means the independent engineering evaluation of the oil, natural gas and NGLs reserves relating to the Denali Assets, prepared by Sproule from January to April 2012 with an effective date of December 31, 2011 and dated April 27, 2012;

"**subsidiary**" has the meaning ascribed thereto in the ABCA;

"**Tax Act**" means the *Income Tax Act* (Canada) and the regulations thereunder, as amended from time to time;

"**Taxation Certification**" means a properly completed and duly executed U.S. Internal Revenue Service Form W-8BEN or W-9, as applicable, or such successor form to such forms as the IRS shall adopt;

"**Transition Services Agreement**" means the services agreement to be entered into between US Opco and Denali, pursuant to which Denali will provide certain technical, operational and administrative services to US Opco in order to accommodate the transition of operatorship of the Denali Assets to US Opco;

"**Treaty**" means the Convention between the United States of America and Canada with Respect to Taxes on Income and on Capital, signed September 26, 1980, as amended;

"**Trust**" means Argent Energy Trust, an unincorporated limited purpose open-ended trust established under the laws of the Province of Alberta;

"**Trust Indenture**" means the trust indenture establishing the Trust made as of January 31, 2012 as amended and restated on May 9, 2012;

"**Trust Property**" means, at any time, all of the money, properties and other assets of any nature or kind whatsoever as are, at such time, held by the Trust or by the Trustee on behalf of the Trust;

"**Trustee**" means the trustee of Argent Energy Trust under the Trust Indenture which, at the closing of the Offering, will be Computershare Trust Company of Canada;

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

"**Underwriters**" means, collectively, Scotia Capital Inc., CIBC World Markets Inc., RBC Dominion Securities Inc., BMO Nesbitt Burns Inc., TD Securities Inc., Canaccord Genuity Corp., National Bank Financial Inc., Acumen Capital Finance Partners Limited, AltaCorp Capital Inc., Cormark Securities Inc., Desjardins Securities Inc., Dundee Securities Ltd., FirstEnergy Capital Corp. and GMP Securities L.P.;

"**Underwriting Agreement**" means the underwriting agreement among the Underwriters and the Trust, the Administrator, Can Holdco, US Opco, Aston Hill and the Administrator Shareholder dated August 1, 2012, as further described under "Plan of Distribution";

"**United States**" or "**U.S.**" means the United States of America, its territories and possessions, any state of the United States and the District of Columbia;

"**Unitholder**" means a registered holder of Units;

"**Units**" means the trust units of the Trust, each such trust unit representing an equal undivided beneficial interest in the Trust;

"**US Opco**" means Argent Energy (US) Holdings Inc., a corporation formed pursuant to the laws of Delaware and a wholly-owned subsidiary of Can Holdco;

"**US Opco Notes**" means the subordinated unsecured promissory notes to be issued by US Opco to Can Holdco, which concurrently with or immediately following the closing of the Offering, will be distributed by Can Holdco to the Trust;

"**US Opco Shares**" means shares in the common stock of US Opco;

"**U.S. Securities Act**" means the United States *Securities Act of 1933*, as amended;

"**Voting Agreement**" means the voting agreement dated May 9, 2012 among the Administrator Shareholder, the Trustee and the Administrator, with regard to, among other matters, the election of the Administrator Directors (as directed by the Trustee as agent for the Unitholders); and

"**WTI**" means West Texas Intermediate light sweet crude oil at a reference sales point in Cushing, Oklahoma, a common benchmark for crude oil.

## THE TRUST AND ITS SUBSIDIARIES

### The Trust

Argent Energy Trust, the Trust, is an unincorporated limited purpose open-ended trust established under the laws of the Province of Alberta on January 31, 2012 by the Trust Indenture. The Trust intends to qualify as a "mutual fund trust" under the Tax Act. The Trust has been established to initially indirectly acquire the Denali Assets through its interest in Can Holdco and US Opco. The Trust has no history of operations or earnings. See "Description of the Trust".

### The Administrator

Argent Energy Ltd., the Administrator, is a corporation formed under the laws of the Province of Alberta on June 9, 2011 and is the administrator of the Trust. The sole shareholder of the Administrator is the Administrator Shareholder. See "Administration of the Trust – Administrative Services Agreement", "Voting Agreement".

### Can Holdco

Argent Energy (Canada) Holdings Inc., the Can Holdco, is a corporation formed under the laws of the Province of Alberta on May 4, 2012 and is a direct wholly-owned subsidiary of the Trust. On Closing of the Offering, Can Holdco will hold all of the issued and outstanding US Opco Shares, will loan certain funds to US Opco in exchange for the US Opco Notes and then will distribute the US Opco Notes to the Trust. See "Description of Can Holdco".

### US Opco

Argent Energy (US) Holdings Inc., the US Opco, is a corporation formed under the laws of the State of Delaware on May 4, 2012 to initially acquire the Denali Assets on closing of the Offering. US Opco is an indirect wholly-owned subsidiary of the Trust. See "Description of US Opco" and "Undertaking of the Trust – Objective and Strategies of the Trust". Management intends that US Opco (or additional entities that may be formed and held, directly or indirectly, by the Trust) will have a broader mandate to acquire additional assets in accordance with the objective and strategies of the Trust. See "Description of US Opco".

### Offices

The principal and head office of the Trust, the Administrator and Can Holdco are located at Suite 500, 321 – 6th Avenue S.W., Calgary, Alberta T2P 3H3. The principal office of US Opco is located at 650 N. Sam Houston Parkway, Suite 500, Houston, Texas 77060. The registered office of the Administrator and Can Holdco is located at 4500 Bankers Hall East, 855 – 2nd Street S.W., Calgary, Alberta, T2P 4K7. The registered office of US Opco is located at The Corporation Trust Center, 1209 Orange Street, Wilmington, County of New Castle, Delaware, 19801.

## UNDERTAKING OF THE TRUST

The Trust is a recently formed energy trust created to provide investors with a publicly traded, oil and natural gas focused, distribution-producing investment, with favourable Canadian income tax treatment relative to taxable Canadian corporations. The strategy of the Trust is to acquire, exploit and develop, indirectly through US Opco, long-life crude oil and natural gas reserves, including the Denali Assets, in established producing basins located primarily in the U.S. The Trust's focus is the ownership and development, indirectly through US Opco, of producing crude oil and natural gas properties with low-risk exploitation potential. The Trust does not intend to engage in high-risk exploration activities. The Trust intends to make monthly distributions of a portion of its available cash to Unitholders and US Opco intends to use the remainder of available cash (which is not ultimately distributed to the Trust) to fund growth through additional acquisitions and capital expenditures.

US Opco entered into the Purchase and Sale Agreement with Denali on May 23, 2012, as amended on June 11, 2012 and July 12, 2012, pursuant to which it will acquire the Denali Assets.

The purchase price for the Denali Assets (excluding the Deep Rights) is US$166.7 million, subject to certain closing adjustments and net of US$36.6 million to be paid by the Trust to Denali on closing of the Offering and which amount will be held in escrow by Denali and applied to US Opco's capital expenditures and general and administrative expenses on the Denali Assets for the 24 month period following closing of the Offering. In addition, pursuant to the Deferred Payment Obligation in the Purchase and Sale Agreement, US Opco is required to pay Denali an aggregate of US$18 million over a three year period commencing January 1, 2013 in respect of the Deep Rights. US Opco will also be obligated to pay an additional US$30 million for additional interests in the Deep Rights upon the occurrence of certain events. See "Funding, Acquisition and Related Transactions – Acquisition – Purchase and Sale Agreement – Deep Rights". The purchase price for the Acquisition will be funded from the net proceeds of the Offering and an advance under the Credit Facilities to be established by US Opco. The Acquisition will have an effective date of January 1, 2012. It is a condition under the Purchase and Sale Agreement that the closing of the Acquisition occurs concurrently with the closing of the Offering and the closing of the Credit Facilities. See "Funding, Acquisition and Related Transactions – Acquisition – Purchase and Sale Agreement", "Use of Proceeds" and "Undertaking of the Trust – Credit Facilities".

The net proceeds to be received by the Trust pursuant to the exercise of the Over-Allotment Option, if exercised, are expected to be provided to US Opco in the same manner as the net proceeds of the Offering. If the Over-Allotment Option is exercised for net proceeds of at least $25 million, US Opco will acquire the Denali Reserved Interest for US$20 million in accordance with the Purchase and Sale Agreement, with the remaining proceeds to be used to reduce the amount outstanding under the Credit Facilities and for general corporate purposes. If the Over-Allotment Option is exercised for net proceeds of less than $25 million, the proceeds will be used to reduce the amount outstanding under the Credit Facilities and for general corporate purposes. See "Use of Proceeds" for a tabular presentation of the use of proceeds and "Funding, Acquisition and Related Transactions – Acquisition – Purchase and Sale Agreement – Denali Reserved Interest".

The Trust intends to qualify as a "mutual fund trust" and not be a "SIFT trust", each as defined in the Tax Act. The SIFT Rules tax certain income earned by a SIFT trust as if it were a corporation and treat certain distributions received by unitholders of a SIFT trust as taxable dividends. The Trust will not be a SIFT trust, provided that the Trust complies at all times with the investment restrictions set forth in the Trust Indenture, which preclude the Trust from holding any "non-portfolio property" (as defined in the Tax Act). Similar restrictions are included in the articles of Can Holdco and US Opco. If the SIFT Rules were to apply to the Trust, they might have an adverse impact on the Trust, including on the amount of distributions received by Unitholders and/or the value of the Units. The Administrator will be responsible for monitoring the Trust's investments and holdings of property to ensure the Trust is not at any time a SIFT trust and does not hold any "non-portfolio property". See "Description of the Trust – General", "Risk Factors" and "Canadian Federal Income Tax Considerations".

US Opco entered into a purchase and sale agreement dated May 23, 2012, as amended on June 11, 2012, with EnergyQuest II, LLC to acquire certain oil and natural gas leases located in Texas and Southern Oklahoma. This purchase and sale agreement was terminated by the parties on July 11, 2012 and is of no force and effect.

**Objective and Strategies of the Trust**

The objective of the Trust is to create stable, consistent returns for investors through the acquisition and development of oil and natural gas reserves and production with low-risk exploitation potential, located primarily in the U.S., and to pay out a portion of available cash to Unitholders on a monthly basis. The Trust believes it can achieve this objective through:

- ***Prudent and Disciplined Capital Investment*** – The Trust will maintain a focus on full cycle economics expected to be generated by all of its capital investments, without reliance upon the expectation of increased commodity prices. US Opco will pursue a prudent capital program in respect of the Denali Assets in order to provide cost-effective production growth having regard to commodity prices and other operational considerations. US Opco intends to allocate its capital prudently over all of US Opco's properties, balancing the need for production maintenance and cash flow generation with new production growth and reserves additions for long term value enhancement. The Trust will focus on increasing net asset value per Unit when making development and exploitation capital investments and acquisitions. All projects will undergo a capital ranking exercise by Management that, in combination with US Opco's overall objectives and strategies, will determine the optimal investment, development and drilling plans.

- ***Accretive Growth*** – The Trust will focus on prudent growth through a combination of internally generated opportunities (with disciplined capital ranking) and accretive acquisitions. At times in the oil and natural gas business it is more cost effective to access new reserves through exploitation of internal opportunities, while at other times it is more cost effective to acquire production and reserves from third parties. The Trust intends to invest its capital in a manner it believes will generate the highest full cycle returns to Unitholders over time. In all cases, the objective of the investments will be to focus on growth which is accretive to Unitholders. Management is experienced in both exploitation and acquisitions of reserves.

- ***Financially Conservative*** – Management believes that prudent utilization of debt can contribute to distribution stability and increased returns to Unitholders. Leverage will generally be maintained at a level appropriate for projected commodity prices and the ability of the Trust (through US Opco) to repay indebtedness without negatively impacting returns to Unitholders. The Trust intends to maintain a prudent debt to EBITDA ratio that will generally not exceed 1.5 times debt to EBITDA. The Trust may temporarily exceed this parameter, particularly in the case of acquisitions, provided that Management has a plan to return this ratio to the preferred range in the short term. Upon closing of the Offering, Management expects the debt to EBITDA (based on the 2012 financial year) ratio to be approximately 0.3 times.

The Trust will utilize a number of strategies intended to achieve its objective, including, in particular:

- ***Asset Location*** – The Trust intends to target its investments on assets primarily located on-shore in the U.S. near its initial operating properties, being the Denali Assets. Management believes that oil and natural gas assets located in the U.S. have certain favourable characteristics compared to Canada, including:

    - There are more discrete oil and natural gas assets in the U.S., a significant percentage of which are held by private or non-industry participants. As a result, Management believes that there are more opportunities for the acquisition of suitably sized assets in the U.S. than in Canada.

    - Operating costs of oil and natural gas assets in the U.S. are generally lower than operating costs for comparable oil and natural gas assets in Canada for a variety of reasons. Firstly, there is year-round access to properties in many parts of the U.S., while in Canada many assets can only be accessed during one of the winter or summer seasons. Secondly, there is generally more competition among service providers in the U.S. as compared to Canada, often resulting in lower service costs. Thirdly, oil and natural gas production in the U.S. tends to be closer to markets, often resulting in lower transportation costs and higher netbacks.

- ***Investment In Long-Life Assets*** – The Trust intends to focus on long-life oil and natural gas assets. These types of assets typically have lower risk development and exploitation potential and a longer reserve life which provides a natural hedge against short term commodity price cycles.

- ***Control Over Capital Expenditures*** – The Trust intends to focus its investments on properties where it has a material degree of control over the pace and degree of capital spending. The Trust will manage its assets as one portfolio, regardless of location and will prioritize its capital investment opportunities accordingly.
- ***Development and Exploitation*** – The Trust intends to focus on the development and exploitation of its properties. Although the Trust may undertake other activities which may technically qualify as exploration, the Trust does not intend to engage in high-risk exploration activities.
- ***Commodity Balance*** – The Trust does not expect to favour oil over natural gas or vice versa in the long-term. However, in the current context of historically low natural gas prices, the current development plan is to defer drilling all but one of the natural gas wells until at least 2014. On balance, the Trust will invest in those opportunities which meet its disciplined investment criteria, having regard to various factors including commodity prices, quality of assets in terms of reserves, production and operating costs, availability of operatorship, and associated operational risks and opportunities.
- ***Hedging Strategy*** – As part of the Trust's risk management strategy, Management plans to use financial instruments to reduce its commodity price exposure. Management intends to implement a rolling hedging program that would reduce the Trust's exposure to changes in commodity prices for up to 36 months. The Trust expects to hedge: (i) up to 70% of US Opco's after royalty forecasted production 12 months forward; (ii) up to 60% of US Opco's after royalty forecasted production 24 months forward; and (iii) up to 50% of US Opco's after royalty forecasted production 36 months forward. The amount and types of hedges will be dependent on, among other things, the Trust's debt level, anticipated capital expenditures, anticipated distributions and market conditions. The purpose of the hedging program is to reduce volatility in cash flows, protect acquisition economics, and to maintain stability of cash distributions to Unitholders. The Trust may also hedge its foreign exchange and interest rate exposure.

**Credit Facilities**

US Opco has received a commitment for the Credit Facilities and expects to establish the Credit Facilities concurrently with the closing of the Offering and the Acquisition. After the closing of the Offering and the Acquisition, Management anticipates that approximately US$5.8 million will have been initially drawn under the Credit Facilities to partially fund the Acquisition, and approximately US$9.7 million will be available for borrowing under the Credit Facilities.

Management expects available credit under the Operating Facility to increase commensurate with the growth of the borrowing base. See "Credit Facilities", "Use of Proceeds" and "Consolidated Capitalization".

## USE OF PROCEEDS

The net proceeds to the Trust from the Offering will be approximately $198.1 million (approximately $228.1 million if the Over-Allotment Option is exercised in full) after deducting the fees payable to the Underwriters of approximately $12.7 million (approximately $14.6 million if the Over-Allotment Option is exercised in full) and the expenses of the Offering estimated to be approximately $3.0 million, of which approximately $1.5 million will be paid from proceeds raised in the Initial Private Placements. The remaining expenses of the Offering of approximately $1.5 million, together with the Underwriters' fee, will be paid by the Trust from the proceeds of the Offering.

The Trust will provide the net proceeds of the Offering to US Opco. US Opco will use those proceeds, plus an advance of approximately US$5.8 million under the Credit Facilities, to fund the purchase price of the Acquisition. The purchase price for the Denali Assets (excluding the Deep Rights) is US$166.7 million, subject to certain closing adjustments and net of US$36.6 million that will be paid by the Trust to Denali on closing of the Offering and which amount will be held in escrow by Denali and applied to US Opco's capital expenditures and general and administrative expenses on the Denali Assets for the 24 month period following closing of the Offering. See "Funding, Acquisition and Related Transactions". Following completion of the Offering and the Acquisition, the Trust will continue to pursue the objective and strategies set out under the heading "Undertaking of the Trust – Objective and Strategies of the Trust".

After the closing of the Offering and the Acquisition, Management anticipates that approximately US$5.8 million will have been initially drawn under the Credit Facilities to partially fund the Acquisition, and approximately US$9.7 million will be available for borrowing under the Credit Facilities.

The Trust's capital expenditure program for the remainder of 2012 (assuming closing of the Acquisition occurs on August 10, 2012) is approximately US$13.6 million, which will be funded from the amount held in escrow by Denali.

The net proceeds to be received by the Trust pursuant to the exercise of the Over-Allotment Option, if exercised, are expected to be provided to US Opco in the same manner as the net proceeds of the Offering. If the Over-Allotment Option is exercised for net proceeds of at least $25 million, US Opco will acquire the Denali Reserved Interest for US$20 million in accordance with the Purchase and Sale Agreement, with the remaining proceeds to be used to reduce the amount outstanding under the Credit Facilities and for general corporate purposes. If the Over-Allotment Option is exercised for net proceeds of less than $25 million, the proceeds will be used to reduce the amount outstanding under the Credit Facilities and for general corporate purposes. See below for a tabular presentation of the use of proceeds and "Funding, Acquisition and Related Transactions – Acquisition – Purchase and Sale Agreement – Denali Reserved Interest", and "Funding, Acquisition and Related Transactions – Acquisition – Purchase and Sale Agreement – Deep Rights".

The following table sets out the proceeds to be received by the Trust upon completion of the Offering and the use of those proceeds:

| | |
|---|---|
| **Proceeds:** | |
| Offering[(1)] | C$212,300,000 |
| Underwriters' fee[(2)] | C$12,673,200 |
| Expenses of the Offering[(3)] | C$1,500,000 |
| Net Proceeds from the Offering | C$198,126,800 |
| Advances under the Credit Facilities[(4)] | C$5,846,311 |
| Converted to US$[(5)] | US$203,300,000 |
| **Use of Proceeds:** | |
| Acquisition of Denali Assets[(6)] | US$203,300,000 |

**Notes:**

(1) Does not include proceeds that may be received pursuant to the exercise of the Over-Allotment Option.

(2) Assuming the Over-Allotment Option is not exercised.

(3) The expenses of the Offering, excluding the Underwriter's fee, is estimated at approximately $3.0 million, of which approximately $1.5 million will be paid from proceeds raised in the Initial Private Placements. The remaining approximately $1.5 million will be paid by the Trust from the proceeds of the Offering.

(4) Advances under the Credit Facilities may vary due to the U.S. dollar equivalent of the net proceeds of the Offering at the time of closing of the Offering. See Note (5) below.

(5) Converted at a foreign exchange rate of C$1.00 = US$0.9967, the noon rate of exchange posted by the Bank of Canada for conversion of Canadian dollars into U.S. dollars on July 30, 2012. The net proceeds from the Offering will be converted into U.S. dollars at the time of the closing of the Offering, which is expected to occur on August 10, 2012, and will therefore be subject to the Canadian dollar/U.S. dollar exchange rate on that date.

(6) The purchase price for the Acquisition is subject to certain closing adjustments. Pursuant to the Purchase and Sale Agreement, Denali will hold an aggregate of US$36.6 million of the proceeds received for the Denali Assets in escrow, which funds will be applied to US Opco's capital expenditures and general and administrative expenses on the Denali Assets for the 24 month period following closing of the Offering.

## FUNDING, ACQUISITION AND RELATED TRANSACTIONS

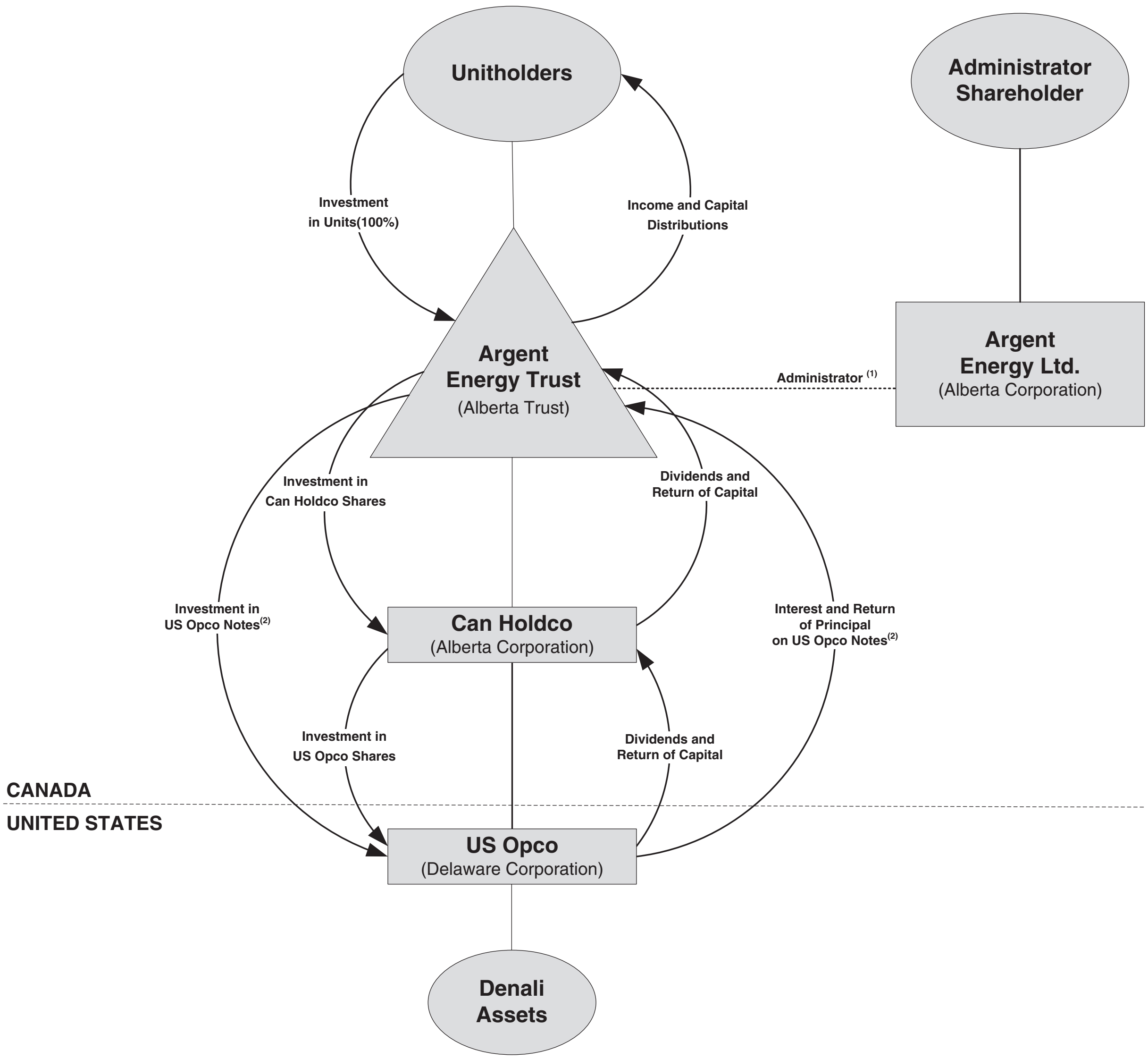
### Closing Transactions

The following is a summary of the principal transactions that will take place in connection with the completion of the Offering:

1. The Trust will use substantially all of the net proceeds of the Offering to acquire approximately 19,812,680 Can Holdco Shares.
2. Can Holdco will use a portion of the proceeds received from the Trust to acquire additional US Opco Shares, and will loan the remaining proceeds to US Opco (in exchange for the US Opco Notes having an aggregate principal amount equal to the U.S. dollar equivalent at the time of closing of approximately $126,734,768).
3. US Opco will acquire the Denali Assets (excluding the Deep Rights) for a purchase price of US$166.7 million, subject to certain closing adjustments and net of US$36.6 million that will be paid to Denali by the Trust on closing of the Offering, which amount will be held in escrow by Denali and applied to US Opco's capital expenditures and general and administrative expenses on the Denali Assets for the 24 month period following closing of the Offering. The Acquisition will be funded from the net proceeds of the Offering and by advances of approximately US$5.8 million under the Credit Facilities (which may vary depending on the U.S. dollar equivalent of the net proceeds of the Offering at the time of closing).
4. Can Holdco will distribute the US Opco Notes to the Trust, such that the principal or interest amount under US Opco Notes will be owed by US Opco directly to the Trust.

### Structure Following Closing

The following chart illustrates the structure of the Trust following completion of the Offering and the indirect investment by the Trust in US Opco and related transactions (as described in more detail in "Funding, Acquisition and Related Transactions"). All subsidiaries of the Trust will be directly or indirectly wholly-owned by the Trust. All of the shares of the Administrator are owned by the Administrator Shareholder and are subject to the terms of the Voting Agreement. See "Voting Agreement".




**Notes:**

(1) Pursuant to the terms of the Administrative Services Agreement, the Administrator will perform all administrative, operational and investment services that are or may be required or advisable, from time to time, for the Trust. The Administrator and the Trust will also enter into the Services Agreement with Aston Hill, pursuant to which Aston Hill will provide certain technical and administrative services that are or may be required or advisable, from time to time, for the Administrator on behalf of the Trust. See "Administration of the Trust–Administrative Services Agreement" and "Administration of the Trust – Services Agreement with Aston Hill".

(2) The US Opco Notes will initially be issued to Can Holdco and will be distributed by Can Holdco to the Trust concurrently with or immediately following the closing of the Offering. As a result, interest and principal will be paid by US Opco directly to the Trust instead of to Can Holdco.

### Acquisition

Pursuant to the Purchase and Sale Agreement, US Opco will acquire the Denali Assets, which include interests in: (i) the Austin Chalk and Eagle Ford Shale oil formations; (ii) the South Texas natural gas assets, including the South

Escobas Field; and (iii) the Deep Rights. If the Over-Allotment Option is exercised for net proceeds of at least $25 million, US Opco is also required to use a portion of the net proceeds it receives from the Trust pursuant to the exercise of the Over-Allotment Option to acquire the Denali Reserved Interest.

***Purchase and Sale Agreement***

US Opco has entered into the Purchase and Sale Agreement pursuant to which it will acquire the Denali Assets. The Purchase and Sale Agreement establishes a January 1, 2012 effective date for the Acquisition.

The purchase price for the Denali Assets (excluding the Deep Rights) is US$166.7 million, subject to certain closing adjustments and net of US$36.6 million that will be paid by the Trust to Denali on closing of the Offering, which amount will be held in escrow by Denali to be applied to US Opco's capital expenditures and general and administrative expenses on the Denali Assets for the 24 month period following closing of the Offering. The escrow funds are required to be released to US Opco within one business day of US Opco providing the escrow agent with a certificate confirming that capital expenditures or general and administrative expenses have been incurred by US Opco with respect to the Denali Assets. Any funds remaining in escrow at the expiration of the 24 month period will be distributed to US Opco. The purchase price will be funded from the net proceeds of the Offering and an advance under the Credit Facilities to be established by US Opco. In connection with the Purchase and Sale Agreement, Denali has agreed to provide certain technical, operational and administrative support to US Opco for a period of up to three years, pursuant to which Denali will be reimbursed for direct costs and will receive consideration of US$100/month. The foregoing services and related compensation will be provided pursuant to the Transition Services Agreement to be entered into by US Opco and Denali prior to the closing of the Acquisition. During the term of the Transition Services Agreement, the operatorship of certain Denali Assets will be transferred from Denali to US Opco.

The Purchase and Sale Agreement includes representations and warranties from Denali in relation to, among other things, its authority and power to transact, the validity and enforceability of the agreement against Denali, litigation affecting the Denali Assets, certain environmental matters and certain information and statements relating to Denali and the Denali Assets contained in this prospectus. The Purchase and Sale Agreement provides that Denali will convey the Denali Assets to US Opco subject to all existing royalties, burdens, liens, encumbrances and surface rights, and without any warranty of title except in relation to matters caused by, through or under Denali. Representations and warranties will generally survive for a period of twelve months following the closing of the Acquisition.

The Purchase and Sale Agreement provides for Denali to indemnify and hold US Opco harmless from and against any and all claims caused by, resulting from or incidental to any breach or default by Denali of any of its representations or warranties in the agreement or any of its covenants or obligations under such agreement, provided that Denali will generally not be required to indemnify US Opco for certain individual claims less than US$250,000 and will generally only be required to indemnify US Opco for certain claims to the extent the aggregate amount of claims exceeds US$1,500,000, up to an aggregate limit of 100% of the purchase price. Purchasers are encouraged to review the terms of the Purchase and Sale Agreement for a complete description of representations, warranties and indemnities (and related limitations). The Purchase and Sale Agreement will be available at www.sedar.com. See "Material Contracts".

Denali is not a promoter and is not a signatory to this prospectus. Purchasers of Units under this prospectus will not have a direct statutory right of action against Denali for any misrepresentations in this prospectus. Unitholders' sole indirect remedy against Denali for any misrepresentations in this prospectus resulting from certain information and statements relating to the Denali Assets provided by Denali to the Trust for use in the prospectus will be through US Opco exercising its rights under the Purchase and Sale Agreement to claim for indemnification in respect of a breach of the representations and warranties in that agreement by Denali, subject to the limitations described above. There can be no assurance of recovery by US Opco from Denali for breaches of Denali's representations and warranties in the Purchase and Sale Agreement. See "Risk Factors".

Completion of the Acquisition contemplated by the Purchase and Sale Agreement is conditional upon, among other things, the closing of the Offering, the closing of the Credit Facilities, and other customary conditions. US Opco is entitled to waive certain closing conditions and elect to complete the transactions contemplated by the Purchase and Sale Agreement. It is also a condition to the Purchase and Sale Agreement that US Opco enter into an operating agreement with a party qualified to operate the Denali Assets, which condition is anticipated to be satisfied by entering into the Transition Services Agreement. The Purchase and Sale Agreement may be terminated by either US Opco or Denali if the closing of the Acquisition does not occur on or before August 31, 2012. See "Use of Proceeds".

*Deep Rights*

Pursuant to the Purchase and Sale Agreement, upon closing of the Acquisition and in exchange for future payments, US Opco will be assigned a 75% net revenue interest in the Deep Rights. The Deep Rights consist primarily of interests in the Eagle Ford Shale oil formation. US Opco is responsible for 100% of the costs associated with the Deep Rights. US Opco will be required to pay to Denali US$5.0 million on January 1, 2013, US$6.0 million on January 1, 2014, and US$7.0 million on January 1, 2015 in respect of its 75% net revenue interest in the Deep Rights. US Opco will have no obligation to drill or develop any part of the Deep Rights.

The Deep Rights will be subject to the Deep Rights ORRI and after certain well costs have been recovered by US Opco from production proceeds, either a net working interest or an additional overriding royalty interest in favour of Denali as discussed below. The Deep Rights ORRI currently equals approximately 4% of gross revenue from the Deep Rights, being (i) 25% of revenue from all oil, natural gas and associated hydrocarbons produced, saved and sold from the Deep Rights by US Opco less (ii) the amount of any burdens, including royalties, taxes and downstream costs, affecting the Deep Rights (such burden currently averaging approximately 21%). For each well drilled by US Opco in the Deep Rights, Denali will have the option, on a well by well basis, after certain well costs have been recovered by US Opco from production proceeds to cause US Opco to assign to Denali either (i) an additional 7.5% net working interest in such well or (ii) an additional 3.0% overriding royalty interest with respect to such well.

During the period commencing on the first anniversary of the closing of the Offering and for three years from such date, such period being the Put Period, Denali will have the right to require US Opco to acquire 100% of the Denali Deep Rights Interests for US$30 million, the Put Amount, which put right will be triggered upon the first to occur of the following:

1. market capitalization of the Trust (based on a ten day volume weighted average trading price) exceeding 130% of the market capitalization of the Trust immediately following the closing of the Offering (based on the initial public offering price of $10.00 per Unit) and, if applicable, the exercise of the Over-Allotment Option;
2. the Trust's debt to EBITDA ratio (using debt as of the end of the most recently reported quarterly reporting period to annualized consolidated EBITDA, calculated by multiplying EBITDA from such quarter by four) falling below 0.4 at the end of any quarterly reporting period;
3. the Trust completing acquisitions, other than the Acquisition, for an aggregate purchase consideration of greater than $125 million; or
4. the Trust completing one or more equity financings following the closing of the Offering and any exercise of the Over-Allotment Option, for an aggregate amount exceeding $125 million.

If none of the foregoing triggering events have occurred during the Put Period, upon the expiration of the Put Period, Denali will have the option to require the Trust to purchase 100% of the Denali Deep Rights Interests and all of its rights to such interests for the Put Amount. US Opco is required to pay the Put Amount within 60 calendar days of the put option being exercised by Denali. In addition, US Opco has the option to pay the Put Amount at any time after closing of the Offering to fully acquire or extinguish the Denali Deep Rights Interests. In the event US Opco pays the Put Amount prior to the payment in full of the Deferred Payment Obligation, any unpaid portion of such amounts will remain outstanding and continue to be an obligation of US Opco until payment thereof. Upon payment of the Put Amount, all right, title and interest in the Denali Deep Rights Interests will be transferred to US Opco and Denali will cease to have any interest in the Deep Rights.

*The Denali Reserved Interest*

In December 2009, Denali assigned leases covering approximately 77,000 net acres in Wilson and Gonzales Counties, Texas to an affiliate of Forest Oil Corporation. In connection with the assignment of such leases, Denali reserved a production payment, being the Denali Production Payment, and the Denali ORRI in respect of the leases that had been assigned.

Pursuant to the Purchase and Sale Agreement, if the Over-Allotment Option is exercised for net proceeds of at least $25 million, US Opco is required to use a portion of the net proceeds it receives pursuant to the exercise of the Over-Allotment Option to acquire the Denali Reserved Interest for US$20 million.

The Denali Production Payment is a production payment currently equal to approximately 4% of gross revenue, being 25% of all gross oil, natural gas and associated hydrocarbons produced, saved and sold from such leases, less the amount of any royalty and overriding royalty burdens on the leases (such burden currently averaging approximately 21%). The Denali Production Payment terminates the first day of the month following the month when the quantity of production attributable to such payment equals 2,500,000 boe (representing approximately 62,500,000 gross boe). In addition, with respect to any reserves that may exist after the production of 74,062,500 boe on a 100% basis from all of the leases, Denali becomes entitled to the Denali ORRI, which is currently equal to approximately 4% of gross revenue, being 25% of all gross oil, natural gas and associated hydrocarbons produced, saved and sold from such leases, less the amount of any royalty and overriding royalty burdens on such leases (such burden currently averaging approximately 21%). From inception to June 30, 2012, Denali has received aggregate payments of US$1,825,967 and the quantity of production attributable to the Denali Production Payment was 19,672 boe.

As of June 30, 2012, 27 horizontal wells have been drilled on the leases subject to the Denali Reserved Interest. For the month of June, gross production before royalties averaged approximately 2,430 boe/d, resulting in production after royalties attributable to the Denali Production Payment of approximately 97 boe/d net to Denali. Pursuant to the Denali Reserved Interest Agreement, Denali is responsible for its net share of all applicable taxes and any downstream costs affecting such leases. For the six-month period ended June 30, 2012, Denali received US$1,099,307 in connection with the Denali Production Payment. Management expects the operator to continue to drill on the leases subject to the Denali Reserved Interest which may increase production and result in a higher Denali Production Payment.

See “Funding, Acquisition and Related Transactions – Acquisition – Purchase and Sale Agreement – Denali Reserved Interest” and “Use of Proceeds”.

***The Denali Assets***

The Denali Assets are located in Zapata, Duval, Brooks, Webb, Lavaca, Houston, Atascosa, Robertson, Wilson, Fayette, Gonzales, and Zavala Counties, Texas and Warren County, Mississippi. The Denali Assets consist of varying working interests in 1,755 oil and natural gas leases covering approximately 143,765 gross acres (117,273 net acres) and an interest in 61 operated wells and eight non-operated wells. The Denali Assets include interests in: (i) the Austin Chalk and Eagle Ford Shale oil formations; (ii) the South Texas natural gas assets, including the South Escobas Field; and (iii) the Deep Rights. Working interest production before royalties for the month of May 2012 in respect of the Denali Assets averaged approximately 1,543 boe/d with an additional 90 bbls/d of oil from the Jendrzey well temporarily shut-in due to a leaking plug, which has since been repaired. With the Jendrzey well back on, production is weighted approximately 21% to oil, 77% to natural gas and 2% to NGLs. The total proved plus probable reserves volumes of the Denali Assets as set forth in the Sproule Reserve Report are weighted approximately 30% to oil, 66% to natural gas and 4% to NGLs, resulting in reserves values weighted approximately 61% to oil, 31% to natural gas and 8% to NGLs.

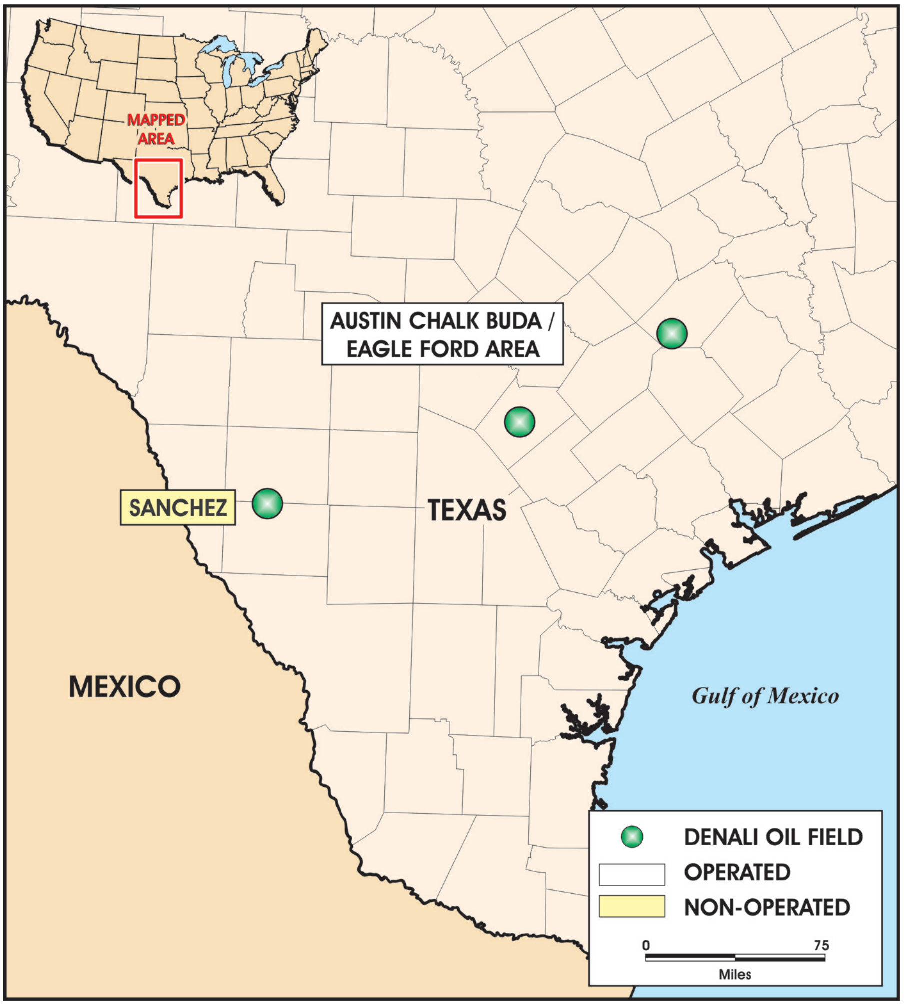
According to the Sproule Reserve Report, the Austin Chalk and Eagle Ford Shale formations account for approximately 37% of the proved plus probable reserves and approximately 72% of the net present value of future net revenue, discounted at 10%, of the Denali Assets. The South Texas natural gas assets account for the remaining 63% of the proved plus probable reserves and approximately 28% of the net present value of future net revenue, discounted at 10%, of the Denali Assets. The Austin Chalk and Eagle Ford Shale oil formations consist primarily of oil, and the South Texas natural gas assets consist primarily of natural gas. The acreage in Warren County, Mississippi consists of approximately 8,000 net acres of undeveloped leasehold, which Management has no current intention of developing.

In respect of the Denali Assets, US Opco’s total estimated asset retirement obligation for 47.1 net wells is estimated at US$2.1 million undiscounted (approximately US$0.9 million discounted at 10%) and includes the abandonment and reclamation of wells to which no reserves have been assigned. In respect of the Denali Assets, US Opco anticipates incurring approximately US$450,000 (the remainder of 2012 – US$270,000; 2013 – US$90,000; 2014 – US$90,000) of its identified abandonment and reclamation costs during the next three years. See “Reserves and Other Oil and Gas Information – Abandonment and Reclamation Costs”.

*Austin Chalk and Eagle Ford Shale Oil Assets*

The Denali Assets located in the Austin Chalk and Eagle Ford Shale formation, which target primarily oil, are shown on the locator map below.

**Denali Assets Located in the Austin Chalk and Eagle Ford Shale Formation**




The Denali Assets include interests in approximately 35,700 gross (26,000 net) acres in the Austin Chalk and Eagle Ford Shale oil formation. The majority of these interests are operated by Denali with approximately 29,000 gross (23,500 net) acres of leasehold interests in Fayette and Gonzales Counties, Texas, on which Denali has drilled and operates six horizontal oil wells. The Denali Assets include an additional 1,704 gross (1,495 net) acres of leasehold interests in Wilson County, Texas, on which Denali has drilled and operates two horizontal oil wells.

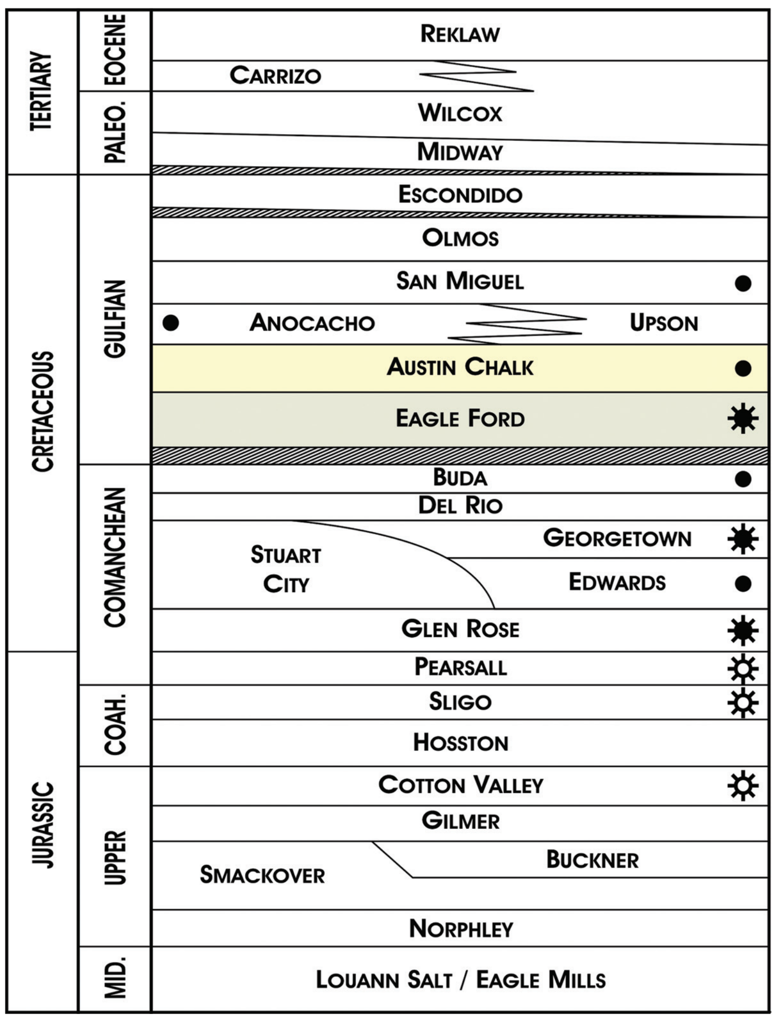
The Denali Assets also include a non-operated interest in 5,056 gross (990 net) acres in Zavala County, Texas. This acreage is operated by Sanchez Oil & Gas Corp., and includes two producing horizontal oil wells in the Austin Chalk oil formation and one producing horizontal oil well in the Eagle Ford Shale oil formation.

The Denali Assets provide drilling opportunities in the Austin Chalk oil formation as well as in the rapidly developing Eagle Ford Shale oil formation. There are numerous other potential drilling targets included in the Denali Assets, including the Buda, Edwards and Pearsall Shale formations. All of these drilling targets will be subject to future evaluation across Denali's leasehold other than approximately 76,300 net acres of rights below the Buda formation reserved by Denali in leases in Wilson and Atascosa Counties, Texas, which leases are expected to be sold to a third party on September 10, 2012 for a net purchase price of approximately US$7.5 million, being the Asset Disposition pursuant to the Asset Purchase Agreement. The Asset Purchase Agreement is subject to customary closing conditions. All amounts owing under the Bridge Facility will become payable upon the earlier of the closing of the Asset Disposition and October 15, 2012, at which time the Bridge Facility will be terminated. See "Risk Factors".

*Geology of the Austin Chalk and Eagle Ford Shale Formations*

The Austin Chalk formation is an upper cretaceous geologic formation which runs from the border of Mexico across South Texas and into Louisiana. Its geology consists of a finely grained limestone comprised of recrystalized, fossiliferous, interbedded chalks and marls. The depths of the deposition of the Austin Chalk formation occurred in approximately 250 metres or 820 feet of water. Volcanic ash layers present in the Austin Chalk formation result in there being several different reservoir targets within the formation. In the specific area of Denali's acreage in Fayette and Gonzales Counties, there are two distinct targets within the Austin Chalk formation which are designated as the Upper Austin Chalk and the Lower Austin Chalk. The Upper Austin Chalk is the primary target of Denali's wells.

As a result of the Austin Chalk formation having very small pore spaces, it has very low or no matrix permeability. When the Austin Chalk formation is naturally fractured it is permeable and productive and generally no commercial fracturing is required. These instances of permeability and productivity occur where the chalk is densely fractured. The Austin Chalk formation is considered a typical basin centered type oil and natural gas play with natural gas being produced down dip at deeper depths and graduating updip into an oil leg. The following stratigraphic chart sets forth the main formations included in Fayette and Gonzales Counties, Texas.



Oil and natural gas were first discovered in the Austin Chalk formation in the 1920s but drilling rates were highest in the late 1970s when oil prices increased. Increased oil prices resulted in a boom of vertical shallow drilling, principally in the Pearsall and Giddings Fields in South Texas. Because better wells result when the well bore encounters the presence of natural fractures, the vertical wells drilled during this era would often miss the vertical fractures and result in marginal wells or dry holes. In the late 1980s, a second oil boom in the productive Austin Chalk formation occurred with the advent of horizontal drilling technology. Horizontal well bores at that time were typically a length of 1,500 feet to 3,500 feet and increased the probability of encountering multiple vertical fractures resulting in better drilling economics.

Denali acquired the majority of its acreage in the Austin Chalk formation in 2008 and 2009. Horizontal drilling technology now makes it possible to drill horizontally at a length of 6,000 feet or longer, thereby improving the drilling economics of the play as longer horizontals have a higher probability of encountering more oil productive fractures. Also, the acreage acquired by Denali sits on top of the productive Eagle Ford Shale oil formation as well as the productive Austin Chalk oil formation. US Opco intends to drill 27 gross (18.6 net) wells in the Austin Chalk formation, with eight gross (5.6 net) wells planned in 2012 and one gross (1.0 net) well in 2013.

The Eagle Ford Shale is a formation of cretaceous sediment resting between the Austin Chalk and the Buda Lime formations at a depth of approximately 5,500 to 11,000 feet. It is considered to be the "source rock", or the original source of hydrocarbons that are contained in the Austin Chalk formation above it. As a hydrocarbon producing formation, the Eagle Ford Shale formation is of significant importance due to its capability of producing not only natural gas but more oil than is typically identified in other traditional shale plays. It contains a high carbonate shale percentage, upwards of 70% in South Texas, which makes it more brittle and amenable to hydraulic fracturing. The shale play trends across Texas from the Mexican border up into East Texas, is roughly 50 miles wide and 400 miles long, with an average thickness of 250 feet.

The Eagle Ford Shale formation is still at a relatively early stage of development. Numerous operators are currently drilling in the field and the total rig count is over 200 rigs. As the number of wells has increased, operators have improved their use of technology, drilling the wells at lower costs while increasing production rates and recoverable reserves. In Management's view, these improvements have made the Eagle Ford Shale formation one of the most commercial fields in the United States and it is expected that further optimization will result as additional drilling occurs. Management currently has one gross (0.9 net) well planned for 2012 and four gross (4.0 net) wells planned for 2013 in the Eagle Ford Shale formation.

In Management's view, the pervasive areal extent of both the Austin Chalk and the Eagle Ford Shale formations make them attractive resource plays. The porosity of the Austin Chalk formation provides an ample reservoir for oil. The unique fracture swarms provide the required permeability within the Austin Chalk formation and are ideally suited to horizontal drilling which can access these multiple fracture zones. The Eagle Ford Shale oil formation is a tighter and lower permeability formation than the Austin Chalk oil formation and has been generally overlooked for years due to the difficulty in exploiting this type of reservoir. However, by virtue of horizontal drilling combined with high pressure, multi-fracturing completion techniques, the Eagle Ford Shale oil formation has recently become a valuable and profitable resource play.

*Production and Operations*

Production from the Austin Chalk and Eagle Ford Shale formations for the month of May 2012, averaged approximately 287 boe/d to Denali's working interest before royalties (231 net boe/d after royalties production), with an additional 90 bbls/d of oil from the Jendrzey well temporarily shut-in due to a leaking plug, which has since been repaired. The majority of this production is from horizontal wells operated by Denali in the Austin Chalk oil formation.

Denali operates eight horizontal oil wells in the Austin Chalk oil formation, all of which have been drilled since 2010. Six of these wells are located on Denali's large acreage block in Fayette and Gonzales Counties and two are located in Wilson County. Denali has a 100% working interest in six of the wells and a 77% and 72% working interest in the remaining two wells, respectively. In addition, Denali has a non-operated interest in two horizontal wells in the Austin Chalk oil formation and one horizontal well in the Eagle Ford Shale formation on acreage in Zavala County, operated by Sanchez Oil & Gas Corp.

*Marketing*

Oil from all but one of Denali's operated wells is sold on a month to month contract to Gulfmark Energy, Inc. with oil from the remaining well being sold on a month to month contract to Eastex Crude Company. These oil contracts achieve favourable pricing due to the close proximity of these wells to the refineries on the Gulf Coast of Texas. Historically, pricing has approached the WTI index but since January 1, 2012 has met or exceeded the WTI index for all the wells. From October 1, 2011 to April 30, 2012, the Denali contract with Gulfmark Energy, Inc. for the wells in the Fayette and Gonzales Counties, Texas has averaged a price of US$103.45/bbl versus the US$99.19/bbl average price for WTI during this period.

In Fayette and Gonzales Counties, Texas, Denali also has a natural gas marketing and NGLs sharing contract with DCP Midstream, L.P. ("**DCP**"). DCP maintains a wet system tied into an NGLs processing facility. The natural gas produced from these wells has a high Btu content (1,400-1,800 Btu) and is rich in NGLs (9-14 gpm). As a result of the NGLs, the wellhead price per Mcf was in excess of the NYMEX price of natural gas, resulting in an uplift in the economics of this area. Denali's average price received for the three months ended March 31, 2012 was US$48.11/bbl for the NGLs component and US$2.32/Mcf for the natural gas component, for a blended wellhead price of US$14.41/Mcf, compared to an average NYMEX natural gas settlement price of US$2.74/MMBtu for the same period.

*Exploitation Opportunities in the Austin Chalk and Eagle Ford Shale Oil Formations*

The wells that Management intends to drill in the Austin Chalk oil formation are at an average vertical depth of 7,800 feet and are expected to have an additional horizontal length averaging 6,000 feet. These wells produce from naturally occurring fractures that occur randomly along the horizontal well path. The wells are completed open hole and do not require fracture stimulation. Spacing is typically 640 acres per well.

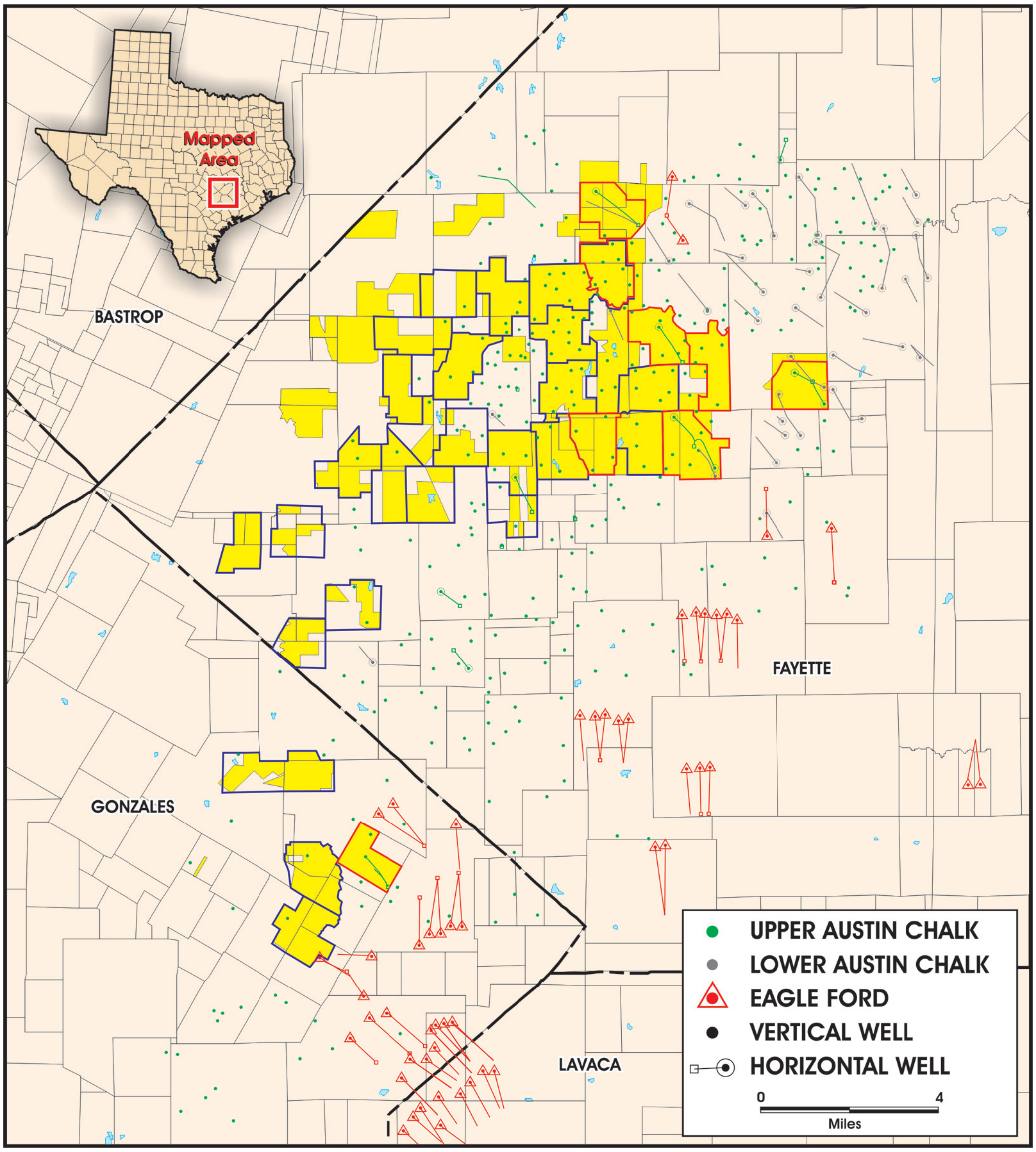
The Sproule Reserve Report includes 14 proved undeveloped drilling locations in the Austin Chalk oil formation (9.7 net), offsetting current production in Fayette and Gonzales Counties, Texas. In addition, the Sproule Reserve Report identified 13 probable drilling locations (8.9 net) in the Austin Chalk oil formation. Management believes additional acreage with drilling potential in the Austin Chalk oil formation will become available for lease over the next few years which will provide US Opco with additional drilling opportunities.

On June 10, 2012, Denali completed the drilling and tie-in of one (one net) of the proved undeveloped drilling locations in the Austin Chalk oil formation in Fayette County, named the Ivy-1H well. Denali completed a 24 hour production flow test as required by the RRC, in which the final hour flow rates were calculated at 792 bbls/d of oil (43.6º API), 735 Mcf/d of natural gas, and 215 barrels of water per day, at an average pressure of 510 psi. This compares to an estimated initial production rate forecast in the Sproule Reserve Report for this well location of 325 boe/d. Total fluid recovery during this period was 752 bbls of oil, 369 Mcf of natural gas and 388 bbls of water. While no pressure transient analysis or well-test interpretation was carried out, there was no significant production or pressure decline during the test. While Management believes that the reference to this initial production rate is useful in confirming the presence of hydrocarbons, such rate is not determinative of the rate at which such well will continue to produce and decline thereafter nor is it indicative of the volume of hydrocarbons ultimately recoverable from such well. While such initial production rate is encouraging, investors are cautioned not to place undue reliance on such rate in calculating the aggregate production for the Trust. The long-term performance of the well may be greater or less than the initial production rate set out above. The well was shut-in after the production test to conduct a test of the casing integrity and to install a pumping unit. The casing was tested successfully to 1500 psi and the pumping unit was installed in early July. Accordingly, production with oil sales has recently commenced and is expected to ramp up over time.

In Fayette and Gonzales Counties, Texas, there are a number of operators drilling and completing wells in the Eagle Ford Shale oil formation near Denali's acreage. These include Magnum Hunter Resources Corp., GeoResources Inc., Zaza Energy Corporation (in partnership with Hess, Inc.) and Weber Energy Corporation.

The Sproule Reserve Report has attributed to the Eagle Ford Shale oil formation, eight gross (7.7 net) probable drilling locations and 1.8 MMboe of gross probable reserves relating to 1,280 net acres out of the Denali acreage located in Fayette and Gonzales Counties, Texas. In addition to the 1,280 net acres, the rights relating to the Eagle Ford Shale oil reservoir under the remainder of Denali's Austin Chalk assets (22,220 net acres) are offset by recent successful drilling activity by third parties.

**Oil Assets in Fayette and Gonzales Counties, Texas**




This drilling activity includes twenty-four Eagle Ford Shale horizontal wells which have been drilled within five miles of Denali's acreage in Fayette and Gonzales Counties, Texas with an average initial production rate of over 925 boe/d. Twenty-nine additional wells have either been permitted to drill, are in the process of being drilled, or are being completed in this area. South and southeast of Denali's acreage in Gonzales County, Magnum Hunter Resources Inc. has drilled and completed 11 wells with an average 24 hour initial production rate of 1,331 boe/d and average flowing tubing pressure of 1,917 psi (RRC, 2011 and 2012). The two wells of Magnum Hunter Resources Inc. that are in the closest proximity to Denali's acreage have produced 85,100 boe in 13 months and 77,300 boe in 18 months, respectively (RRC, 2012). Magnum Hunter Resources Inc. has been permitted to drill ten additional wells in this area. In addition, to the south of Denali's acreage in Gonzales County, Tidal Petroleum, Inc. has drilled and completed a well that had a 24 hour initial production rate of 361 boe/d and flowing pressure of 700 psi (RRC, 2012). Tidal Petroleum, Inc. has also been permitted to drill three additional wells in this area. Immediately east of Denali's acreage in Fayette and Gonzales Counties, GeoResources Inc. has drilled and completed nine wells with an average 24 hour initial production of 705 boe/d and average flowing pressure of 2,020 psi (RRC, 2011 and 2012). GeoResources Inc. has 13 additional wells that have either been permitted to drill, are in the process of being drilled, or are being completed. Also immediately adjacent to Denali's acreage in Gonzales County, Zaza Energy Corporation (in a joint venture with Hess Corporation) has drilled a well which realized a 24 hour initial production rate of 291 boe/d with

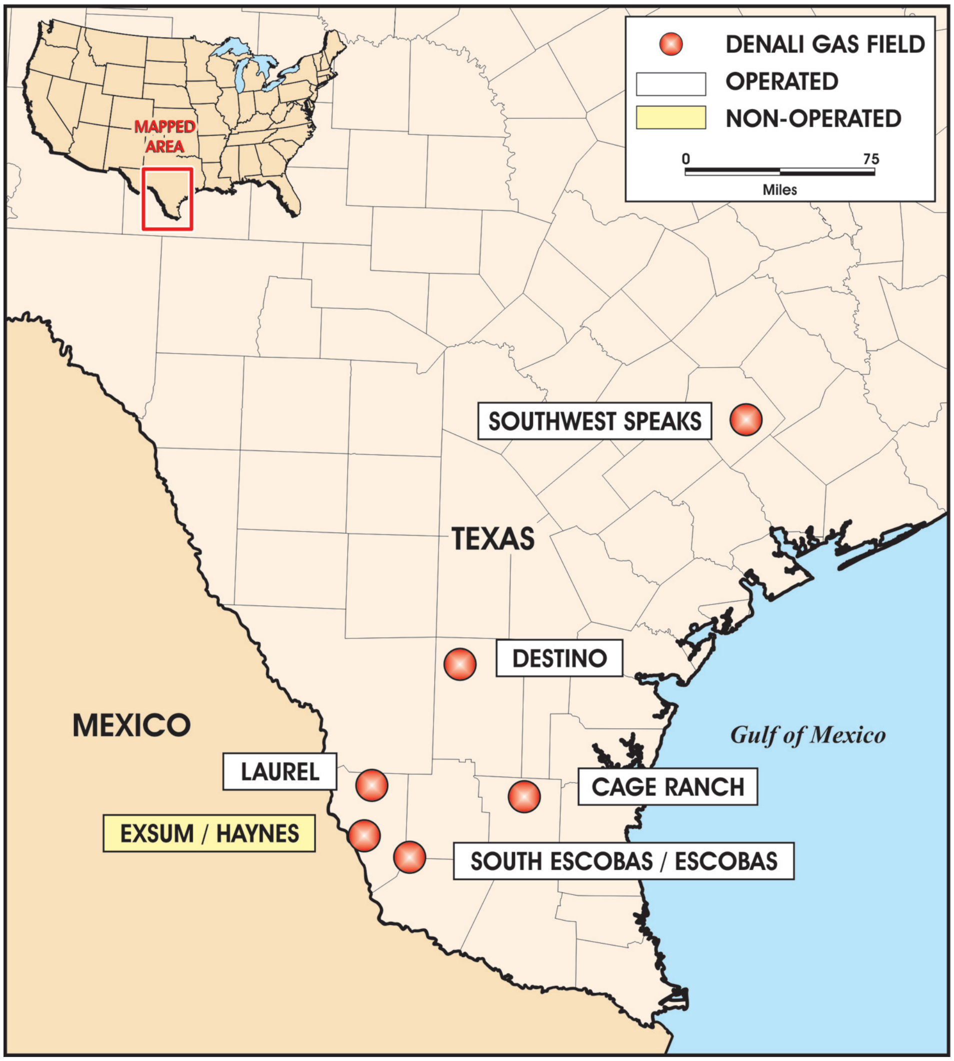
556 psi flowing pressure (RRC, 2012) and has been permitted to drill an additional well in this area. To the northeast of Denali's acreage in Fayette County, Weber Energy Corporation has drilled two short lateral horizontal Eagle Ford Shale wells, which have a combined lateral length of approximately 4,765 feet and tested a total of 610 boe/d with average flowing tubing pressure of 520 psi (RRC, 2011). These wells have produced 52,500 boe in the first 6 months of production reporting (RRC, 2012). Sanchez Oil & Gas Corp. has also been permitted to drill two wells, one of which was spud in June 2012.

Management believes production from wells drilled by third parties in the Eagle Ford Shale oil formation may be indicative of possible production that can be achieved by US Opco on its properties and that there is sufficient production data from nearby wells to conclude that the undeveloped acreage in Fayette and Gonzales Counties, Texas, is commercial to drill. However, at this stage of development, Management cannot accurately predict the quantity of reserves per well or the anticipated production levels from such wells. Management also believes at least 15,000 net acres of the Deep Rights acreage in Fayette and Gonzales Counties, Texas, is prospective for the Eagle Ford Shale oil formation at current drilling costs and oil prices. Management expects that drilling in the Eagle Ford Shale oil formation will be on 160 acre well spacing, which would provide approximately 95 net prospective Eagle Ford Shale drilling locations on the Denali Assets.

***South Texas Natural Gas Assets***

The Denali natural gas assets in South Texas consist of 53 operated and five non-operated wells extending across 9,966 gross (5,768 net) acres. These assets are primarily natural gas weighted and are anchored by the South Escobas Field in Zapata County, Texas, where Denali operates 41 gross (29.6 net) wells. According to the Sproule Reserve Report, 28% of the net present value of future net revenue, discounted at 10%, of the Denali Assets are attributable to the South Texas natural gas assets, with approximately 84% of Denali's proved plus probable natural gas reserves located in the South Escobas Field and immediate vicinity. Denali's remaining South Texas natural gas assets, being those not located in the South Escobas Field, consist of 12 operated and five non-operated wells and, according to the Sproule Reserve Report, include approximately 16% of Denali's proved plus probable natural gas reserves. Most of these assets produce from the Wilcox/Lobo formations with some of the production from the Frio/Vicksburg formation. The Sproule Reserve Report has designated four proved (2.7 net) drilling locations accounting for 6.2 Bcfe of proved natural gas reserves. Management has identified an additional nine drilling locations (5.8 net) that are not economical at current natural gas prices.

**Location of Denali's South Texas Natural Gas**




*South Escobas Geology*

The South Escobas Field produces from the Wilcox formation in the southern portion of the downdip Wilcox trend of South Texas. The downdip Wilcox trend extends 150 miles and has produced over 3.5 Tcf to date. The South Escobas Field is one of a number of large natural gas fields in the Zapata delta area which is an ancestral depocenter of the Rio Grande River. Geologically, these type of depocenters can be viewed as mini-basins in which sediments pile up on the upper slope and eventually fail gravitationally, resulting in bedding slippage faults which move large sediment blocks downdip. Individual listric fault systems are favored as sites of optimum sand concentration. These listric growth faults with counter-regionally dipping fault blocks are recognized as the most effective traps of growth fault systems in this region.

Specifically, in the South Escobas Field, the Wilcox formation consists of a series of sands of the Eocene era that were deposited along the South Texas Gulf Coast and constitute the oldest of the thick sandstone/shale sequences within the Gulf Coast system. Sediments within the updip section were deposited primarily by fluvial processes. Downdip sediments were transported across the Wilcox fluvial plain and were deposited in huge deltaic systems. Some deltaic sediments were reworked and transported along the shore by marine processes and then redeposited on barrier bars and strand plains. Growth faults developed near the shorelines of several of the larger deltaic lobes where thick layers of sand were redeposited on previous sediments.

In terms of reservoir characteristics, the Wilcox formation is a tight, low permeability, consolidated, fine grained sandstone that requires fracture stimulation to yield commercial production rates. The reservoirs are over pressured allowing for a high amount of natural gas in place per acre. Further, it is common for reservoir quality to be best in the highest portion of each fault block as early natural gas migration helps preserve porosity and permeability.

Denali's discovery well, the Violeta Ranch #1, was drilled as an updip well to an old show well which was drilled in 1979 and abandoned after a series of mechanical failures. The Violeta Ranch #1 well is natural gas productive in the Hinnant 7 and Hinnant 5 sands and has produced over 3.0 Bcf since January 2008.

As additional wells were drilled, additional natural gas productive sands were encountered with completion depths ranging from 9,000 feet to 15,000 feet across multiple Wilcox sands (Hinnant, House, and Deep Wilcox). These sands have porosities which average 14.5% to 17% and require fracture stimulation with 100,000 to 300,000 pounds of proppant per zone. Thus, multiple sands (commonly, two to four vertically stacked sands) are perforated, fracture stimulated and then commingled prior to production. Typical well initial production rates are from 5,000 Mcf/d to 12,000 Mcf/d. There are no liquid hydrocarbons associated with this production.

*Production and Operations*

Production from the South Escobas Field for the month of May 2012, averaged approximately 968 boe/d to Denali's working interest before royalties (707 net boe/d after royalties production). Since Denali's initial discovery in January 2008, Denali has produced 21.7 Bcfe from this field from ten wells. Production from the other South Texas natural gas assets for the month of May 2012, was approximately 288 boe/d to Denali's working interest before royalties (217 net boe/d after royalties production). The average operating cost of Denali gas production in the first quarter of 2012 was approximately US$0.80/Mcfe.

Including the Violeta Ranch #1 discovery well, Denali has drilled a total of 10 gross (5.1 net) wells in South Escobas. In 2010, Denali acquired additional producing wells and acreage from a third party, bringing the total well count in South Escobas to 41 gross (29.6 net) wells, all of which are operated by Denali. In the South Escobas area, Denali has an interest in 6,853 gross (3,885 net) acres. At Escobas, Denali has central facilities to handle separation, dehydration and chemical treatment for any hydrogen sulfide content that may exist in order to meet pipeline specifications.

*Marketing*

Denali's South Escobas natural gas is under a contract to Kinder Morgan until April 30, 2013 and on a month to month basis thereafter. The contract terms provide for a price that, after deducting charges for treating and gathering, has averaged approximately US$0.33/MMBtu less than NYMEX since January 2011. Natural gas from the South Escobas Field contains approximately 10% carbon dioxide which is removed in a treating facility on the Kinder Morgan system eliminating the need for Denali to own or maintain carbon dioxide treating facilities. Kinder Morgan currently has approximately 35,000 to 40,000 Mcf/d in open capacity. In the event that Kinder Morgan is unable to transport natural gas on its system, Denali has the ability to switch sales to the Energy Transfer Pipeline system which also has spare capacity and treating facilities under similar terms to the Kinder Morgan contract.

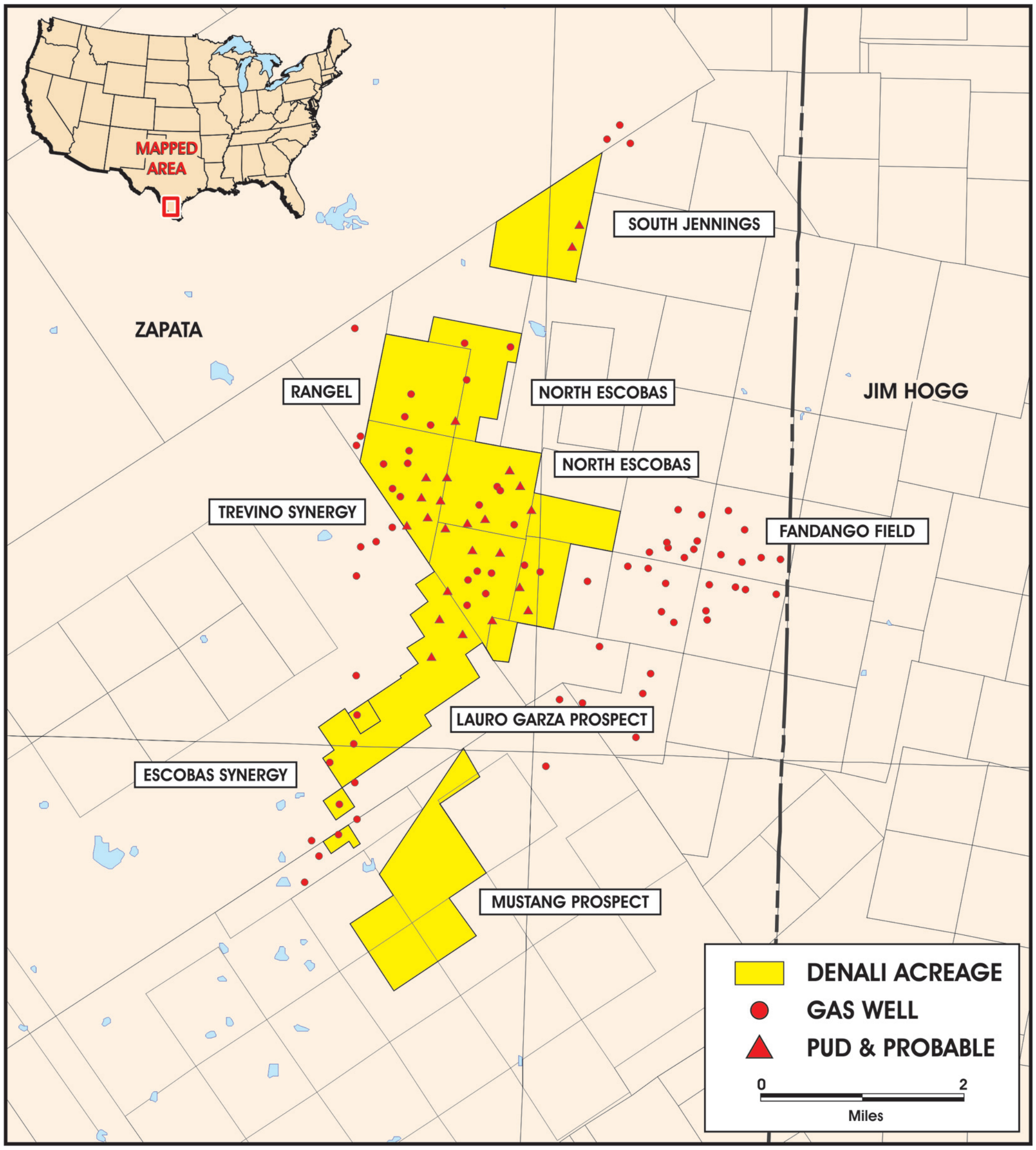
The production associated with the South Texas natural gas assets that is not located in the South Escobas Field is sold under various natural gas purchase agreements under a Houston Ship Channel Index pricing convention.

*Exploitation Opportunities in South Escobas and Adjacent Leases*

Subsequent to the Violeta Ranch #1 discovery well, Denali performed proprietary reprocessing on 114 square miles of 3-D data covering the South Escobas Field and its surrounding area. Reprocessing the 3-D data and a detailed field study led to further drilling successes and discoveries in additional reservoirs above and below the original targets of Denali's entry-well into the field. According to the Sproule Reserve Report, the South Escobas Field has 40.4 Bcfe proved plus probable reserves attributable to Denali's working interest before royalty. Also following the seismic reprocessing and field study, Denali purchased adjacent producing fields and open acreage yielding an additional 10.1 Bcfe proved plus probable reserves attributable to Denali's working interest before royalty.

There are a total of 15 gross (8.1 net) wells to be drilled on Denali's Escobas acreage as per the development plan in the Sproule Reserve Report. As a result of the historically low natural gas prices at this time, the current development plan is to defer drilling all but one of the natural gas wells until at least 2014. In addition to the 8.1 net wells reflected in the Sproule Reserve Report, Management believes there are an additional 4.2 net wells that may be drilled in future years on acreage that is held by production and can be drilled in future years.

**Leasehold Position for Denali's Assets at South Escobas and Surrounding Fields**



### Summary of Drilling Opportunities

The table below provides a summary of the drilling opportunities with respect to the Denali Assets:

| | Drilling Opportunities | | |
|---|---|---|---|
| | Eagle Ford Shale Oil | Austin Chalk Oil | South Texas Gas[6] |
| **Well Parameters[1]** | | | |
| Well Cost – Drill, Complete and Tie-in (US$M)[2] | 6,400 | 2,800 | 4,295 |
| Estimated Recoverable Reserves (Mboe)[3] | 236 | 195 | 769 |
| 30 Day Initial Production (boe/d) | 445 | 386 | 458 |
| **Well Economics[1]** | | | |
| Costs per boe of Reserves (US$/boe)[2] | 27.17 | 14.37 | 5.59 |
| Cost to Initial boe/d Production Rates (US$/boe/d) | 14,382 | 7,254 | 9,378 |
| Internal Rate of Return or IRR (%)[4][5] | 24 | 228 | 62 |
| **Total Drilling Opportunities[1]** | | | |
| Drilling Locations | 8 | 27 | 19 |
| Capital (US$M)[2] | 51,200 | 75,600 | 81,600 |
| Incremental Reserves (Mboe)[6] | 1,854 | 5,238 | 14,611 |
| Incremental Reserves net to US Opco (Mboe)[6][7] | 1,788 | 3,606 | 7,916 |

**Notes:**

(1) Estimates are 100% gross well interest, on a proved plus probable basis, before royalties based on the Sproule Reserve Report.

(2) Development costs presented in 2011 U.S. dollars.

(3) Technical reserves not subject to economic limits.

(4) IRR has been calculated using Sproule's December 31, 2011 price forecast and is the discount rate at which net present value is equal to zero.

(5) Values are an average of all locations.

(6) Reserves are subject to economic limits.

(7) Values are working interest before royalties.

## RESERVES AND OTHER OIL AND GAS INFORMATION

### Disclosure of Reserves Data

In accordance with NI 51-101, the reserves data of the Denali Assets set forth below is based upon an evaluation by Sproule using the Sproule Reserve Report. Sproule's December 31, 2011 price forecast was used in the Sproule Reserve Report. The effective date of the information provided in the Sproule Reserve Report is December 31, 2011 and the report was prepared January to April 2012 and is dated April 27, 2012. The Sproule Reserve Report evaluated, as at December 31, 2011, the oil, natural gas and NGLs reserves associated with the Denali Assets. The Sproule Reserve Report does not include any data in respect of the Deep Rights or the Denali Reserved Interest. The tables below are a summary of the reserves and the net present value of future net revenue attributable to the reserves as evaluated in the Sproule Reserve Report based on Sproule's December 31, 2011 forecast price and cost assumptions and supplied operating expenses. The tables summarize the data contained in the Sproule Reserve Report and, as a result, may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly.

Estimates of after-tax future net revenue are not presented in the following tables because Management does not expect the Trust to be subject to any material income taxes in the U.S. or Canada. Management does not expect taxes to be payable by the Trust in Canada because the Trust intends to distribute its full taxable income each year to Unitholders. The Trust intends to qualify as a "mutual fund trust" and will not be a "SIFT trust" (each as defined in the Tax Act), provided that the Trust complies at all times with the investment restrictions set forth in the Trust Indenture, which preclude the Trust from holding any "non-portfolio property" (as defined in the Tax Act).

**The net present value of future net revenue attributable to the reserves is stated without provision for interest costs, income taxes and general and administrative costs, but after providing for estimated royalties, production costs, capital, production taxes (which in the U.S. consist of severance and ad valorem), development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by Sproule. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the reserves estimated by Sproule represent the fair market value of the reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery estimates of the reserves provided herein are estimates only and there is no guarantee that the reserves, as estimated, will be recovered. Actual reserves may be greater than or less than the estimates provided herein.**

In preparing the Sproule Reserve Report, information was obtained from Denali, which included working and net revenue interest data, historical production, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, financial data and future development and operating plans for the Denali Assets. Other engineering, geological or economic data required to conduct the evaluations and upon which the Sproule Reserve Report is based was obtained from public records and from non-confidential files. The extent and character of ownership and the accuracy of all factual data supplied for the independent evaluation, from all sources, was accepted by Sproule as represented.

The Report on Reserves Data by Sproule in Form 51-101F2 and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are attached to this prospectus as Appendix C and Appendix D, respectively. There can be no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of oil, natural gas and NGLs reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered.

Sproule was engaged by the Administrator to provide an evaluation of proved plus probable reserves. All of the reserves associated with the Denali Assets to be acquired by US Opco are located in the U.S.

### Reserves Data – Forecast Prices and Costs

*Summary of Reserves*

| Reserves Category | Light and Medium Oil Gross(1) | Light and Medium Oil Net(1) | Natural Gas Gross(1) | Natural Gas Net(1) | NGLs Gross(1) | NGLs Net(1) | Total Oil Equivalent Gross(1) | Total Oil Equivalent Net(1) |
|---|---|---|---|---|---|---|---|---|
| | (Mbbls) | (Mbbls) | (MMcf) | (MMcf) | (Mbbls) | (Mbbls) | (Mboe) | (Mboe) |
| **Proved** | | | | | | | | |
| Developed Producing | 263.9 | 208.9 | 9,378 | 7,010 | 17.9 | 14.5 | 1,844.8 | 1,391.8 |
| Developed Non-Producing | 65.6 | 52.5 | 18 | 15 | 6.8 | 5.4 | 75.4 | 60.3 |
| Undeveloped | 1,013.1 | 831.1 | 22,639 | 16,483 | 208.7 | 171.2 | 4,995.0 | 3,749.6 |
| **Total Proved** | 1,342.6 | 1,092.5 | 32,034 | 23,508 | 233.4 | 191.1 | 6,915.2 | 5,201.7 |
| **Total Probable** | 3,498.6 | 2,831.7 | 30,959 | 23,301 | 371.2 | 304.2 | 9,029.7 | 7,019.4 |
| **Total Proved Plus Probable** | 4,841.2 | 3,924.2 | 62,994 | 46,809 | 604.6 | 495.3 | 15,944.8 | 12,221.1 |

* *Numbers may not add due to rounding.*

**Note:**

(1) Gross reserves represent the working interest share before deduction of any royalty obligations and without including any royalty interests. Net reserves represent the working interest share after deduction of royalty obligations, plus royalty interests in production or reserves.

*Summary of Net Present Value of Future Net Revenue of Reserves*

| Reserves Category | Net Present Value of Future Net Revenue Before Income Taxes Discounted at (%/year)(2)(3) 0% | 5% | 10% | 15% | 20% | Unit Value Before Income Tax Discounted at 10%/year Gross Reserves(1) | Net Reserves(1) |
|---|---|---|---|---|---|---|---|
| | (US$M) | (US$M) | (US$M) | (US$M) | (US$M) | (US$/boe) | (US$/boe) |
| **Proved** | | | | | | | |
| Developed Producing | 34,010 | 28,759 | 25,285 | 22,799 | 20,917 | 13.71 | 18.17 |
| Developed Non-Producing | 3,909 | 3,449 | 3,086 | 2,792 | 2,550 | 40.93 | 51.16 |
| Undeveloped | 92,238 | 67,261 | 52,108 | 42,112 | 35,125 | 10.43 | 13.90 |
| **Total Proved** | 130,158 | 99,469 | 80,479 | 67,703 | 58,592 | 11.64 | 15.47 |
| **Total Probable** | 242,951 | 148,408 | 102,409 | 75,446 | 57,938 | 11.34 | 14.59 |
| **Total Proved Plus Probable** | 373,108 | 247,877 | 182,888 | 143,149 | 116,530 | 11.47 | 14.96 |

* *Numbers may not add due to rounding.*

**Notes:**

(1) Gross reserves represent the working interest share before deduction of any royalty obligations and without including any royalty interests. Net reserves represent the working interest share after deduction of royalty obligations, plus royalty interests in production or reserves.

(2) Estimates of after-tax future net revenue are not presented because the Trust is not expected to be subject to any material income taxes in the U.S. or Canada.

(3) Reclamation costs were not deducted in estimating US Opco’s future net revenue in this table. For a discussion on abandonment and reclamation costs see “Reserves and Other Oil and Gas Information – Abandonment and Reclamation Costs”.

### *Additional Information Concerning Future Net Revenue (Undiscounted)*

| Reserves Category | Revenue | Royalties | Ad Valorem and Severance | Operating Costs | Development Costs | Abandonment and Disconnection Costs[(2)(3)] | Future Net Revenue Before Income Tax Expenses[(1)(3)] |
|---|---|---|---|---|---|---|---|
| | (US$M) | (US$M) | (US$M) | (US$M) | (US$M) | (US$) | (US$) |
| **Proved** | | | | | | | |
| Developed Producing | 66,718 | 15,628 | 2,421 | 13,928 | — | 730 | 34,010 |
| Developed Non-Producing | 6,608 | 1,322 | 337 | 890 | 145 | 6 | 3,909 |
| Undeveloped | 232,799 | 53,810 | 7,384 | 33,106 | 45,369 | 892 | 92,238 |
| **Total Proved** | 306,125 | 70,760 | 10,142 | 47,924 | 45,514 | 1,628 | 130,158 |
| **Total Probable** | 585,547 | 123,427 | 23,996 | 99,626 | 93,964 | 1,584 | 242,951 |
| **Total Proved Plus Probable** | 891,672 | 194,187 | 34,137 | 147,550 | 139,478 | 3,212 | 373,108 |

**Notes:**

(1) Estimates of future income tax expenses and after-tax future net revenue are not presented because the Trust is not expected to be subject to any material income taxes in the U.S. or Canada.

(2) Abandonment and disconnection costs include estimates of abandonment and disconnection services only for those wells to which reserves were assigned. Additional abandonment and disconnection costs for wells to which no reserves were assigned, as well as costs associated with abandonment of facilities, injectors, pipelines and reclamation of any well, satellite, battery or other facility are not included in this estimate.

(3) Reclamation costs were not deducted in estimating US Opco's future net revenue in this table. For a discussion on abandonment and reclamation costs see "Reserves and Other Oil and Gas Information – Abandonment and Reclamation Costs".

### *Future Net Revenue by Production Group[(1)(2)]*

| Reserves Category | Future Net Revenue Before Income Taxes (Discounted at 10%/year)[(3)] | Unit Value | |
|---|---|---|---|
| | (US$M) | (US$/boe) | (US$/Mcfe) |
| **Proved** | | | |
| Light and Medium Oil | 51,197 | 37.37 | 6.23 |
| Natural Gas | 29,282 | 7.64 | 1.27 |
| **Total Proved** | 80,479 | 15.47 | 2.58 |
| **Proved Plus Probable** | | | |
| Light and Medium Oil | 131,526 | 27.60 | 4.60 |
| Natural Gas | 51,362 | 6.89 | 1.15 |
| **Total Proved Plus Probable** | 182,888 | 14.96 | 2.49 |

**Notes:**

(1) Light and medium oil includes solution gas and other by-products. Natural gas includes by-products but excludes solution gas.

(2) Other revenue and costs not related to a specific production group have been allocated proportionately to production groups. Unit values are based on the Trust's net reserves.

(3) Reclamation costs were not deducted in estimating US Opco future net revenue in this table. For a discussion on abandonment and reclamation costs see "Reserves and Other Oil and Gas Information – Abandonment and Reclamation Costs".

For future net revenue of the total proved reserves, discounted at 10%, 64% of the revenue is from light and medium oil and 36% is from natural gas and NGLs. For the total proved plus probable reserves, 72% of the revenue is from light and medium oil and 28% is from natural gas and NGLs.

### *Revenue and Expense Forecast*

The following table provides a detailed cash flow analysis for proved plus probable reserves from the Sproule Reserve Report.

| | Working Interest Revenue (US$M) | | | | | | | | | Before Tax Cash Flow | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **Light and Medium Oil** | **Natural Gas** | **NGLs** | **Total** | **Royalties (US$M)** | **Ad Valorem and Severance Taxes (US$M)** | **Operating Expenses (US$M)** | **Net Capital Investments (US$M)** | **Abandonment and Disconnection Costs (US$M)** | **Annual (US$M)** | **Cumulative (US$M)** | **10.0% Discounted (US$M)** |
| 2012 | 32,200 | 7,725 | 2,366 | 42,290 | 8,737 | 1,960 | 2,188 | 3,247 | 65 | 26,094 | 26,094 | 24,520 |
| 2013 | 54,083 | 10,696 | 2,710 | 67,489 | 13,318 | 3,144 | 3,283 | 33,709 | 64 | 13,972 | 40,066 | 11,263 |
| 2014 | 48,864 | 14,086 | 3,337 | 66,288 | 13,493 | 2,972 | 3,752 | 25,736 | 48 | 20,286 | 60,352 | 15,448 |
| 2015 | 47,616 | 19,144 | 3,773 | 70,532 | 14,421 | 3,161 | 4,226 | 17,272 | 25 | 31,428 | 91,780 | 22,513 |
| 2016 | 44,419 | 25,355 | 3,769 | 73,542 | 15,402 | 3,020 | 4,702 | 19,253 | — | 31,165 | 122,945 | 20,296 |
| 2017 | 47,956 | 27,980 | 3,099 | 79,036 | 16,489 | 3,151 | 5,361 | 25,556 | — | 28,478 | 151,423 | 16,860 |
| 2018 | 30,357 | 30,093 | 2,040 | 62,490 | 13,928 | 2,396 | 5,448 | 14,342 | — | 26,377 | 177,800 | 14,196 |
| 2019 | 22,737 | 23,244 | 1,495 | 47,476 | 10,641 | 1,790 | 5,418 | — | 16 | 29,611 | 207,411 | 14,488 |
| 2020 | 18,619 | 17,523 | 1,196 | 37,338 | 8,315 | 1,419 | 5,370 | — | — | 22,235 | 229,646 | 9,890 |
| 2021 | 15,856 | 15,307 | 997 | 32,160 | 7,193 | 1,201 | 5,455 | 362 | 55 | 17,894 | 247,539 | 7,235 |
| 2022 | 13,858 | 12,654 | 856 | 27,368 | 6,100 | 1,033 | 5,351 | — | 120 | 14,764 | 262,304 | 5,427 |
| 2023 | 12,277 | 10,973 | 748 | 23,998 | 5,337 | 911 | 5,136 | — | — | 12,614 | 274,918 | 4,215 |
| Sub-total | 388,842 | 214,760 | 26,386 | 630,007 | 133,374 | 26,158 | 55,690 | 139,478 | 393 | 274,918 | 373,108 | 166,351 |
| Rem | 100,439 | 157,191 | 4,054 | 261,665 | 60,813 | 7,981 | 91,861 | — | 2,819 | 98,191 | — | 16,536 |
| **Total** | **489,281** | **371,951** | **30,440** | **891,672** | **194,187** | **34,137** | **147,550** | **139,478** | **3,212** | **373,108** | | **182,888** |

## Notes and Definitions

In the tables set forth above and elsewhere in this prospectus, the following notes and other definitions are applicable.

### *Reserve Categories*

The determination of oil and natural gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods are required to properly use and apply reserves definitions.

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

(a) analysis of drilling, geological, geophysical and engineering data;

(b) the use of established technology; and

(c) specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

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

"**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 plus probable reserves.

Each of the reserves categories 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 (e.g. 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 (e.g., 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 category (proved, probable, possible) to which they are assigned.

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

***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:

(a) at least a 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves;

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

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

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

### Pricing Assumptions – Forecast Prices and Costs

Sproule employed the following pricing, inflation rate and exchange rate assumptions as of December 31, 2011 in estimating reserves data using forecast prices and costs.

| Year | Natural Gas | Light and Medium Oil | NGLs | Forecast Factors |
|---|---|---|---|---|
| | Henry Hub Price | WTI - Cushing Oklahoma(1) | NGL Mix Field Gate(1) | Inflation Rate |
| | (US$/MMBtu) | (US$/bbl) | (US$/bbl) | (%/yr) |
| Historical | | | | |
| 2011 | 4.04 | 95.00 | 46.90 | 1.5 |
| Forecast | | | | |
| 2012 | 3.55 | 98.07 | 48.42 | 2.0 |
| 2013 | 4.18 | 94.90 | 46.85 | 2.0 |
| 2014 | 4.54 | 92.00 | 45.42 | 2.0 |
| 2015 | 5.95 | 97.42 | 48.09 | 2.0 |
| 2016 | 6.07 | 99.37 | 49.06 | 2.0 |
| 2017 | 6.19 | 101.35 | 50.03 | 2.0 |
| 2018 | 6.32 | 103.38 | 51.04 | 2.0 |
| 2019 | 6.44 | 105.45 | 52.06 | 2.0 |
| 2020 | 6.57 | 107.56 | 53.10 | 2.0 |
| 2021 | 6.70 | 109.71 | 54.16 | 2.0 |
| 2022+ | Calculated at 2.0% per annum thereafter | | | |

**Note:**

(1) NGLs pricing is based on a percentage of WTI on a property by property basis. The average NGL Mix presented here and used in the Sproule Reserve Report is 50.6% of WTI and was based on actual data.

### Undeveloped Reserves

The following discussion generally describes the basis on which proved plus probable undeveloped reserves were attributed. The Trust's plans for developing the undeveloped reserves are described under "Funding, Acquisition and Related Transactions – Acquisition".

#### *Proved Undeveloped Reserves*

Proved undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. In addition, such reserves may relate to planned infill drilling locations. The majority of these reserves are planned to be on stream within a six year timeframe. The following table provides the timing of the initial reserve assignments for the proved undeveloped gross reserves of the Denali Assets.

| Year | Light & Medium Oil (Mbbls) | | Natural Gas (MMcf) | | NGLs (Mbbls) | | Oil Equivalent (Mboe) | |
|---|---|---|---|---|---|---|---|---|
| | First Attributed(1) | Total at Year-End(2) | First Attributed(1) | Total at Year-End(2) | First Attributed(1) | Total at Year-end(2) | First Attributed(1) | Total at Year-end(2) |
| Prior | — | — | — | — | — | — | — | — |
| 2011 | 1,013.1 | 1,013.1 | 22,639 | 22,639 | 208.7 | 208.7 | 4,995 | 4,995 |

**Notes:**

(1) First attributed refers to reserves first attributed at the effective date of December 31, 2011.

(2) Total at Year-End refers to reserves at year-end December 31, 2011.

### *Probable Undeveloped Reserves*

Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. The majority of these reserves are planned to be on stream within a six year timeframe. The following table provides the timing of the initial reserve assignments for the probable undeveloped gross reserves of the Denali Assets.

| | **Light & Medium Oil (Mbbls)** | | **Natural Gas (MMcf)** | | **NGLs (Mbbls)** | | **Oil Equivalent (Mboe)** | |
|---|---|---|---|---|---|---|---|---|
| **Year** | **First Attributed(1)** | **Total at Year-End(2)** | **First Attributed(1)** | **Total at Year-End(2)** | **First Attributed(1)** | **Total at Year-end(2)** | **First Attributed(1)** | **Total at Year-end(2)** |
| Prior . | — | — | — | — | — | — | — | — |
| 2011 . | 3,397.3 | 3,397.3 | 27,324 | 27,324 | 362.9 | 362.9 | 8,314.2 | 8,314.2 |

**Notes:**

(1) First attributed refers to reserves first attributed at the effective date of December 31, 2011.

(2) Total at Year-End refers to reserves at year-end December 31, 2011.

### *Significant Factors or Uncertainties*

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and natural gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. The reserves are evaluated by Sproule, an independent, qualified reserves evaluator.

As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

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

### Future Development Costs

The table below sets out the development costs deducted in the estimation of future net revenue attributable to proved reserves and proved plus probable reserves (using forecast prices and costs) in the Sproule Reserve Report. The development costs for 2012 have been determined from the current and ongoing development and drilling activities being conducted by Denali for which Sproule was able to assign proved or proved plus probable reserves. Denali has supplied the Trust with an estimate of capital spent in relation to these projects prior to the effective date of the Acquisition, as well as the anticipated development costs for the remainder of 2012.

| | Annual Development Costs[(1)] | |
|---|---|---|
| **Year** | **Total Proved** | **Total Proved Plus Probable** |
| | (US$M) | (US$M) |
| 2012[(2)] | 151 | 3,247 |
| 2013 | 4,162 | 33,709 |
| 2014 | 10,226 | 25,736 |
| 2015 | 6,740 | 17,272 |
| 2016 | 9,419 | 19,253 |
| Thereafter | 14,818 | 40,260 |
| Total Undiscounted | 45,514 | 139,478 |
| 10% Discounted | 31,550 | 102,016 |

**Notes:**

(1) Abandonment and reclamation costs not included above. See "Reserves and Other Oil and Gas Information – Abandonment and Reclamation Costs".

(2) The 2012 costs are net of the capital expenditures funded by Denali. The Sproule Reserve Report has assumed that Denali will hold in escrow US$22.6 million from the aggregate purchase price for the Denali Assets, of which US$21.6 million will be applied to US Opco's capital expenditures on the Denali Assets for the 24 month period following the closing of the Offering.

The estimated expenditures for 2012 include approximately US$0.1 million for recompletion programs in respect of 1 gross (0.7 net) locations and approximately US$3.1 million (net of US$21.6 million that the Sproule Reserve Report has assumed will be paid out of the amount held in escrow by Denali for funding capital expenditures on the Denali Assets for the 24 month period following the closing of the Offering), for conventional drilling in respect of 9 gross (6.5 net) locations.

The Trust expects to have available three sources of funding to finance the capital expenditure program of US Opco: internally generated cash flow from operations in excess of cash distributions to Unitholders, external debt financing when appropriate, including borrowing under the Credit Facilities, and new capital through the issuance of additional Units, if available on favourable terms. Management anticipates that debt financing will be available pursuant to the Credit Facilities at market rates plus margins subject to a pricing grid based on the then applicable ratio of consolidated debt to consolidated cash flow. See "Credit Facilities". The costs of funding will not materially affect the Trust's estimated proved plus probable reserves or related future net revenue as disclosed herein. The Trust may in the future consider alternative sources of financing in light of new or changing circumstances.

The Trust intends to maintain a prudent debt to EBITDA ratio that will generally not exceed 1.5 times debt to EBITDA. The Trust may temporarily exceed this parameter, particularly in the case of acquisitions, provided that Management has a plan to return this ratio to the preferred range in the short term. Upon closing of the Offering, Management expects the debt to EBITDA (based on the 2012 financial year) ratio to be approximately 0.3 times.

### Abandonment and Reclamation Costs

Well abandonment costs within the calculation of future net revenue in the Sproule Reserve Report are estimated without deduction of reclamation costs or salvage values and are costs only for wells that have been assigned reserves. Future well abandonment costs for 31 inactive wells to be acquired by US Opco for which no reserves have been assigned were not included in the Sproule Reserve Report. US Opco's total estimated asset retirement obligation for 47.1 net wells is estimated at US$2.1 million undiscounted (US$0.9 million discounted at 10%) and includes the abandonment and reclamation of wells to which no reserves have been assigned. US Opco anticipates incurring approximately US$450,000 (the remainder of 2012 – US$270,000; 2013 – US$90,000; 2014 – US$90,000) of its identified abandonment and reclamation costs during the next three years.

### Oil and Natural Gas Properties and Wells

The following tables summarize the number of producing and non-producing wells comprising the Denali Assets being acquired.

| | Producing Wells | | | |
|---|---|---|---|---|
| | Light and Medium Oil | | Natural Gas | |
| Area | Gross | Net | Gross | Net |
| Texas | 11 | 7.9 | 27 | 15.7 |
| Totals | 11 | 7.9 | 27 | 15.7 |

| | Non-Producing Wells | | | |
|---|---|---|---|---|
| | Light and Medium Oil | | Natural Gas | |
| Area | Gross | Net | Gross | Net |
| Texas | 1 | 0.8 | 30 | 22.8 |
| Totals | 1 | 0.8 | 30 | 22.8 |

### Properties With No Attributable Reserves

As at March 31, 2012, the Denali Assets included 118,263 gross (100,652 net) acres of undeveloped land in Texas (including lands covered by the undeveloped leases comprising the Deep Rights) and 12,344 gross (8,084 net) acres of undeveloped land in Mississippi. The Trust expects its rights to explore, develop and exploit approximately 6,296 gross (4,081 net) acres of its unproved properties in Texas and approximately 11,265 gross (6,718 net) acres of its unproved properties in Mississippi to expire within the next year. The expiring lands are located primarily in Wilson and Zapata Counties, Texas and Warren County, Mississippi.

Management expects that US Opco's planned operations will extend its rights to explore, develop and exploit approximately 10% of this expiring acreage and approximately 7% is currently held by production. None of the planned operations are subject to any work commitments.

### Significant Factors or Uncertainties Relevant to Properties With No Attributed Reserves

There are several economic factors and significant uncertainties that affect the Trust's anticipated development of the US Opco properties to which no reserves are attributed. The Trust through US Opco will be required to make substantial capital expenditures in order to prove, exploit, develop and produce oil and natural gas from these properties in the future. If cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Trust. Failure to obtain such financing on a timely basis could cause US Opco to forfeit its interest in certain properties, miss certain opportunities and reduce or terminate its operations. The inability of the Trust to access sufficient capital for its exploration and development purposes could have a material adverse effect on the Trust's ability to execute the Trust's business strategy to develop these prospects. See also "Risk Factors".

The primary economic factors that affect the development of these lands to which no reserves have been attributed are future commodity prices for crude oil and natural gas (and the Trust's outlook relating to such prices) and the future costs of drilling, completing, tying in and operating wells at the time that such activities are considered in the future.

The primary uncertainties that affect the development of such lands are the future drilling and completion results achieved in the development activities, drilling and completion results achieved by others on lands in close proximity to these lands, and future changes to applicable regulatory or royalty regimes that affect timing or economics of proposed development activities. All of these uncertainties have the potential to delay the development of such lands. Conversely, uncertainty as to the timing and nature of the evolution or development of better exploration, drilling, completion and production technologies have the potential to accelerate development activities and enhance the economics relating to such lands.

## Drilling Activity

The following table summarizes the gross and net exploration and development wells comprising the Denali Assets that were completed between January 1, 2012 and the date of this prospectus.

| | Development Wells | | Exploration Wells | | Total Wells | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| Oil Wells | 2 | 2 | — | — | 2 | 2 |
| Natural gas wells | — | — | — | — | — | — |
| Service wells | — | — | — | — | — | — |
| Standing wells | — | — | — | — | — | — |
| Dry holes | — | — | — | — | — | — |
| Total | 2 | 2 | — | — | 2 | 2 |

For details on anticipated future development activities, see "Funding, Acquisition and Related Transactions – Acquisition".

## Tax Horizon

The tax horizon as determined from a full cycle corporate model developed by Management and incorporating all applicable U.S. deductions, indicates that no material U.S. federal income taxes are expected to be payable in respect of income attributable to the Denali Assets until at least 2021. Management expects to maintain this situation through continued capital investments and acquisitions primarily in the U.S. No income taxes are expected to be payable by the Trust in Canada as the Trust intends to distribute all of its taxable income each year to Unitholders and will not be a SIFT trust provided that the Trust does not hold any "non-portfolio property", as defined in the Tax Act. No material income taxes are expected to be paid by Can Holdco based on the activities and location of central management and control of US Opco. See "Canadian Federal Income Tax Considerations" and "Risk Factors". The model developed by Management is based on production and cost assumptions from the Sproule Reserve Report and WTI and NYMEX forward strip commodity pricing as of July 11, 2012.

## Costs Incurred

The following table summarizes anticipated property acquisition costs, exploration costs and development costs for the year ended December 31, 2012. The total capital costs for the period are estimated to be approximately US$21.8 million.

| Acquisition Costs (net) | | | |
|---|---|---|---|
| Proved Properties | Unproved Properties | Exploration Costs (net) | Development Costs (net) |
| (US$M) | (US$M) | (US$M) | (US$M) |
| Nil | Nil | Nil | 21,847 |

## Production Estimates

The following table discloses for each product type the gross volume of production estimated by Sproule for the year ended December 31, 2012 in the estimates of gross proved and gross probable reserves disclosed above under the heading "Reserves and Other Oil and Gas Information – Disclosure of Reserves Data".

| Reserve Category | Light and Medium Oil | Natural Gas | NGLs | Total | Percent of Total |
|---|---|---|---|---|---|
| | (bbls/d) | (Mcf/d) | (bbls/d) | (boe/d) | |
| Total Proved | 649 | 6,824 | 92 | 1,878 | 83 |
| Total Probable | 289 | 303 | 44 | 384 | 17 |
| Total Proved Plus Probable | 938 | 7,127 | 136 | 2,262 | 100 |

The Austin Chalk and Eagle Ford Shale Field included in the Denali Assets accounts for greater than 20% of the estimated production disclosed above. The Austin Chalk and Eagle Ford Shale Field is collectively, forecast to have gross production volumes in 2012 of approximately 775 boe/d on a proved basis and approximately 1,133 boe/d on a total proved plus probable basis. In addition, the South Escobas Field included in the Denali Assets also accounts for greater than 20% of the estimated production disclosed above. The South Escobas Field is forecast to have gross production volumes in 2012 of approximately 857 boe/d on a proved basis and approximately 861 boe/d on a total proved plus probable basis.

The following table discloses for each reserve classification the gross daily volume production forecast by Sproule for the years indicated in the Sproule Reserve Report.

| | **Reserve Classification[(2)]** | | |
|---|---|---|---|
| **Year** | **Proved Producing** | **Total Proved** | **Proved Plus Probable** |
| | (boe/d) | (boe/d) | (boe/d) |
| 2012[(1)] | 1,404 | 1,878 | 2,261 |
| 2013 | 768 | 1,807 | 3,181 |
| 2014 | 525 | 1,907 | 3,412 |
| 2015 | 392 | 1,604 | 3,317 |
| 2016 | 311 | 1,808 | 3,708 |
| 2017 | 250 | 1,638 | 3,938 |
| 2018 | 196 | 1,626 | 3,483 |
| 2019 | 164 | 1,212 | 2,616 |
| 2020 | 140 | 842 | 1,970 |
| 2021 | 121 | 655 | 1,688 |
| 2022 | 99 | 529 | 1,383 |
| 2023 | 82 | 441 | 1,182 |

**Notes:**

(1) During 2012, it is expected that approximately 41% of estimated production volumes will be oil, 6% will be NGLs and 53% will be natural gas (proved plus probable).

(2) Disclosure based on boes may be misleading, particularly if used in isolation. A boe conversion ratio of six Mcf to one 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.

## Production History

The following table discloses, on a quarterly basis for the five most recently completed quarters, what would have been the Trust's share of average daily production volume, before royalties and production taxes, if the Trust had beneficial ownership of the Denali Assets for those periods, and the prices received, royalties paid and production costs incurred and resulting netbacks on a per unit of volume basis for each product type.

Production volumes provided in the tables below are equal to gross production volumes before the deduction of royalties and production taxes. There is an average royalty interest of approximately 20% of revenue after allowance for processing costs in the properties.

### Average Daily Production Volumes

| | **Three Months Ended** | | | | |
|---|---|---|---|---|---|
| | **March 31, 2011** | **June 30, 2011** | **September 30, 2011** | **December 31, 2011** | **March 31, 2012** |
| Light and Medium Crude Oil (bbls/d) | 296 | 491 | 562 | 536 | 387 |
| NGLs (bbls/d) | 85 | 72 | 58 | 47 | 36 |
| Natural Gas (Mcf/d) | 12,891 | 10,430 | 8,167 | 7,145 | 8,856 |
| Total (boe/d) | 2,530 | 2,301 | 1,981 | 1,774 | 1,898 |

### Prices Received, Royalties and Production Taxes and Operating Expenses Incurred

| | Three Months Ended | | | | |
|---|---|---|---|---|---|
| | March 31, 2011 | June 30, 2011 | September 30, 2011 | December 31, 2011 | March 31, 2012 |
| Average Prices Received | | | | | |
| Light and Medium Crude Oil (US$ per boe) | 92.37 | 95.73 | 85.03 | 94.96 | 103.14 |
| NGLs (US$ per boe) | 42.98 | 47.21 | 48.63 | 49.34 | 45.91 |
| Natural Gas(US$ per Mcf) | 3.54 | 3.70 | 3.61 | 2.89 | 2.07 |
| Total (US$ per boe) | 30.29 | 38.68 | 40.44 | 41.63 | 31.52 |
| Royalties and Production Taxes (US$/boe) | 7.31 | 9.87 | 10.37 | 10.43 | 8.07 |
| Operating Expenses (US$/boe) | 6.84 | 6.56 | 4.90 | 9.57 | 4.38 |
| Netback (US$/boe) | 16.14 | 22.26 | 25.17 | 21.63 | 19.07 |

### Year Ended December 31, 2011

| Region | Light and Medium Oil (bbls/d) | NGLs (boe/d) | Natural Gas (Mcf/d) | Total (boe/d) | % (boe/d) |
|---|---|---|---|---|---|
| Texas | | | | | |
| South Escobas Field | — | — | 6,936 | 1,156 | 54 |
| Other Texas | 472 | 65 | 2,703 | 988 | 46 |
| Total | 472 | 65 | 9,639 | 2,144 | 100 |

## FINANCIAL INFORMATION

The following table sets out financial information for the Denali Assets for the periods indicated.

The financial information set out below has been derived from the Operating Statements Containing Gross Revenues, Royalties and Production Taxes and Operating Expenses attached to this prospectus as Appendix B. Investors should read the financial information in conjunction with such operating statements and the accompanying notes. See "Summary of Distributable Cash" and "Risk Factors".

### Operating Statement Information

| | Three Months Ended March 31, 2012 US$ (unaudited) | Three Months Ended March 31, 2011 US$ (unaudited) | Year Ended December 31, 2011 US$ (audited) | Year Ended December 31, 2010 US$ (audited) | Year Ended December 31, 2009 US$ (audited) |
|---|---|---|---|---|---|
| Oil, Gas and NGLs Sales | 5,444,808 | 6,897,570 | 29,163,580 | 21,063,802 | 8,906,926 |
| Royalties and Production Taxes | (1,393,887) | (1,664,106) | (7,323,145) | (5,989,472) | (2,223,908) |
| Net Revenues | 4,050,921 | 5,233,464 | 21,840,435 | 15,074,330 | 6,683,018 |
| Operating Expenses | (756,041) | (1,557,870) | (5,386,952) | (2,933,882) | (2,272,075) |
| | 3,294,880 | 3,675,594 | 16,453,483 | 12,140,448 | 4,410,943 |

## CONSOLIDATED CAPITALIZATION

The following table sets out the consolidated Unit and loan capitalization of the Trust as at June 30, 2012 and the pro forma Unit and loan capitalization of the Trust as at that date after giving effect to the Offering and the Acquisition.

| Designation | Authorized | As at June 30, 2012(1) | As at June 30, 2012 after giving effect to the Offering and the Acquisition |
|---|---|---|---|
| Debt(2) | See note (2) | — | 5,846,311(3)(6) |
| Units(4) | Unlimited | $2,975,742 (600,000 Units) | $199,602,542 (4)(5)(6)(7) (21,830,000 Units) |

**Notes:**

(1) The Trust was established under the laws of the Province of Alberta on January 31, 2012 by the Trust Indenture. The Trust will have no assets, other than the cash proceeds from the Initial Private Placements, or operating history until the successful completion of the Offering and the Acquisition.

(2) At the closing of the Offering US Opco intends to enter into the Credit Facilities arranged by a Canadian chartered bank, providing for a US$8 million extendible revolving term credit facility, subject to an initial US$8 million borrowing base, and a US$7.5 million term credit facility which will bear interest at a margin over a base rate, a prime rate, LIBOR or a bankers' acceptance rate, as applicable. Each of the Trust and Can Holdco will guarantee the obligations of US Opco under the Credit Facilities. See "Credit Facilities".

(3) Based on the anticipated advances under the Credit Facilities required to complete the Acquisition of approximately US$5.8 million, converted to Canadian dollars at a foreign exchange rate of US$1.00 = C$1.0033, the noon rate of exchange posted by the Bank of Canada for conversion of U.S. dollars to Canadian dollars on July 30, 2012. See "Use of Proceeds".

(4) Net of offering costs of $24,258 in respect of the Initial Private Placements. The Trust issued one Unit at a subscription price of $5.00 to the settlor of the Trust in connection with the establishment of the Trust on January 31, 2012, which was repurchased by the Trust for the same price on February 3, 2012. The Trust also issued an aggregate of 600,000 Units at a price of $5.00 per Unit pursuant to the Initial Private Placements. See "Prior Sales".

(5) Net of Offering expenses of approximately $3.0 million, of which approximately $1.5 million will be paid from proceeds raised in the Initial Private Placements, and Underwriters' fee estimated to be $12.7 million.

(6) Before giving effect to the Over-Allotment Option. If the Over-Allotment Option is exercised in full, the Unit capitalization will be $229,536,842 (25,014,500 Units) and outstanding indebtedness under the Credit Facilities is expected to be C$ nil.

(7) In addition, the Trust has adopted the RTUP. The Trust intends to grant RTUs at the closing of the Offering. See "Restricted Trust Unit Plan".

## CREDIT FACILITIES

On closing of the Offering, US Opco expects to enter into the Credit Facilities arranged by a Canadian chartered bank. The Credit Facilities are expected to be in the aggregate amount of US$15.5 million, comprised of a US$8 million extendible revolving term credit facility (the "**Operating Facility**") and a US$7.5 million term credit facility (the "**Bridge Facility**"). US Opco intends to use the Credit Facilities to fund a portion of the purchase price of the Denali Assets and for general corporate purposes, including working capital, capital expenditures and future acquisitions.

The borrowing base for the Operating Facility will initially be set at US$8 million. The Operating Facility will provide generally for a semi-annual evaluation of the borrowing base, determined, among other things, based on the reserves of US Opco. In addition, the borrowing base may also be re-determined by the lender in its discretion one additional time per calendar year. If at any time, the aggregate principal amount outstanding under the Operating Facility exceeds the then applicable borrowing base (a "**Borrowing Base Shortfall**"), US Opco will be obligated to eliminate such Borrowing Base Shortfall within a 60 day period.

In connection with the Credit Facilities, US Opco, the Trust and Can Holdco will be required to satisfy certain customary affirmative and negative covenants. US Opco will have the option to borrow under the Credit Facilities using a base rate, a prime rate, a LIBOR option or a bankers' acceptance rate, as applicable. The margins above base rate, prime rate, LIBOR or bankers' acceptance rate, as applicable, for the Credit Facilities will be subject to a pricing grid based on the then applicable ratio of consolidated debt to EBITDA (the "**Margin Ratio**"). Documentation for the Credit Facilities will also provide for an issuance fee on the outstanding amount of the letters of credit equal to the margin applicable to LIBOR loans (subject to a reduction in fees for non-financial letters of credit). In connection with the Operating Facility, US Opco will pay the lender a standby fee calculated on the unused amount of its commitment at a percentage based on the applicable Margin Ratio. In connection with the Bridge Facility, US Opco will pay the lender a fee on drawdowns under the Bridge Facility and a fee on the commitment that remains unused as of September 11, 2012.

US Opco may borrow under the Credit Facilities in both U.S. and Canadian dollars. The Operating Facility is expected to revolve until August 10, 2013 (or such later date to be determined by US Opco and the lender in connection with the Operating Facility), at which time it shall be extendible for revolving periods of up to 364-days, subject to lender consent. In the event the Operating Facility is not extended, US Opco would be required to repay all amounts outstanding under the Operating Facility on the 366th-day following the last day of any revolving period. The Bridge Facility will be available to US Opco until the earlier of the closing of the Asset Disposition and October 15, 2012, at which time the Bridge Facility will be terminated.

The Credit Facilities will be secured by a first priority security interest on substantially all of the property and assets of US Opco, including all of its oil and natural gas properties, and substantially all of the property and assets of the Trust and Can Holdco, including the interest in US Opco held by Can Holdco and will be guaranteed by the Trust and Can Holdco.

The documentation for the Credit Facilities will provide for customary negative covenants which, among other things, may limit US Opco, the Trust and Can Holdco from making distributions of cash flow to their shareholders, noteholders or unitholders in certain circumstances. The documentation for the Credit Facilities will provide, among other things, that the aggregate distributions of US Opco plus net capital expenditures in any 12 month period shall not exceed 115% of the aggregate available cash flow of US Opco for such preceding 12 month period. Distributions will not be permitted unless amounts outstanding under the Operating Facility are less than 90% of the commitment amounts both before and after giving effect to any such distributions. The documentation for the Credit Facilities will also include other customary restrictive covenants including limitations on indebtedness, liens, contingent obligations, dispositions, and mergers, consolidations, liquidations and dissolutions. A failure to comply with any of the affirmative and negative covenants would result in an event of default which, if not cured or waived, would permit acceleration of the indebtedness pursuant to the Credit Facilities. Non-compliance with the terms of the covenants under the Credit Facilities could adversely impact the distributable cash of the Trust. See "Risk Factors".

An affiliate of Scotia Capital Inc. has committed to be the lender under the Credit Facilities. Consequently, the Trust may be considered a "connected issuer" to such Underwriter within the meaning of applicable Canadian securities legislation. See "Relationship Between the Trust and An Underwriter".

## MANAGEMENT'S DISCUSSION AND ANALYSIS

### General

The Trust and each of its affiliates have only recently been formed or incorporated and as such have not completed their first fiscal year and have had limited activity. Accordingly, the following Management's Discussion and Analysis ("**MD&A**") is dated August 1, 2012 and should be read in conjunction with the audited Consolidated Statement of Financial Position as at June 30, 2012 and the Consolidated Statements of Comprehensive Loss, Changes in Unitholders' Equity and Cash Flows for the period from the date of establishment on January 31, 2012 to June 30, 2012 and the related notes in Appendix A to this prospectus and the Operating Statements Containing Gross Revenues, Royalties and Production Taxes and Operating Expenses of the Denali Assets for the three month periods ended March 31, 2012 and 2011 and for the years ended December 31, 2011, 2010 and 2009 in Appendix B to this prospectus.

This MD&A disclosure makes reference to the term "netback", which is not a recognized measure under IFRS and does not have a standardized meaning prescribed by IFRS. Accordingly, the use of the term "netback" in this MD&A disclosure may not be comparable to similarly defined measures presented by other companies. "Netback" is equal to oil, natural gas and NGL sales revenue less royalties, transportation costs, production taxes and operating expenses. Management considers netback important as it is a measure of profitability and reflects the quality of production. Management uses this non-IFRS measurement for its own performance measures and to provide Unitholders and potential investors with a measurement of the Trust's efficiency and its ability to fund a portion of its future growth expenditures.

The Trust is an unincorporated limited purpose open-ended trust established under the laws of the Province of Alberta. The objective of the Trust is to create stable, consistent returns for investors through the acquisition and development of oil and natural gas reserves and production with low-risk exploitation potential, located primarily in the U.S., and to pay out a portion of available cash to Unitholders on a monthly basis.

The Trust was created on January 31, 2012 and it issued one Unit to the settlor of the Trust for a subscription price of $5.00, which Unit was subsequently repurchased by the Trust for the same consideration. The Trust also issued an aggregate of 600,000 Units at a price of $5.00 per Unit pursuant to the Initial Private Placements. See "Prior Sales".

In addition to the following discussion about the structure of the Trust and its subsidiaries, please refer to the sections in this prospectus entitled "The Trust and its Subsidiaries" and "Funding, Acquisition and Related Transactions – Structure Following Closing" for an overview of the structure of the Trust.

The Trust owns all of the issued and outstanding shares of Can Holdco, which in turn owns all of the issued and outstanding shares of US Opco. Can Holdco was incorporated on May 4, 2012 to acquire and hold, on closing of the Offering, all of the issued and outstanding shares of US Opco. US Opco was incorporated on May 4, 2012 to acquire, on closing of the Acquisition, the Denali Assets, as described under "Significant Acquisition" below.

### Activities of the Trust since its Formation through to Closing of the Offering

Since the date of its formation through to the closing of the Offering (as described under "– Liquidity and Capital Resources") and the Acquisition (as described under "– Significant Acquisition"), the Trust will not have had any substantial active operations. However, the Administrator incurred approximately $1.5 million of general and administrative expenses from the date of its inception on January 31, 2012 to June 30, 2012 in connection with officer and employee costs, office rent and includes approximately $600,000 of expenses incurred by Aston Hill on behalf of the Trust to source and review potential oil and natural gas asset acquisitions, which expenses were reimbursed by the Trust to the Administrator.

The expenses of the Offering (excluding the Underwriters' fee) are estimated to be approximately $3.0 million, of which approximately $1.5 million will be paid from proceeds raised in the Initial Private Placements.

### Significant Acquisition

US Opco entered into the Purchase and Sale Agreement with Denali on May 23, 2012, as amended on June 11, 2012 and July 12, 2012, pursuant to which it will acquire the Denali Assets.

The purchase price for the Denali Assets (excluding the Deep Rights) is US$166.7 million subject to certain closing adjustments and net of US$36.6 million that will be held in escrow by Denali and applied to US Opco's capital expenditures and general and administrative expenses on the Denali Assets for the 24 month period following closing of the Offering. The Acquisition will have an effective date of January 1, 2012. The purchase price for the Acquisition will be funded from the net proceeds of the Offering and an advance under the Credit Facilities to be established by US Opco. It is a condition under the Purchase and Sale Agreement that the closing of the Acquisition occurs concurrently with the closing of the Offering and the closing of the Credit Facilities. See "Use of Proceeds", "Undertaking of the Trust – Credit Facilities" and "Funding, Acquisition and Related Transactions – Acquisition – Purchase and Sale Agreement".

If the Over-Allotment Option is exercised in full, the net proceeds to the Trust from the Offering will be approximately $229.6 million before expenses of the Offering. The net proceeds to be received by the Trust pursuant to the exercise of the Over-Allotment Option, if exercised, are expected to be provided to US Opco in the same manner as the net proceeds of the Offering. If the Over-Allotment Option is exercised for net proceeds of at least $25 million, US Opco will acquire the Denali Reserved Interest for US$20 million in accordance with the Purchase and Sale Agreement, with the remaining proceeds to be used to reduce the amount outstanding under the Credit Facilities and for general corporate purposes. If the Over-Allotment Option is exercised for net proceeds of less than $25 million, the proceeds will be used to reduce the amount outstanding under the Credit Facilities and for general corporate purposes. See "Use of Proceeds" for a tabular presentation of the use of proceeds and "Funding, Acquisition and Related Transactions – Acquisition – Purchase and Sale Agreement – Denali Reserved Interest", and "Funding, Acquisition and Related Transactions – Acquisition – Purchase and Sale Agreement – Deep Rights".

**Outlook**

Certain information contained in this MD&A constitutes "forward-looking statements". See "Notice to Investors – Forward-Looking Statements".

US Opco expects to drill approximately six (3.7 net) new wells from July, 2012 to the end of 2012 and approximately six (six net) new wells during 2013 on the Denali Assets. According to the development plan in the Sproule Reserve Report, five of the proposed Austin Chalk locations and one of the Eagle Ford Shale locations are expected to be developed in the latter half of 2012. In addition, one of the Austin Chalk, four of the Eagle Ford Shale and one of the South Escobas development locations will be developed in 2013.

Management expects that US Opco will spend in aggregate US$13.6 million during the remainder of 2012 in connection with its capital program on the Denali Assets (based on an August 10, 2012 closing date for the Acquisition). Management expects favourable drilling, completion and tie-in costs of approximately US$18.32 per boe in 2012 and approximately US$15.72 per boe in 2013 for the 2013 drilling program. Pursuant to the Purchase and Sale Agreement, Denali will be obligated to fund US$35.6 million of US Opco's capital expenditures on the Denali Assets for the 24 month period following closing of the Offering out of the amounts that will be held in escrow. US Opco intends to fund any unforeseen additional capital cost associated with the 2012 drilling program through borrowings under the Operating Facility as well as operating cash flow not distributed to Unitholders. Based on the Sproule Reserve Report, Management expects this drilling activity and resulting new production to increase US Opco's working interest production from an average of approximately 1,633 boe/d for the month of May 2012 (with shut-in production added back on) to an average of 3,184 boe/d for 2013.

The Trust intends to make monthly distributions of a portion of its available cash to Unitholders and use the remainder of its available cash, and advances under the Credit Facilities, to fund growth through additional acquisitions and capital expenditures.

The Trust intends to make monthly distributions to Unitholders of record as of the close of business on the last business day of each month which are expected to be paid to Unitholders on or about the 23rd day of the following month or, if not a business day, the next business day thereafter. The amount of cash to be distributed on a *pro rata* basis per month per Unit will be determined in the discretion of the Trust. The Trust expects that the initial monthly cash distribution rate will be $0.0875 per Unit. The initial cash distribution, which will be for the period from and including the date of closing of the Offering to August 31, 2012, is expected to be paid on September 24, 2012 to

Unitholders of record on August 31, 2012 and is estimated to be $0.0621 per Unit (assuming the closing of the Offering occurs on August 10, 2012). As results of operations may vary, the distribution of cash is not guaranteed. See "Risk Factors".

The Administrator anticipates that approximately 30% to 40% of the distributable cash during the first year of the Trust following the closing of the Offering will be included in the income of Unitholders for Canadian federal income tax purposes. The balance will not be taxable and will be deducted from the adjusted cost base of their Units.

**Results of Operations**

The average benchmark prices for crude oil and natural gas for the three-year period were as follows:

| Year | WTI US$ per barrel | Henry Hub Natural Gas US$ Per MMBtu |
|---|---|---|
| 2009 | $61.63 | $4.01 |
| 2010 | $79.49 | $4.38 |
| 2011 | $95.08 | $3.99 |

***Year ended December 31, 2011 compared to year ended December 31, 2010***

*Production and Sales*

Oil, natural gas and NGLs sales from the Denali Assets for the year ended December 31, 2011 were approximately US$29.2 million. This represents a 38% increase in sales over the US$21.1 million in sales for the year ended December 31, 2010.

The increase in sales from the Denali Assets is due to an increase in oil sales of US$13.8 million relating to both a significant increase in production and the oil price received. Oil production increased 518% from 2010 to 2011 primarily as a result of the completion of four new Austin Chalk wells. The average oil price received in 2011 was US$91.78/bbl compared to US$74.30/bbl in 2010. The increase in oil sales was offset by a decrease in gas sales of US$5.7 million for the same period associated with the shut-in of one well and normal production declines on the other wells. Also, the average gas price received decreased from $3.64/Mcf in 2010 to $3.48/Mcf in 2011.

**Sales – Production and Commodity Price Variance Table**

| | Year Ended December 31 US$MM |
|---|---|
| 2010 Sales | $21.1 |
| Sales Variance due to: | |
| Commodity Prices | 5.7 |
| Production | 2.4 |
| 2011 Sales | $29.2 |

*Royalties and Production Taxes*

In the United States, deductions (often from proceeds, but sometimes from a share of the production, in kind) are made for royalties, production taxes, and other burdens on an oil and natural gas lessee's interest. These deductions are similar to the freehold royalty and mineral tax regimes in Canada.

Under oil and natural gas leases, royalties in the U.S. are paid to the owners of the mineral rights, which can include private citizens (to the extent the oil and natural gas lease covers private lands) as well as state governments (to the extent the oil and natural gas lease covers state lands) or the U.S. federal government (to the extent the oil and natural gas lease covers federal lands), not solely the government or Crown (the latter being the common case in Canada). These royalties are set forth in the applicable oil and natural gas lease and can range from a fraction of a percent to 25% or more. Royalties can also be granted out of the lessee's interest in the lease (often referred to as an overriding royalty). Royalty owners typically bear no share of the cost of drilling and production.

The average royalty interest in the Denali Assets for the year ended December 31, 2011 was approximately 22% (2010 – 25%).

Production taxes in the U.S., also referred to as severance taxes, are paid to the local governments and are generally a fixed percentage of the sales from oil and natural gas. Production taxes vary from state to state. In Texas, the location of the Denali Assets, the severance portion of these taxes is currently approximately 4.6% for oil and condensate and 7.5% for natural gas and NGLs (other than condensate) subject to a High Gas Cost Exemption, which Denali qualifies for on certain wells and which receives the severance tax rate. These percentages do not vary with prices or production levels. The production taxes in the historical operating statements for the Denali Assets at Appendix B are reflective of Texas severance taxes and the production split between natural gas, oil and NGLs.

Royalties and production taxes for the Denali Assets were 25.1% of sales (US$7.3 million) for the year ended December 31, 2011 compared to 28.4% of sales (approximately US$6.0 million) for the year ended December 31, 2010.

*Operating expenses*

Operating expenses for the Denali Assets are comprised of fixed and variable components and represent the costs of maintaining and operating the properties and equipment and include field labour, insurance, maintenance, repairs, ad valorem taxes, utilities and supplies. Operating expenses also include the costs incurred to extract, gather, and transport product to the purchaser. The largest components of operating expenses are field labour, compressor maintenance and ad valorem taxes.

Operating expenses increased from US$2.9 million (US$3.34/boe) for the year ended December 31, 2010 to US$5.4 million (US$6.88/boe) for the year ended December 31, 2011. Operating costs on a gross and per boe basis were higher in 2011 over 2010 primarily due to the start-up of four Austin Chalk wells, which have higher per unit operating costs than the gas wells included with the Denali Assets. In addition workovers on 34 wells contributed US$2.5 million to operating costs on the Denali Assets in 2011, whereas $1.1 million was spent in workovers in 2010 on the Denali Assets.

***Three month period ended December 31, 2011***

*Production and Sales*

Oil, natural gas and NGLs sales for the Denali Assets for the quarter ended December 31, 2011 were approximately US$6.8 million, representing a 3% increase from the US$6.6 million in sales for the fourth quarter of 2010 and a 8% decrease from the US$7.4 million in sales for the third quarter of 2011.

The increase in sales compared to the same quarter in the prior year was primarily due to the increase in oil production from 154 bbls/d to 536 bbls/d as a result of four Austin Chalk wells coming on production throughout 2011, together with an increase in oil price received from US$77.39/bbl in fourth quarter of 2010 to US$94.96/bbl in the fourth quarter of 2011. This oil production and sales increase more than offset the natural gas production declines and workovers on certain Denali gas wells that resulted in natural gas production declining from 17,087 mcf/d to 7,145 mcf/d over the same period.

The decrease in sales from the third quarter of 2011 was due to natural declines in oil and gas production, with overall production falling from 1,981 boe/d to 1,774 boe/d, being partly offset by an increase in oil price received from US$85.03/bbl to US$94.96/bbl.

*Royalties and Production Taxes*

Royalties and production taxes for the Denali Assets were 25.1% of sales (US$1.7 million) for the fourth quarter of 2011 compared to 24.4% of sales (approximately US$1.6 million) for the fourth quarter of 2010. This increase in rate reflects the higher average production tax rates due to the higher oil prices received in the fourth quarter of 2011.

*Operating expenses*

Operating expenses increased from US$0.8 million (US$2.76/boe) for the three months ended December 31, 2010 to US$1.6 million (US$9.57/boe) for the three months ended December 31, 2011. The fourth quarter of 2011 includes an annual charge of approximately US$350,000 for ad valorem taxes and a higher than normal work-over expense on certain Denali wells of US$525,000 (these amounts were US$192,000 and US$nil respectively in the fourth quarter of 2010). Adjusting the fourth quarter 2011 expenses to reflect the difference on these items to 2010 would reduce fourth quarter 2011 operating expenses incurred to approximately $0.9 million (US$5.39/boe). While this would still represent an increase on a per boe basis compared to 2010, reflecting the increase in oil-weighted production having higher per well operating costs, it is more consistent with the operating expenses per boe through 2011 and into the first quarter of 2012.

***Year ended December 31, 2010 compared to year ended December 31, 2009***

*Production and Sales*

Oil, natural gas and NGLs sales from the Denali Assets for the year ended December 31, 2010 was approximately US$21.1 million. This represents a 137% increase, in sales over the US$8.9 million in sales for the year ended December 31, 2009 from the Denali Assets.

The increase in sales from the Denali Assets was primarily due to an increase in gas production with the completion of four South Texas gas wells, which more than offset natural declines, together with an increase in oil production due to two Austin Chalk wells and two Cage Ranch wells coming on production in 2010. Furthermore the average gas price received increased from $3.29/Mcf in 2009 to $3.64/Mcf in 2010, while the average oil price received increased from US$70.46/bbl in 2009 to US$74.30/bbl in 2010.

*Royalties and Production Taxes*

The average royalty interest in the Denali Assets for the year ended December 31, 2010 was approximately 27% (2009 – 29%). The royalty rate for Denali decreased primarily due to the new oil production from the two Austin Chalk wells which have a lower royalty burden relative to the South Texas gas wells.

Royalties and production taxes for the Denali Assets were 28.4% of sales (US$6.0 million) for the year ended December 31, 2010 compared to 25.0% of sales (approximately US$2.2 million) for the year ended December 31, 2009 reflecting a production tax credit of $319,984 received by Denali in 2009 compared to an expense of $384,389 in 2010 which more than offset the Denali royalty rate reduction.

*Operating expenses*

Operating expenses increased from US$2.3 million (US$6.77/boe) for the year ended December 31, 2009 to US$2.9 million (US$3.34/boe) for the year ended December 31, 2010. Operating costs on a per boe basis were lower in 2010 over 2009 due to the lower operating costs on a per boe basis associated with the higher production from the new gas wells in 2010 and as a result of operating efficiencies achieved by Denali management.

***Three month period ended March 31, 2012 compared to three month period ended March 31, 2011***

*Production and Sales*

Oil, natural gas and NGLs sales from the Denali Assets for the three month period ended March 31, 2012 were approximately US$5.4 million. This represents a 21% decrease in sales over the US$6.9 million in sales for the three month period ended March 31, 2011 from the Denali Assets.

The decrease in sales from the Denali Assets was primarily due to the reduction in natural gas prices and expected declines in natural gas production, offset partially by increases in oil production with four Austin Chalk wells coming on production in mid-2011. The average natural gas price received in the first quarter of 2012 was US$2.07/Mcf compared to US$3.54/Mcf in the first quarter of 2011 and natural gas production declined from an average of 12,891 Mcf/d to 8,856 Mcf/d over the same period, while oil production increased from 296 bbls/d to 387 bbls/d over the same period and oil price received increased from US$92.37/bbl to US$103.14/bbl in the first quarter of 2012.

*Royalties and Production Taxes*

The average royalty interest in the Denali Assets for the three month period ended March 31, 2012 was approximately 22.6% (2011 – 23.7%).

Royalties and production taxes for the Denali Assets were 25.6% of sales (US$1.4 million) for the first quarter of 2012 compared to 24.1% of sales (approximately US$1.7 million) for the first quarter of 2011. This increase reflects the higher average production tax rates due to the higher oil prices received in 2012 on larger oil volumes, offset partially by the comparatively lower natural gas prices received in the first quarter of 2012.

*Operating expenses*

Operating expenses decreased from US$1.6 million (US$6.84/boe) for the three months ended March 31, 2011 to US$0.8 million (US$4.38/boe) for the three months ended March 31, 2012. Operating costs were lower in 2012 over 2011 due to the reduction in production and, on a per boe basis, due to the continued implementation of operating efficiencies on the new oil wells on the Denali Assets.

***Summary of Quarterly Results***

| | Q1 2010 | Q2 2010 | Q3 2010 | Q4 2010 | Q1 2011 | Q2 2011 | Q3 2011 | Q4 2011 | Q1 2012 |
|---|---|---|---|---|---|---|---|---|---|
| Oil production (bbls/d) | 18 | 55 | 78 | 154 | 296 | 491 | 562 | 536 | 387 |
| NGLs production (bbls/d) | 37 | 74 | 127 | 85 | 85 | 72 | 58 | 47 | 36 |
| Total liquids (bbls/d) | 55 | 128 | 205 | 239 | 381 | 563 | 620 | 583 | 422 |
| Natural gas production (Mcf) | 7,444 | 11,497 | 17,836 | 17,087 | 12,891 | 10,430 | 8,167 | 7,145 | 8,856 |
| Total production (boe/d) | 1,296 | 2,045 | 3,178 | 3,087 | 2,530 | 2,301 | 1,981 | 1,774 | 1,898 |
| % Oil and NGLs | 4.3% | 6.3% | 6.4% | 7.7% | 15.1% | 24.5% | 31.3% | 32.9% | 22.3% |
| WTI Benchmark (US$/bbl) | 78.76 | 77.93 | 76.01 | 85.22 | 94.28 | 102.40 | 89.55 | 94.15 | 102.86 |
| NYMEX Benchmark (US$/Mcf) | 5.11 | 4.32 | 4.28 | 3.81 | 4.18 | 4.37 | 4.12 | 3.31 | 2.45 |
| Oil sales (US$000) | $118 | $359 | $500 | $1,095 | $2,461 | $4,281 | $4,396 | $4,680 | $3,629 |
| NGLs sales (US$000) | $130 | $239 | $377 | $303 | $330 | $308 | $259 | $215 | $150 |
| Oil and NGLs sales (US$000) | $248 | $598 | $876 | $1,399 | $2,791 | $4,588 | $4,655 | $4,894 | $3,779 |
| Natural Gas sales (US$000's) | $3,067 | $3,647 | $6,044 | $5,185 | $4,107 | $3,513 | $2,716 | $1,900 | $1,666 |
| Total sales (US$000) | $3,315 | $4,245 | $6,920 | $6,584 | $6,898 | $8,101 | $7,371 | $6,794 | $5,445 |
| Royalties and production taxes (US$000) | $(972) | $(1,297) | $(2,113) | $(1,607) | $(1,664) | $(2,067) | $(1,889) | $(1,703) | $(1,394) |
| Operating expenses (US$000) | $(658) | $(426) | $(1,066) | $(783) | $(1,558) | $(1,373) | $(894) | $(1,562) | $(756) |
| Netback (US$000's) | $1,685 | $2,521 | $3,741 | $4,194 | $3,676 | $4,661 | $4,588 | $3,529 | $3,295 |
| Oil sales (US$/bbl) | $74.03 | $72.27 | $69.67 | $77.39 | $92.37 | $95.73 | $85.03 | $94.96 | $103.14 |
| NGLs sales (US$/bbl) | $38.67 | $35.58 | $32.24 | $38.68 | $42.98 | $47.21 | $48.63 | $49.34 | $45.91 |
| Oil and NGLs sales (US$/bbl) | $49.99 | $51.17 | $46.49 | $63.58 | $81.32 | $89.55 | $81.64 | $91.26 | $98.29 |
| Natural Gas sales (US$/Mcf) | $4.58 | $3.49 | $3.68 | $3.30 | $3.54 | $3.70 | $3.61 | $2.89 | $2.07 |
| Total sales (US$/boe) | $28.42 | $22.81 | $23.67 | $23.18 | $30.29 | $38.68 | $40.44 | $41.63 | $31.52 |
| Royalties and production taxes (US$/boe) | $8.33 | $6.97 | $7.23 | $5.66 | $7.31 | $9.87 | $10.37 | $10.43 | $8.07 |
| Royalties and production taxes (% of Sales) | 29.3% | 30.6% | 30.5% | 24.4% | 24.1% | 25.5% | 25.6% | 25.1% | 25.6% |
| Operating expenses (US$/boe) | $5.64 | $2.29 | $3.65 | $2.76 | $6.84 | $6.56 | $4.90 | $9.57 | $4.38 |
| Netback (US$/boe) | $14.45 | $13.55 | $12.80 | $14.77 | $16.14 | $22.26 | $25.17 | $21.63 | $19.07 |

***Discussion of Quarterly Trends***

Production from the Denali Assets increased from the first quarter of 2010 through the third quarter of 2010 primarily as a result of four new wells coming on production in the South Escobas Field and one new well coming on production in the Austin Chalk oil formation. Production began to decline in the fourth quarter of 2010 due to a well in the South Escobas Field being shut-in as well as due to natural declines which were offset slightly by the addition of four Austin Chalk wells and an Eagle Ford Shale well coming on production throughout 2011. Into the first quarter of 2012, gas production improved as a result of a successful Denali gas well coming on production in late December 2011, while oil production decreased reflecting the initial decline rate on the Austin Chalk and Eagle Ford Shale wells.

Sales attributable to production from the Denali Assets slowly and steadily increased from the first quarter of 2010 through the third quarter of 2010 primarily due to the increase in production during that period. Sales continued to steadily increase from the fourth quarter of 2010 through the second quarter of 2011, despite the overall declining production base, due to increases in oil commodity price as well as a shift in the overall oil and NGLs weighting of the asset base (6.4% oil and NGLs to 24.5% oil and NGLs over that period of time). Sales declined slightly over the last two quarters of 2011, despite the continuing rise in proportion of oil and NGLs production (24.5% to 32.9%) as oil commodity prices retreated to the levels experienced in the first quarter of 2011. The composition of overall production shifted further toward oil and NGLs from the first quarter of 2011 to the fourth quarter of 2011, resulting in sales being roughly consistent from the first quarter of 2011 and the fourth quarter of 2011 despite decreasing natural gas prices and relatively consistent oil prices over this same period. This trend reversed partially in the first quarter of 2012 due to lower oil production more than offsetting the increase in oil prices, while conversely natural gas prices continued to decline offsetting the increase in gas production.

The aggregate of Royalties and Production Taxes as a percentage of sales has dropped noticeably since early 2010 as a result of reducing gas prices and a higher percentage of oil production, which carries a lower production tax rate than gas, such that the average combined rate has dropped from approximately 30% in the first half of 2010 to between approximately 24% and 26% from the fourth quarter of 2010 to the first quarter of 2012. There have been mild fluctuations within this band due to the shutting in and starting up of various wells over that time period.

Operating expenses decreased on both a gross and per boe basis from the first quarter of 2010 ($5.64/boe) through the fourth quarter of 2010 ($2.76/boe) as efficiencies implemented in the first quarter of 2010 allowed for reductions in operating costs over the remainder of 2010. In 2011 operating expenses on a gross basis were higher in general than the last three quarters of 2010 due to the incremental costs of additional wells in the Austin Chalk and Eagle Ford Shale formations, which increased in the first quarter of 2011 and declined over the next two quarters. On a per boe basis, gas production also declined sharply starting in the first quarter of 2011 contributing to an uptick in per boe operating costs ($2.76/boe in fourth quarter 2010 to $6.84/boe in first quarter 2011) in addition to the startup of the Austin Chalk wells which have higher than existing average well per unit operating costs. Per boe operating costs declined slightly from the first quarter of 2011, which also included a significant South Escobas well workover, to the third quarter of 2011 and then increased, on a gross and per boe basis, in the fourth quarter of 2011 due to the inclusion of US$350,000 annual ad valorem taxes and $525,000 of workover costs. On a per boe basis, the operating costs then returned to a more consistent rate of US$4.38/boe in the first quarter of 2012.

**Tax Horizon**

The tax horizon as determined from a full cycle corporate model developed by Management and incorporating all applicable U.S. deductions, indicates that no material U.S. taxes are expected to be payable in respect of income attributable to the Denali Assets until at least 2021. Management expects to maintain this position through capital investments and acquisitions primarily in the U.S. No taxes are expected to be payable by the Trust in Canada as the Trust intends to distribute all of its taxable income each year to Unitholders and will not be a SIFT trust provided that the Trust does not hold any “non-portfolio property”, as defined in the Tax Act. The model developed by Management is based on production and cost assumptions from the Sproule Reserve Report and the WTI and NYMEX forward strip commodity pricing as of July 11, 2012.

**Business Risks**

The Trust’s business is subject to the risks normally encountered in the U.S. oil and natural gas industry and the Trust’s early stage of development. See the section of this prospectus entitled “Risk Factors”.

**Liquidity and Capital Resources**

The Trust will use the net proceeds of the Offering along with borrowings by US Opco under the Credit Facilities to acquire the Denali Assets. In addition, Management may seek to issue additional Units in the future to provide sufficient capital to fund growth acquisition opportunities. After the closing of the Offering and the Acquisition, the Trust anticipates that there will be drawn approximately US$5.8 million under the Credit Facilities and that there will be approximately US$9.7 million remaining in undrawn availability under the Credit Facilities. Of the funds that will be held in escrow by Denali, an aggregate of US$35.6 million will be applied to capital expenditures on the

Denali Assets for the 24 month period following closing of the Offering, which together with the cash flow generated by the assets in excess of distributions, plus advances under the Operating Facility, if required, will be used to fund US Opco's portion of the costs of drilling and completing the wells in the drilling program in respect of the Denali Assets. See "Funding, Acquisition and Related Transactions – Acquisition".

If the Over-Allotment Option is exercised in full, the net proceeds to the Trust from the Offering will be approximately $229.6 million before expenses of the Offering. The net proceeds to be received by the Trust pursuant to the exercise of the Over-Allotment Option, if exercised, are expected to be provided to US Opco in the same manner as the net proceeds of the Offering. If the Over-Allotment Option is exercised for net proceeds of at least $25 million, US Opco will acquire the Denali Reserved Interest for US$20 million in accordance with the Purchase and Sale Agreement, with the remaining proceeds to be used to reduce the amount outstanding under the Credit Facilities and for general corporate purposes. If the Over-Allotment Option is exercised for net proceeds of less than $25 million, the proceeds will be used to reduce the amount outstanding under the Credit Facilities and for general corporate purposes. See "Use of Proceeds" for a tabular presentation of the use of proceeds and "Funding, Acquisition and Related Transactions – Acquisition – Purchase and Sale Agreement – Denali Reserved Interest", and "Funding, Acquisition and Related Transactions – Acquisition – Purchase and Sale Agreement – Deep Rights".

Generally, three sources of funding for future capital expenditures are expected by Management to be available: (i) internally generated cash flow from operations; (ii) external debt financing, when appropriate; and (iii) new capital through the issuance of additional Units, if available on favourable terms. Management's objective is to maintain a prudent debt to EBITDA ratio that will generally not exceed 1.5 times. The Trust may temporarily exceed this parameter, particularly in the case of acquisitions, provided that Management has a plan to return this ratio to the preferred range in the short term.

US Opco has received a commitment for the Credit Facilities and expects to establish the Credit Facilities concurrently with closing of the Offering and the Acquisition. The Credit Facilities are expected to be arranged by a Canadian chartered bank and are expected to be comprised of the Operating Facility and the Bridge Facility, which are intended to be used for general corporate purposes, including capital expenditures and future acquisitions. The borrowing base for the Operating Facility will initially be set at US$8 million. Management expects the borrowing base of US$8 million to increase commensurate with any growth in reserves of US Opco. The Bridge Facility is expected to be available until the earlier of the closing of the Asset Disposition and October 15, 2012, at which time the Bridge Facility will be terminated. See "Credit Facilities" and "Risk Factors".

**Outstanding Unit Data**

At the date of this prospectus, 600,000 Units were issued and outstanding and no RTUs were outstanding. All of the outstanding Units were issued pursuant to the Initial Private Placements and 316,000 Units are subject to escrow conditions. See "Prior Sales" and "Securities Subject to Contractual Restrictions on Transfer".

**International Financial Reporting Standards**

The Canadian Accounting Standards Board requires that all Canadian publicly accountable enterprises transition from Canadian generally accepted accounting principles in effect prior to January 1, 2011 to IFRS for interim and annual reporting periods for fiscal years beginning on or after January 1, 2011. The Trust will report its financial statements in accordance with IFRS from inception. In addition, the Operating Statements Containing Gross Revenues, Royalties and Production Taxes and Operating Expenses for the Denali Assets have been prepared in accordance with IFRS. See "Exemptions from Certain Disclosure Requirements".

**Critical Accounting Policies Adopted and Intended to be Adopted**

The Trust is undertaking an analysis of IFRS accounting policy alternatives and determining the policies that are most appropriate for the Trust. The general analysis of IFRS accounting policies specifically considers the current IFRS standards that are in effect. The Trust will monitor the adoption efforts of other oil and natural gas entities in Canada before finalizing all of its IFRS accounting policies. The Trust's first quarterly financial statements are expected to be for the quarter ended June 30, 2012 and all policies adopted by the Trust will be disclosed in the first quarterly financial statements issued for the Trust.

## SUMMARY OF DISTRIBUTABLE CASH

The following summary has been prepared by Management on the basis of the information contained in this prospectus and its estimate of the expenses to be incurred by the Trust and its subsidiaries. This analysis may be considered a financial outlook. **The actual results of operations of the Trust and its subsidiaries and of the Denali Assets for any period, whether before or after closing of the Acquisition, will likely vary from the amounts set forth in the following analysis, and such variations may be material. See "Notice to Investors – Forward-Looking Statements" and "Risk Factors" for a discussion of the risks that could cause actual results to vary.**

The purpose of the following summary is to provide a reasonable estimate of what the cash flow available for distribution by the Trust will be for the 18-month period ending December 31, 2013 if the closing of the Offering and the completion of the transactions described under "Funding, Acquisition and Related Transactions" occurred on August 10, 2012, with an effective date of January 1, 2012, and should not be relied upon for any other purpose. This summary has been prepared using assumptions which reflect the Trust's and its subsidiaries' planned courses of action given Management's current expectations about the most probable set of economic conditions. The estimate is based on 2012 and 2013 production from the Denali Assets estimated in the Sproule Reserve Report and is adjusted for a variety of factors as described in the table below. See "Reserves and Other Oil and Gas Information". In forming these assumptions and estimates, Management relied on its knowledge of the oil and natural gas business, the development plan for the Denali Assets based on certain assumptions in the Sproule Reserve Report, certain tax assumptions as described in the prospectus, the Denali Assets' historical financial results and supplemental financial analysis. Further information related to the underlying assumptions is provided in the footnotes to the table for each reconciling item. Cash flow available for distribution does not have any standardized meaning as prescribed by IFRS and as a result such term is unlikely to be comparable to similar measures presented by other issuers. See "Notice to Investors – Non-IFRS Financial Measures".

### Estimated Cash Flow Available for Distribution From July 1, 2012 to December 31, 2013

| | Amount |
|---|---|
| | ($M) |
| Revenue before royalties (US$)(1) | 92,324 |
| Less: Royalty interest (US$)(2) | (18,259) |
| Revenue after royalty interest (US$) | 74,065 |
| Less: Operating Expenses (US$)(3) | (4,571) |
| Production Taxes (US$)(4) | (4,361) |
| General and Administrative Expenses Related to Field Operations (US$)(5) | (3,206) |
| Federal and State Taxes (US$)(6) | (1,278) |
| Subtotal (US$) | 60,648 |
| Subtotal (C$)(7) | 62,333 |
| Less: General and Administrative Expenses Related to Trust and its affiliates (C$)(8) | (4,500) |
| Interest Costs on Bank Facility (C$ equivalent)(9) | (541) |
| Cash Flow Available for Distribution Before Capital Expenditures (C$)(10) | 57,293 |
| Capital Expenditures (US$)(11) | (18,431) |
| Deferred Payment Obligation (US$)(12) | (5,000) |
| Asset Disposition (US$)(13) | 7,500 |

**Notes:**

(1) Estimated revenue based on: (i) forecasted average production from the Sproule Reserve Report for the period from July 1, 2012 to December 31, 2013 of 2,992 boe/d (51% oil) for the total proved plus probable case, prior to royalty interests of approximately 20% of revenue on average after allowance for processing costs; and (ii) commodity prices based on forward strip prices as at July 11, 2012 of on average US$88.05/bbl WTI for oil and US$3.26/MMBtu NYMEX for natural gas.

(2) Royalty interest equal to approximately 20% of revenue on average after allowance for processing costs.

(3) Estimated operating expenses from the Sproule Reserve Report for the July 1, 2012 to December 31, 2013 period.

(4) Estimated production taxes are based on: (i) the assumptions in Note 1 above; and (ii) rates for production taxes reflected in the Sproule Reserve Report, being approximately 4.7%.

(5) Represents the aggregate of the estimated annual general and administrative expenses of US Opco, net of US$1.0 million that will be paid by the Trust to Denali on closing of the Offering and that will be held in escrow by Denali and applied to US Opco's general and administrative expenses for the twelve month period following closing of the Offering.

(6) Federal and state taxes represent the applicable Alternative Minimum Tax, at a rate of 20%, and Texas Margin Tax, at a rate of 1%, applied against qualifying net income after allowable deductions including interest, certain expenses, depreciation and/or capital cost allowances, and Dividend Withholding Tax, at a rate of 5% on the dividend portion of distributions from US Opco to Can Holdco.

(7) U.S. dollar netback converted to Canadian dollar equivalent based on average 18 month forward C$/US$ exchange rate of US$1.00 equals C$1.0278 as at July 11, 2012.

(8) Estimated general and administrative costs of the Trust are based on Management's estimate of salaries, rent, office supplies and administrative costs required to operate a public oil and gas entity of a similar size plus an initial overhead charge of $700,000 per year payable to Aston Hill pursuant to the Services Agreement. See "Administration of the Trust – Services Agreement with Aston Hill".

(9) Interest costs based on assumed initial advances of approximately C$9.2 million under the Credit Facilities and market interest at the closing of the Acquisition. Borrowings under the Credit Facilities will bear interest at a floating rate.

(10) The sensitivity of cash flow available for distribution before capital expenditures due to commodity price or exchange rate fluctuations for the 18 month period is estimated as follows: US$1/bbl change in WTI oil price equals approximately C$869,000; US$0.10/MMBtu change in NYMEX natural gas price equals approximately C$261,000; and $0.01 change in the C$/US$ exchange rate equals approximately C$608,000.

(11) Estimated capital expenditures plus abandonment and reclamation expenditures from the Sproule Reserve Report for the July 1, 2012 to December 31, 2013 period for the total proved plus probable case, net of an aggregate of US$29.1 million from the amount that will be paid by the Trust to Denali on closing of the Offering and that will be held in escrow by Denali and applied to US Opco's capital expenditures on the Denali Assets for the 24 month period following closing of the Offering. Capital expenditures are to be financed from both cash flow not distributed to Unitholders and advances under the Credit Facilities, if required.

(12) This is a non-recurring payment and relates to the payments in respect of the Deep Rights pursuant to the Purchase and Sale Agreement, which consists of payments of US$5.0 million payable on January 1, 2013; US$6.0 million payable on January 1, 2014; and US$7.0 million payable on January 1, 2015. See "Funding, Acquisition and Related Transactions – Acquisition – Purchase and Sale Agreement – Deep Rights."

(13) This is a non-recurring receipt of funds relating to the expected sale of approximately 76,300 net acres of rights below the Buda formation reserved by Denali in leases in Wilson and Atascosa Counties, Texas, which leases are expected to be sold to a third party on September 10, 2012 pursuant to the Asset Purchase Agreement. Closing of this transaction is subject to customary closing conditions. See "Risk Factors".

## TRUSTEE, DIRECTORS AND MANAGEMENT

### The Trust

Computershare has been appointed as the trustee of the Trust and will continue in office until replaced by the Unitholders. Pursuant to the terms of the Administrative Services Agreement, the Trustee has delegated a number of the management, administrative and governance duties relating to the Trust to the Administrator. As a result, the Administrator Directors fulfill the majority of the oversight and governance role for the Trust, with the balance of those duties remaining with the Trustee. See "Administration of the Trust – Administrative Services Agreement". In addition, the Trust and the Administrator will enter into the Services Agreement with Aston Hill, pursuant to which Aston Hill will provide certain technical and administrative services that may be required by the Administrator, on behalf of the Trust. See "Administration of the Trust – Services Agreement with Aston Hill".

### Can Holdco

Can Holdco is wholly-owned by the Trust. Its sole functions will be to own all of the issued and outstanding US Opco Shares and receive distributions on such shares, to acquire the US Opco Notes and distribute such notes to the Trust upon completion of the Offering, and to make distributions to the Trust, to the extent possible. Upon completion of the Offering, the directors of Can Holdco will be Eric Tremblay and Brian Prokop and the executive officers of Can Holdco will be the same as the executive officers of the Administrator. See "Description of Can Holdco".

### US Opco

US Opco is wholly-owned by Can Holdco. Its initial function will be to acquire, operate and manage the Denali Assets, to pay interest to the Trust on the US Opco Notes, and to declare and pay dividends to Can Holdco. Upon completion of the Offering, the directors of US Opco will be John Elzner, Richard Louden and Brian Prokop and the executive officers of US Opco will be John Elzner, Richard Louden, Brian Prokop and Sean Bovingdon. See "Description of US Opco".

### The Administrator

The Administrator is wholly-owned by the Administrator Shareholder. Under the terms of the Administrative Services Agreement, the Administrator has certain management, administrative and governance duties with respect to the Trust. The Administrator performs its services pursuant to the Administrative Services Agreement on a cost recovery basis.

From and after closing of the Offering, the number of the Administrator Directors shall be fixed at seven until such time as the Administrator Directors pass a resolution to fix the number of the Administrator Directors at a new number. The Voting Agreement will provide that Unitholders will be entitled, among other things, to elect all of the Administrator Directors. See "Voting Agreement".

**Directors and Executive Officers of the Administrator**

The following table provides the names and municipalities of residence of the executive officers of the Administrator and the Administrator Directors, as well as their offices held with the Administrator, the date they were first appointed as executive officers of the Administrator or Administrator Directors and their principal occupation. Messrs. Tremblay, Prokop and Bovingdon will be employed by Aston Hill pursuant to the Services Agreement and Messrs. Louden and Elzner will be employed by US Opco. Other than Mr. Tremblay, each of the executive officers will be employed on a full-time basis and will devote 100% of their time to the business and affairs of the Argent Group. See "Administration of the Trust – Services Agreement with Aston Hill".

| Name, Province and Country of Residence | Current Positions and Offices Held | Principal Occupation | Director or Officer Since |
|---|---|---|---|
| Brian Prokop<br>Alberta, Canada | Director and Chief Executive Officer | Chief Executive Officer of the Administrator. | August 5, 2011 |
| Richard Louden(1)<br>Texas, United States | Director and President | President of the Administrator(4). | May 4, 2012 |
| Sean Bovingdon<br>Alberta, Canada | Chief Financial Officer | Chief Financial Officer of the Administrator. | August 5, 2011 |
| John Elzner<br>Texas, United States | Senior Vice-President | Senior Vice-President of the Administrator(4). | May 4, 2012 |
| Eric Tremblay<br>Alberta, Canada | Director and Executive Chairman of the Board | Executive Chairman of the Administrator, Chief Executive Officer of Aston Hill Financial Inc. (an asset management company). | June 9, 2011 |
| John Brussa(2)<br>Alberta, Canada | Director | Partner, Burnet, Duckworth & Palmer LLP (a law firm). | August 5, 2011 |
| Scott Butler(2)(3)<br>Ontario, Canada | Director | Corporate Director. | August 5, 2011 |
| William D. Robertson(1)(3)<br>Alberta, Canada | Director | Corporate Director. | August 5, 2011 |
| Glen C. Schmidt(1)(3)<br>Alberta, Canada | Director | President & Chief Executive Officer of Laricina Energy Ltd. (an oil sands company). | August 5, 2011 |

**Notes:**

(1) Member of the Reserves & Environment, Health & Safety Committee. Mr. Schmidt is the Chairman of the Reserves & Environment, Health & Safety Committee.

(2) Member of the Governance, Nomination & Compensation Committee. Mr. Brussa is the Chairman of the Governance, Nomination & Compensation Committee.

(3) Member of Audit Committee. Mr. Robertson is the Chairman of the Audit Committee.

(4) Until closing of the Offering and the Acquisition, Mr. Louden's and Mr. Elzner's principal occupation will be President and Chief Executive Officer and Senior Vice-President, respectively, of Denali.

The term of office of all Administrator Directors will expire at the first annual meeting of Unitholders of the Trust and, thereafter, at each annual meeting of Unitholders of the Trust or at the time at which his or her successor is elected or appointed, or earlier if any Administrator Director otherwise dies, resigns, is removed or is disqualified. Pursuant to the Voting Agreement, the Administrator Shareholder is to elect the Administrator Directors as directed by the Unitholders immediately following each annual meeting of Unitholders of the Trust. Each director will devote the amount of time as is required to fulfill their obligations to the Administrator.

Messrs. Tremblay, Prokop and Bovingdon are executive officers of the Administrator and will be employed by Aston Hill in accordance with the terms of the Services Agreement, which will be entered into concurrently with closing of the Offering. The Administrator's officers will serve at the discretion of the Administrator Directors.

**Directors and Executive Officers Biographical Information**

The following are brief profiles of each of the executive officers and directors of the Administrator, which includes a description of their present occupation and their principal occupations for the past five years.

***Brian Prokop, Director and Chief Executive Officer***

Mr. Prokop is the Chief Executive Officer and a director of the Administrator and was appointed to such office in August of 2011. Mr. Prokop has over 28 years of operational and financial experience in the oil and gas industry, at both banking institutions and corporations. Mr. Prokop is employed by Aston Hill and provides his services to the Administrator pursuant to the Services Agreement. Prior to his appointment as the Chief Executive Officer of the Administrator, Mr. Prokop had been the Vice President, Capital Markets of Daylight Energy Ltd. (an oil and gas company) until June 2011. Previously he served as Director, Institutional Equity Sales, Energy Specialist at National Bank Financial from December of 2007 to April of 2010 establishing the Calgary Institutional Sales Desk, prior to which he served as Vice President, Oil and Gas Specialist, Institutional Equity Sales at Canaccord Capital Corporation from May of 2005 to November of 2007 dealing with North American and European institutions with a specific emphasis on energy companies and royalty trusts. Prior thereto, Mr. Prokop was a sell-side analyst providing Canadian and U.S. equity and income trust coverage, and macroeconomic industry analysis. Mr. Prokop has also held executive technical and financial roles with Talisman Energy Inc. and Shell Canada Ltd. Mr. Prokop has a Bachelor of Science (Geological Engineering) from the University of Manitoba, a Master of Business Administration from the University of Calgary, and is a Chartered Financial Analyst. Mr. Prokop received the designation of a Professional Engineer in 1986.

***Richard Louden, Director and President***

Mr. Louden is the current President and Chief Executive Officer of Denali and, upon closing of the Offering, will be appointed as the President of the Administrator. Mr. Louden has over 30 years of operation and management experience. Prior to joining Denali, Mr. Louden held senior positions with El Paso Corporation, Coastal Corporation, Union Texas Petroleum Holdings, Inc. and Amoco Corporation. Mr. Louden graduated from Louisiana Tech University in 1978 with a Bachelor of Science degree in Mechanical Engineering.

***Sean Bovingdon, Chief Financial Officer***

Mr. Bovingdon is the Chief Financial Officer of the Administrator and was appointed to such office in August of 2011. Mr. Bovingdon is employed by Aston Hill and provides his services to the Administrator pursuant to the Services Agreement. Mr. Bovingdon has over 20 years of financial executive experience, most recently as the Chief Financial Officer of Petrodorado Energy Ltd. (an oil and gas company) and prior thereto as Vice-President Finance and Chief Financial Officer of Great Plains Exploration Inc. (an oil and gas company) from March 2007 until its sale in November 2010. Previously, Mr. Bovingdon was the Vice President Finance and Chief Financial Officer of Fuel-x International Inc., (an oil and gas company) from October 2005 until February 2007. Mr. Bovingdon also held senior financial positions with Western Oil Sands Inc. and Electronics Manufacturing Group Inc. and commenced his career with KPMG LLP in London, England and Calgary, Alberta. Mr. Bovingdon has a Bachelor of Arts (Honours) in Accounting and Economics from the University of Kent and is a member of the Institute of Chartered Accountants in England and Wales.

***John Elzner, Senior Vice-President***

Mr. Elzner has over 31 years of experience in the international oil and gas industry. He has served as the Senior Vice President of Denali for eight years, overseeing all matters of business development, land, legal and marketing, including direction and execution for all acquisitions and divestitures. Prior to joining Denali, Mr. Elzner served in various senior executive positions for Coastal Corporation and El Paso Corporation, most recently therein as Senior Vice President of South American E&P Operations for El Paso. He graduated in 1978 with a MSc from Texas A&M University.

***Eric Tremblay, Director and Executive Chairman***

Mr. Tremblay is the Chief Executive Officer of Aston Hill Financial Inc. (an asset management company) since December 2006 and Chief Executive Officer of Catapult Energy 2008 Inc., a wholly-owned subsidiary of Aston Hill and the General Partner of Catapult Energy 2008 FTS Limited Partnership (a non-redeemable investment fund) since

August 19, 2008. He has over 18 years of executive experience acquiring, producing and developing oil & gas assets in Canada and the U.S. Mr. Tremblay served as Senior Vice President, Capital Markets of Enerplus Resources Fund (an oil and gas income trust) from September 2000 to June 2006 and was a Director from April 2000 until April 2005. Mr. Tremblay had served as Senior Vice President, Corporate Development of Enerplus Resources Fund since January 2000 and prior thereto was Vice President, Corporate Development of Enerplus Resources Fund. Mr. Tremblay has also held positions with British Petroleum p.l.c., Canadair Ltd. (a subsidiary of Bombardier Inc.) and the Boeing Company. Mr. Tremblay graduated in 1989 from Ryerson University in Toronto with a Bachelor of Engineering degree in Aerospace Engineering.

***John Brussa, Director***

Mr. Brussa is a senior partner and head of the Tax Department at the law firm of Burnet, Duckworth & Palmer LLP. He has been a partner since 1987 and has worked at the firm since 1981. Mr. Brussa's current practice includes structured finance, taxation of international energy operations, corporate and income trust restructuring and reorganization, dispute resolution and acquisitions and divestitures. Mr. Brussa has lectured extensively to the Canadian Tax Foundation, the Canadian Institute, the Canadian Petroleum Tax Society and Insight. Mr. Brussa is also a director of a number of energy and energy-related corporations and is a member and former Governor of the Executive Committee of the Canadian Tax Foundation. Mr. Brussa attended the University of Windsor and received his Bachelor of Arts in History and Economics in 1978 and his Bachelor of Laws in 1981.

***Scott Butler, Director***

Mr. Butler's career includes over 20 years in the investment banking industry. Mr. Butler has extensive experience raising capital, notably for royalty trusts and companies in the oil and gas sector, including serving as Managing Director at CIBC World Markets Inc. where he worked for 14 years until his retirement in August of 2006. Mr. Butler attended Concordia University and received his Bachelor of Arts in 1976.

***William D. Robertson, Director***

Mr. Robertson is a Fellow Chartered Accountant and was formerly the lead oil and gas specialist at PricewaterhouseCoopers LLP in Calgary, Alberta. After a 36 year career with PricewaterhouseCoopers LLP, Mr. Robertson retired from practice in 2002. Prior to this, he served on the CIM Petroleum Society Standing Committee on Reserve Definitions, as well as a number of other committees overseeing the practice of accounting in Alberta. Mr. Robertson graduated with a Bachelor of Commerce degree from the University of Alberta.

***Glen C. Schmidt, Director***

Mr. Schmidt is currently President and Chief Executive Officer of Laricina Energy Ltd. and has held his position since 2005. Prior to his current position he was President, Chief Executive Officer and director of Deer Creek Energy Limited since 2001. Mr. Schmidt has 30 years of oil and gas experience with more than 20 years at the executive level. Formerly, Mr. Schmidt was President of Torex Resources Ltd. and Pioneer Natural Resources Canada Inc. and was previously the Vice President Canada at Chauvco Resources Ltd. and Vice President Production and Engineering at Mark Resources Inc. Mr. Schmidt holds both a Master of Business Administration and Bachelor of Science in Chemical Engineering (with Distinction) from the University of Calgary and is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

***Security Ownership by Directors and Officers***

As at the date hereof, the Administrator Directors and executive officers of the Administrator beneficially own or exercise control or direction over, directly or indirectly, 112,000 Units. Following the completion of the Offering, the Administrator Directors and executive officers of the Administrator are expected to beneficially own or exercise control or direction over, directly or indirectly, approximately 220,000 Units, representing approximately 1.0% of the issued and outstanding Units (excluding Units issuable pursuant to the exercise of the Over-Allotment Option).

## Cease Trade Orders, Bankruptcies, Penalties or Sanctions

### *Cease Trade Orders*

To the knowledge of the Administrator, except as described under the heading "Trustee, Directors and Management – Cease Trade Orders, Bankruptcies, Penalties or Sanctions – Bankruptcies", no director or executive officer of the Administrator (nor any personal holding company of any of such persons) is, as of the date of this prospectus, or was within ten years before the date of this prospectus, a director, chief executive officer or chief financial officer of any company (including the Administrator), that: (a) was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**"), that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (b) was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

### *Bankruptcies*

To the knowledge of the Administrator, other than as disclosed herein, no director or executive officer of the Administrator (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of the Administrator to affect materially the control of the Administrator: (a) is, as of the date of this prospectus, or has been within the ten years before the date of this prospectus, a director or executive officer of any company (including the Administrator) that, while that 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 or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (b) has, within the ten years before the date of this prospectus, 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, executive officer or shareholder.

Mr. Bovingdon was a director and the acting Chief Financial Officer of Elite Technical Inc., a manufacturing company that was listed on the TSX Venture Exchange, which was put into receivership and declared bankruptcy in November 2005. Elite Technical Inc. was subsequently made subject to a cease trade order by the Alberta Securities Commission and the British Columbia Securities Commission for failing to file interim and annual financial statements.

Mr. Brussa was a director of Imperial Metals Limited, a corporation engaged in both oil and natural gas and mining operations, in the year prior to that corporation implementing a plan of arrangement under the *Company Act* (British Columbia) and under the *Companies' Creditors Arrangement Act* (Canada) which resulted in the separation of its two businesses. The reorganization resulted in the creation of two public corporations, Imperial Metals Corporation and IEI Energy Inc. (subsequently Rider Resources Ltd.), both of which were traded on the TSX following the reorganization.

### *Penalties or Sanctions*

To the knowledge of the Administrator, other than as disclosed herein, no director or executive officer of the Administrator (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of the Administrator to affect materially the control of the Administrator, 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 officers and directors of the Administrator are also officers and/or directors of other companies engaged in the oil and natural gas business generally. As a result, situations may arise where the duties of such directors and officers of the Administrator conflict with their interests as directors and officers of other companies. In addition, Messrs. Tremblay, Prokop and Bovingdon are each directors and/or officers of the Administrator and are also directors, officers and/or employees of Aston Hill. The Administrator will be reliant to a significant degree on Aston Hill for certain technical and administrative services pursuant to the Services Agreement. As a result, situations may arise where the duties of certain officers and directors of the Administrator conflict with their interests as directors, officers and/or employees of Aston Hill. The resolution of such conflicts is governed by applicable corporate laws, which require that directors and officers act honestly, in good faith and with a view to the best interests of the Administrator and in the case of conflicts between the Trust, the Administrator and Aston Hill such will be dealt with in accordance with the Services Agreement and the ABCA and, in certain circumstances could result in the termination of the Services Agreement by the Administrator. See "Administration of the Trust – Services Agreement with Aston Hill". The ABCA provides that in the event that a director or officer has an interest in a contract or proposed contract or agreement, the director or officer shall disclose his interest in such contract or agreement and, in the case of a director, shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA. Management is not aware of any existing or potential material conflicts of interest between the Administrator, the Trust or a subsidiary of the Trust and a director or officer of the Administrator.

**Insurance Coverage and Indemnification**

The Administrator obtained a policy of insurance for the Administrator Directors, officers of the Administrator and the directors and officers of Can Holdco and US Opco. Under the policy, each entity has reimbursement coverage to the extent that it has indemnified the directors and officers. The policy includes securities claims coverage, insuring against any legal obligation to pay on account of any securities claims brought against the Trust, the Administrator, Can Holdco, US Opco and any of their respective subsidiaries and their respective trustees, directors and officers. The total limit of liability is shared among the Trust, the Administrator, Can Holdco and US Opco and their respective subsidiaries and their respective trustees, directors and officers so that the limit of liability will not be exclusive to any one of the entities or their respective trustees, directors and officers.

The by-laws of the Administrator, Can Holdco and US Opco provide for the indemnification of its directors and officers from and against liability and costs in respect of any action or suit brought against them in connection with the execution of their duties of office, subject to certain limitations. The Trust Indenture also provides for the indemnification of the Administrator Directors from and against liability and costs in respect of any action or suit brought against them in connection with the execution of their duties of office, subject to certain limitations.

Under the Administrative Services Agreement, the Administrator, its affiliates and associates and any person who is serving or shall have served as a director, officer, employee or agent of the Administrator, Can Holdco or US Opco, or of their respective affiliates or associates, will be indemnified by the Trust in respect of such activities undertaken on its behalf unless the claim arises from the fraud, willful misconduct, gross negligence or breach of the standard of care required under the Administrative Services Agreement of the person claiming indemnification.

## CORPORATE GOVERNANCE

The Administrator Directors consider good corporate governance to be central to the effective and efficient operation of the Trust and its subsidiaries. The Canadian Securities Administrators have published guidelines for issuers to consider in developing their own corporate governance practices. Annual disclosure of those practices is required. The Administrator's corporate governance practices are set forth below.

### The Board

The Administrator has seven directors, four of whom are independent. A director is independent if he or she has no direct or indirect material relationship with the Trust, its subsidiaries or the Administrator. A "material relationship" is a relationship which could, in the view of the Board, be reasonably expected to interfere with the exercise of a director's independent judgment. Certain types of relationships are, by their nature, considered to be material relationships.

Directors John Brussa, Scott Butler, Glen C. Schmidt and William D. Robertson are independent. Eric Tremblay is not an independent director because he is an executive officer of Aston Hill, an affiliate of the Administrator Shareholder, and Brian Prokop and Richard Louden are not independent because they are executive officers of the Administrator.

The current Chairman of the Board is not independent for the purposes of NI 52-110. However, in order to provide leadership for Administrator Directors that are independent, an Administrator Director that is independent will, as required from time to time, chair meetings of independent Administrator Directors and assume other responsibilities.

The Administrator will take steps to ensure that adequate structures and processes are in place to permit the Board to function independently of management of the Administrator. Where matters arise at meetings of the Board which require decision making and evaluation that is independent of management and interested directors, the Administrator Directors will hold an "in-camera" session among the independent and disinterested Administrator Directors, without management present at such meeting.

Certain Administrator Directors are also directors of other reporting issuers (or the equivalent):

| Director | Other Directorships | Stock Exchange Listing |
|---|---|---|
| John Brussa . . . . . . . . . . | Baytex Energy Corp. | TSX and New York Stock Exchange |
| | Calmena Energy Services Inc. | TSX |
| | Chinook Energy Inc. | TSX |
| | Crew Energy Inc. | TSX |
| | Deans Knight Income Corporation | TSX |
| | Enseco Energy Services Corp. | TSX Venture Exchange |
| | Guide Exploration Ltd. | TSX |
| | Just Energy Group Inc. | TSX |
| | North American Energy Partners Inc. | TSX and New York Stock Exchange |
| | Penn West Petroleum Ltd. | TSX and New York Stock Exchange |
| | Pinecrest Energy Inc. | TSX Venture Exchange |
| | Progress Energy Resources Corp. | TSX |
| | RMP Energy Inc. | TSX |
| | Storm Resources Ltd. | TSX Venture Exchange |
| | Twin Butte Energy Ltd. | TSX |
| | WestFire Energy Ltd. | TSX |
| | Yoho Resources Inc. | TSX Venture Exchange |
| William Robertson . . . . | Harvest Operations Corp. | TSX |
| | Inter Pipeline Fund | TSX |
| Eric Tremblay . . . . . . . . | Aston Hill Financial Inc. | TSX |

## Mandate

The Board has responsibility for the overall stewardship of both the Trust and its direct and indirect subsidiaries (the "**Argent Group**"), and Management has responsibility for conducting the day to day business of the Trust. The Board discharges this responsibility directly and indirectly through the delegation of specific responsibilities to committees of the Board, the Chairman of the Board, and the officers of the Administrator, all as more particularly described in the Board of Directors' Mandate, a copy of which is attached to this prospectus as Appendix F. The Mandate provides that the primary responsibilities of the Board are to (i) enhance and preserve long term Unitholder value, (ii) approve the strategy of the Argent Group to ensure the long term success of the Argent Group, (iii) oversee the business and affairs of the Argent Group in accordance with the terms of all applicable laws and (iv) ensure that the Argent Group meets its obligations on an ongoing basis and operates in a reliable and safe manner.

The Board has established three committees to assist with its responsibilities: the Audit Committee, the Reserves & Environment, Health & Safety Committee and the Governance, Nomination & Compensation Committee. Each committee has a charter defining its responsibilities.

## Position Descriptions

The Board has adopted written position descriptions for the Executive Chairman of the Board, the Chair of each of the Audit Committee, Governance, Nomination & Compensation Committee and Reserves & Environment, Health & Safety Committee and the Chief Executive Officer of the Administrator.

The primary responsibilities of the Executive Chairman of the Board include (i) ensuring that the Board is organized properly, functions effectively and meets its oversight obligations and responsibilities in all aspects of its work and (ii) working with the President, and Chief Executive Officer of the Administrator to coordinate the affairs of the Board and ensure effective relations with the Administrator Directors, Management and Unitholders.

The responsibilities of the Chair of each committee include (i) ensuring that their respective committee is organized properly, functions effectively and meets its obligations and responsibilities in accordance with its mandate and (ii) reporting to the Board on any decision or recommendation of their committee.

The primary responsibilities of the Chief Executive Officer of the Administrator include (i) providing overall leadership and vision in developing, in concert with the members of the Board, the strategic direction of the Argent Group and the tactics and business plans necessary to realize the Argent Group's objectives and (ii) managing the overall business to ensure strategic and business plans are effectively implemented, results are monitored and reported to the Board, and financial and operational objectives are attained.

## Orientation and Continuing Education

The orientation and continuing education of the Administrator Directors is the responsibility of the Governance, Nomination & Compensation Committee. The details of the orientation of new Administrator Directors will be tailored to their needs and areas of expertise and will include the delivery of written materials and participation in meetings with Management and Administrator Directors. The focus of the orientation program will be on providing new Administrator Directors with (i) information about the duties and obligations of directors, (ii) information about the Argent Group's strategy, business and operations, (iii) the expectations of Administrator Directors, (iv) opportunities to meet with Management and any other senior employees or consultants designated for this purpose and (v) access to documents from recent meetings of the Board.

The Administrator Directors have all been chosen for their specific level of knowledge and expertise. All Administrator Directors will be provided with materials relating to their duties, roles and responsibilities. In addition, Administrator Directors will be kept informed as to matters impacting, or which may impact, the Trust's operations through reports and presentations by internal and external presenters at meetings of the Board and during periodic strategy sessions held by the Board. Administrator Directors may periodically take part in site visits to well sites and facility locations in the field to observe the Argent Group's operations for themselves.

**Ethical Business Conduct**

The Board will adopt a written code of business conduct that encourages and promotes a culture of ethical business conduct that will be applicable to Administrator Directors, Management, employees and consultants of the Administrator. Upon the adoption of a code of business conduct, the Administrator will file a copy on SEDAR at www.sedar.com. In addition, the Board will implement a "whistle blower" policy whereby directors, officers, employees and consultants will be encouraged to report unethical behavior directly to Board members.

**Nomination of Administrator Directors**

The responsibility for proposing new nominees for the Board falls within the mandate of the Governance, Nomination & Compensation Committee. The Governance, Nomination & Compensation Committee is comprised of John Brussa, as Chairman and Scott Butler, both of whom are independent. New candidates for nomination to the Board will be identified and selected having regard to the strengths and constitution of the Board and the needs of the Board. The Governance, Nomination & Compensation Committee is responsible for determining the size of the Board and its composition, identifying the skills, experience and capability required by the Board to discharge its oversight responsibilities, organizing the process for recruiting new members of the Board and providing orientation to such members and structuring the membership of committees of the Board.

**Compensation of Directors and Officers**

The remuneration of the Administrator Directors will be set and periodically reviewed by the Board on the recommendation of the Governance, Nomination & Compensation Committee. The level of remuneration will be designed to provide a competitive level of remuneration relative to directors of comparable energy trusts and corporations. Consultants may be periodically retained to obtain this information and to assess the Board's relative remuneration position.

The Services Agreement will provide for the initial salaries and benefits of Messrs. Tremblay, Prokop and Bovingdon for the period ended December 31, 2012 (calculated and paid on a *pro rata* basis for the 11 month period from February 1, 2012 to December 31, 2012), which amounts will not be subject to modification during this initial period except as otherwise provided in the Services Agreement. The salaries and benefits for Messrs. Tremblay and Bovingdon will be reviewed and determined annually beginning in 2013, and bonuses will be reviewed and determined annually beginning with the bonus for the 2012 calendar year, by Aston Hill, subject to the recommendation and approval of the Governance, Nomination & Compensation Committee, which Aston Hill shall comply with. The salaries and benefits for Mr. Prokop will be reviewed and determined annually beginning in 2013, and bonuses will be reviewed and determined annually beginning with the bonus for the 2012 calendar year, by Aston Hill, subject to the recommendation and approval of the Board on the recommendation of the Governance, Nomination & Compensation Committee, which Aston Hill shall comply with. The salaries, bonuses and benefits of Mr. Louden will be considered annually beginning with the remainder of the 2012 calendar year by the Governance, Nomination & Compensation Committee and may be modified at such time in the sole discretion of the Board on the recommendation of the Governance, Nomination & Compensation Committee. The salaries, bonuses and benefits of Mr. Elzner will be considered annually beginning with the remainder of the 2012 calendar year by the Governance, Nomination & Compensation Committee and may be modified at such time in the sole discretion of that Committee.

**Board Committees**

The Board has formally appointed three standing committees: the Audit Committee, the Governance, Nomination & Compensation Committee and the Reserves & Environment, Health & Safety Committee.

***Audit Committee***

The Audit Committee is comprised of William D. Robertson, as Chairman, and Scott Butler and Glen C. Schmidt, all of whom are independent and financially literate for purposes of NI 52-110. The specific responsibilities of the Audit Committee are set out in the Audit Committee Charter, a copy of which is attached to this prospectus as Appendix E. The Audit Committee Charter will be filed on SEDAR at www.sedar.com. The committee's primary role is to assist the Board in fulfilling its oversight responsibilities regarding the integrity, accuracy and completeness of the Trust's consolidated financial statements and related management discussion and analysis, the design and implementation of an effective system of internal financial controls and disclosure controls and procedures for the Argent Group; the selection (subject to approval by Unitholders), engagement, and monitoring of the activities of the Trust's external auditor and the Argent Group's risk management strategy; the Argent Group's compliance with legal, statutory and regulatory requirements as they relate to financial statements and taxation matters; and any additional duties delegated to it by the Board.

The Trust believes that each of the members of the Audit Committee possesses: (i) an understanding of the accounting principles used by the Trust to prepare its financial statements; (ii) the ability to assess the general application of such accounting principles in connection with the accounting for estimates, accruals and reserves; (iii) 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 Trust's financial statements, or experience actively supervising one or more individuals engaged in such activities; and (iv) an understanding of internal controls and procedures for financial reporting. For a summary of the education and experience of each member of the Audit Committee that is relevant to the performance of his responsibilities as a member of the Audit Committee, see "Trustee, Directors and Management – Directors and Executive Officers Biographical Information".

***Governance, Nomination & Compensation Committee***

The Governance, Nomination & Compensation Committee is comprised of John Brussa, as Chairman, and Scott Butler, both of whom are independent for the purposes of National Instrument 58-101 – *Disclosure of Corporate Governance Practices*. The specific responsibilities of the Governance, Nomination & Compensation Committee are set out in the Governance, Nomination & Compensation Committee Charter, a copy of which will be available on the Trust's website upon closing of the Offering. The primary role of the Governance, Nomination & Compensation Committee is to develop and monitor governance standards and best practices; review the mandates of the Board and its committees; regularly assess the effectiveness of the Board as a whole, the committees of the Board and the contributions of individual Administrator Directors; oversee the preparation of the annual "Statement of Corporate Governance Practices"; evaluate corporate communication policies; identify and recommend individuals for nomination as members of the Board and its committees and for appointment as officers; review and recommend to the Board all matters pertaining to the compensation of Administrator Directors and the Chief Executive Officer and President of the Administrator; and consider and modify all matters pertaining to the compensation of Management, other than the Chief Executive Officer and President of the Administrator.

***Reserves & Environment, Health & Safety Committee***

The Reserves & Environment, Health & Safety Committee is comprised of Glen C. Schmidt, as Chairman, Richard Louden and William D. Robertson, of whom Glen C. Schmidt and William D. Robertson are independent for purposes of NI 51-101. The specific responsibilities of the Reserves & Environment, Health & Safety Committee are set out in the Reserves & Environment, Health & Safety Committee Charter, a copy of which will be availible on the Trust's website upon closing of the Offering. The Reserves & Environment, Health & Safety Committee is responsible for assisting the Board in fulfilling its oversight responsibilities in the annual review of the Argent Group's petroleum and natural gas reserves; for considering, reviewing and reporting to the Board in respect of the appointment of independent consultants to assist the Argent Group in its annual evaluation of petroleum and natural gas reserves; for developing and monitoring the approach of the Argent Group to environmental, health and safety matters; and for performing any additional duties delegated to it by the Board.

**Assessment of Administrator Directors, the Board and Board Committees**

The members of the Board will collectively assess the performance of the Board as a whole, the committees of the Board and all Administrator Directors. Such assessment will occur annually with an emphasis on the overall effectiveness and contributions made by the Board as a whole, the committees of the Board and all Administrator Directors individually.

## ADMINISTRATION OF THE TRUST

### Administrative Services Agreement

The following is a summary of the material terms of the Administrative Services Agreement pursuant to which the Trustee has delegated to the Administrator responsibility for the general administration of the affairs of the Trust. The description below is qualified by reference to the text thereof. See "Material Contracts".

The Administrator will provide administrative services to the Trust. These arrangements are set forth in the Administrative Services Agreement. In exercising its powers and discharging its duties under the Administrative Services Agreement, the Administrator will be required to act honestly, in good faith and in the best interests of the Trust and exercise the degree of care, diligence and skill that a reasonably prudent administrator having responsibility for services similar to the Administrative Services (as defined below) would exercise in comparable circumstances.

Pursuant to the Administrative Services Agreement, the Administrator will, on an exclusive basis, perform or procure all administrative, operational and investment services as may be required to administer the operations of the Trust, other than the excluded services described below (the "**Excluded Services**").

The services the Administrator will provide to the Trust (the "**Administrative Services**") shall be in addition to the Indenture Conferred Duties (as defined in the Trust Indenture). The services to be provided under the Administrative Services Agreement will include the following: (i) preparing all returns, filings and other documents and taking all other actions necessary to discharge the Trustee's obligations under the Trust Indenture; (ii) assisting with the calculation of distributions to Unitholders, withholding all amounts required by applicable tax law, and making the remittances and filings in connection with such withholdings; (iii) providing investor relations services; (iv) performing all services in connection with acquiring or disposing of assets and property; (v) establishing, and implementing and amending distribution reinvestment plans, Unit purchase plans and incentive option or other compensation plans; (vi) calling and holding all annual and/or special meetings of Unitholders pursuant to the Trust Indenture and preparing, approving and arranging for the distribution of all materials including notices of meetings and information circulars in respect thereof; (vii) preparing and causing to be provided to Unitholders on a timely basis all information to which Unitholders are entitled under the Trust Indenture and under applicable laws; (viii) engaging and overseeing third party providers of services to the Trust in connection with provision of Administrative Services; (ix) monitoring the Trust's status as a "mutual fund trust" and a "unit trust" within the meaning of Tax Act and providing the Trustee with written notice when the Trust ceases or is at risk of ceasing to be such a unit trust or such a mutual fund trust; (x) monitoring the Trust's investment and holding in or of property to ensure that the Trust (A) is not at any time a SIFT trust, and (B) does not hold any "non-portfolio property" as defined in the Tax Act; (xi) monitoring the investments of the Trust to ensure that they comply with the investment restrictions in the Trust Indenture; (xii) monitoring the status of the Trust to ensure the Units are a "qualified investment" for a Registered Plan, and providing the Trustee with written notice when the Units cease, or are at risk of ceasing, to so qualify; (xiii) monitoring the Trust's compliance with subsection 132(7) of the Tax Act and Section 3.8 of the Trust Indenture; (xiv) undertaking, performing and providing for and on behalf of the Trust, all acts, duties and responsibilities necessary or desirable in connection with, or for completion of, any sale of securities of the Trust from time to time; (xv) delegating to and overseeing US Opco in connection with the day to day operational services and management of the Trust's subsidiaries' oil and gas business; and (xvi) providing all other services as may be necessary, or requested by the Trustee, for the administration of the Trust.

The Excluded Services include the following: (i) the issue, certification, exchange or cancellation of Units after the closing date of the Offering; (ii) the maintenance of registers of Unitholders after the closing date of the Offering; (iii) making the distribution of payments or property to Unitholders and statements in respect thereof; (iv) any mailings to Unitholders; (v) executing any amendment to the Trust Indenture or any amended and restated Trust Indenture following any amendment thereto; (vi) voting securities owned by the Trust at any and all meetings of holders of such securities, or exercising any rights to pass resolutions in lieu of securityholder meetings; and (vii) any matters ancillary or incidental to any of those set forth in (i) through (vi) immediately above.

#### *Fees and Expenses*

Under the Administrative Services Agreement, the Administrator will receive no fees in consideration of the services it provides as Administrator of the Trust. The Administrator will be entitled to the reimbursement of all costs and expenses reasonably incurred by the Administrator in carrying out its obligations and duties under the Administrative Services Agreement, including costs and expenses incurred by the Administrator under the Services Agreement with Aston Hill.

***Reliance, Limitation of Liability and Indemnification***

The Administrative Services Agreement provides that, in carrying out the Administrative Services, the Administrator and its delegates will be entitled to rely on: (a) statements of fact of other persons (any of which may be persons with whom the Administrator is affiliated or associated) who are considered by the Administrator to be knowledgeable of such facts, provided that the Administrator has satisfied its standard of care under the Administrative Services Agreement in making the assessment as to whether such persons are knowledgeable of such facts (each, a "**Knowledgeable Person**"); and (b) statements from, the opinion or advice of, or information from any solicitor, auditor, valuator, financial advisor, engineer, surveyor, appraiser or other expert selected by the Administrator ("**Experts**"), provided that the Administrator has satisfied its standard of care under the Administrative Services Agreement in selecting such Expert to provide such statements, opinion, advice or information.

The Administrative Services Agreement provides that the Administrator, its affiliates and associates and any of their respective directors, officers, employees, contractors and agents (collectively, the "**Administrator Service Providers**"), will not, either directly or indirectly, be liable, answerable or accountable to the Trust, the Trustee or any beneficiary for: (i) any loss or damage resulting from, incidental to or relating to the performance or non-performance of the Administrative Services by any of the Administrator Service Providers, or any act or omission believed by an Administrator Service Provider to be within the scope of authority conferred thereon by the Administrative Services Agreement or the Trust Indenture, unless such loss or damage resulted from the fraud, willful misconduct or gross negligence of a Administrator Service Provider in which case the benefit of this limitation will not apply to such Administrator Service Providers; (ii) any loss or damage resulting from the performance or non-performance of the Administrative Services by any of the Administrator Service Providers, where such loss or damage is attributable to acting in accordance with the instructions of the Trustee, provided that the Administrator Service Providers will bear, on a several basis, their proportionate share of liability in the event of joint or contributory liability with the Trustee; (iii) any loss or damage resulting from any act or omission by any of the Administrator Service Providers, provided that such act or omission is based upon the Administrator Service Provider's reliance on (A) statements of fact of Knowledgeable Persons (excluding persons with whom the Administrator is affiliated); or (B) the opinion or advice of or information obtained from any Expert; and (iv) any damage, injury or loss of an indirect or consequential nature, including loss of profits, suffered by the Trust, the Trustee or any beneficiary, or any of their respective affiliates, which is in any way connected with the activities, investments or affairs of the Trust or the performance or non-performance of the Administrative Services or any other aspect of the Administrative Services Agreement or the Trust Indenture.

The Administrative Services Agreement provides that the Administrator, its affiliates, associates and any person who is serving or shall have served as a director, officer, employee or agent of the Administrator, Can Holdco or US Opco, or of their respective affiliates or associates and any respective heirs, legal representatives and successors of the foregoing (collectively the "**Administrator Indemnitees**"), will be indemnified out of the Trust's property from and against all losses, claims, damages, liabilities, obligations, costs and expenses (including judgments, fines, penalties, amounts paid in settlement (with the approval of the Trustee, acting reasonably), legal fees and disbursements) ("**Claims**") incurred by, borne by or asserted against any of the Administrator Indemnitees and which in any way arise from or relate in any manner to the Administrative Services Agreement, the Trust Indenture, or the performance or non-performance of the Administrative Services, unless such Claims arise from the fraud, willful misconduct, gross negligence or breach of the terms and conditions of the Administrative Services Agreement, of any of the Administrator Indemnitees, provided that in such case only the Administrator Indemnitee guilty of the same will lose its right of indemnity as long as such Administrator Indemnitee was delegated its responsibility in accordance with the Administrator's standard of care under the Administrative Services Agreement.

The Administrative Services Agreement further provides that, subject to limitations on liability of the Administrator described above, the Trust, the Trustee and any person who is serving or shall have served as a director, officer or employee of the Trustee and any respective heirs, legal representatives and successors of the foregoing (the

"**Trust Indemnitees**") will be indemnified by the Administrator from and against all losses, claims, damages, liabilities, obligations, costs and expenses (including judgments, fines, penalties, amounts paid in settlement (with the approval of the Administrator, acting reasonably), legal fees and disbursements) ("**Trust Claims**") incurred by, borne by or asserted against any of the Trust Indemnitees and which arise from the fraud, willful misconduct or gross negligence of the Administrator in the performance of the Administrative Services, unless such Trust Claims arise from the fraud, willful misconduct or gross negligence on the part of a Trust Indemnitee, or are attributable to actions undertaken on the specific instructions of the Trustee.

***Term and Termination***

The Administrative Services Agreement will have an initial term to December 31, 2012 and will be automatically renewable for additional successive terms of one year unless terminated by the Administrator on prior written notice which is provided at least 30 days before the expiry of the initial term or any renewal term. The Administrative Services Agreement will also provide that it may, by written notice given by one party to the other, be immediately terminated in the event of (i) certain events of bankruptcy, insolvency, receivership or liquidation of the other party or (ii) a breach by the other party in the performance of a material obligation, covenant or responsibility under the agreement (other than as a result of the occurrence of a force majeure event) which is not remedied, or when not reasonably capable of being remedied within 60 days, such party nonetheless fails to commence and diligently pursue steps to remedy such default, within 60 days after notice of such breach has been delivered; provided that, prior to the Trust or any of its affiliates (as applicable) being entitled to terminate the Administrative Services Agreement for breach by the Administrator of performance of a material obligation, receipt of approval of the Unitholders by Ordinary Resolution must be obtained authorizing such termination.

A change of control (as such term is defined in the Administrative Services Agreement) of the Administrator will require the prior consent of the Unitholders by Ordinary Resolution, provided that the shares of the Administrator may be transferred in compliance with the terms and conditions of the Voting Agreement without the prior consent of the Unitholders. The Administrative Services Agreement will permit the Administrator to delegate its responsibilities, but no such delegation will relieve the Administrator of its responsibility for ensuring the performance of its duties and obligations under each such agreement. If, however, the Administrator delegates its responsibilities to a third party and in so doing does not breach its standard of care under the Administrative Services Agreement, the Administrator will not be liable for the acts or omissions of such delegate (except where such delegate is an affiliate of the Administrator). It is anticipated that the Administrator may, from time to time, delegate certain responsibilities to the GP, which shall not constitute a breach of its standard of care.

**Services Agreement with Aston Hill**

The following is a summary of the material terms of the Services Agreement pursuant to which Aston Hill will provide certain technical and administrative services to the Trust. The description below is qualified by reference to the text thereof. See "Material Contracts".

The Trust and the Administrator will enter into the Services Agreement with Aston Hill, pursuant to which Aston Hill will, on a non-exclusive basis, provide or procure certain technical and administrative services that are or may be required for the Administrator to perform its duties and satisfy its obligations pursuant to the Administrative Services Agreement. Such services will include the provision of certain staff required by the Administrator; office space, furniture and day-to-day office supplies and services; accounting, payroll, information technology and the maintenance of books and records; and assistance with all continuous disclosure obligations of the Trust. The Services Agreement will also provide for the provision of services by Eric Tremblay, Brian Prokop and Sean Bovingdon, the Executive Chairman, Chief Executive Officer and Chief Financial Officer of the Administrator, respectively. Messrs. Tremblay, Prokop and Bovingdon will be employees of Aston Hill. Mr. Tremblay will discharge his duties as an Administrator Director and Messrs. Prokop and Bovingdon will devote 100% of their time to the Argent Group in their roles as Chief Executive Officer and Chief Financial Officer of the Administrator, respectively. US Opco will employ all of the other executive officers of the Administrator and the employees needed to operate the business of US Opco and the services performed by such individuals will not form part of the services being provided by Aston Hill pursuant to the Services Agreement.

Aston Hill, the sole shareholder of the Administrator Shareholder, is an asset management company that offers its clients expertise in several areas including managing institutional private equity energy investments, which includes the purchase, development and sale of oil and gas properties; and fund management and portfolio advisory of mutual funds, closed end funds and hedge funds tailored to income, energy and other sectors. Aston Hill conducts business essentially along two distinct lines: (i) oil and gas property management, for which there are three full-time personnel engaged with technical and financial expertise specific to the oil and gas industry; and (ii) financial portfolio management and advisory services, for which there are 43 employees engaged. Aston Hill's multidisciplinary team includes a management team with significant expertise in equity, income trust, royalty trust, fixed income, credit and alternative investment management.

***Executive Compensation and Employment Matters***

The executive officers of the Administrator are Eric Tremblay (Executive Chairman), Brian Prokop (Chief Executive Officer), Richard Louden (President), Sean Bovingdon (Chief Financial Officer), and John Elzner (Senior Vice-President). The Services Agreement will provide for the initial salaries and benefits of Messrs. Tremblay, Prokop and Bovingdon for the period ended December 31, 2012 (calculated and paid on a *pro rata* basis for the 11 month period from February 1, 2012 to December 31, 2012), which amounts will not be subject to modification during this initial period except as otherwise provided in the Services Agreement. The salaries and benefits for Messrs. Tremblay and Bovingdon will be reviewed and determined annually beginning in 2013, and bonuses will be reviewed and determined annually beginning with the bonus for the 2012 calendar year, by Aston Hill, subject to the recommendation and approval of the Governance, Nomination & Compensation Committee, which Aston Hill shall comply with. The salary and benefits for Mr. Prokop will be reviewed and determined annually beginning in 2013, and bonuses will be reviewed and determined annually beginning with the bonus for the 2012 calendar year, by Aston Hill, subject to the recommendation and approval of the Board on the recommendation of the Governance, Nomination & Compensation Committee, which Aston Hill shall comply with. The salaries, bonuses and benefits of the other executive officers will be determined by the Board and/or the Governance, Nomination & Compensation Committee as set forth under the heading "Executive Compensation".

The Board may, in its sole discretion, remove any officer of the Administrator (including any officer whose services are provided pursuant to the Services Agreement and who has been designated as an officer of the Administrator). If the Board removes an officer who provides services pursuant to the Services Agreement for any reason other than misconduct or poor performance by the officer equivalent to just cause for termination of employment, and if as a direct result of such removal the employment agreement between the officer and Aston Hill is terminated and severance is paid to the officer by Aston Hill, the Administrator will reimburse Aston Hill for such severance payment provided that such employee has not accepted a position with the Trust, the Administrator or any affiliate of the Trust that provides for a similar level of responsibility and compensation within 14 days of the date of termination of the Services Agreement and further provided that such employment agreement or arrangement has been approved in advance in writing by the Governance, Nomination & Compensation Committee and the individual spent a significant amount of time and attention on the affairs and business of the Trust or any affiliate. In the event an officer of the Administrator whose services are provided pursuant to the Services Agreement is terminated, resigns or otherwise ceases employment, the Board, directly or through the Governance, Nomination & Compensation Committee, may appoint a replacement officer, and may from time to time appoint additional officers of the Administrator. Aston Hill will only be entitled to propose, on a non-exclusive basis, candidates for any such officer appointment. The Board or the Governance, Nomination & Compensation Committee will have exclusive authority to make all such appointment determinations. Pursuant to the Services Agreement, Aston Hill has agreed that the Board, directly or through the Governance, Nomination & Compensation Committee, will be responsible for approving in advance all amendments to the employment agreements of any officers or employees who will devote time and attention to the affairs and business of the Trust or any affiliate of the Trust.

***Cost and Overhead Recovery***

On or before November 30 in each year, Aston Hill will provide the Board, for the review and approval by the independent members of the Board of Directors, with an administration budget for services to be provided pursuant to and in accordance with the Services Agreement for the next calendar year and will discuss in good faith with independent members of the Board any concerns raised by them with the objective of finalizing a budget by

December 31 of each year for the next calendar year. In the event Aston Hill becomes aware of any increase or expected increase in costs that would reasonably be expected to result in a variance to budget in excess of 10% for a calendar year, it shall promptly advise the Board in writing setting forth details of the cost overrun and the parties will work in good faith to agree on a revised budget for services to be provided pursuant to the Services Agreement for such calendar year.

The Services Agreement will provide for the recovery by Aston Hill of its direct costs incurred in providing the services plus an annual overhead allocation (the "**Overhead Allocation**") based on the enterprise value of the Trust (such amount being calculated as the market capitalization of the Trust plus its aggregate bank and other interest bearing indebtedness less any cash or cash equivalents). The Overhead Allocation shall be based on the following:

| Enterprise Value of the Trust | Annual Overhead Allocation Charge |
|---|---|
| Less than $250 million | $ 700,000 |
| $250 million to $500 million | $1,200,000 |
| $500 million to $1 billion | $2,000,000 |
| Over $1 billion | $4,000,000 |

Aston Hill will invoice the Administrator for each calendar quarter by April 30, July 31, October 31 and January 31 of each year with respect to the cost of services, plus overhead allocation and applicable taxes, for the immediately preceding calendar quarter. The Services Agreement will require that Aston Hill make commercially reasonable efforts to procure and provide all services at commercially reasonable rates, consistent with the cost of such services generally incurred by comparable entities contracting on an arm's length basis in the oil and natural gas sector.

***RTU Grant***

The Services Agreement will also provide that Aston Hill will receive 210,000 RTUs for the provision of services under the Services Agreement. Aston Hill, in its sole discretion, may direct the Trust to grant all or part of such RTUs to employees of Aston Hill who spend a significant amount of time and attention on the business and affairs of a member of the Argent Group. The 210,000 RTUs granted to Aston Hill will be in addition to the RTUs granted, or that may be granted in the future, directly, to Messrs. Tremblay, Prokop and Bovingdon in their capacities as executive officers of the Administrator or as officers of the Trust. See "Executive Compensation". Future grants and allocations of RTUs to Messrs. Tremblay, and Bovingdon are expected to be determined by the Governance, Nomination & Compensation Committee, in its sole discretion, and to Mr. Prokop by the Board on the recommendation of the Governance, Nomination & Compensation Committee.

***Conflicts of Interest***

The Services Agreement will acknowledge that Aston Hill and its affiliates and their respective employees, may provide technical and administrative services to the Administrator or its affiliates and other entities engaged in the oil and natural gas industry in North America, and that conflicts of interest may arise with the interests of the Trust and its affiliates.

The Services Agreement will provide that Aston Hill will disclose any material conflict of interest involving Aston Hill or its affiliates to the Board of Directors promptly and in any event within 10 business days following any such conflict of interest arising, setting forth the nature of the conflict in sufficient detail to allow the Board of Directors to reasonably consider such conflict.

The Administrator, on recommendation of the independent members of the Board of Directors, may terminate the Services Agreement on 60 business days written notice, without any additional payment or penalty, if: (i) Aston Hill fails to disclose a material conflict of interest to which Aston Hill or, to the knowledge of Aston Hill, any of its directors, officers, employees or direct service providers are subject in the manner required; (ii) Aston Hill or any of its directors, officers, employees or direct service providers is subject to a conflict of interest, the nature of which is such that Aston Hill cannot reasonably provide the services contemplated by the Services Agreement in a manner satisfactory to such independent members of the Board of Directors, acting reasonably; or (iii) Aston Hill or an affiliate proposes to commence, commences or carries on (including by way of acquisition by or of the Administrator Shareholder) a "competing business" either directly or through an affiliate (each, a "**Conflict Termination Event**").

A "competing business" means a business that could reasonably be expected to directly compete with the Trust or any of its affiliates for future business opportunities involving the acquisition of oil, natural gas and NGLs reserves and production in the U.S., including the entering into of a services or similar agreement with any third party pursuant to which Aston Hill or an affiliate provides substantially similar services to such third party as contemplated by the Services Agreement where that third party will carry on a competing business.

Nothing in the Services Agreement will obligate Aston Hill or its affiliates to offer any business opportunities to the Trust or its controlled entities. Nothing in the Services Agreement will in any way alter the duty of care and loyalty owed by the executive officers (including those employed by Aston Hill) to the Administrator pursuant to applicable laws.

***Term***

The Services Agreement shall have an initial term of three years and will be automatically renewed for subsequent one year terms if not terminated in accordance with the following provisions. The Services Agreement may be terminated by notice given in writing: (i) by either party providing the other a notice of termination not later than six months prior to the end of the then current term of the Services Agreement; (ii) by either party if the Administrative Services Agreement is terminated and the Administrator does not continue to act as the administrator of the Trust on terms substantially similar to those set out in the Administrative Services Agreement; (iii) by either party in the event that the other party breaches or fails to observe or perform any of its material obligations, covenants or responsibilities under the Services Agreement and fails to cure such breach or failure as provided for in the Services Agreement; (iv) by either party in the event that the other party institutes proceedings to be adjudicated a bankrupt, consents to the filing of a bankruptcy proceeding against it, consents to the appointment of a receiver, liquidator, trustee or assignee in bankruptcy, is voluntarily liquidated or wound-up or otherwise takes any action acknowledging its insolvency; (v) by the Administrator upon the occurrence of a Conflict Termination Event; (vi) by the Administrator in the event that Aston Hill or an affiliate, breaches the terms of the Voting Agreement; (vii) by either party in the event of a change of control of the Trust; or (viii) by the Administrator in the event of a change of control (as defined in the Voting Agreement) of the Administrator Shareholder or Aston Hill.

If the Administrator terminates the Services Agreement as a result of the circumstances set out in (i), (ii) or (vii) above, or if Aston Hill terminates the Services Agreement as a result of the circumstances set out in (ii), (iii) or (iv) above, the Administrator shall pay to Aston Hill an amount equal to: (i) the change of control or severance costs, as applicable, payable by Aston Hill to employees of Aston Hill (including Messrs. Prokop and Bovingdon) who have been terminated or constructively dismissed as a direct result of the termination of the Services Agreement (provided where an employee of Aston Hill did not devote all of his time and attention to the business and to the affairs of the Trust, the Trust is only obligated to reimburse Aston Hill for the proportion of the change of control or severance costs payable to such employee as is equal to the amount of time and attention that such employee devoted to the business and to the affairs of the Trust), except in respect of any such employees who accept a position with a member of the Argent Group that provides for a similar level of responsibility and compensation within 14 days of the termination of the Services Agreement; and (ii) the cost of any excess office space for which Aston Hill is unable to otherwise utilize or sublease, after making reasonable commercial efforts to do so. Notwithstanding the foregoing, the Administrator shall not be required to pay to Aston Hill any amount in respect of change of control or severance costs that are: (i) payable under an employment or other agreement or arrangement that was not approved in writing by the Governance, Nomination and Compensation Committee prior to the entering into of such agreement or arrangement; or (ii) in respect of an individual that did not spend a significant amount of time and attention on the affairs and business of the Trust or any affiliate of the Trust.

## VOTING AGREEMENT

The following is a summary of the material terms of the Voting Agreement pursuant to which the Administrator Shareholder will agree to vote its shares in the Administrator at the direction of the Unitholders, as communicated by the Trustee as agent for the Unitholders. The description below is qualified by reference to the text thereof. See "Material Contracts".

The Administrator Shareholder, as the sole shareholder of the Administrator, will enter into the Voting Agreement with the Trustee, as agent for the Unitholders, and the Administrator pursuant to which the Administrator Shareholder will agree to vote its shares in the Administrator at the direction of the Unitholders, as communicated by the Trustee as agent for the Unitholders, with regard to, among other things, the election or removal of the Administrator Directors and the appointment of the auditors of the Trust. The Voting Agreement is a unanimous shareholders agreement pursuant to the ABCA and will restrict the business of the Administrator to acting as administrator of the Trust pursuant to the terms of the Trust Indenture and the Administrative Services Agreement; and such other activities as are necessary to perform its obligations as the Administrator.

The Administrator Shareholder will also waive certain shareholder rights afforded to it under the ABCA, including the right to appoint an auditor, dissent rights, and oppression rights. The Voting Agreement will also provide the Administrator with the right to compel the Administrator Shareholder, in certain circumstances (including on a direct or indirect change of control of the Administrator Shareholder and on the termination of the Services Agreement), to transfer its shares in the Administrator to the Administrator or another director or officer of the Administrator, or to another director or officer of one or more members of the Argent Group, for nominal consideration equal to the original subscription price at which the shares were issued by the Administrator. The Administrator's articles require that all transfers of its shares require the approval of the Board.

The Administrator has indemnified the Administrator Shareholder for any claims of any nature borne by or asserted against the Administrator Shareholder, its affiliates or each of their respective directors, officers, employees, partners, shareholders and agents in connection with the discharge of the Administrator Shareholder's obligations under the Voting Agreement.

## EXECUTIVE COMPENSATION

All executive officer services will be provided to the Trust by the Administrator under the Administrative Services Agreement, and the Administrator will, in turn, be provided certain necessary technical and administrative services, including the services of Messrs. Tremblay, Prokop and Bovingdon, by Aston Hill pursuant to the Services Agreement. See “Administration of the Trust – Services Agreement with Aston Hill”. The following discussion describes the significant elements of the Administrator’s executive compensation program, with particular emphasis on the process for determining compensation payable to Brian Prokop, as the Chief Executive Officer (“**CEO**”), Sean Bovingdon, as the Chief Financial Officer (“**CFO**”), and Richard Louden, President, Eric Tremblay, the Executive Chairman and John Elzner, Senior Vice-President as the three other executive officers of the Administrator, other than the CEO and the CFO, whose total annual compensation is expected to exceed $150,000 (collectively, the “**Named Executive Officers**” or “**NEOs**”).

The initial compensation arrangement for Messrs. Tremblay, Prokop and Bovingdon will be set out in the Services Agreement. The salaries and benefits for Messrs. Tremblay and Bovingdon will be reviewed and determined annually beginning in 2013, and bonuses will be reviewed and determined annually beginning with the bonus for the 2012 calendar year, by Aston Hill, subject to the recommendation and approval of the Governance, Nomination & Compensation Committee, which Aston Hill shall comply with. The salaries and benefits for Mr. Prokop will be reviewed and determined annually beginning in 2013, and bonuses will be reviewed and determined annually beginning with the bonus for the 2012 calendar year, by Aston Hill, subject to the recommendation and approval of the Board on the recommendation of the Governance, Nomination & Compensation Committee, which Aston Hill shall comply with. See “Administration of the Trust – Services Agreement with Aston Hill”. The salaries, bonuses and benefits of Mr. Louden will be considered annually beginning with the remainder of the 2012 calendar year by the Governance, Nomination & Compensation Committee and may be modified at such time in the sole discretion of the Board on the recommendation of the Governance, Nomination & Compensation Committee. The salaries, bonuses and benefits of Mr. Elzner will be considered annually beginning with the remainder of the 2012 calendar year by the Governance, Nomination & Compensation Committee and may be modified at such time in the sole discretion of that committee. It is anticipated that beginning in 2013 and thereafter, the Governance, Nomination & Compensation Committee will meet with Management on at least an annual basis to review the Administrator’s executive compensation program and, if deemed appropriate, will make further recommendations to the Board regarding changes to the program in light of the Trust’s status as a public entity and other relevant factors.

### *Compensation Discussion and Analysis*

*General*

The initial compensation arrangement for Messrs. Tremblay, Prokop and Bovingdon, will be set out in the Services Agreement and, for the NEOs other than Messrs. Tremblay, Prokop and Bovingdon, will be set out in the relevant employment agreements between US Opco and such individuals. After completion of the Offering and based on recommendations made by the Governance, Nomination & Compensation Committee, the Board will make decisions regarding salaries, annual bonuses and equity incentive compensation for the executive officers, and will approve corporate goals and objectives relevant to the compensation of the CEO and the other executive officers. The Board will solicit input from the CEO, the President and the Governance, Nomination & Compensation Committee regarding the performance of the Administrator’s other executive officers. Finally, the Board will also administer the incentive compensation and benefit plans with the assistance of the Governance, Nomination & Compensation Committee.

The Trust has benchmarked its compensation structure to its peer group (Eagle Energy Trust and Parallel Energy Trust) in determining a fair and equitable compensation structure. The peer group, although limited, represents the entire Canadian cross-border trust sector and as such, provides a transparent and tangible comparative. Specific performance goals and related performance compensation will be determined by the Governance, Nomination and Compensation Committee following the closing of the Offering and is expected to reflect industry standards.

*CEO and President Compensation*

The compensation of the CEO will be determined pursuant to the Services Agreement until December 31, 2012. Commencing in 2013, the compensation of the CEO will be determined by the Administrator Directors as a whole, on the recommendation of the Governance, Nomination & Compensation Committee. The compensation of the President will be determined by the Administrator Directors as a whole, on the recommendation of the Governance, Nomination & Compensation Committee. The level of CEO and President compensation will be determined by the Administrator Directors considering all factors which they deem appropriate, including comparative CEO and President salaries for public trusts and companies of comparable size and complexity. The annual incentive and Unit-based incentive entitlements will be determined by the Board, upon recommendation of the Governance, Nomination & Compensation Committee, based on the Trust's overall performance, relative Unitholder returns and other relevant factors.

*Compensation Objectives and Principles*

The Board recognizes that the Trust's success depends greatly on its ability to attract, retain and motivate superior performing employees at all levels, which can only occur if the Trust has an appropriately structured and executed compensation program. The Trust's compensation policies will be founded on the principle that executive and employee compensation should be consistent with Unitholders' interests and the Trust's compensation plans are therefore intended to encourage decisions and actions that will result in the Trust's growth and create long-term Unitholder value. In determining the compensation to be paid to the executive officers, the Governance, Nomination & Compensation Committee will consider corporate achievements, comparative market data and information supplied by Management.

The principal objectives of the Administrator's executive compensation program are as follows:

- to attract and retain qualified executive officers;
- to have a compensation package that is competitive within the marketplace;
- to align the executives' interests with those of the Unitholders; and
- to reward the demonstration of both leadership and performance.

The Governance, Nomination & Compensation Committee's objective will be to ensure the compensation of the NEOs provides a competitive package that reflects the above objectives, as well as provide a link between discretionary short and long-term incentives with short and long-term corporate goals. The compensation package will be designed to reward performance based on the achievement of performance goals and objectives and to be competitive with comparable companies in the market in which the Trust competes for talent.

*Components of Compensation*

The following components are currently intended to comprise the compensation package for the NEOs: base salary; annual incentive and participation in the Trust's long-term compensation plans, being the RTU Plan or, in the case of Messrs. Louden and Elzner, the PURP, if adopted by US Opco. See "– Long Term Compensation" below. Commencing in 2013, all salary increases, cash bonuses and Unit-based compensation for the NEOs will be reviewed by the Governance, Nomination & Compensation Committee.

*Base Salary*

The salaries and benefits for Messrs. Tremblay and Bovingdon will be reviewed and determined annually beginning in 2013, and bonuses will be reviewed and determined annually beginning with the bonus for the 2012 calendar year, by Aston Hill, subject to the recommendation and approval of the Governance, Nomination & Compensation Committee, which Aston Hill shall comply with. The salaries and benefits for Mr. Prokop will be reviewed and determined annually beginning in 2013, and bonuses will be reviewed and determined annually beginning with the bonus for the 2012 calendar year, by Aston Hill, subject to the recommendation and approval of the Board on the recommendation of the Governance, Nomination & Compensation Committee, which Aston Hill shall comply with. The salaries, bonuses and benefits of Mr. Louden will be considered annually beginning with the remainder of the 2012 calendar year by the Governance, Nomination & Compensation Committee and may be modified at such time in the sole discretion of the Board on the recommendation of the Governance, Nomination & Compensation Committee. The base salary for Mr. Elzner will be reviewed annually commencing with the remainder of 2012 by the Governance, Nomination and Compensation Committee. The base salary of each NEO will reflect the complexity of the NEO's role in addition to the amount of industry experience they possess. Salaries will be reviewed annually and compared to industry peers through publicly available documents and available compensation surveys prepared by compensation consultants. Consideration will be given to the growth plans of the Trust and the objective to attract and retain highly talented individuals from the industry.

*Annual Incentive Compensation*

Annual incentive compensation for Messrs. Tremblay and Bovingdon will initially be determined pursuant to the Services Agreement and will, in respect of all matters other than bonuses, be reviewed and determined annually commencing in 2013, and in respect of bonuses will be reviewed and determined annually commencing in 2012, by Aston Hill, subject to the recommendation and approval of the Governance, Nomination & Compensation Committee, which Aston Hill shall comply with. Annual incentive compensation for Mr. Prokop will initially be determined pursuant to the Services Agreement and will, in respect of all matters other than bonuses, be reviewed and determined annually commencing in 2013, and in respect of bonuses will be reviewed and determined annually beginning with the bonus for the 2012 calendar year, by Aston Hill, subject to the recommendation and approval of the Board on the recommendation of the Governance, Nomination & Compensation Committee, which Aston Hill shall comply with. The salaries, bonuses and benefits of Mr. Louden will be considered annually beginning with the remainder of the 2012 calendar year by the Governance, Nomination & Compensation Committee and may be modified at such time in the sole discretion of the Board on the recommendation of the Governance, Nomination & Compensation Committee. The annual incentive compensation for Mr. Elzner will be considered annually beginning with the remainder of the 2012 calendar year by the Governance, Nomination and Compensation Committee and may be modified at such time in the sole discretion of that Committee. Annual incentive compensation will provide for annual cash awards, RTU awards and PUR awards, as applicable, which are intended to motivate and reward NEOs for achieving and surpassing annual corporate and individual goals. The amount of the cash award or "bonus" will be determined by reference to a target percentage of base salary. Bonus awards for the NEOs, excluding the CEO and President, will be recommended by the CEO and President and reviewed and approved by the Governance, Nomination & Compensation Committee. Bonus awards for the CEO and President will be recommended by the Governance, Nomination & Compensation Committee and approved by the Board. Peer performance and practices will also be considered each year in determining the final amounts to be awarded. The targeted bonus percentage for the CEO and President will be 100% of base salary, of which half is targeted to be paid in cash and half is targeted to be paid in RTUs and/or PURs (as applicable). The target bonus percentage for the other NEO's is 50% of base salary, of which half is targeted to be paid in cash and half is targeted to be paid in RTUs and/or PURs (as applicable). See "Restricted Trust Unit Plan".

*Long-Term Compensation*

Long-term compensation in respect of Messrs. Tremblay, Prokop and Bovingdon will initially be determined pursuant to the Services Agreement for all RTUs to be granted at the closing of the Offering. Long-term compensation in respect of all other NEOs will be determined pursuant to employment agreements between such NEOs and US Opco for all RTUs to be granted at closing of the Offering. All future grants and allocations of RTUs to Messrs. Tremblay, and Bovingdon will be made indirectly through Aston Hill by the Governance, Nomination & Compensation Committee, in its sole discretion, and to Mr. Prokop by the Board on the recommendation of the Governance, Nomination & Compensation Committee. All future RTU and PUR grants and allocations to the other executive officers will be determined by the Governance, Nomination & Compensation Committee in its sole discretion. Subject to the description below, the long-term compensation plan of the Trust will initially be comprised of the RTUP and the PURP, which are intended to encourage participants to focus on creating and improving the Trust's long-term financial success by providing participants an opportunity to increase their ownership interests in the Trust. The purpose of the RTUP and of the PURP is to align the interests of Unitholders and Management. See "Restricted Trust Unit Plan". There are no restrictions prohibiting the purchase of financial instruments including prepaid variable forward contracts, equity swaps, collars, or units of exchange funds that are designed to hedge or offset a decrease in market value of equity securities granted as compensation or held, directly or indirectly, by a NEO or Administrator Director. The

Administrator Directors have determined that the compensation policies of the Trust adequately reward and compensate Management for their services while balancing the appropriate level of short-term and long-term objectives of the Trust.

US Opco may adopt a cash settled PURP for the benefit of directors, officers or employees or direct or indirect service providers of US Opco resident in the United States (the "**U.S. Participants**") prior to the closing of the Offering. The purpose of the PURP will be to provide incentive bonus compensation based on the appreciation in value of the Units and distributions payable in respect of Units, thereby providing additional incentive for continued efforts in promoting the growth and success of the Argent Group and in attracting and retaining management personnel in the United States. The PURP is expected to mirror the material terms of the RTUP with the exception that phantom unit rights may only be settled with cash payments by US Opco. The PURP will allow U.S. Participants to comply with tax and securities laws in the United States applicable to the awards.

***Summary Compensation Table***

Based on the information available at the date hereof, the following table sets out information concerning the annualized compensation anticipated to be paid by the Administrator, directly or pursuant to the Services Agreement, to the NEOs during the year ended December 31, 2012.

| | | | | Non-Equity Incentive Plan Compensation ($) | | | |
|---|---|---|---|---|---|---|---|
| **Name and Principal Position** | **Year** | **Salary ($)[1]** | **Unit-Based Awards ($)[2]** | **Annual Incentive Plans[3]** | **Long-Term Incentive Plans[3]** | **All Other Compensation ($)[4]** | **Total Compensation ($)** |
| Brian Prokop[5]<br>Chief Executive Officer | 2012 | 290,000 | 1,200,000 | — | — | — | 1,490,000 |
| Richard Louden[5][6]<br>President | 2012 | 290,000 | 1,200,000 | — | — | — | 1,490,000 |
| Sean Bovingdon<br>Chief Financial Officer | 2012 | 230,000 | 1,200,000 | — | — | — | 1,430,000 |
| John Elzner[6]<br>Senior Vice-President | 2012 | 230,000 | 1,200,000 | — | — | — | 1,430,000 |
| Eric Tremblay[5]<br>Executive Chairman | 2012 | 200,000 | 1,200,000 | — | — | — | 1,400,000 |

**Notes:**

(1) Base salaries for 2012 have been annualized. The actual salary paid during the year to Messrs. Tremblay, Prokop and Bovingdon will be adjusted on a *pro rata* basis for the 11 month period from February 1, 2012 to December 31, 2012. The actual salary paid to the NEOs other than Messrs Louden and Elzner, will be paid by Aston Hill, which in turn will be reimbursed on a cost recovery basis pursuant to the Services Agreement. See "Administration of the Trust – Services Agreement with Aston Hill".

(2) Represents the market value of the RTUs and/or PURs (as applicable), that are anticipated to be awarded to the NEO under the RTUP or the PURP concurrent with closing of the Offering. These RTUs and PURs will vest over three years, subject to meeting performance targets based on the net asset value per Unit. It is not anticipated that there will be additional grants under the RTUP or the PURP to the NEO's during calendar year 2012, however, the Governance, Nomination & Compensation Committee, the Board, and US Opco reserve the right to issue additional RTUs and/or PURs during 2012. The market value of the RTUs and PURs awarded under the RTUP and the PURP, respectively, does not necessarily equal the value of these RTUs and PURs that will be allocated for accounting purposes.

(3) The amount of Non-Equity Incentive Compensation to be paid to the NEOs for the 2012 calendar year has not yet been determined by the Governance, Nomination & Compensation Committee and the Board.

(4) The amount of "Other Compensation" that might be paid to the NEOs during the 2012 calendar year has not yet been determined by the Governance, Nomination & Compensation Committee and the Board, although it is not expected that the amounts will be a material component of a NEO's total compensation.

(5) This amount includes $149,000 that relates to Mr. Tremblay's compensation for acting in his capacity as a director of the Administrator. Mr. Prokop and Mr. Louden are not compensated for acting in their capacity as an Administrator Director.

(6) Mr. Louden's and Mr. Elzner's salaries will be paid in U.S. dollars, which shall be converted at the exchange rate set by the Bank of Canada on the applicable date.

(7) For information on Units acquired by the NEOs prior to completion of the Offering, see "Prior Sales".

### *Unit-Based Awards Outstanding*

The following table sets forth, for each NEO, the value of all Unit-based awards that are anticipated to be outstanding on the closing of the Offering. The Trust will not have any option-based awards outstanding on the closing of the Offering.

| | Unit-Based Awards | | |
|---|---|---|---|
| **Name and Principal Position** | **Number of Units that have not Vested (#)(1)** | **Market Value of Units that have not Vested ($)(2)** | **Market Value of Vested Unit-Based Awards not Paid Out or Distributed ($)** |
| Brian Prokop<br>Chief Executive Officer | 120,000 | 1,200,000 | Nil |
| Richard Louden<br>President | 120,000 | 1,200,000 | Nil |
| Sean Bovingdon<br>Chief Financial Officer | 120,000 | 1,200,000 | Nil |
| John Elzner<br>Senior Vice-President | 120,000 | 1,200,000 | Nil |
| Eric Tremblay<br>Executive Chairman | 120,000 | 1,200,000 | Nil |

**Notes:**

(1) None of the RTUs or PURs will be vested on the date of closing of the Offering.

(2) Market value of the Units on closing of the Offering will be equal to the initial offering price of $10.00 per Unit.

### *Unit-Based Awards – Value Vested or Earned*

None of the Unit-based awards granted to NEOs will be vested or earned on the closing of the Offering.

### *Termination and Change of Control Benefits*

Concurrent with the closing of the Offering, Aston Hill will enter into executive employment agreements pursuant to the Services Agreement with each of Messrs. Prokop and Bovingdon. Concurrent with the closing of the Offering, US Opco will enter into executive employment agreements with each of Messrs. Louden and Elzner. The terms of all employment agreements will be in accordance with current market standards for agreements of a similar nature and will include a payment of two years base salary plus target bonus for the CEO and President and 1.5 years based salary plus target bonus for the other NEOs in the event that they are terminated without cause, or if there has been a change of control of the Trust, or further in the case of Messrs. Prokop and Bovingdon if, in limited circumstances, there has been a change of control of Aston Hill (except, in each such case, where Messrs. Prokop and Bovingdon continue their employment with Aston Hill in their role as CEO and CFO, respectively, of the Administrator or accept employment with a member of the Argent Group within 14 days of the date of the change of control). In certain circumstances the Administrator has agreed to reimburse Aston Hill for the cost of severance paid to Messrs. Prokop and Bovingdon. See "Administration of the Trust – Services Agreement with Aston Hill – Term".

### *Administrator Directors' Compensation*

It is anticipated that each of the Administrator Directors will receive an annual retainer of $35,000 and $1,000 per meeting for attending meetings of the Board or any meeting of a committee of the Board. Only one meeting fee per Administrator Director or committee member per day will be paid. The chair of each committee of the Board will receive additional compensation of $5,000 per year. The Administrator will also reimburse Administrator Directors for out-of-pocket expenses for attending meetings. Administrator Directors will participate in the RTUP in accordance with the recommendation of the Governance, Nomination & Compensation Committee. The total amount of units awarded under the RTUP, taken together, to independent directors is not to exceed 2% of the aggregate number of Units issued and outstanding.

The following table sets forth information concerning the expected annualized compensation expected to be paid to the Administrator Directors for the year ending December 31, 2012.

| Name[1] | Fees Earned ($)[2] | Unit-Based Awards ($)[3] | Non-Equity Incentive Plan Compensation ($) | Pension Value ($) | All Other Compensation ($) | Total ($) |
|---|---|---|---|---|---|---|
| John Brussa[4] | 45,000 | 110,000 | Nil | Nil | Nil | 155,000 |
| Scott Butler | 44,000 | 110,000 | Nil | Nil | Nil | 154,000 |
| William Robertson[4] | 49,000 | 110,000 | Nil | Nil | Nil | 159,000 |
| Glen Schmidt[4] | 49,000 | 110,000 | Nil | Nil | Nil | 159,000 |

**Notes:**

(1) Mr. Tremblay is not identified in the list of Administrator Directors as his compensation for acting as an Administrator Director is included in the summary of NEO compensation above. Mr. Prokop and Mr. Louden are not compensated for acting in their capacity as an Administrator Director.

(2) Represents the Administrator Director's annualized retainer, chair fees and estimated committee meeting attendance fees for a full year. Actual fees earned during the year ending December 31, 2012 will be based on the number of meetings attended by the Administrator Director.

(3) Represents the market value of the RTUs anticipated to be awarded to the Administrator Director under the RTUP concurrent with closing of the Offering. These RTUs will vest over three years, subject to meeting performance targets based on the net asset value per Unit. It is not anticipated that there will be additional grants under the RTUP to the Administrator Directors during calendar year 2012; however, the Governance, Nomination & Compensation Committee and the Board reserve the right to issue additional RTUs during 2012. The market value of the RTUs awarded under the RTUP does not necessarily equal the value of these RTUs that will be allocated for accounting purposes.

(4) Mr. Brussa is the Chairman of the Governance, Nomination & Compensation Committee. Mr. Robertson is the Chairman of the Audit Committee. Mr. Schmidt is the Chairman of the Reserves & Environment, Health & Safety Committee.

(5) For information on Units acquired by the Administrator Directors prior to completion of the Offering, see "Prior Sales".

Administrator Directors will participate in the insurance and indemnification arrangements described under "Trustee, Directors and Management – Insurance Coverage and Indemnification".

### *Administrator Director Outstanding Unit-Based Awards*

The following table sets forth, for each Administrator Director, all Unit-based awards that are anticipated to be outstanding on the closing of the Offering.

| Name[1] | Number of Units that have not Vested (#)[2] | Market Value of Units that have not Vested ($)[2][3] | Market Value of Vested Unit-Based Awards not Paid-out or Distributed |
|---|---|---|---|
| John Brussa | 11,000 | 110,000 | Nil |
| Scott Butler | 11,000 | 110,000 | Nil |
| William Robertson | 11,000 | 110,000 | Nil |
| Glen Schmidt | 11,000 | 110,000 | Nil |

**Notes:**

(1) Mr. Tremblay is not identified in the list of Administrator Directors as his compensation for acting as an Administrator Director is included in the summary of NEO compensation above. Mr. Prokop and Mr. Louden are not compensated for acting in their capacity as an Administrator Director.

(2) Market value of the Units on closing of the Offering will be equal to the initial Offering price of $10.00 per Unit.

(3) None of the RTUs awarded under the RTUP were vested on the date of closing of the Offering.

### *Unit-Based Awards – Value Vested or Earned*

No Unit-based awards granted to the Administrator Directors will be vested or earned on the closing of the Offering.

## RESTRICTED TRUST UNIT PLAN

Pursuant to the RTUP, RTUs may be granted by the Administrator Directors or an appointed committee thereof (the "**RTUP Administrator**") to directors, officers, employees or direct or indirect service providers ("**Participants**") of the Argent Group (for the purpose of the disclosure under this heading, "**Argent Group**" means the Trust and its subsidiaries and affiliates and the Administrator). The purpose of the RTUP is to advance the interests of the Argent Group by: (a) increasing the proprietary interests of Participants in the Trust; (b) aligning the interests of Participants with the interests of the Unitholders generally; (c) encouraging Participants to remain associated with the Argent Group; and (d) furnishing the Participants with an additional incentive in their efforts on behalf of the Argent Group.

Pursuant to the RTUP, the number of Units reserved for issuance pursuant to the redemption of RTUs granted under the RTUP and pursuant to all other security-based compensation arrangements of the Trust shall, in the aggregate, not exceed 10% of the number of Units then issued and outstanding. If any RTUs are redeemed, the number of Units to which such redeemed RTUs relate shall be available for the purpose of granting additional RTUs under the RTUP. In addition, if any RTUs expire or terminate for any reason without having been redeemed, any unissued Units to which such RTUs relate shall be available for the purposes of granting additional RTUs under the RTUP.

The vesting of RTUs will be determined by the RTUP Administrator at the time of grant, provided that no vesting conditions shall extend beyond November 30th of the third calendar year following the Service Year (as defined in the RTUP) in respect of which the RTUs were granted. Unless otherwise provided in the applicable award agreement, all RTUs shall vest: (i) one-third on the first anniversary of the date of grant of such RTUs (the "**Grant Date**"); (ii) an additional one-third on the second anniversary of the Grant Date; and (iii) the final one-third on the third anniversary of the Grant Date, subject to other vesting conditions and blackout extensions. If a redemption date for an RTU occurs during a blackout period of the Trust or within ten business days of the expiry of a blackout period, then the redemption date will be the tenth business day following the expiry of such blackout period, provided that such date shall be on or prior to the RTU Entitlement Date (as defined below).

On a date on or before the date which is three years following the end of the Service Year in respect of which the RTUs were granted (the "**RTU Entitlement Date**") the holder will receive, subject to applicable withholding taxes, for each RTU held either: (i) the cash equivalent of one Unit; or (ii) at the election of the Trust, one Unit, which may be issued from treasury or purchased by a designated broker on the TSX. Notwithstanding the foregoing, no RTU granted under the RTUP that is held by: (i) a citizen or permanent resident of the United States for purposes of the Code; or (ii) a Participant for whom the compensation subject to deferral under the RTUP would otherwise be subject to United States federal income tax under the Code, will be redeemed for Units absent registration under, or an exemption from, as determined in the discretion of the Board, the U.S. Securities Act. The determination of the value of the cash equivalent of Units will be determined based upon the volume weighted average trading price of the Units on the TSX for the last five trading days prior to the date of calculation. A Participant's RTU account will be credited with additional RTUs in respect of any distributions declared by the Trust on the Units that would have been paid to the Participant if the RTUs in the Participant's account were outstanding Units during the relevant period.

The RTUP Administrator will determine the Participants who shall participate under the RTUP and the number of RTUs granted to such Participants, provided that: (a) the aggregate number of Units reserved for issuance under RTUs granted to any one Participant shall not exceed 5% of the issued and outstanding Units at the Grant Date, calculated on a non-diluted basis; (b) the aggregate number of Units which may be reserved for issuance to "insiders" (as such term is referred to in the policies of the TSX), under the RTUP and all other security-based compensation arrangements of the Argent Group shall not, in the aggregate, exceed 10% of the issued and outstanding Units at the date of grant, calculated on a non-diluted basis; (c) during any one-year period, the Committee shall not grant to such insiders, under the RTUP and all other security-based compensation arrangements of the Argent Group, in the aggregate, a number of Units exceeding 10% of the issued and outstanding Units, calculated on a non-diluted basis; and (d) the aggregate number of Units issuable on the settlement of Units outstanding at any time held by directors of the Administrator who are not officers or employees of the Argent Group shall be limited to 1% of the issued and outstanding Units. The restrictions referred to in (b) through (d) above are referred to as the "**RTUP Insider and Independent Director Participation Restrictions**".

Subject to termination by reason of death or termination other than for cause and subject to the provisions of any applicable RTU award agreement, unless otherwise determined by the RTUP Administrator in its sole discretion, upon the Participant terminating employment with the Argent Group for any reason including, without limitation, due to involuntary termination with cause or voluntary termination by the Participant, all RTUs previously credited to such Participant which did not become vested RTUs on or prior to the Participant's termination date shall be terminated and forfeited as of the Participant's termination date. Upon termination by reason of death or termination other than for cause, a proportion of a Participant's RTUs will vest, with such proportion being determined based upon the Participant's termination date relative to the date of grant and vesting date. Awards granted under the RTUP are not assignable.

The RTUP also provides that vesting of RTUs will accelerate on a "change of control". A "change of control" of the Trust is defined under the RTUP as follows: (a) the acceptance by the Unitholders, representing in the aggregate more than 50% of all issued and outstanding Units, of any offer, whether by way of a take-over bid or otherwise, for all or any of the Units; (b) the acquisition by whatever means (including, without limitation, by way of an arrangement, merger or amalgamation), by any person (or two or more persons acting jointly or in concert), directly or indirectly, of the beneficial ownership of Units or rights to acquire Units that, together with such person's then owned Units and rights to acquire Units, if any, represent in the aggregate more than 50% of all issued and outstanding Units; (c) the passing of a resolution by the Trustee, the Board or the Unitholders to substantially liquidate the assets or wind-up or significantly rearrange the affairs of the Trust in one or more transactions or series of transactions (including by way of an arrangement, merger or amalgamation) or the commencement of proceedings for such a liquidation, winding-up or re-arrangement; (d) the sale by the Trust of all or substantially all of its assets (other than to an affiliate of the Trust in circumstances where the affairs of the Trust are continued, directly or indirectly, and where unitholdings of the Trust remain substantially the same following the sale as existed prior to the sale); (e) persons who were proposed as nominees (but not including nominees under a Unitholder proposal) to become directors of the Administrator immediately prior to a meeting of the Unitholders involving a contest for, or an item of business relating to the election of directors of the Administrator, not constituting a majority of the directors of the Administrator following such election; or (f) any other event which, in the opinion of the Board, reasonably constitutes a change of control of the Trust; provided that a change of control shall not occur solely as a result of a reorganization of the Argent Group in circumstances where the unitholdings, shareholders or ultimate ownership remains substantially the same upon completion of the reorganization, including a reorganization, in a transaction or series of related transactions, of the Trust for the purposes of avoiding the actual or potential application of the SIFT Rules and any related tax or trust, corporate or partnership reorganization or restructuring, including, without limitation, the contemporaneous or, to the extent entered into in connection with such reorganization, restructuring, subsequent termination or winding-up of the Trust.

The Board may, at any time, amend, suspend or terminate the RTUP, or any portion thereof, or any RTU granted thereunder, without Unitholder approval, subject to those provisions of applicable law (including, without limitation, the rules, regulations and policies of the TSX), if any, that require the approval of Unitholders or any governmental or regulatory body. However, except as expressly set forth in the RTUP, no action of the Board or Unitholders shall alter or impair the rights of a Participant under any RTU previously granted to the Participant without the consent of the affected Participant. Without limiting the generality of the foregoing, the Board may make the following types of amendments to the RTUP without seeking Unitholder approval:

(a) amendments of a "housekeeping" or ministerial nature including, without limiting the generality of the foregoing, any amendment for the purpose of curing any ambiguity, error or omission in the RTUP or to correct or supplement any provision of the RTUP that is inconsistent with any other provision of the RTUP;

(b) amendments necessary to comply with the provisions of applicable law;

(c) amendments respecting administration of the RTUP;

(d) amendments to the vesting provisions of the RTUP or any RTUs;

(e) amendments to the early termination provisions of the RTUP or any RTUs, whether or not such RTUs are held by an insider, provided such amendment does not entail an extension beyond the original expiry date;

(f) amendments to the termination provisions of the RTUP or any RTUs, other than RTUs held by an insider in the case of the amendment extending the term of an RTU, provided any such amendment does not entail an extension of the expiry date of such RTU beyond its original expiry date;

(g) amendments necessary to suspend or terminate the RTUP; and

(h) any other amendment, whether fundamental or otherwise, not requiring Unitholder approval under applicable law (including, without limitation, the rules, regulations and policies of the TSX).

Unitholder approval will be required for the following types of amendments:

(a) amendments to the number of Units issuable under the RTUP, including a change from a fixed maximum percentage to a fixed maximum number of Units;

(b) amendments to the calculation of the cash equivalent value of an RTU;

(c) removing or amending the RTUP Insider and Independent Director Participation Restrictions; and

(d) amendments required to be approved by Unitholders under applicable law (including, without limitation, the rules, regulations and policies of the TSX).

The Administrator has reviewed the RTUP and, based on this review and its consideration of the remuneration paid to directors, officers, employees and consultants of other publicly traded entities, is satisfied that the RTUP is an appropriate long-term incentive plan for the Trust. The RTUP was approved by the Board.

As at the date hereof, no RTUs are issued and outstanding.

## DESCRIPTION OF THE TRUST

The following is a summary of the material terms of the Trust Indenture which, together with other summaries of the terms of the Trust Indenture appearing elsewhere in this prospectus, are qualified in their entirety by reference to the text of the Trust Indenture. Reference is made to the Trust Indenture for a complete description of the Units and the full text of its provisions. See "Material Contracts". A copy of the Trust Indenture will be available on SEDAR at www.sedar.com under the Trust's profile.

### General

The Trust is an unincorporated limited purpose open-ended trust established under the laws of the Province of Alberta on January 31, 2012 by the Trust Indenture. The Trust intends to qualify as a "mutual fund trust" under the Tax Act. The Trust has been established to indirectly acquire an interest in US Opco through its acquisition of Can Holdco Shares. Although it is intended that the Trust qualify as a "mutual fund trust" under the Tax Act, the Trust will not be a mutual fund under applicable securities laws.

The Trust is a limited purpose trust and the undertaking of the Trust is restricted to investing its funds in property (other than real property or an interest in real property or an immovable or a real right in an immovable).

Subject to the investment restrictions contained in the Trust Indenture, including those just noted, the Trustee has the authority to deal with the Trust's property on behalf of the Trustee as if it were the beneficial owner of such property, and in particular, may:

(a) temporarily hold cash and other investments in connection with, and for the purposes of, the Trust's activities, including paying liabilities of the Trust (including administration and trust expenses), paying any amounts required in connection with the redemption of Units and making distributions to Unitholders;

(b) give a guarantee on behalf of the Trust to secure performance of an obligation of another person;

(c) mortgage, hypothecate, pledge or otherwise create a security interest in all or any movable or immovable, personal or real or other property of the Trust, owned or subsequently acquired, to secure any obligation of the Trust;

(d) lend, including loans to subsidiaries;

(e) invest, hold shares, securities, units, beneficial interests, partnership interests, joint venture interests or other interests in any person necessary or useful to carry out the purpose of the Trust;

(f) issue or provide for the issuance of debt or equity securities of the Trust, including Units and Other Trust Securities, on such terms and conditions and at such time or times as the Trustee may determine, provided recourse shall be limited to the property of the Trust;

(g) redeem or repurchase Units in accordance with the terms set forth in the Trust Indenture;

(h) make or cause to be made application for the listing or quotation on any stock exchange or market of any Units or Other Trust Securities, and to do all things which in the opinion of the Trustee may be necessary or desirable to effect or maintain such listing or listings or quotation;

(i) possess and exercise all the rights, powers and privileges pertaining to the ownership of any securities held by the Trust;

(j) to the extent not prohibited by applicable law, to delegate any of the powers and duties of the Trustee to any one or more agents, representatives, officers, employees, independent contractors, subcontractors or other persons (including to the Administrator pursuant to the terms of the Administrative Services Agreement or otherwise) without liability to the Trustee except as provided in the Trust Indenture; and

(k) do all such other acts and things as are necessary, useful, incidental or ancillary to the foregoing and to exercise all powers and authorities which are necessary, useful, incidental or ancillary to carry on the affairs of the Trust, to promote any purpose for which the Trust is formed and to carry out the provisions of the Trust Indenture, including, without limitation, the negotiation and execution of the Administrative Services Agreement.

### Units of the Trust

The beneficial interests in the Trust are represented and constituted by one class of units described and designated as "Units". An unlimited number of the Units may be issued pursuant to the Trust Indenture. The Trust may also issue an unlimited number of Other Trust Securities. Upon closing of the Offering, there will be 21,830,000 Units outstanding (or 25,014,500 Units outstanding if the Over-Allotment Option is exercised in full). See "Consolidated Capitalization".

Each Unit represents an equal, undivided beneficial interest in the Trust Property and all Units shall rank equally and ratably with all of the other Units without discrimination, preference or priority. Each Unit entitles the holder to one vote at all meetings of Unitholders or in respect of written resolutions of the Unitholders.

Unitholders are entitled to receive non-cumulative distributions from the Trust if, as and when declared by the Trust. Units are redeemable on demand by the holders thereof, and may be purchased for cancellation by the Trust through offers made to, and accepted by, such holders. See "Description of the Trust – Redemption at the Option of Unitholders" and "Description of the Trust – Repurchase of Securities". There are no other conversion, retraction, redemption or pre-emptive rights for Unitholders.

### Issuance of Units

Units are to be issued by the Trustee only when fully paid in money, property or past services, provided that: (a) Units may be issued for consideration payable in installments if the Trust takes security over any such Units for unpaid installments; and (b) the consideration for any Unit issued by the Trust shall be paid in money or in property or in past services that are not less in value than the fair equivalent of the money that the Trust would have received if the Unit had been issued for money, provided that property may include a promissory note or promise to pay given by the allottee. In determining whether property or past services are the fair equivalent of monetary consideration, the Trustee or the Administrator may take into account reasonable charges and expenses of organization and reorganization and payments for property and past services reasonably expected to benefit the Trust, and the resolution of the Administrator allotting and issuing those Units shall express the fair equivalent in money of the non-cash consideration received. The Trust Indenture provides that any Units or Other Trust Securities may be created, issued, sold and/or delivered at such times, to the persons (subject to certain non-resident restrictions in the Trust Indenture), in the jurisdictions, for the consideration and on the terms and conditions that the Trustee determines, including pursuant to a Unitholder rights plan, distribution reinvestment plan, or any compensation plan established by the Trust. The authority to determine the timing and terms of future offerings of Units has been delegated by the Trustee to the Administrator. See "Description of the Trust – Delegation to the Administrator". Units may be issued in satisfaction of any non-cash distribution by the Trust to Unitholders on a *pro rata* basis. The Trust Indenture also provides that immediately after any *pro rata* distribution of Units to Unitholders in satisfaction of any non-cash distribution, the number of outstanding Units will be automatically consolidated such that each Unitholder will hold after the consolidation the same number of Units as the Unitholder held before the distribution of such additional Units, subject to reduction for payment of applicable withholding taxes. In this case, each certificate representing a number of Units prior to the distribution of additional Units is deemed to represent the same number of Units after the distribution of such additional Units and the consolidation.

### Limitation on Non-Resident Ownership

A mutual fund trust may lose its status under the Tax Act as a "mutual fund trust" if it can reasonably be considered that the trust was established or is maintained primarily for the benefit of non-residents of Canada. However, this requirement will not apply if all or substantially all of the mutual fund trust's property is not "taxable Canadian property", as defined by the Tax Act. The Trust anticipates that its property will not be taxable Canadian property. In the event that the Trust determines that such non-resident ownership restrictions nevertheless apply, the Administrator has various powers that can be used for the purpose of monitoring and controlling the extent of non-resident ownership of the Units.

### U.S. Resident Restriction

The Trust is a "foreign private issuer" as such term is defined in the U.S. Securities Act. The Trust Indenture provides that at no time may more than 50% of the outstanding voting securities of the Trust be directly or indirectly owned of record by U.S. Residents (as such term is defined in the Trust Indenture), and it shall be the responsibility solely of the Administrator to monitor compliance by the Trust with this U.S. residency restriction, and to take all such actions as may reasonably be undertaken on behalf of the Trust to cause the Trust to maintain its status as a "foreign private issuer". The Administrator has various powers that can be used for the purpose of monitoring and controlling the extent of U.S. resident ownership of the Units at all times prior to the Trust filing a registration statement in accordance with the U.S. Securities Act or registering a class of securities under the United States *Securities Exchange Act of 1934*, as amended, other than, in either case, in compliance with the Multijurisdictional Disclosure System between Canada and the United States.

### Book Entry Only System

Except as otherwise provided below, the Units will be issued in "book entry only" form and must be purchased or transferred through participants ("**Participants**") in the depositary service of CDS, which include securities brokers and dealers, banks and trust companies. On the date of closing of the Offering, the Trust will cause a global certificate or certificates representing the Units to be delivered to, and registered in the name of, CDS or its nominee. Except as described below, no Unitholder will be entitled to a certificate or other instrument from the Trust or CDS evidencing that holder's ownership thereof, and no Unitholders will be shown on the records maintained by CDS except through a book entry account of a Participant acting on behalf of such holder. Each purchaser acquiring a beneficial interest in the Units (a "**Beneficial Owner**") will receive a customer confirmation of purchase from the registered dealer from which the Unit is purchased in accordance with the practices and procedures of that registered dealer. The practices of registered dealers may vary, but generally customer confirmations are issued promptly after execution of a customer order. CDS will be responsible for establishing and maintaining book entry accounts for its Participants having interests in the Units.

Neither the Trust nor the Underwriters will assume any liability for: (a) any aspect of the records relating to the beneficial ownership of the Units held by CDS or the payments relating thereto; (b) maintaining, supervising or reviewing any records relating to the Units; or (c) any statement made with respect to CDS and contained in this prospectus and relating to the rules governing CDS or any action to be taken by CDS or at the direction of its Participants. The rules governing CDS provide that it acts as the agent and depositary for the Participants. As a result, Participants must look solely to CDS and Beneficial Owners must look solely to Participants for the payment of the distributions on the Units paid by or on behalf of the Trust to CDS.

As indirect holders of Units, investors should be aware that they (subject to the situations described below): (a) may not have Units registered in their name; (b) may not have physical certificates representing their interest in the Units; (c) may not be able to sell the Units to institutions required by law to hold physical certificates for securities they own; and (d) may be unable to pledge Units as security.

If: (i) CDS resigns or is removed from its responsibilities as depositary with respect to the Units and the Trust is unable or does not wish to locate a qualified successor, or (ii) the Administrator or the Trust, at their option (including to ensure compliance with the Trust's limitations on non-resident ownership) elects, or is required by law, to terminate the book entry system, or (iii) Unitholders representing more than $66^2/_3\%$ of the aggregate votes entitled to be voted at a meeting of Unitholders determine that the continuation of the book entry system is no longer in the best interests of the Unitholders, then Units will be issued in fully registered form to Unitholders or their nominees.

### Transfer of Units

Units are transferable at any time and from time to time. Transfers of ownership in the Units will be affected only through records maintained by CDS or its nominee for such Units with respect to interests of Participants, and on the records of Participants with respect to interests of persons other than Participants. Unitholders who are not Participants, but who desire to purchase, sell or otherwise transfer ownership of or other interests in the Units, may do so only through Participants.

### Repurchase of Securities

The Trust is entitled, from time to time, to offer to purchase Units or Other Trust Securities for cancellation at a price per security and on a basis determined by the Trustee in its discretion, but in compliance with applicable securities legislation and the rules prescribed under applicable stock exchange or regulatory policies. The authority to determine the timing and terms of any such repurchase of Units has been delegated by the Trustee to the Administrator. Any such purchase will constitute an "issuer bid" under Canadian provincial securities legislation and, if not exempt, must be conducted in accordance with the applicable requirements thereof. Units purchased by the Trust will be cancelled.

### Take-over Bids

If there is a take-over bid for all of the outstanding Units and within 120 days after the date of a take-over bid for the Units (which, depending on the terms of the take-over bid, may also include Units issuable upon conversion, exercise or exchange of Other Trust Securities), the bid is accepted by the holders of not less than 90% of the Units and, as applicable, the Units issuable upon the conversion, exercise or exchange of any relevant Other Trust Securities, taken together (collectively, the "**Bid Units**"), other than Bid Units held by or on behalf of, or issuable to, the offeror or an affiliate or associate of the offeror, then the offeror is entitled to acquire the Bid Units held by persons who did not accept the take-over bid, with such acquisition to occur on the same terms on which the offeror acquired Bid Units from persons who accepted the take-over bid. The Trust Indenture does not provide a mechanism for Unitholders who do not tender their Units to a take-over bid to apply to a court to fix the fair value of their Units.

### Investments and Investment Restrictions

Monies or other property received by the Trust or the Trustee on behalf of the Trust, including the net proceeds of any offering (including the Initial Private Placement and this Offering), may be used at any time and from time to time, for any purpose not inconsistent with the Trust Indenture (including making distributions and redemptions). See "Description of the Trust – General".

The Trust Indenture contains investment restrictions to ensure that the Trust:

(a) complies at all times with the requirements for a "mutual fund trust", as defined in the Tax Act;

(b) does not take any action, or acquire or retain any investment, that would result in the Trust not being considered a "mutual fund trust" for purposes of the Tax Act;

(c) does not take any action, or acquire, retain or hold any investment in any entity or other property that would result in the Trust being a "SIFT trust"; and

(d) does not hold any "non-portfolio property", as defined in the Tax Act.

### Distributions

The Trust intends to make monthly distributions to Unitholders of record as of the close of business on the last business day of each month which are expected to be paid to Unitholders on or about the 23rd day of the following month or if not a business day, the next business day thereafter. The amount of cash to be distributed on a *pro rata* basis per month per Unit will be determined in the discretion of the Trust. The Trust expects that the initial monthly cash distribution rate will be \$0.0875 per Unit. The initial cash distribution, which will be for the period from and including the date of closing of the Offering to August 31, 2012, is expected to be paid on September 24, 2012 to Unitholders of record on August 31, 2012 and is estimated to be \$0.0621 per Unit (assuming the closing of the Offering occurs on August 10, 2012). As results of operations may vary, the distribution of cash is not guaranteed.

The Administrator anticipates that approximately 30% to 40% of the distributable cash during the first year of the Trust will be included in the income of Unitholders for income tax purposes. The balance will not be taxable and will be deducted from the adjusted cost base of their Units.

Where the Administrator determines that the Trust does not have cash in an amount sufficient to make payment of the full amount of any distribution which has been declared to be payable, payment of such distribution may, at the option of the Administrator, include the issuance of additional Units, if necessary, having an aggregate value equal to the difference between the amount of such declared distribution and the amount of cash which has been determined by the Administrator to be available for the payment of such distribution. The value of each Unit which is to be issued in payment of distributions shall be the "market price" (as determined in accordance with the provisions of the Trust Indenture). See "Description of the Trust – Issuance of Units". Such additional Units will be issued pursuant to applicable exemptions under applicable securities laws, discretionary exemptions granted by applicable securities regulatory authorities or a prospectus or similar filing.

Payments of distributions on each Unit issued in "book entry only" form will be made by the Trust to CDS or its nominee, as the case may be, as the registered owner of Units, and the Trust understands that such payments will be forwarded by CDS or its nominee, as the case may be, to Participants. As long as CDS or its nominee is the registered owner of Units, CDS or its nominee, as the case may be, will be considered the sole owner of those Units for the purposes of receiving payments on those Units. The responsibility and liability of the Trust in respect of the payment of distributions in respect of the Units is limited to making payment of any income or capital in respect of those Units to CDS or its nominee.

The Trust's ability to pay distributions to Unitholders is dependent upon the ability of US Opco and Can Holdco to meet their interest, principal and other distribution obligations. US Opco's income will be derived from the production of oil and natural gas primarily from its U.S. resource properties and is susceptible to the risks and uncertainties associated with the oil and natural gas industry generally, and particularly in the U.S. See "Risk Factors".

US Opco will be required to comply with covenants under the documentation for the Credit Facilities. In the event that it does not comply with such covenants, the ability to make distributions to Unitholders may be restricted. See "Risk Factors".

**Distribution Reinvestment Plan**

Following completion of the Offering and subject to the receipt of all necessary regulatory approvals, the Trust intends to adopt a distribution reinvestment plan. The DRIP will allow eligible Unitholders to elect to have their monthly cash distributions reinvested in additional Units on the applicable distribution payment date at a purchase price to be determined in accordance with the terms of the DRIP. It is currently anticipated that the purchase price for such Units will be equal to 97% of the Average Market Price (to be defined in the DRIP). The DRIP is designed to provide an efficient and cost effective way to issue additional equity to existing Unitholders.

Participation in the DRIP will be voluntary and will only be available to eligible Unitholders. Eligibility to participate in the DRIP will depend upon certain Unitholder residency criteria:

- residents of Canada will be eligible to participate in the DRIP;
- residents of the United States will not be eligible to participate in the DRIP; and
- residents of foreign jurisdictions other than the United States will only be entitled to participate in the DRIP if their participation is permitted by the laws of the jurisdiction in which they reside and provided that the Trust is satisfied, in its sole discretion, that such laws do not subject the DRIP, the Trust or the plan broker to additional legal or regulatory requirements.

Unitholders who do not enroll in the DRIP will receive their regular cash distributions. The Administrator reserves the right to limit the amount of new equity available under the DRIP on any particular distribution date. Accordingly, participation may be prorated in certain circumstances. In the event of proration, or if for any other reason all or a portion of the distributions cannot be reinvested under the DRIP, Unitholders enrolled in the DRIP will receive their regular cash distributions.

No commissions, service charges or similar fees will be payable in connection with the purchase of Units from treasury under the DRIP. All administrative costs of the DRIP will be paid by the Trust. Participation in the DRIP will not relieve Unitholders of any liability for taxes that may be payable in respect of distributions that are reinvested in new Units under the DRIP.

**Redemption at the Option of Unitholders**

Units are redeemable at any time and from time to time on demand by the Unitholders thereof upon delivery to the Trust at its head office and to CDS (if a global unit certificate has been issued by the Trust) of a duly completed and properly executed notice, in a form reasonably acceptable to the Trustee, requesting redemption, together with written instructions as to the number of Units to be redeemed and together with the certificates, if any, representing Units to be redeemed (if a global unit certificate has not been issued by the Trust). Upon tender of Units by a Unitholder for redemption, all rights to and under the Units tendered for redemption shall immediately cease, provided that the Unitholder thereof shall retain the right to receive distributions thereon which have been declared payable to Unitholders of record prior to the date of tender for redemption (the "**Redemption Date**") and the right to receive a price per Unit (the "**Redemption Price**") in cash equal to the lesser of: (i) 90% of the volume weighted average trading price of the Units for the last ten consecutive trading days ended immediately prior to the Redemption Date; and (ii) 100% of the volume weighted average trading price of the Units on the Redemption Date.

The aggregate Redemption Price payable by the Trust in respect of any Units tendered for redemption during any month shall be paid by cheque drawn on a Canadian chartered bank or trust company in lawful money of Canada payable to, or to the order of, the Unitholder who exercised the right of redemption, on or before the fifth business day after the end of the calendar month following the calendar month in which the Units were tendered for redemption; provided that Unitholders shall not be entitled to receive cash upon the redemption of their Units if: (i) the total amount payable by the Trust in respect of such Units and all other Units tendered for redemption in the same month exceeds $100,000 (provided that such limitation may be waived at the discretion of the Trustee); (ii) at the time such Units are tendered for redemption, the outstanding Units are not listed for trading on the TSX and are not traded or quoted on any other stock exchange or market which the Trustee considers, in its discretion, provides representative fair market value prices for the Units; (iii) the normal trading of Units is suspended or halted on any stock exchange on which the Units are listed for trading (or, if not listed on a stock exchange, on any market on which the Units are quoted for trading) on the Redemption Date or for more than five trading days during the ten consecutive trading-day period immediately prior to the Redemption Date; or (iv) the Trust or any affiliate of the Trust (including US Opco) is, or after such redemption would be, in default under the Credit Facilities or any other agreements entered into by the Trust or any of its affiliates, from time to time, which set forth the terms and conditions of any debt financing obtained by the Trust, or by any one of its affiliates (as the case may be), from any person or persons not affiliated with the Trust (and for further certainty, shall include all agreements pertaining to issuances of debentures or other debt securities to the public).

If a Unitholder is not entitled to receive cash upon the redemption of Units as a result of the limitations set forth in the immediately preceding paragraph, then the Redemption Price for each Unit tendered for redemption shall be equal to the fair market value of a Unit as determined by the Trustee, in its discretion, and shall, subject to all necessary regulatory approvals, be paid and satisfied by way of a distribution *in specie* of Trust Property (other than Can Holdco Shares, US Opco Notes or other securities or property of US Opco except as made in compliance with applicable U.S. federal and state securities laws), as determined by the Trustee in its discretion. To the extent that the Trust does not hold Trust Property (other than Can Holdco Shares, US Opco Notes or other securities or property of US Opco) having a sufficient amount outstanding to effect payment in full of the *in specie* Redemption Price, the Trust may effect such payment by issuing Redemption Notes, being unsecured subordinated promissory notes.

It is anticipated that the redemption right will not be the primary mechanism for Unitholders to dispose of their Units. The assets of the Trust which may be distributed *in specie* to Unitholders in connection with a redemption will not be listed on any stock exchange and no market is expected to develop in the assets of the Trust. Any Trust Property so distributed is expected to be subject to resale restrictions under applicable securities laws and are not expected to be qualified investments for Registered Plans. See "Canadian Federal Income Tax Considerations".

**Redemption by the Trustee for Non-Compliance**

The Trustee or Administrator may require any Unitholder, following a request by the Trustee or the Administrator, to furnish an executed U.S. Internal Revenue Service Form W-8BEN or W-9, as applicable (a "**Taxation Certification**"), and to use reasonable efforts to obtain a Taxation Certification from each beneficial unitholder holding Units in such Unitholder's name. If any Unitholder fails to furnish a Taxation Certification within 30 days following such a request or fails to use reasonable efforts to obtain a Taxation Certification from beneficial holders of Units, the Administrator may notify the Trustee, and upon notice by the Trustee to the non-complying Unitholder, redeem the Units held by any non-complying Unitholders at the Redemption Price in accordance with the terms of the Indenture.

**Trustee**

Computershare is the Trustee and the transfer agent and registrar for the Units. Subject to the express limitations contained in the Trust Indenture and any grant of certain powers to the Administrator, as administrator of the Trust, the Trustee has full, absolute and exclusive power, control and authority over the Trust Property and over the affairs of the Trust to the same extent as if the Trustee were the sole and absolute beneficial owner of the Trust Property in its own right, and to do all such acts and things as in its discretion are necessary or incidental to, or desirable for, the carrying out of the duties of the Trust created pursuant to the Trust Indenture. The Trustee has no obligation to Unitholders beyond the obligations set out in the Trust Indenture, except as may be mandated by law.

The Trust Indenture provides that the Trustee must discharge its duties honestly, in good faith and in the best interests of the Trust and the Unitholders and in connection therewith, exercise the degree of care, diligence and skill that a reasonably prudent trustee would exercise in comparable circumstances.

Except as expressly prohibited by law and by the terms of the Trust Indenture, the Trustee may in its discretion delegate the execution of certain of its authority and powers to the Administrator, as the administrator of the Trust, pursuant to the terms of the Administrative Services Agreement. The Trustee may in its discretion also delegate the execution of certain of its authority and powers to such other persons as is necessary or desirable to carry out and effect the actual management and administration of the duties of the Trustee under the Trust Indenture without regard to whether such authority is normally delegated by trustees. See "Description of the Trust – Delegation to the Administrator".

The Trustee shall be entitled to make any reasonable decisions, designations or determinations not contrary to the Trust Indenture which it may determine are necessary or desirable in interpreting, applying or administering the Trust Indenture, or in administering, managing or operating the Trust. Any Trustee's decisions, designations or determinations made pursuant to the Trust Indenture shall be conclusive and binding upon the Trust and the Unitholders.

The Trustee may resign as Trustee by giving to the Administrator, in its capacity as administrator of the Trust, not less than 90 days' prior written notice, unless the Administrator agrees to a shorter period of notice. The Trustee may be removed at any time with or without cause by Ordinary Resolution. The Trustee may also be removed at any time by the Administrator, in its capacity as administrator of the Trust, by notice in writing to the Trustee upon the occurrence of certain events, including where the Trustee is declared bankrupt or insolvent or enters into liquidation to wind up its affairs, all of its assets (or a substantial part thereof) are subject to seizure or confiscation, it becomes incapable or refuses to perform its responsibilities under the Trust Indenture, or the Trustee at any time ceases (i) to be incorporated under the laws of Canada or a province thereof, (ii) to be resident in Canada for the purposes of the Tax Act, or (iii) to be authorized and registered under the laws of the Province of Alberta to carry on the business of a trust company.

Any resignation or removal of the Trustee will take effect on the date upon which the last of the following occurs (i) a successor Trustee is appointed or elected pursuant to the Trust Indenture, and (ii) the new successor Trustee has accepted such election or appointment and has legally and validly assumed all obligations of the Trustee under the Trust Indenture. If no successor Trustee has been appointed or elected within 60 days of notice being given by the Trustee of its resignation, approval of an Ordinary Resolution to remove the Trustee, or the giving of notice by the Administrator to remove the Trustee, as the case may be, any Unitholder, the Trustee, the Administrator or any other interested person may apply to a court of competent jurisdiction for the appointment of a successor trustee.

Upon the taking effect of any resignation or removal of the Trustee under the terms of the Trust Indenture, the Trustee shall cease to be a party to the Administrative Services Agreement and the Voting Agreement.

The Trust Indenture provides that the Trustee shall be entitled to rely on and shall have no liability to any Unitholder, holder of Other Trust Securities, or any person for acting or failing to act, in good faith, in relation to any matter relating to the Trust where such action or failure is based upon, statements from, the opinion or advice of, or information from auditors, counsel or any valuator, engineer, surveyor or appraiser where it is reasonable to conclude that the matter in respect of which such statements are made, or opinion or advice given, ought to be within the expertise of such advisor or expert, provided that with respect to advisors and experts, the Trustee has satisfied its standard of care in selecting such advisors and experts. The Trustee shall have no liability whatsoever to any Unitholder or holder of Other Trust Securities for any obligation, liability or claim arising in connection with, directly or indirectly, the Trust Property or the conduct and undertaking of the affairs of the Trust, including (i) any action or failure to act by the Trustee in respect to its duties, responsibilities, powers, authorities and discretion under the Trust Indenture (including failure to compel in any way any trustee to redress any breach of trust or any failure of the Administrator to perform its duties under, or delegated to it under, the Trust Indenture, the Administrative Services Agreement or any other contract), (ii) any error in judgment, (iii) any matters pertaining to the administration or termination of the Trust, (iv) any environmental liabilities, (v) any action or failure to act by the Administrator or any other person to whom the Trustee has, as permitted by the Trust Indenture, delegated any of its duties, and (vi) any depreciation of, or loss to, the Trust incurred by reason of the retention or sale of any Trust Property; unless such liabilities arise from or out of the willful misconduct, fraud or gross negligence of the Trustee or the breach by the Trustee of its standard of care under the Trust Indenture. Where the Trustee is held liable to any person in circumstances or its property or assets are subject to levy, execution or other enforcement resulting in personal loss to the Trustee where there is to be no liability on the Trustee on the basis just described, the Trustee shall be indemnified out of the Trust Property to the full extent of such liability and the costs of any action, suit or proceeding or threatened action, suit or proceeding, including without limitation, reasonable legal fees and disbursements. The Trust Indenture also contains other customary provisions limiting the liability of the Trustee.

### Certain Restrictions on Trustee's Powers

The Trust Indenture provides that: (i) a change to the Administrative Services Agreement, the Voting Agreement or any extension thereof (which includes any increase in fees or other amounts payable by the Trust or its affiliates thereunder); (ii) any amendment to the terms of a constating document of a subsidiary of the Trust; and (iii) the terms of any agreement entered into by the Trust or its affiliates with the Administrator or any affiliate of the Administrator, must be approved by a majority of the Administrator Directors.

The Trust Indenture further provides that the Trustee shall not, without approval of Unitholders by Ordinary Resolution, (i) vote or instruct on the voting of any share of the Administrator pursuant to the Voting Agreement for the appointment of Administrator Directors by the Unitholders, or (ii) appoint or change the auditors of the Trust, except in the event of a voluntary resignation of such auditors.

In addition, the Trust Indenture provides that the Trustee shall not, without approval of Unitholders by Special Resolution, (i) amend the Trust Indenture, except as permitted by the Trust Indenture (as described under "Amendments to the Trust Indenture" below), (ii) sell, lease or exchange all or substantially all of the Trust Property, other than (a) pursuant to *in specie* redemptions permitted under the Trust Indenture, (b) in order to acquire Can Holdco Shares in connection with pursuing the purpose of the Trust and completing the transactions described herein, (c) in conjunction with an internal reorganization involving the sale, lease, exchange or other transfer of the Trust Property (whether or not involving all or substantially all of the Trust Property) as a result of which the Trust has substantially the same interest, whether directly or indirectly, in the Trust Property that it had prior to the reorganization and, for greater certainty, such reorganization includes an amalgamation, arrangement or merger of the Trust and its affiliates with any entities; or (iii) authorize the termination, liquidation or winding up of the Trust, other than at the end of the term of the Trust.

### Amendments to the Trust Indenture

Except where otherwise specifically provided therein, the Trust Indenture may only be amended or altered by Special Resolution. The Trustee will be entitled, at its discretion (which discretion has been delegated to the Administrator) and without the approval of the Unitholders, to make amendments to the Trust Indenture at any time for any of the following purposes: (i) ensuring the Trust continues to comply with applicable laws, regulations, requirements or policies of any governmental or regulatory authority having jurisdiction over the Trustee or the Trust; (ii) providing, in the opinion of the Trustee, additional protection for the Unitholders or to obtain, preserve or clarify the provision of desirable tax treatment to Unitholders; (iii) making amendments which, in the opinion of the Trustee, are necessary or desirable in the interests of the Unitholders as a result of changes in taxation laws or in their interpretation or administration; (iv) making corrections, or removing or curing any conflicts or inconsistencies between the provisions of the Trust Indenture or any supplemental indenture, and any other agreement to which the

Trust is a party, or any applicable law or regulation of any jurisdiction, or any prospectus filed with any governmental or regulatory authority with respect to the Trust, provided that, in the opinion of the Trustee, based on the advice of counsel, in each case, the rights of the Unitholders are not materially prejudiced thereby; (v) providing for the electronic delivery by the Trust to Unitholders of documents relating to the Trust (including annual and quarterly reports, including financial statements, notice of Unitholder's meetings and information circulars and proxy related materials) at such time as applicable securities laws have been amended to permit such electronic delivery in place of normal delivery procedures, provided that such amendments are not contrary to or do not conflict with such laws; (vi) curing, correcting or rectifying any ambiguities, defective or inconsistent provisions, errors, mistakes or omissions, provided that, in the opinion of the Trustee, based on the advice of counsel, the rights of the Unitholders are not materially prejudiced thereby; (vii) making amendments as are required to undertake an internal reorganization involving the sale, lease, exchange or other transfer of the Trust as a result of which the Trust has substantially the same interest, whether direct or indirect, in the Trust Property that it had prior to the reorganization and, for greater certainty, includes an amalgamation, arrangement or merger of the Trust and its affiliates with any entities provided that in the opinion of the Trustee, based on the advice of counsel, the rights of Unitholders are not materially prejudiced thereby; and (viii) making amendments for any purpose provided that in the opinion of the Trustee, based on the advice of counsel, the rights of Unitholders are not materially prejudiced thereby.

No amendment may be made to modify the voting rights attributable to Units or to reduce the fractional undivided beneficial interest in the Trust Property represented by any Unit without obtaining the consent of the holder of such Unit.

**Rights of Unitholders**

Following the completion of the Offering, the rights of the Unitholders will be established by the Trust Indenture. A Unitholder of the Trust has all of the material protections, rights and remedies a shareholder of a corporation would have under the ABCA, except as described below.

Many of the provisions of the ABCA respecting the governance and management of a corporation have been incorporated in the Trust Indenture. For example, Unitholders are entitled to exercise voting rights in respect of their holdings of Units in a manner comparable to shareholders of an ABCA corporation, including to elect Administrator Directors and to appoint auditors. The Trust Indenture also includes provisions modeled after comparable provisions of the ABCA dealing with the calling and holding of meetings of Unitholders, the quorum for and procedures at such meetings and the right of Unitholders to participate in the decision-making process where certain fundamental actions are proposed to be undertaken. Unlike shareholders of an ABCA corporation, Unitholders do not have a comparable right to make a unitholder proposal at a general meeting of the Trust. The matters in respect of which Unitholder approval is required under the Trust Indenture are generally less extensive than the rights conferred on the shareholders of an ABCA corporation, but effectively extend to certain fundamental actions that may be undertaken by the Trust and its subsidiary entities. These Unitholder approval rights are supplemented by provisions of applicable securities laws that are generally applicable to issuers (whether corporations, trusts or other entities) that are "reporting issuers" or the equivalent or listed on the TSX.

Unitholders do not have recourse to a dissent right under which shareholders of an ABCA corporation are entitled to receive the fair value of their shares where certain fundamental changes affecting the corporation are undertaken (such as an amalgamation, a continuance under the laws of another jurisdiction, the sale of all or substantially all of its property, a going private transaction or the addition, change or removal of provisions restricting (i) the business or businesses that the corporation can carry on, or (ii) the issue, transfer or ownership of shares). As an alternative, Unitholders seeking to terminate their investment in the Trust are entitled to redeem their Units, as described under "Description of the Trust – Redemption at the Option of Unitholders". Unitholders similarly do not have recourse to the statutory oppression remedy that is available to shareholders of an ABCA corporation where the corporation undertakes actions that are oppressive, unfairly prejudicial or disregarding the interests of securityholders and certain other parties.

Shareholders of an ABCA corporation may apply to a court to order the liquidation and dissolution of the corporation in those circumstances, whereas Unitholders can rely only on the general provisions of the Trust Indenture which permit the winding up of the Trust with the approval of a Special Resolution of the Unitholders. Shareholders of an ABCA corporation may also apply to a court for the appointment of an inspector, subject to court oversight and other investigative procedures, to investigate the manner in which the business of the corporation and its affiliates is being carried on where there is reason to believe that fraudulent, dishonest or oppressive conduct has occurred. By virtue of the right to requisition a meeting of Unitholders, the Trust Indenture allows Unitholders to call meetings to consider the appointment or removal of the Trustee and the Administrator Directors, but does not specifically contemplate the appointment of an inspector. The ABCA also permits shareholders to bring or intervene in derivative actions in the name of the corporation or any of its subsidiaries, with the leave of a court. The Trust Indenture does not include a comparable right of the Unitholders to commence or participate in legal proceedings with respect to the Trust. The protections, rights and remedies available to a Unitholder are described in the Trust Indenture. See "Risk Factors – Risks Relating to the Trust's Structure and Ownership of Units". The above-mentioned protections, rights and remedies are contained in the Trust Indenture, a copy of which is available at www.sedar.com.

**Meetings of Unitholders**

The Trust Indenture provides that there shall be an annual meeting of the Unitholders for the purpose of: (i) presentation of the financial statements of the Trust for the immediately preceding fiscal year; (ii) appointing the auditors of the Trust for the ensuing year; (iii) directing and instructing the Trustee as to the manner in which the Trustee shall vote (or how to compel the voting for) as agent for the Unitholders pursuant to the Voting Agreement for the election of the Administrator Directors; and (iv) transacting such other business as the Trustee may determine or as may be properly brought before the meeting. Pursuant to the Voting Agreement, the Administrator Shareholder will agree to vote its shares in the Administrator at the direction of the Unitholders, as communicated by the Trustee as agent for the Unitholders, with regard to, among other things, the election or removal of the Administrator Directors and the appointment of an auditor of the Administrator from time to time. See "Voting Agreement".

The Trust Indenture provides that special meetings of Unitholders may be convened at any time and for any purpose by the Trustee or the Administrator and must be convened, except in certain circumstances, if requisitioned in writing by the Unitholders representing not less than 20% of all votes entitled to be voted at a meeting of Unitholders. A requisition will be required to state in reasonable detail the business proposed to be transacted at the meeting.

Unitholders may attend and vote at all meetings of the Unitholders either in person or by proxy. A proxyholder will not be required to be a Unitholder. Two or more persons present in person and being Unitholders or representing, by proxy, Unitholders who hold in the aggregate not less than 10% of all votes entitled to be voted at a meeting of Unitholders shall constitute a quorum for the transaction of business at all such meetings. At any meeting at which a quorum is not present within 30 minutes after the time fixed for the holding of such meeting, the meeting, if convened upon the requisition of the Unitholders, shall be terminated, but in any other case, the meeting will stand adjourned to a day not less than 14 days later and to a place and time as determined by the chairman of the meeting and if at such adjourned meeting a quorum is not present, the Unitholders present either in person or by proxy shall be deemed to constitute a quorum.

Every question submitted to a meeting, other than questions to be decided by Special Resolution, shall, unless a poll vote is demanded, be decided by a show of hands on which every person present and entitled to vote shall be entitled to one vote. On a poll vote at any meeting of Unitholders, each Unit shall entitle the holder thereof to one vote.

The Trust Indenture contains provisions as to the notice required and other procedures with respect to the calling and holding of meetings of Unitholders.

**Information and Reports**

The Administrator, will furnish to Unitholders, in accordance with applicable securities laws, all financial statements of the Trust (including quarterly and annual financial statements and certifications) and other reports as are from time to time required by applicable law, including prescribed forms needed for the completion of Unitholder's tax returns under the Tax Act and equivalent provincial legislation. See "Plan of Distribution".

Each voting Unitholder has the right to obtain, on demand and without fee, from the head office of the Trust a copy of the Trust Indenture and any amendments thereto, and will be entitled to examine a list of Unitholders, subject to providing an affidavit to the Administrator, as administrator of the Trust, similar to the affidavit required under the ABCA for a shareholder to obtain a list of shareholders.

Prior to each meeting of Unitholders, the Administrator, as administrator of the Trust, will provide to the Unitholders (along with notice of the meeting) all information, together with such certifications, as are required by applicable law and by the Trust Indenture to be provided to Unitholders.

**Term of the Trust**

The Trust has been established for a term ending 21 years after the date of death of the last surviving issue of Her Majesty, Queen Elizabeth II, alive on January 31, 2012. The termination or winding-up of the Trust may also be effected by passage of a Special Resolution authorizing the same.

**Delegation to the Administrator**

Under the terms of the Trust Indenture, the Trustee is authorized to delegate any of the powers and duties granted to it (to the extent not expressly prohibited by law or by the Trust Indenture) to any person as the Trustee may deem necessary or desirable. The Trustee has delegated many of its powers and duties to the Administrator, as administrator of the Trust, pursuant to the terms of the Administrative Services Agreement. Among other things, the Administrative Services Agreement will set forth all of the rights, restrictions and limitations (including, without limitation, limitations of liability and indemnification rights) which pertain to the performance by the Administrator of the duties delegated to it by the Trustee. Pursuant to the terms of the Trust Indenture, those rights, restrictions and limitations also apply in all respects to the Administrator, as administrator of the Trust, in the exercise and performance by it of all powers, duties and authorities conferred upon or delegated to the Administrator under the terms of the Trust Indenture. In the event of a termination of the Administrative Services Agreement, the Trustee will, until a successor administrator is appointed, perform the duties otherwise to have been performed by the Administrator under the Administrative Services Agreement and the Trust Indenture on the same terms and conditions as they were performed by the Administrator. See "Administrative Services Agreement". The Trust Indenture provides that the Trustee shall have no liability to any Unitholder as a result of the delegation by the Trustee of its powers and duties to the Administrator.

In performing the duties delegated to it, the Administrator must exercise its power and carry out its function honestly, in good faith and in the best interests of the Trust and will also be obligated to exercise that degree of care, diligence and skill as would be exercised, in Canada, by a reasonably prudent person having responsibilities of a similar nature to those under the Administrative Services Agreement in comparable circumstances. The Administrator Directors will be indemnified by the Trust in respect of their activities on behalf of the Trust, as referred to above, unless the Administrator Directors act in a manner which is fraudulent, grossly negligent or in willful default of their duties or have breached the terms and conditions of the Administrative Services Agreement.

**Power of Attorney**

Upon becoming a Unitholder, each Unitholder, pursuant to the terms of the Trust Indenture, grants to the Trustee, its successors and assigns, a power of attorney constituting the Trustee, with full power of substitution, as the true and lawful attorney of such Unitholder to act on his behalf, with full power and authority in his name, place and stead, to execute, swear to, acknowledge, deliver, make, file or record (and to take all requisite action in connection with such matters), when, as and where required: (i) the Trust Indenture and any other instrument required or desirable to qualify, continue and keep in good standing the Trust as a "mutual fund trust" under the Tax Act in all jurisdictions that the Trustee deems appropriate and to ensure that the Trust is not a "SIFT trust" under the Tax Act in all jurisdictions that the Trustee deems appropriate; (ii) any instrument, deed, agreement or document in connection with carrying on the affairs of the Trust as authorized in the Trust Indenture, including all conveyances, transfers and other documents required to facilitate any sale of Units or in connection with any disposition of Units required by the Trust Indenture; (iii) all conveyances, transfers and other documents required in connection with the dissolution, liquidation or termination of the Trust; (iv) any and all elections, determinations or designations whether jointly with third parties or otherwise, under the Tax Act or any other taxation or other legislation or similar laws of Canada or of any other jurisdiction in respect of the affairs of the Trust or of a Unitholder's interest in the Trust; (v) any instrument, certificate and other documents necessary or appropriate to reflect and give effect to any duly authorized amendment to the Trust Indenture; and (vi) all transfers, conveyances and other documents required to facilitate the acquisition of Units or Other Trust Securities of non-tendering offerees in the event of a take-over bid.

Each Unitholder is agreeing that the power of attorney is, to the extent permitted by applicable law, irrevocable, is a power coupled with an interest, and shall survive the death, mental incompetence, disability and any subsequent legal incapacity of the Unitholder and shall survive the assignment by the Unitholder of all or part of the Unitholder's interest in the Trust and will extend to and bind the heirs, executors, administrators and other legal representatives and successors and assigns of the Unitholder. Each Unitholder agrees to be bound by any representations or actions made or taken by the Trustee pursuant to the power of attorney and waive any and all defenses which may be available to contest, negate or disaffirm any actions taken by the Trustee in good faith under the power of attorney.

## DESCRIPTION OF CAN HOLDCO

### General

Can Holdco is a corporation formed under the laws of the Province of Alberta on May 4, 2012. The sole shareholder of Can Holdco is the Trust. Can Holdco was created to form, acquire and hold on closing of the Offering all of the issued and outstanding US Opco Shares and to pass distributions from US Opco through to the Trust, to the extent possible.

### Governance

On the closing of the Offering, the directors of Can Holdco will be Eric Tremblay and Brian Prokop and the executive officers of Can Holdco will be the same as the executive officers of the Administrator. See "Trustee, Directors and Management – Directors and Executive Officers of the Administrator".

### Distributions

The dividends or return of capital of Can Holdco are amounts determined in the discretion of the Can Holdco board of directors, subject to applicable corporate law. The board of Can Holdco intends to make monthly cash distributions to the Trust so as to facilitate the Trust's monthly cash distributions to Unitholders.

## DESCRIPTION OF US OPCO

### General

US Opco is a corporation formed under the laws of the State of Delaware on May 4, 2012. The sole shareholder of US Opco is Can Holdco. US Opco was created to initially, acquire, operate and manage on closing of the Offering the Denali Assets and to issue the US Opco Notes and pay interest thereon.

### Governance

On the closing of the Offering, the directors of US Opco will be John Elzner, Richard Louden and Brian Prokop and the executive officers of US Opco will be John Elzner, Richard Louden, Brian Prokop and Sean Bovingdon. See "Trustee, Directors and Management – Directors and Executive Officers of the Administrator".

### Distributions

The cash required to fund distributions to Unitholders will be funded from two sources: (i) distributions on US Opco Shares held by Can Holdco and then distributed to the Trust and; (ii) interest payments on the US Opco Notes. The dividends or return of capital of US Opco are amounts determined in the discretion of the US Opco board of directors, subject to applicable corporate law. The board of US Opco intends to make monthly cash distributions to Can Holdco so as to facilitate the Trust's monthly cash distributions to Unitholders.

### The US Opco Notes

Following is a summary of the material attributes and characteristics of the US Opco Notes. This summary is qualified in its entirety by reference to the provisions of the US Opco Notes.

The US Opco Notes will be issued to Can Holdco in connection with the closing of the Offering. Concurrent with or immediately following the closing of the Offering, the US Opco Notes will be distributed by Can Holdco to the Trust.

***Interest and Maturity***

Except as described below, the US Opco Notes will bear interest at the rate of 9.50%, payable monthly, in arrears, with such payment to be made within 23 days of the end of each month or such earlier date as the principal balance outstanding and all accrued and unpaid interest is payable by US Opco to the holder(s) of the US Opco Notes. The US Opco Notes will mature ten years after issuance with principal payments amortized over ten years starting in the first year during which the US Opco Notes are outstanding. During the 10 year term of the US Opco Notes, US Opco will be permitted to repay all or any portion of the principal amount outstanding under the US Opco Notes at any time, together with accrued and unpaid interest and a make-whole amount calculated in accordance with the terms of the US Opco Notes.

***Additional Covenant***

The US Opco Notes shall require US Opco to ensure that the consolidated indebtedness of US Opco (including amounts outstanding under the Credit Facilities) shall not exceed approximately 65% of the consolidated capitalization of US Opco. The terms of the US Opco Notes prohibit them from being distributed to the public.

***Subordination/Security***

Payment of the principal amount and interest on the US Opco Notes will be subordinated in right of payment to the prior payment in full of the principal of and accrued and unpaid interest on, and all other amounts owing in respect of all senior indebtedness, which will be defined as all indebtedness, liabilities and obligations of US Opco (other than trade payables) that, by the terms of the instrument creating or evidencing the same, is not expressed to rank in right of payment in subordination to or *pari passu* with the indebtedness evidenced by the US Opco Notes. The US Opco Notes shall rank *pari passu* with US Opco's trade payables. The US Opco Notes will provide that upon any distribution of the assets of US Opco in the event of any dissolution, liquidation, reorganization or other similar proceedings relative to US Opco, the holders of all such senior indebtedness will be entitled to receive payment in full before the holder of a US Opco Note is entitled to receive any payment.

***Default***

The US Opco Notes will provide that any of the following shall constitute an event of default: (i) default in payment of the principal of the US Opco Notes when the same becomes due and the continuation of such default for a period of ten business days; (ii) default in payment of any interest due on the US Opco Notes and continuation of such default for a period of 15 business days; (iii) default in the observance or performance of any other covenant or condition of the US Opco Notes and continuance of such default for a period of 30 days after notice in writing has been given by the holder of the US Opco Notes specifying such default and requiring the US Opco to rectify the same; (iv) if there occurs, with respect to any issue of indebtedness of US Opco having an outstanding principal amount of $10 million or more, an event of default that has caused the holder thereof to declare such indebtedness to be due and payable prior to its maturity and such indebtedness has not been discharged in full or such acceleration has not been rescinded or annulled within 30 days of such acceleration; and (v) certain events of dissolution, liquidation, reorganization or other similar proceedings relative to US Opco.

## PLAN OF DISTRIBUTION

The Offering consists of 21,230,000 Units (24,414,500 Units if the Over-Allotment Option is exercised in full). See "Description of the Trust" for a description of the attributes of the Units.

Under an agreement dated August 1, 2012 among the Trust, the Administrator, Can Holdco, US Opco, Aston Hill, the Administrator Shareholder and the Underwriters (the "**Underwriting Agreement**"), the Trust has agreed to issue and sell and the Underwriters have agreed to purchase on August 10, 2012, or on such other date as may be agreed upon among the parties thereto, but in any event no later than August 31, 2012, the 21,230,000 Units qualified for distribution under this prospectus pursuant to the Offering at a price of $10.00 per Unit for a total consideration of $212,300,000 payable in cash to the Trust against delivery of certificates representing such Units.

The offering price of the Units to be issued pursuant to the Offering was determined by negotiation between the Administrator, on behalf of the Trust, and the Underwriters. The Trust has agreed to pay a fee to the Underwriters in the amount of $0.60 per Unit issued pursuant to the Offering, being an aggregate fee of $12,673,200 ($14,583,900 if the Over-Allotment Option is exercised in full). The Underwriter's fee is payable on closing of the Offering. No fee will be paid in respect of the 108,000 Units subscribed for by directors and officers of the Administrator.

The Underwriters propose to offer the Units initially at the offering price specified on the cover page of this prospectus. After the Underwriters have made a reasonable effort to sell all of the Units at the price specified on the cover page, the offering price may be decreased and may be further changed from time to time to an amount not greater than that set out on the cover page. In the event that the offering price of the Units to be issued under the Offering is reduced, the compensation received by the Underwriters will be decreased by the amount that the aggregate price paid by purchasers for the Units is less than the gross proceeds paid by the Underwriters to the Trust for such Units. Any such reduction in price will not affect the proceeds received by the Trust.

The obligations of the Underwriters under the Underwriting Agreement are several and not joint, and may be terminated at their discretion on the basis of their assessment of the state of the financial markets and may also be terminated upon the occurrence of certain stated events. If an Underwriter fails to purchase the Units which it has agreed to purchase, the remaining Underwriter(s) may, but are not obligated to, purchase such Units, provided that if the number of Units that a defaulting Underwriter or Underwriters agreed but failed to purchase is not more than 2% of the aggregate number of Units purchased, then the other Underwriters are severally obligated to purchase their respective portions of the Units which the defaulting Underwriter or Underwriters failed to purchase. The Underwriters are, however, obligated to take up and pay for all of the Units if any of the Units are purchased under the Underwriting Agreement. The Underwriting Agreement also provides that the Trust, the Administrator, Can Holdco and US Opco will jointly and severally indemnify the Underwriters, their respective affiliates and each of their respective directors, officers, employees, partners, shareholders, agents and each other person, if any, controlling an Underwriter or any of its subsidiaries and each shareholder of the Underwriter against certain liabilities, claims, actions, complaints, losses, costs, fines, penalties, taxes, interest, damages and expenses.

The Offering is being made in each of the provinces of Canada. The Units to be issued pursuant to the Offering will be offered in each of the provinces of Canada through those Underwriters or their affiliates who are registered to offer such Units for sale in such provinces and such other registered dealers as may be designated by the Underwriters. Subject to applicable law and the provisions of the Underwriting Agreement, the Underwriters may offer such Units outside of Canada. Aston Hill, as the promoter of the Trust, and the Administrator Shareholder have each provided a separate, similar joint indemnity as to certain matters, including breaches and misrepresentations relating to Aston Hill and the Administrator Shareholder.

The TSX has conditionally approved the listing of the Units under the Symbol "AET.UN". Listing is subject to the Trust fulfilling all the requirements of the TSX on or before October 23, 2012, including distribution of the Units to a minimum number of public securityholders.

In addition, the Trust has granted to the Underwriters the Over-Allotment Option to purchase up to an additional 3,184,500 Units, representing up to 15% of the Offering, at a price of $10.00 per Unit on the same terms and conditions as the Offering, exercisable in whole or in part, from time to time, not later than the 30th day following the closing of the Offering, to cover over-allotments, if any, and for market stabilization purposes. If the Over-Allotment Option is exercised in full, the total price to public, Underwriters' fee and net proceeds to the Trust in respect of the Offering (before deducting expenses of the Offering) will be $244,145,000, $14,583,900 and $229,561,100, respectively. A purchaser who acquires Units forming part of the Underwriters' over-allotment position acquires those Units under this prospectus regardless of whether the over-allotment position is ultimately filled through exercise of the Over-Allotment Option or secondary market purchases. This prospectus also qualifies for distribution the Over-Allotment Option and the issuance of the additional Units pursuant to the exercise of the Over-Allotment Option.

The Units offered hereby to be issued pursuant to the Offering have not been, and will not be, registered under the U.S. Securities Act, or any state securities laws, and may not be offered or sold within the United States absent registration or pursuant to an applicable exemption from the registration requirements of the U.S. Securities Act, and applicable state securities laws. Accordingly, except to the extent permitted by the Underwriting Agreement and except for offers and sales made by the Trust pursuant to an available exemption from registration requirements of the U.S. Securities Act, the Units to be issued pursuant to the Offering may not be offered or sold within the United States. Each Underwriter has agreed that it will not offer or sell Units within the United States, except in transactions exempt from the registration requirements of the U.S. Securities Act and applicable state securities laws. The Underwriting Agreement provides that the Underwriters may re-offer and re-sell the Units that they have acquired pursuant to the Underwriting Agreement in the United States to qualified institutional buyers in accordance with Rule 144A under the U.S. Securities Act. The Underwriting Agreement also provides that the Underwriters will offer and sell the Units outside the United States in accordance with Regulation S under the U.S. Securities Act. In addition, until 40 days after the closing of the Offering, an offer or sale of the Units within the United States by any dealer (whether or not participating in the Offering) may violate the registration requirements of the U.S. Securities Act, unless such offer is made pursuant to an exemption from registration under the U.S. Securities Act.

Prior to the Offering, there has been no public market for the Units. The sale of a substantial amount of the Units in the public market after the Offering, or the perception that such sales may occur, could adversely affect the prevailing market price of the Units.

Subscriptions for Units comprising the Offering will be received subject to rejection or allotment in whole or in part and the right is reserved to close the subscription books at any time without notice. One or more certificates representing the Units to be sold in the Offering will be issued in registered form to CDS, or to its nominee, and deposited with CDS on the date of closing of the Offering. A purchaser of Units comprising the Offering will receive only a customer confirmation from the registered dealer from or through which the Units are purchased. The Units comprising the Offering (other than any Units transferable or issuable, as applicable, upon exercise of the Over-Allotment Option) are to be taken up by the Underwriters, if at all, on or before a date not later than 42 days after the date of the final receipt for this prospectus.

The Trust has filed an undertaking with the securities regulatory authorities in each of the provinces of Canada in accordance with sections 6.1 and 6.4 of National Policy 41-201 – *Income Trusts and Other Indirect Offerings* ("**NP 41-201**") pursuant to which it has agreed that, among other things: (i) in complying with its reporting issuer obligations, it will treat all operating entities (as such term is used in NP 41-201) of the Trust as subsidiaries of the Trust; however, if IFRS as used by the Trust prohibits the consolidation of financial information of any of the Trust's operating entities and the Trust, then for as long as any such operating entity (including any of its significant business interests) represents a significant asset of the Trust, the Trust will provide Unitholders with separate audited annual financial statements and interim financial reports prepared in accordance with the same IFRS as the Trust's financial statements, and related management's discussion and analysis, prepared in accordance with National Instrument 51-102 – *Continuous Disclosure Obligations* or its successor, for each such operating entity (including information about any of its significant business interests); and (ii) for so long as the Trust is a reporting issuer, it will take the appropriate measures to require each person who would be required as an insider of such operating entities or a person or company in a special relationship with such operating entities if such operating entities were a reporting issuer to file insider reports about trades in Units of the Trust (including securities which are exchangeable into Units) and to comply with statutory prohibitions against insider trading. The Trust will also agree to annually certify it has complied with such undertaking and to file such certification electronically at www.sedar.com concurrent with the filing of its annual consolidated financial statements.

## Price Stabilization, Short Positions and Passive Market Making

In connection with the Offering, the Underwriters may over-allocate or effect transactions which stabilize or otherwise affect the market price of the Units at levels other than those which otherwise might prevail on the open market, including: stabilizing transactions; short sales; purchases to cover positions created by short sales; imposition of penalty bids; and syndicate covering transactions.

Stabilizing transactions consist of bids or purchases made for the purpose of preventing or retarding a decline in the market price of the Units while the Offering is in progress. These transactions may also include making short sales of the Units, which involve the sale by the Underwriters of a greater number of Units than they are required to purchase in the Offering. Short sales may be "covered short sales", which are short positions in an amount not greater than the Over-Allotment Option, or may be "naked short sales", which are short positions in excess of that amount.

The Underwriters may close out any covered short position either by exercising the Over-Allotment Option, in whole or in part, from time to time, or by purchasing Units in the open market or as otherwise permitted by applicable law.

In making this determination, the Underwriters will consider, among other things, the price of Units available for purchase in the open market compared with the price at which they may purchase Units through the Over-Allotment Option. The Underwriters must close out any naked short position by purchasing Units in the open market or as otherwise permitted by applicable law. A naked short position is more likely to be created if the Underwriters are concerned that there may be downward pressure on the price of the Units in the open market that could adversely affect investors who purchase in the Offering. Any naked short sales will form part of the Underwriters' over-allocation position.

In addition, in accordance with rules and policy statements of certain Canadian securities regulators, the Underwriters may not, at any time during the period of distribution, bid for or purchase Units. The foregoing restriction is, however, subject to exceptions where the bid or purchase is not made for the purpose of creating actual or apparent active trading in, or raising the price of, the Units. These exceptions include a bid or purchase permitted under the by-laws and rules of applicable regulatory authorities and the TSX, including the Universal Market Integrity Rules for Canadian Marketplaces, relating to market stabilization and passive market making activities and a bid or purchase made for and on behalf of a customer where the order was not solicited during the period of distribution.

As a result of these activities, the price of the Units may be higher than the price that otherwise might exist in the open market. If these activities are commenced, they may be discontinued by the Underwriters at any time. The Underwriters may carry out these transactions on any stock exchange on which the Units are listed, in the over-the-counter market, or as otherwise permitted by applicable law.

## Restrictions on the Sales of Units of the Trust

### *Restrictions on the Trust*

The parties to the Underwriting Agreement have agreed that without the prior consent of Scotia Capital Inc., CIBC World Markets Inc. and RBC Dominion Securities Inc., on behalf of the Underwriters, which consent shall not be unreasonably withheld, delayed or refused, none of them will (and will cause Can Holdco, US Opco and the Administrator, to not), during the period ending 180 days after the closing of the Offering, (i) create, allot, authorize, offer, issue, secure, pledge, sell, offer to sell, grant any option, right or warrant for the sale of, or contract to purchase or sell, or otherwise lend, transfer or dispose of, directly or indirectly, any Units, rights to purchase such Units or any securities convertible into or exercisable or exchangeable for such Units or (ii) enter into any swap or other arrangement that transfers to another, in whole or in part, any of the economic consequences of ownership of such Units, whether any such transaction described in clause (i) or (ii) above is to be settled by delivery of such Units, or such other securities or interests, in cash or otherwise, or agree or, within such period, announce any intention to do so, other than: (i) Units issuable under the RTUP, (ii) Units issued pursuant to the exercise of the Over-Allotment Option, (iii) Units issued as full or partial consideration for arm's length acquisitions of assets or a corporate acquisition; and (iv) Units issuable under the DRIP.

### *Restrictions on Certain Unitholders*

The Underwriters will enter into Lock-up Agreements with all of the Administrator Directors, Management and certain other non-arms length investors, including Aston Hill (the "**Locked-up Unitholders**") holding in aggregate 424,000 Units, representing approximately 1.9% of the outstanding Units on a fully-diluted basis on the closing of the Offering. Pursuant to the Lock-up Agreements, the Locked-up Unitholders have agreed for a period of 180 days following the closing of the Offering, subject to certain exceptions, not to offer, sell, contract to sell, pledge or otherwise dispose of, directly or indirectly, any Units or securities convertible into or exchangeable or exercisable for any Units, enter into a transaction which would have the same effect, or enter into any swap, hedge or other arrangement that transfers, in whole or in part, any of the economic consequences of ownership of the Units, whether any such aforementioned transaction is to be settled by delivery of such Units or such other securities, in cash or otherwise, or publicly disclose the intention to make any such offer, sale, pledge or disposition, or to enter into any such transaction, swap, hedge or other arrangement, without, in each case, the prior written consent of Scotia Capital Inc., CIBC World Markets Inc. and RBC Dominion Securities Inc., on behalf of the Underwriters.

Pursuant to the Lock-up Agreements, the Locked-up Unitholders are permitted to make transfers, sales, tenders or other dispositions of Units pursuant to a take-over bid for securities of the Trust or any other transaction, including, without limitation, a merger, arrangement or amalgamation, involving a change of control of the Trust (including, without limitation, entering into any lock-up, voting or similar agreement pursuant to which the Locked-up Unitholders may agree to transfer, sell, tender or otherwise dispose of Units in connection with any such transaction, or vote any Units in favour of any such transaction), provided that all Units subject to the Lock-up Agreements that are not so transferred, sold, tendered or otherwise disposed of remain subject to the Lock-up Agreements; and provided further that it shall be a condition of transfer, sale, tender or other disposition that if such take-over bid or other transaction is not completed, any Units subject to the Lock-up Agreements shall remain subject to the restrictions therein.

The Lock-up Agreements will not apply to (i) Units acquired by the Locked-up Unitholders in the open market after the completion of the Offering; or (ii) transfers of Units to any affiliate or associate, which includes a Registered Plan, provided that the transferee agrees in writing to be bound by the Lock-up Agreement. In addition, Scotia Capital Inc., CIBC World Markets Inc. and RBC Dominion Securities Inc. have the authority, on behalf of the Underwriters, to provide consents to release any one or all of the Locked-up Unitholders from their respective Lock-up Agreements.

## RELATIONSHIP BETWEEN THE TRUST AND AN UNDERWRITER

It is expected that an affiliate of Scotia Capital Inc. (the "**Lender**") will make the Credit Facilities available to US Opco at or before closing of the Offering. The Credit Facilities will be secured by a first priority security interest on substantially all of the property and assets of US Opco, including all of its oil and natural gas properties, and substantially all of the property and assets of the Trust and Can Holdco, including the interest in US Opco held by Can Holdco and will be guaranteed by the Trust and Can Holdco. See "Credit Facilities" and "Consolidated Capitalization". Accordingly, under applicable securities laws, the Trust may be considered a "connected issuer" to such Underwriter.

The decision to offer the Units to be issued pursuant to the Offering was made by the Administrator and the determination of the terms of the Offering, including the offering price of such Units, has been determined by negotiation among the Administrator (on behalf of the Trust) and the Underwriters. The Lender did not have any involvement in such decision or determination; however, the Lender has been advised of the Offering and the terms thereof. As a consequence of the Offering, each of the Underwriters will receive a share of the Underwriters' fee.

## PRINCIPAL SECURITYHOLDERS

There are no persons known to the Trust or to the Administrator who, following closing of the Offering, will beneficially own, or control or direct, directly or indirectly, more than 10% of the Units.

## PRIOR SALES

On January 31, 2012, in connection with the establishment of the Trust, the Trust issued one Unit to the initial unitholder, as settlor of the Trust, for $5.00. This Unit was repurchased by the Trust for the same price and cancelled on February 3, 2012.

The Trust issued an aggregate of 600,000 Units to the Administrator Directors, Management and certain other investors, including Aston Hill: (i) 153,000 Units on February 3, 2012; (ii) 220,000 Units on February 13, 2012; (iii) 217,000 Units on February 27, 2012; and (iv) 10,000 Units on February 29, 2012, at a price of $5.00 per Unit, resulting in the aggregate proceeds to the Trust of $3,000,000 (the "**Initial Private Placements**"). The proceeds from Units issued pursuant to the Initial Private Placements have been used for general and administrative expenditures, including salaries and office expenses and fees of third party service providers, and to source and review potential asset acquisitions, including the Acquisition. Approximately $1.5 million of the proceeds raised from the Initial Private Placements will be used to cover the expenses of the Offering. A majority of the Units issued pursuant to the Initial Private Placements are subject to escrow conditions. See "Securities Subject to Contractual Restrictions on Transfer".

The following table sets forth the Units acquired (and beneficially owned, or over which control or direction is exercised directly or indirectly) by the Administrator Directors, Management and Aston Hill in the Initial Private Placements:

| Subscriber | Date | Number of Units |
|---|---|---|
| Sean Bovingdon | February 3, 2012 | 2,000 |
| Scott Butler | February 3, 2012 | 10,000 |
| John Elzner | February 3, 2012 | 10,000 |
| Richard Louden | February 3, 2012 | 20,000 |
| Brian Prokop | February 3, 2012 | 20,000 (1) |
| William D. Robertson | February 3, 2012 | 5,000 |
| Glen Schmidt | February 3, 2012 | 15,000 |
| Eric Tremblay | February 3, 2012 | 20,000 |
| Aston Hill Financial Inc.(2) | February 13, 2012 | 200,000 |
| John Brussa | February 29, 2012 | 10,000 |
| **Total** | | **312,000** |

**Notes:**

(1) Includes 10,000 Units held by his spouse.

(2) Subsequent to the purchase of 200,000 Units, Aston Hill sold an aggregate of 30,000 Units to three arms-length parties at a price of $5.00 per Unit.

## SECURITIES SUBJECT TO CONTRACTUAL RESTRICTIONS ON TRANSFER

On closing of the Offering, the Underwriters will enter into Lock-up Agreements with the Locked-up Unitholders holding in aggregate 424,000 Units and RTUs to acquire up to 854,000 Units, representing approximately 5.6% of the outstanding Units on a fully-diluted basis. Pursuant to the Lock-up Agreements, the Locked-up Unitholders have agreed for a period of 180 days following the closing of the Offering, subject to certain exceptions, not to offer, sell, contract to sell, pledge or otherwise dispose of, directly or indirectly, any Units or securities convertible into or exchangeable or exercisable for any Units, enter into a transaction which would have the same effect, or enter into any swap, hedge or other arrangement that transfers, in whole or in part, any of the economic consequences of ownership of the Units, whether any such aforementioned transaction is to be settled by delivery of such Units or such other securities, in cash or otherwise, or publicly disclose the intention to make any such offer, sale, pledge or disposition, or to enter into any such transaction, swap, hedge or other arrangement, without, in each case, the prior written consent of Scotia Capital Inc., CIBC World Markets Inc. or RBC Dominion Securities Inc., on behalf of the Underwriters.

Pursuant to the Lock-up Agreements, the Locked-up Unitholders are permitted to make transfers, sales, tenders or other dispositions of Units pursuant to a take-over bid for securities of the Trust or any other transaction, including, without limitation, a merger, arrangement or amalgamation, involving a change of control of the Trust (including, without limitation, entering into any lock-up, voting or similar agreement pursuant to which the Locked-up Unitholders may agree to transfer, sell, tender or otherwise dispose of Units in connection with any such transaction, or vote any Units in favour of any such transaction), provided that all Units subject to the Lock-up Agreements that are not so transferred, sold, tendered or otherwise disposed of remain subject to the Lock-up Agreements; and provided further that it shall be a condition of transfer, sale, tender or other disposition that if such take-over bid or other transaction is not completed, any Units subject to the Lock-up Agreements shall remain subject to the restrictions therein.

The Lock-up Agreements will not apply to (i) Units acquired by the Locked-up Unitholders in the open market after the completion of the Offering; or (ii) transfers of Units to any affiliate or associate, which includes a Registered Plan, provided that the transferee agrees in writing to be bound by the Lock-up Agreement. In addition, Scotia Capital Inc., CIBC World Markets Inc. and RBC Dominion Securities Inc. have the authority, on behalf of the Underwriters, to provide consents to release any one or all of the Locked-up Unitholders from their respective Lock-up Agreements.

The securities subject to the Lock-up Agreements are summarized in the following table.

| Designation of class | Number of securities held in escrow or that are subject to a contractual restriction on transfer | Percentage of class[(1)] |
|---|---|---|
| Units | 424,000 | 1.9% |
| RTUs | 854,000 | 100% |

**Note:**

(1) Prior to any exercise of the Over-Allotment Option.

## FIDUCIARY RESPONSIBILITY OF THE ADMINISTRATOR

The Administrator, as administrator of the Trust, will have a duty to administer the Trust in a manner beneficial to the Unitholders thereof. As well, the Administrator Directors and officers of the Administrator will have fiduciary obligations in that capacity to the Unitholders of the Trust and the directors and officers of each of Can Holdco and US Opco will have fiduciary obligations in that capacity to Can Holdco and US Opco, respectively. Situations may arise in which the interests of the Trust and its affiliates and associates may conflict with the interests of the Administrator, and the directors of the subsidiaries of the Trust and the Administrator Directors will be obligated to resolve such conflicts.

## PROMOTER

Aston Hill may be considered to be the promoter of the Trust in that it directly took the initiative in founding and organizing the Trust and its affiliates.

The following table represents the Units that will be held, directly or indirectly, or controlled by Aston Hill on the closing of the Offering:

| Name | Number of Units Held, Directly or Indirectly, or Controlled | Percentage of Outstanding Units after giving effect to the Offering |
|---|---|---|
| Aston Hill Financial Inc. | 170,000 | 0.8% |

On February 13, 2012, the Trust issued 200,000 Units at a price of $5.00 per Unit to Aston Hill. Subsequent to the purchase of 200,000 Units, Aston Hill sold in aggregate 30,000 Units to three arms-length parties at a price of $5.00 per Unit. Following the closing of the Offering, Aston Hill, directly or indirectly, is expected to own, control or direct less than 1% of the issued and outstanding Units. In addition, following the closing of the Offering, Aston Hill will be granted 210,000 RTUs pursuant to the Services Agreement for the provision of services under such agreement. All Units held by Aston Hill will be subject to a voluntary contractual restriction on transfer for 180 days after the closing of the Offering. See "Securities Subject to Contractual Restrictions on Transfer" and "Prior Sales".

The Services Agreement will provide for the recovery by Aston Hill of its direct costs incurred in providing certain technical and administrative services to the Administrator plus the Overhead Allocation. See "Administration of the Trust – Services Agreement with Aston Hill" and "Risk Factors". Eric Tremblay, the Chief Executive Officer of Aston Hill, is also an Administrator Director. See "Interest of Management and Others in Material Transactions".

## INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as described below or elsewhere in this prospectus, there is no material interest, direct or indirect, of: (i) any director or executive officer of the Administrator; (ii) any person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of the Units; or (iii) any affiliate of the persons or companies referred to above in (i) or (ii), in any transaction within the three years before the date of this prospectus that has materially affected or is reasonably expected to materially affect the Trust or a subsidiary of the Trust. See "Administration of the Trust – Services Agreement with Aston Hill".

Eric Tremblay, an Administrator Director, is also the Chief Executive Officer of Aston Hill, an affiliate of the Administrator Shareholder. Aston Hill will also enter into the Services Agreement with the Administrator to provide certain technical and administrative services to the Trust and the Administrator. See "Administration of the Trust – Services Agreement with Aston Hill". Aston Hill subscribed for and purchased 200,000 Units at a price of $5.00 pursuant to the Initial Private Placements. Subsequent to the purchase of such Units, Aston Hill sold an aggregate of 30,000 Units to three arms-length parties at a price of $5.00 per Unit. See "Prior Sales". In addition, pursuant to the Services Agreement, Aston Hill will receive 210,000 RTUs upon closing of the Offering.

## THE INDUSTRY

### United States Oil and Natural Gas Industry

#### *Overview*

The oil and natural gas industry in the United States is well-established. Since the 1860s oil has been produced in economic quantities in a number of discrete sedimentary basins in most states in the United States. Accompanying this production has been the development of supportive infrastructure including pipelines, natural gas processing facilities and a drilling and service sector as well as a wide range of professional services.

The demand for low-cost, domestic sources of hydrocarbons remains strong. U.S. domestic policy has historically supported the development and exploitation of oil and natural gas reserves to assure access to domestic supplies of hydrocarbons. Many state and municipal governments are also supportive and recognize the monetary contribution that the industry makes to their state and municipal budgets.

### Background

This section provides a brief overview of the legal structure of the parts of the U.S. oil and natural gas exploration and production industry in which the Trust, through Can Holdco and US Opco, will primarily operate.

In the United States, ownership of land typically carries with it ownership of or the exclusive right to enjoy substances under the surface, including oil, natural gas and other minerals. A landowner may generally convey an estate in the oil and natural gas rights separate and apart from the ownership of the surface rights. When the oil and natural gas interest is severed from the surface interest, two distinct estates or interests are created – the mineral estate and the surface estate.

The owner of the mineral estate has many interests which are capable of being conveyed alone or in various combinations, including the right to convey a working interest to an oil and natural gas exploration and production company to explore for and produce oil and natural gas from the mineral estate. Such a working interest is typically conveyed by the owner or owners of the mineral estate to the working interest owner pursuant to an oil, natural gas and mineral lease. The owner of the mineral estate typically retains a royalty interest, which is the right to receive a specified percentage of the production (or, in some cases, a share of the proceeds or market value) of any oil and natural gas recovered from the mineral estate, prior to deduction of any costs or expenses. Reference to the term "working interest" typically refers to the operating (and expense bearing) interest under an oil, natural gas and mineral lease.

The rights of exploration, drilling and production conveyed by a typical lease agreement customarily require that production of oil and natural gas in paying quantities be established within a specified period of time, often two to five years. Absent an ability to extend the primary term of the lease, the lease terminates if such production is not established (or, depending on the express language of the applicable oil and natural gas lease, if commencement of drilling operations has not commenced) within the specified time period. Once such production is established during the primary term, the lease agreement would generally continue in effect (either in whole or in part as to the proration units located around producing wells) so long as production in paying quantities continues, subject to the terms of the applicable lease. Some leases also contain provisions that could result in a forfeiture of certain acreage covered by the lease, notwithstanding drilling and/or producing prior to the expiration of the primary term, if drilling operations are not continued within specified periods after the last drilling operations were completed, or for other reasons or conditions that may be specified in the applicable lease. The interest of the lessee under an oil and natural gas lease is also capable of being abandoned by the lessee and may also be subject to forfeiture for failure on the part of the lessee to comply with express covenants and implied obligations, including, for example, the duty to reasonably develop the premises, the duty to protect the leasehold against drainage and the duty to manage and administer the lease.

### Operations

#### *Purchase and Sale Agreement*

The Purchase and Sale Agreement provides for the Acquisition and the execution of other assignments, conveyances and other instruments that are customary in transactions of this nature. By virtue of the Acquisition, US Opco will acquire the Denali Assets. Capital spending on the Denali Assets will be determined solely by US Opco, as the principal operator of the Denali Assets.

### *Title to Properties*

Most of the oil and natural gas leases comprising the Denali Assets have been held in effect for long periods by continuous production. Various reviews of title of a substantial portion of the producing leases and wells in the Denali Assets have been undertaken at the direction of Denali. These reviews included the preparation of leasehold title memoranda or opinions by law firms, or oil and gas land service companies. These title opinions, memoranda and reviews revealed title defects, encumbrances, or other restrictions that are typical of interests in oil and natural gas leasehold interests in the State of Texas and included curative title requirements, some of which have not or cannot be satisfied. In addition, these opinions, memoranda and reviews are limited primarily to the interests in leasehold acreage related to currently producing wells in part due to the large numbers of leases and the complexity of private land ownership in Texas. All title opinions provided are limited to matters of record which were provided to the individual rendering the opinion. In each opinion, the examining attorney has assumed that each of the subject leases has not terminated as a result of lack of continuous operations on the tracts subject to the leases. As is typical in the United States, Denali has provided only limited representations regarding the status of title to the Denali Assets in the Purchase and Sale Agreement. Management has reviewed title information provided by Denali with respect to the Denali Assets as to the leases and wells that comprise a substantial portion of the producing reserves value of the Denali Assets, as reflected in the Sproule Reserve Report. Based on its due diligence investigations of title, including the fact that most of the producing Denali Assets have long production histories with no known material title disputes, Management does not believe that any known title defects and other matters affecting title to the Denali Assets will materially impact US Opco operations or its ability to receive revenues from production from the Denali Assets.

As is customary in the U.S. oil and gas industry, in connection with leasing or acquisition of undrilled or non-producing oil and gas leases, only preliminary title review fieldwork is performed, typically by oil and gas land professionals or land services companies on the basis of governmental real property records, run sheets, available title abstracts and other title field notes. Denali has performed only such preliminary title work as Management believes is customary with respect to the non-producing leasehold interests that constitute a large portion of the net acreage of the Denali Assets, including the Deep Rights. Accordingly, the undrilled and non-producing acreage comprising part of the Denali Assets may be subject to more significant title defects with more costly or complicated curative requirements incurred prior to drilling.

Management intends to follow customary U.S. oil and natural gas industry due diligence practices in connection with any future acquisitions, including performing title reviews on producing properties, undeveloped properties that are assigned significant value and the more significant leases prior to completing an acquisition and, depending on the materiality of the properties, Management may obtain title opinions or reports or review previously obtained title opinions or reports. Depending on the nature of each acquisition, to the extent title opinions or other investigations reflect material title defects, either the purchaser or the seller would be responsible for the costs and for curing any title defects or accepting uncured defects. As discussed above, a title examination on other properties and leaseholds would typically be performed prior to the commencement of drilling operations thereon and any curative work would be performed. US Opco's oil and natural gas properties will be subject to customary royalty and other interests, liens for current taxes and other customary burdens. See "Risk Factors".

### *Competition*

The U.S. oil and natural gas industry is highly competitive in all phases. The Trust, through US Opco, will encounter competition from other oil and natural gas companies in all areas of operation, including the acquisition of leasing options on oil and natural gas properties to the exploration and development of those properties. The Trust's competitors will include numerous independent and major oil and natural gas companies, individuals and drilling and income programs. Many of the Trust's competitors are large, well established companies that have substantially larger operating staffs and greater capital resources than the Trust will have. Such competitors may be able to pay more for lease options on oil and natural gas properties and exploratory locations and to define, evaluate, bid for and purchase a greater number of properties and locations than the Trust's financial or human resources will permit. The Trust's ability to acquire additional properties and to discover reserves in the future will depend upon its ability through US Opco to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. See "Risk Factors".

*Regulation of the Oil and Natural Gas Industry*

Operations will be substantially affected by U.S. federal, state and local laws and regulations. In particular, oil and natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which the Trust plans to acquire interests through US Opco in properties for oil and natural gas production have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, the abandonment of wells, and reports concerning operations. Operations are also subject to various conservation laws and regulations. These include regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of oil and natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas and that impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties, and the regulatory burden on the industry in the U.S. increases the cost of doing business and affects profitability. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by the United States Congress ("**Congress**"), the states, the federal Energy Regulatory Commission ("**FERC**"), the U.S. Environmental Protection Agency ("**EPA**") and the courts. The Trust cannot predict when or whether any such proposals may become effective or the costs of complying therewith.

*Regulation of Transportation of Oil*

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could re-enact price controls in the future. Sales of crude oil will be affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate and access regulation. FERC regulates interstate oil pipeline transportation rates under the *Interstate Commerce Act*. In general, interstate oil pipeline rates must be cost-based, although settlement rates and market based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil that allowed for an increase or decrease in the cost of transporting oil to the purchaser. A review of these regulations by the FERC in 2000 was successfully challenged on appeal by an association of oil pipelines. On remand, the FERC in February 2003 increased the index ceiling slightly, effective July 2001. Following the FERC's five-year review of the indexing methodology, the FERC issued an order in 2006 increasing the index ceiling. The FERC reviews the annual indexing factor every five years. For the five year period commencing July 1, 2011, the annual indexing factor is equal to the Producer Price Index for Finished Goods plus 2.65%. The FERC's order setting this index factor has been appealed. The Trust cannot predict whether or to what extent the index factor may change in the future.

Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, Management believes that the regulation of oil transportation rates will not affect operations in any way that is of material difference from those of competitors who are similarly situated.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by pro-rationing provisions set forth in the pipelines' published tariffs. Accordingly, Management believes that access to oil pipeline transportation services generally will be available to US Opco to the same extent as to similarly situated competitors.

*Regulation of Transportation and Sales of Natural Gas and NGLs*

The transportation of natural gas in interstate commerce is regulated by FERC under the *Natural Gas Act of 1938* ("**NGA**"), the *Natural Gas Policy Act of 1978* ("**NGPA**"), and regulations issued pursuant to those statutes. FERC is continually proposing and implementing new rules and regulations affecting the interstate transportation of natural gas, and to a lesser extent, the interstate transportation of NGLs. These initiatives also may indirectly affect the intrastate transportation of natural gas and NGLs under certain circumstances. Management cannot predict the ultimate impact of these or the above regulatory changes to US Opco's natural gas operations. Management does not believe that US Opco would be affected by any such action materially differently than similarly situated competitors.

The price at which US Opco sells natural gas and NGLs is currently not subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to US Opco's physical sales of these energy commodities and any related hedging activities that it undertakes, US Opco is required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the U.S. Commodity Futures Trading Commission. See "– Other Federal Laws and Regulations Affecting the Industry – Energy Policy Act of 2005." Since May 1, 2009, companies are required to report FERC information regarding natural gas sale and purchase transactions for certain operations depending on the volume of natural gas transacted during the prior calendar year. See "– Other Federal Laws and Regulation Affecting Our Industry – FERC Market Transparency Rules." If US Opco were to violate the anti-market manipulation laws and regulations, US Opco could also be subject to related third party damage claims by, among others, market participants, sellers, royalty owners and taxing authorities.

In the past, the U.S. federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, Congress could re-enact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA and culminated in adoption of the *Natural Gas Wellhead Decontrol Act* of 1989 which deregulated all price controls affecting wellhead sales of natural gas effective January 1, 1993.

### *Gathering Pipeline Regulation*

In 2007, Texas enacted new laws regarding rates, competition and confidentiality for natural gas gathering and transmission pipelines ("**Competition Statute**") and new informal complaint procedures for challenging determinations of lost and unaccounted for natural gas by natural gas gatherers, processors and transporters ("**LUG Statute**"). The Competition Statute gives the RRC the ability to use either a cost-of-service method or a market-based method for setting rates for natural gas gathering and transportation pipelines in formal rate proceedings. This statute also gives the RRC specific authority to enforce its statutory duty to prevent discrimination in natural gas gathering and transportation, to enforce the requirement that parties participate in an informal complaint process and to punish purchasers, transporters, and gatherers for taking discriminatory actions against shippers and sellers. The Competition Statute also provides producers with the unilateral option to determine whether or not confidentiality provisions are included in a contract to which a producer is a party for the sale, transportation, or gathering of natural gas. The LUG Statute modifies the informal complaint process at the RRC with procedures unique to lost and unaccounted for natural gas issues. Such statute also extends the types of information that can be requested and provides the RRC with the authority to make determinations and issue orders in specific situations. Management cannot predict what effect, if any, these statutes might have on US Opco's future operations in Texas.

Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, Management believes that the regulation of similarly situated intrastate natural gas transportation in any states in which US Opco operates and ships natural gas on an intrastate basis will not affect operations in any way that is materially different from those of US Opco's competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas, as well as the revenues US Opco receives for sales of natural gas.

### *Regulation of Production*

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds, reports concerning operations, and may require other credit or financial support. The jurisdictions in which the Denali Assets are located and in which Management anticipates operating have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that US Opco can produce from, and to limit the number of, wells or the locations at which US Opco can drill, although US Opco can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each jurisdiction generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGLs.

The failure to comply with these rules and regulations can result in substantial penalties. Competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect US Opco's operations.

If US Opco conducts operations on federal, state or Indian oil and natural gas leases, these operations must comply with numerous regulatory restrictions, including various non-discrimination statutes, royalty and related valuation requirements, and certain of these operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by the Bureau of Land Management, the Bureau of Ocean Energy Management, Regulation and Enforcement or other appropriate federal or state agencies.

***Other Federal Laws and Regulations Affecting the Industry***

*Energy Policy Act of 2005*

In August 2005, Congress enacted the *Energy Policy Act of 2005* (the "**EPAct 2005**"). Among other matters, EPAct 2005 amends the NGA to add an anti-manipulation provision which makes it unlawful for any entity, including otherwise non-jurisdictional producers, to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. EPAct 2005 provides the FERC with the power to assess civil penalties of up to US$1 million per day for violations of the NGA and increases the FERC's civil penalty authority under the NGPA from US$5,000 per violation per day to US$1 million per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. FERC issued Order No. 670 to implement the anti-market manipulation provision of EPAct 2005. This order makes it unlawful for natural gas pipelines and storage companies that provide interstate services to: (1) in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act, practice, or course of business that operates as a fraud or deceit upon any person. The new anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but do apply to activities of natural gas pipelines and storage companies that provide interstate services, such as Section 311 service, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" natural gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order 704 (as defined below). The anti-manipulation rules and enhanced civil penalty authority reflect an expansion of FERC's NGA enforcement authority. Should Management fail to comply with all applicable FERC administered statutes, rules, regulations, and orders, the Trust could be subject to substantial penalties and fines.

*FERC Market Transparency Rules*

In 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing ("**Order 704**"). Under Order 704, wholesale buyers and sellers of more than 2.2 million MMBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors, natural gas marketers and natural gas producers, are required to report, on May 1st of each year beginning in 2009, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC's policy statement on price reporting.

*Energy Independence and Security Act of 2007*

Effective November 4, 2009, pursuant to the *Energy Independence and Security Act of 2007*, the Federal Trade Commission ("**FTC**") issued a rule prohibiting market manipulation in the petroleum industry. The FTC rule prohibits any person, directly or indirectly, in connection with the purchase or sale of crude oil, gasoline or petroleum distillates at wholesale from: (a) knowingly engaging in any act, practice or course of business, including the making of any untrue statement of a material fact, that operates as a fraud or deceit upon any person; or (b) intentionally failing to state a material fact that under the circumstance renders a statement made by such person misleading, provided that such omission distorts or is likely to distort market conditions for any such product. A violation of this rule may result in civil penalties of up to US$1 million per day per violation, in addition to any applicable penalty under the *Federal Trade Commission Act*.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. Management cannot predict the ultimate impact of these or the above regulatory changes to the Trust's natural gas operations. Management does not believe that the Trust would be affected by any such action materially differently than similarly situated competitors.

**Environmental and Occupational, Health and Safety Regulation**

US Opco will acquire exploration, development and production operations which are subject to stringent and complex federal, state and local laws and regulations governing worker health and safety, the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may, among other things, require the acquisition of permits to conduct exploration, drilling and production operations; govern the amounts and types of substances that may be released into the environment in connection with oil and natural gas drilling and production; restrict the handling or disposal of wastes; limit or prohibit construction or drilling activities in sensitive areas such as wetlands, wilderness areas or areas inhabited by endangered or threatened species; require investigatory and remedial actions to mitigate pollution conditions caused by operations or attributable to former operations; and impose obligations to reclaim and abandon well sites and pits. In addition, such legal requirements will require application of specific health and safety criteria addressing worker protection. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of orders limiting or prohibiting some or all of US Opco's oil and natural gas exploration and production operations.

The clear trend in environmental laws and regulation has been to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly well construction, drilling, completion or water management activities, or waste handling, storage, transport, disposal, or remediation requirements could have a material adverse effect on the operations, profitability and financial position of US Opco and the Trust. Numerous governmental authorities, including the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions. Of particular note, the EPA identified the enforcement of environmental laws and regulations applicable to the oil and natural gas exploration and production sector as a National Enforcement Initiative for 2011 to 2013. Increased compliance costs may not be able to be passed on to purchasers or customers. Moreover, accidental releases or spills may occur in the course of operations, and significant costs and liabilities may arise as a result of such releases or spills, including any third party claims for damage to property, natural resources or persons.

The following is a summary of the more significant existing environmental and occupational health and safety laws and regulations to which the Trust's proposed business operations will be subject and for which compliance may have a material adverse impact on capital expenditures, results of operations or financial position.

***Hazardous Substances and Wastes***

The *Comprehensive Environmental Response, Compensation, and Liability Act*, as amended, (the "**CERCLA**"), also known as the Superfund law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include current and prior owners or operators of the site where a release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these "responsible persons" may be subject to joint and several, strict liability for the costs of cleaning up hazardous substances that have been released into the environment, for investigating and mitigating vapor intrusion, for damages to natural resources, and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other pollutants into the environment. Oil and natural gas exploration and production operations generate substances that may be regulated as hazardous substances.

Oil and natural gas exploration and development activities also generate solid and hazardous wastes that may be subject to the requirements of the *Resource Conservation and Recovery Act*, as amended, (the "**RCRA**"), and comparable state statutes. RCRA imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Drilling fluids, produced waters and a number of other wastes associated with the exploration, development and production of oil or natural gas are currently exempt from regulation under the RCRA's hazardous waste provisions and, instead are regulated under less stringent non-hazardous waste standards. However, it is possible that certain or all of these oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous in the future. In September 2010, a non-governmental organization filed a petition with the EPA requesting them to reconsider the RCRA exemption for exploration, production and development wastes. To date, the EPA has not taken action on the petition.

Once the Acquisition is complete, the Trust will have an interest in, and in connection with future acquisitions, Management anticipates that the Trust will acquire interests through US Opco in properties that have been used for numerous years to explore and produce oil and natural gas. Hydrocarbons and wastes have been disposed of or released on or under these properties or on or under other locations where these hydrocarbons and wastes have been taken for treatment or disposal. In some instances, the properties are located in areas with known regional groundwater oil and natural gas impacts. In addition, certain of these properties may have been operated by third parties whose treatment and disposal or release of hydrocarbons and wastes may result in liability. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA, other federal laws, and analogous state laws. These laws could require removal of previously disposed wastes (including wastes disposed of or released by prior owners or operators), remediation or cleanup of contaminated property (including contaminated groundwater) and performance of operations to prevent future contamination.

***Air Emissions***

The *Clean Air Act*, as amended, and comparable state laws and regulations restrict the emission of air pollutants from many sources and also impose various monitoring and reporting requirements. These laws and regulations may require US Opco, as the operator of the Denali Assets, to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions. These laws and regulations may also require permits or the use of specific equipment or technologies to control emissions. Obtaining permits has the potential to delay the development of oil and natural gas projects. In addition, the EPA and state regulators have under way a number of regulatory changes (such as, by way of example, the EPA's compressor engine emissions standards and the potential aggregation of exploration and production-related emissions sources to make what have historically been multiple "minor" sources, into larger "major" sources) that may significantly increase the regulatory burdens and costs of oil and natural gas exploration and production operations in the U.S.

On April 17, 2012, the EPA approved final regulations under the *Clean Air Act* that, among other things, require additional emissions controls for natural gas and natural gas liquids production, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("**VOCs**") and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations require the reduction of VOC emissions from natural gas wells through the use of reduced emission completions or "green completions" on all hydraulically fractured wells constructed or refractured after January 1, 2015. For well completion operations occurring at such well sites before January 1, 2015, the final regulations allow operators to capture and direct flowback emissions to completion combustion devices, such as flares, in lieu of performing green completions. These regulations also establish specific new requirements regarding emissions from dehydrators, storage tanks and other production equipment. Compliance with these requirements could require a number of modifications to operations, including the installation of new equipment, and could significantly increase US Opco's costs of development and production, although Management does not expect these requirements to be any more burdensome to US Opco than to other similarly situated companies involved in oil and natural gas exploration and production operations.

***Climate Change***

In December 2009, the EPA determined that emissions of carbon dioxide, methane and other "greenhouse gases" ("**GHGs**") present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has adopted two sets of rules regulating emissions under the *Clean Air Act*, one of which requires a reduction in emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources. The EPA's rules relating to emissions of GHGs from large stationary sources of emissions are currently subject to a number of legal challenges, but the federal courts have thus far declined to issue any injunctions to prevent the EPA from implementing, or requiring state environmental agencies to implement, the rules. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified GHG emission sources in the United States, including, among others, certain onshore oil and natural gas production, facilities, on an annual basis.

In addition, Congress has from time to time considered legislation to regulate GHG emissions, and almost one-half of the states have begun taking actions to control and/or reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Although most of the state-level initiatives have to date focused on large sources of GHG emissions, such as coal-fired electric plants, it is possible that smaller sources of emissions could become subject to GHG emission limitations or allowance purchase requirements in the future.

The adoption and implementation of laws and regulations imposing reporting obligations or limiting emissions of GHGs from equipment and operations of US Opco and in which the Trust will invest could increase costs associated with oil and natural gas exploration and production operations or could adversely affect demand for the oil and natural gas produced. At this time, it is not possible to accurately estimate how potential future laws or regulations addressing GHG emissions would impact the operations of the business in which the Trust will invest, but such legal requirements could have a material adverse effect on the Trust's business and financial condition.

***Water Discharges***

The *Federal Water Pollution Control Act*, as amended, also known as the *Clean Water Act*, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters and navigable waters of the U.S. Any such discharge of pollutants into regulated waters must be performed in accordance with the terms of a permit issued by the EPA or an analogous state agency. Spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the *Clean Water Act* and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Further, disposal of various waste products from oil and natural gas exploration and production may be subject to permitting requirements.

The *Oil Pollution Act of 1990*, as amended, (the "**OPA**"), which amends the *Clean Water Act*, establishes strict liability for owners and operators of facilities that are the site of a release of oil into waters of the U.S. The OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A "responsible party" under the OPA includes owners and operators of certain onshore facilities from which a release may affect waters of the U.S.

### *Underground Injection Wells and Hydraulic Fracturing*

Operations of the business in which the Trust will invest produce waste waters that are disposed via injection in underground wells. These injection wells are regulated by the *Safe Drinking Water Act* (the "**SDWA**") and analogous state and local laws. The underground injection well program under the SDWA requires permits from the EPA or analogous state agencies for disposal wells, establishes minimum standards for injection well operations, and restricts the types and quantities of fluids that may be injected. Any prospective changes in the regulations that would impose more stringent requirements or any inability to obtain permits for new injection wells in the future may affect US Opco's ability, as operator of the Denali Assets, to dispose of produced waters and ultimately increase the cost of the operations.

In addition, the operations of the assets in which the Trust will invest through US Opco routinely utilize hydraulic fracturing techniques in many of their drilling and completion programs. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. To date, the process has been regulated by state oil and natural gas commissions. However, on April 17, 2012, the EPA approved final regulations under the *Clean Air Act* that, among other things, require the reduction in VOCs emitted from natural gas wells by requiring the use of green completions on all gas wells hydraulically-fractured or re-fractured after January 1, 2015. Moreover, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the SDWA Underground Injection Control Program and on May 4, 2012, issued draft guidance for *Safe Drinking Water Act* permits issued to oil and natural gas exploration and production operators using diesel during hydraulic fracturing. In addition, legislation called the *Fracturing Responsibility and Awareness of Chemicals Act*, or "FRAC Act," has been introduced in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Also, some states have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, disclosure or well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. In June 2011, Texas adopted a law and has since adopted regulations that require the disclosure to the RRC and the public of certain information regarding the substances used in the hydraulic fracturing process.

In addition, a number of governmental reviews that focus on environmental aspects of hydraulic fracturing practices are either underway or have been proposed. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the U.S. House of Representatives has conducted an investigation of hydraulic fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. The EPA also is proposing to develop effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities by 2014. In addition, the Natural Gas Subcommittee of the Secretary of Energy Advisory Board issued a report in August 2011, which includes recommendations to address concerns related to hydraulic fracturing and shale gas production, including conducting added field studies on possible methane leakage from shale gas wells to water reservoirs and adopting new rules and enforcement practices to protect drinking and surface water. Also, on May 4, 2012, the U.S. Department of the Interior proposed regulations that would require operators to disclose chemicals that they use during hydraulic fracturing on federal and Indian lands and also, would strengthen standards for well-bore integrity and the management of fluids that return to the surface during and after fracturing operations on federal and Indian lands. Moreover, certain members of the Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the U.S. Securities & Exchange Commission to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. These on-going or proposed studies or reviews, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or otherwise.

A mandatory disclosure of information regarding the constituents of hydraulic fracturing fluids could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based upon allegations that specific chemicals used in the fracturing process could adversely affect the environment. Moreover, if new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA or other federal agencies, fracturing activities on the assets in which the Trust invests through US Opco could become subject to additional permitting requirements and attendant permitting delays as well as potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that US Opco is ultimately able to produce from its reserves.

### *Endangered Species, Migratory Birds, Natural Resource Damages*

Various state and federal statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, migratory birds, wetlands, and natural resources. These statutes include the *Endangered Species Act*, the *Migratory Bird Treaty Act*, the *Clean Water Act* and CERCLA. Where the taking of or harm to such species or birds occurs or may occur, or where damages to wetlands, habitat or natural resources occur or may occur, government entities (or, at times, private parties) may act to prevent oil and natural gas exploration activities or may seek damages resulting from the death of endangered animals or migratory birds, the filling of wetlands, unauthorized construction activities or releases of oil, wastes, hazardous substances or other regulated materials. Some of the well drilling operations that will be conducted by US Opco, as operator of the Denali Assets, are in, and additional assets that the Trust may invest in through US Opco may be in, areas where protected species and/or their habitats are suspected or known to exist. In these areas, the operator of the assets may be obligated to develop and implement plans to mitigate or avoid potential adverse effects to protected species and their habitats, and also may be prohibited from conducting drilling operations in certain locations or during certain seasons, such as breeding and nesting seasons, when operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to drilling activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. The presence of a protected species in areas where the Trust invests through US Opco could impair the operator of such asset's ability to timely complete well drilling and development and could adversely affect future production from those areas.

### *Inactive Wells*

The RRC annually prepares an Inactive Well Aging Report ("**IWAR**") that lists all wells of a given operator that have been inactive for a year or more. Operators with inactive wells are required under applicable RRC rules to conduct certain well-related activities, depending on the age of the inactive well, to assure that these wells, as necessary, have had the electricity disconnected, their lines purged and/or surface locations cleaned. In addition, at least 10% of the inactive wells listed must be plugged or put back on production each year. Denali has inactive wells listed on the IWAR that are included among the Denali Assets. Consequently, following the effective date of the Purchase and Sale Agreement, US Opco will be obligated during 2012 to undertake certain inactive well-related activities with respect to the inactive wells included amongst the Denali Assets as necessary to comply with applicable RRC inactive well requirements. Management does not believe that the costs to comply with applicable RRC inactive well requirements are material to US Opco's results of operations.

Effective September 1, 2010, Texas amended its statewide rules to require all operators to annually address their complete inventory of inactive wells prior to obtaining approval of their annual Organization Report renewal. Failure to comply with the inactive well requirements could result in the inability to renew the Organization Report, inability to receive permits, the severance or sealing of leases and wells, and, ultimately, the collection of financial security.

## Insurance

The Trust will maintain insurance coverage on its assets in the amounts and against the risks typical of entities carrying on businesses similar to the Trust. Insurance for drilling, completion and production operations in respect of the Denali Assets will be maintained by US Opco as the operator of such assets.

The Trust is not fully insured against all risks. For example, US Opco does not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations. In addition, pollution and environmental risks generally are not fully insurable. Additionally, Management may elect not to obtain insurance if they believe that the cost of available insurance is excessive relative to the perceived risks presented. Therefore, losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Moreover, insurance may not be available in the future at commercially reasonable costs and on commercially reasonable terms. Losses and liabilities from uninsured and underinsured events and a delay in the payment of insurance proceeds could adversely affect the Trust's business, financial condition, results of operations and ability to make distributions to Unitholders.

**Employees**

There are approximately 29 full-time equivalent employees (including contractors) of the Administrator, Aston Hill or its affiliates (pursuant to the Services Agreement) and US Opco involved in the operations, commercial, accounting and administrative functions of the business of the Argent Group.

**Employee Health and Safety**

The oil and natural gas operations in which the Trust will invest may be subject to a number of federal and state laws and regulations, including the federal *Occupational Safety and Health Act*, as amended (the "**OSHA**"), and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal *Superfund Amendment and Reauthorization Act* and comparable state statutes require that information be maintained concerning hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens.

Management is committed to conducting its activities in a manner that will safeguard the health and safety of its employees, contractors and the general public. Management is responsible for providing and maintaining a safe work environment with proper procedures, training, equipment and programs to ensure that work is performed in compliance with accepted and legislated standards. Employees share the responsibility to work in a manner which safeguards themselves with equal concern for co-workers, contractors and the general public. The Administrator will administer a comprehensive health and safety program, which will include corporate commitment, risk assessment and monitoring, capability, development, emergency response plans and systems for incident reporting, tracking and investigation.

## CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

In the opinion of Bennett Jones LLP, Canadian counsel to the Trust, and Blake, Cassels & Graydon LLP, Canadian counsel to the Underwriters, the following is a summary of the principal Canadian federal income tax considerations under the Tax Act generally applicable as of the date hereof to a purchaser who acquires Units pursuant to this prospectus and who, for the purposes of the Tax Act and at all relevant times, is resident in Canada, deals at arm's length with and is not affiliated with the Trust and holds the Units as capital property (in this section of the prospectus, referred to as a "**Unitholder**"). The Units will generally be capital property to a Unitholder provided that the Unitholder does not hold such Units in the course of carrying on a business and has not acquired them in a transaction or transactions considered to be an adventure or concern in the nature of trade.

This summary does not apply to a Unitholder: (i) that is a financial institution for purposes of the mark-to-market rules; (ii) that is a partnership; (iii) an interest in which would be a tax shelter investment; or (iv) that has elected to determine its Canadian tax results in a foreign currency pursuant to the functional currency reporting rules, all within the meaning of the Tax Act.

This summary is based on the current provisions of the Tax Act, all specific proposals to amend the Tax Act publicly announced by or on behalf of the Minister of Finance (Canada) before the date hereof ("**Proposed Amendments**") and counsel's understanding of the current published administrative policies and assessing practices of the CRA, and relies upon advice, including in the form of a certificate, from an officer of the Administrator as to certain factual matters. Except for the Proposed Amendments, this summary does not take into account or anticipate any changes in law, whether by legislative, governmental or judicial action, nor does it take into account other federal or any provincial, territorial or foreign income tax legislation or considerations which may differ significantly from the Canadian federal income tax considerations discussed herein. No assurance can be given that the Proposed Amendments will be enacted in the form publicly announced or at all.

This summary is of a general nature only and is not exhaustive of all possible Canadian federal income tax considerations applicable to an investment in Units. The income and other tax consequences of acquiring, holding or disposing of Units will vary depending on a purchaser's particular status and circumstances, including the province or territory in which the purchaser resides or carries on business. **This summary is not intended to be, nor should it construed to be, legal or tax advice to any particular purchaser. Purchasers should consult their own tax advisors for advice with respect to the income tax consequences of an investment in Units in their own circumstances.**

### *Status of the Trust*

This summary assumes the Trust will qualify at all times as a mutual fund trust within the meaning of the Tax Act and that the Trust will validly elect under the Tax Act to be a mutual fund trust from the date it was established. The Administrator has advised counsel that it intends to ensure that the Trust will meet the requirements necessary for it to qualify as a mutual fund trust no later than the closing of the Offering and at all times thereafter and to file the necessary election so that the Trust will qualify as a mutual fund trust throughout its first taxation year.

If the Trust were not to qualify as a mutual fund trust at all times, the income tax considerations would be materially and adversely different from those described below.

This summary also assumes that the Trust will not at any time be a SIFT trust. Provided that the Trust does not hold any "non-portfolio property", as defined in the Tax Act, it will not be a SIFT trust. The investment restrictions set out in the Trust Indenture, the articles of incorporation of Can Holdco and the certificate of incorporation of US Opco preclude the Trust, Can Holdco and US Opco, respectively, from owning non-portfolio property. If the Trust were to become a SIFT trust, the income tax considerations may be materially and adversely different from those described below.

### *Taxation of the Trust*

The Trust is subject to tax in each taxation year on its income for the year, including dividends received from Can Holdco, interest received or receivable on the US Opco Notes and net realized taxable capital gains (including any portion thereof arising from foreign currency gains on the repayment of the US Opco Notes). The taxation year of the

Trust is the calendar year. The Trust must compute its income or loss for each taxation year as though it were an individual resident in Canada. The Trust is required to include in its income for each taxation year dividends received from Can Holdco and any interest on the US Opco Notes that accrues to the Trust to the end of the year, or that becomes receivable or is received by it before the end of the year, except to the extent that such interest was included in computing its income for a preceding taxation year. In computing its income, the Trust will be entitled to deduct reasonable current administrative and other expenses incurred to earn income. Costs incurred in the issuance of Units may generally be deducted by the Trust on a five year, straight-line basis.

Amounts received by the Trust from Can Holdco as a return of paid-up capital (within the meaning of the Tax Act) on the Can Holdco Shares will not generally be taxable to the Trust. However, the adjusted cost base of the Can Holdco Shares held by the Trust will be reduced by any such distributions received. If at any time the adjusted cost base of the Can Holdco Shares held by the Trust would otherwise be less than zero, the Trust will be deemed to have realized a capital gain equal to such negative amount.

To the extent the Trust has taxable income for a taxation year after the inclusions and deductions outlined above, the Trust may deduct amounts which are paid or become payable by it to Unitholders in such year. An amount will be considered to be payable in a taxation year if it is paid to a Unitholder in the year by the Trust or if a Unitholder is entitled in the year to enforce payment of the amount. Counsel has been advised by the Administrator that an amount equal to the income of the Trust for each year, together with the taxable and non-taxable portion of any capital gains realized by the Trust in the year (excluding income or capital gains realized by the Trust on an *in specie* redemption of Trust Units), less any losses of the Trust that may be deducted in computing the taxable income of the Trust for such year, will be payable to holders of the Units by way of a distribution of cash or additional Units ("**Reinvested Units**"). The Trust may fund a redemption of Units by a Unitholder by distributing any property of the Trust, other than Can Holdco Shares or US Opco Notes. The Trust will be considered to dispose of any such property distributed on a redemption of Units for proceeds of disposition equal to the fair market value of such property and may realize a capital gain on the disposition of such property to the extent that the fair market value of the property exceeds its adjusted cost base. The Trust Indenture provides that where Unitholders elect to have their Units redeemed by the Trust in a particular year, the taxable portion of any capital gain realized in that year by the Trust as a result of such redemptions shall be treated as income paid to, and designated as a taxable capital gain of, the redeeming Unitholders. Any amount so designated must be included in the income of the redeeming Unitholders and will be deductible by the Trust.

***Taxation of Can Holdco***

Can Holdco will be subject to tax in each taxation year on its income for the year, including any dividends received by it in the year on the shares of a foreign affiliate, as defined in the Tax Act. US Opco is a foreign affiliate of Can Holdco. Pursuant to Proposed Amendments, dividends will include any distribution received by Can Holdco on the US Opco Shares (except distributions received on a liquidation of US Opco or on a redemption of US Opco Shares). Can Holdco will generally be entitled to deduct an amount equal to the portion of such dividends prescribed to have been paid out of US Opco's exempt surplus or pre-acquisition surplus, each as defined in the Tax Act.

Can Holdco will generally be entitled to deduct an amount with respect to dividends prescribed to have been paid out of US Opco's taxable surplus that reflects the foreign tax prescribed to be applicable to the dividend and withholding tax on such dividend (such deduction computed using a rate equivalent to the corporate tax rate applicable in Canada). As no material U.S. federal income tax is expected to be payable by US Opco, there would be no material deduction against dividends prescribed to have been paid out of US Opco's taxable surplus, other than a deduction in respect of any U.S. withholding tax applicable to such dividends. If US Opco fails to maintain its central management and control in the U.S., its earnings would generally give rise to taxable surplus.

Pursuant to Proposed Amendments, dividends prescribed to have been paid out of US Opco's hybrid surplus, as defined in the Proposed Amendment, are effectively treated as having been paid half out of exempt surplus and half out of taxable surplus for the purpose of determining the deduction to which Can Holdco is entitled in respect of such dividends.

The adjusted cost base to Can Holdco of its shares in US Opco will be reduced to the extent that dividends paid by US Opco are considered to have been paid out of pre-acquisition surplus. If the adjusted cost base to Can Holdco of its shares in US Opco becomes a negative amount, Can Holdco will be deemed to realize a capital gain equal to such negative amount for that year. Can Holdco will also generally be entitled to deduct reasonable current administrative and other expenses incurred to earn income.

The Administrator has advised counsel that, based on the activities of US Opco and its intention to maintain, at all times, central management and control of US Opco in the U.S., it anticipates that the earnings of US Opco will be included in exempt surplus, and accordingly Can Holdco will not be subject to a material amount of Canadian income tax on the dividends received by it on its US Opco Shares.

The Administrator expects that Can Holdco will generally be entitled to designate taxable dividends paid by it to the Trust as eligible dividends for purposes of the Tax Act.

If US Opco earns income that constitutes foreign accrual property income ("**FAPI**"), as defined in the Tax Act, such income must be included in computing Can Holdco's income, whether or not Can Holdco actually receives a distribution of such income. Any amount so included will increase the adjusted cost base to Can Holdco of its shares in US Opco. When Can Holdco receives a distribution of income that was previously treated as FAPI, that distribution will not be taxable to Can Holdco and there will be a corresponding reduction in the adjusted cost base to Can Holdco of its shares in US Opco.

***Taxation of Taxable Unitholders***

*Trust Distributions*

A Unitholder generally will be required to include in computing income for a particular taxation year of the Unitholder, as income from property, the portion of the net income of the Trust, including net realized taxable capital gains, that is paid or payable to the Unitholder in that taxation year, including any such amount which is payable in Reinvested Units. Any loss of the Trust for purposes of the Tax Act cannot be allocated to, or treated as a loss of, a Unitholder.

Provided that the appropriate designations are made by the Trust, taxable dividends received (or deemed to be received) from Can Holdco and net taxable capital gains realized by the Trust that are paid or become payable to a Unitholder will retain their character as taxable dividends or taxable capital gains to Unitholders for purposes of the Tax Act. Amounts that are designated as taxable dividends paid or payable to a Unitholder will be subject to the ordinary dividend gross up and tax credit rules with respect to Unitholders who are individuals (other than certain trusts). Taxable dividends in respect of which the appropriate designations are made by Can Holdco and the Trust may benefit from the enhanced dividend tax credit available in respect of eligible dividends to Unitholders who are individuals. A Unitholder that is a corporation is required to include amounts designated as taxable dividends in computing its income for tax purposes and generally will be entitled to deduct the amount of such dividends in computing its taxable income. Certain corporations, including private corporations or subject corporations (as such terms are defined in the Tax Act), may be liable to pay a refundable tax at the rate of $33^1/_3$% of such dividends to the extent that such dividends are deductible in computing taxable income.

The non-taxable half of any net realized capital gains of the Trust that is paid or payable to a Unitholder in a year will not be included in computing the Unitholder's income for the year. Any other amount in excess of the net income of the Trust that is paid or payable to a Unitholder in a year generally should not be included in the Unitholder's income for the year. However, such an amount which becomes payable to a Unitholder (other than as proceeds of disposition in respect of the redemption of Units) will reduce the adjusted cost base of the Units held by such Unitholder, except to the extent that the amount either was included in the income of the Unitholder or was the Unitholder's share of the non-taxable portion of the net capital gains of the Trust, the taxable portion of which was designated by the Trust in respect of the Unitholder. To the extent that the adjusted cost base of a Unit otherwise would be less than zero, the Unitholder will be deemed to have realized a capital gain equal to the negative amount. The cost for tax purposes of a Unit acquired pursuant to this Offering will be the subscription price of the Unit. Reinvested Units will have a cost to the Unitholder equal to the amount of income of the Trust distributed by the issuance of such Reinvested Units. Under the Tax Act, the adjusted cost base of Reinvested Units will be averaged with the adjusted cost base of all other Units held by the Unitholder as capital property in determining the adjusted cost base of each such Unit.

*Disposition of Units*

Upon the disposition or deemed disposition of Units by a Unitholder, whether on a redemption or otherwise, the Unitholder generally will realize a capital gain (or a capital loss) equal to the amount by which the proceeds of disposition (excluding any amount payable by the Trust which represents an amount that must otherwise be included in the Unitholder's income as described herein) are greater (or less) than the aggregate of the Unitholder's adjusted cost base of the Units immediately before such disposition and any reasonable costs of disposition.

Where Units are redeemed and the redemption price is paid by the delivery of Trust Property or Redemption Notes to the redeeming Unitholder, the proceeds of disposition to the Unitholder will be equal to the fair market value of such Trust Property or Redemption Notes so distributed or issued. The cost for tax purposes to a Unitholder of the Trust Property or Redemption Notes distributed or issued by the Trust to the Unitholder upon a redemption of Units will be equal to the fair market value of such property at the time of the distribution or issuance less any accrued interest thereon for which the Unitholder claims a deduction under the Tax Act. Such a Unitholder will be required to include in income interest on such Redemption Notes in accordance with the provisions of the Tax Act.

*Capital gains and losses*

One-half of any capital gain realized by a Unitholder from a disposition of Units and the amount of any net taxable capital gains designated by the Trust in respect of the Unitholder will be included in the Unitholder's income under the Tax Act as a taxable capital gain. One-half of any capital loss realized on the disposition of a Unit may be deducted against any taxable gains realized by the Unitholder in the year of disposition, in the three preceding taxation years or any subsequent taxation year, subject to the detailed rules contained in the Tax Act.

A Unitholder which is a Canadian-controlled private corporation (as defined in the Tax Act) will be subject to a refundable tax of $6^2/_3$% in respect of its aggregate investment income for the year, which will generally include all income and capital gains distributed to the Unitholder by the Trust and capital gains realized on a disposition of Units. Taxable capital gains, resulting from a disposition of Units by a Unitholder who is an individual or the designation by the Trust in respect of such a Unitholder, may give rise to alternative minimum tax, depending on the Unitholder's circumstances.

***Taxation of Registered Plans***

Amounts of income and capital gains with respect to Units included in a Registered Plan's income are not generally taxable provided that the Units are qualified investments and are not prohibited investments for the Registered Plan. See "– Eligibility for Investment" below. Unitholders should consult their own tax advisors regarding the tax implications of establishing, amending, terminating or withdrawing amounts from a Registered Plan.

The Trust Property distributed on a redemption of Units or Redemption Notes may not be a qualified investment for a Registered Plan. Accordingly, Unitholders who hold their Units through a Registered Plan should consult their own tax advisors prior to redeeming their Units.

***Eligibility for Investment***

In the opinion of Bennett Jones LLP, counsel to the Trust, and Blake, Cassels & Graydon LLP, counsel to the Underwriters, based on the current provisions of the Tax Act and the regulations thereunder, and subject to the provisions of any particular plan, provided that the Trust qualifies at all times as a mutual fund trust (as defined in the Tax Act), the Units will be a qualified investment for trusts governed by an RRSP, registered education savings plan, RRIF, deferred profit sharing plan, registered disability savings plan or a TFSA.

The Units will not be a prohibited investment for an RRSP, RRIF or TFSA provided the holder of the RRSP, RRIF or TFSA, for purposes of the Tax Act, deals at arm's length with the Trust and does not have a significant interest in the Trust or a corporation, partnership or trust with which the Trust does not deal at arm's length. Generally, a holder will have a significant interest in the Trust if the holder and/or persons not dealing at arm's length with the holder own, directly or indirectly, 10% or more of the fair market value of the Units. Holders to whom Units otherwise would be prohibited investments as described above should consult their own tax advisors, including with respect to any potential relief under an undated "comfort letter" of the Department of Finance provided by it in 2012 to the Joint Committee on Taxation of the Canadian Bar Association and the Canadian Institute of Chartered Accountants.

## U.S. FEDERAL INCOME TAXATION OF THE TRUST, CAN HOLDCO AND US OPCO

*Circular 230*

**TO COMPLY WITH U.S. TREASURY DEPARTMENT CIRCULAR 230, PROSPECTIVE INVESTORS ARE HEREBY NOTIFIED THAT: (A) ANY DISCUSSION OF U.S. FEDERAL TAX ISSUES CONTAINED OR REFERRED TO IN THIS PROSPECTUS IS NOT INTENDED OR WRITTEN TO BE USED, AND CANNOT BE USED, BY PROSPECTIVE INVESTORS FOR THE PURPOSE OF AVOIDING PENALTIES THAT MAY BE IMPOSED ON THEM UNDER THE U.S. INTERNAL REVENUE CODE; (B) SUCH DISCUSSION IS BEING USED IN CONNECTION WITH THE PROMOTION OR MARKETING OF THE TRANSACTIONS OR MATTERS ADDRESSED HEREIN; AND (C) PROSPECTIVE INVESTORS SHOULD SEEK ADVICE BASED ON THEIR PARTICULAR CIRCUMSTANCES FROM AN INDEPENDENT TAX ADVISOR.**

**PROSPECTIVE INVESTORS SHOULD CONSULT THEIR TAX ADVISORS REGARDING THE APPLICATION OF THE U.S. FEDERAL TAX RULES TO THEIR PARTICULAR CIRCUMSTANCES AS WELL AS THE STATE, LOCAL, NON-U.S. AND OTHER TAX CONSEQUENCES TO THEM OF THE PURCHASE, OWNERSHIP AND DISPOSITION OF THE UNITS.**

The following is a summary of certain U.S. federal income tax considerations applicable to the Trust, Can Holdco and US Opco that was prepared by Vinson & Elkins L.L.P., special counsel to the Trust. This summary does not address any U.S. federal tax considerations applicable to a Unitholder. No rulings have been or will be sought from the IRS with respect to any of the U.S. federal income tax issues discussed in this summary. As a result, there can be no assurance that the IRS will not successfully challenge the conclusions reached in this summary. U.S. federal income tax treatment that is different from this summary could negatively impact cash flows, the cash flow available for distribution to the Unitholders, and the value of the Units.

***This summary is not exhaustive of all possible U.S. federal income tax considerations applicable to the Trust, Can Holdco and US Opco. This summary is of a general nature only and is not intended to be legal or tax advice to any prospective purchaser of Units.***

This summary is based on the Code, final, temporary and proposed regulations promulgated by the U.S. Treasury Department under the Code ("**Treasury Regulations**"), IRS rulings and official pronouncements, judicial decisions and the Treaty, all as in effect on the date of this prospectus and all of which are subject to change, possibly with retroactive effect, or different interpretations, which could affect the accuracy of the statements and conclusions set forth below.

### *U.S. Federal Income Taxation of the Trust*

The Trust is expected to be treated as a resident of Canada eligible for the benefits of the Treaty. The Trust does not expect to be engaged in a U.S. trade or business or have a permanent establishment in the United States for purposes of the Treaty; however, if it were to engage in a U.S. trade or business through a permanent establishment in the United States, then the Trust would be subject to U.S. federal income tax with respect to its net taxable income attributable to the U.S. permanent establishment at regular U.S. federal corporate income tax rates and could be subject to a secondary U.S. branch profits tax at a rate of 5%. As set forth below, the interest income the Trust earns on the US Opco Notes is expected to be treated as arising from a source within the United States. Nonetheless, this U.S.-source interest income is expected to be exempt from U.S. federal income tax under the Treaty. The distributions the Trust receives from Can Holdco with respect to the shares it owns in Can Holdco are not expected to constitute U.S.-source income or be subject to U.S. federal income tax.

### *U.S. Federal Income Taxation of Can Holdco*

*Generally*

Can Holdco is expected to be treated as a resident of Canada eligible for the benefits of the Treaty. Can Holdco does not expect to be engaged in a U.S. trade or business or have a permanent establishment in the United States for purposes of the Treaty; however, if it were to engage in a U.S. trade or business through a permanent establishment in the United States, then Can Holdco would be subject to U.S. federal income tax with respect to its net taxable income attributable to the U.S. permanent establishment at regular U.S. federal corporate income tax rates and could be subject to a secondary U.S. branch profits tax at a rate of 5%.

The distributions that Can Holdco receives from US Opco will be treated as (i) dividends, to the extent of the earnings and profits of US Opco, then (ii) a return of capital, to the extent of Can Holdco's adjusted tax basis in the stock of US Opco, and thereafter (iii) gain from the sale of the stock of US Opco. The dividend portion of any distribution is expected to be treated as arising from a source within the United States and subject to 5% U.S. federal income tax pursuant to the Treaty. The taxation of the portion of any distribution from US Opco that is not treated as a dividend is discussed immediately below.

*Distributions in Excess of Earnings and Profits*

A non-U.S. corporation that is not engaged in trade or business in the United States generally is not subject to U.S. federal income tax on any gain from the disposition of the stock of a U.S. corporation. However, a non-U.S. corporation is subject to U.S. federal withholding and income taxation upon the disposition of stock in a U.S. corporation if more than 50% of the value of the U.S. corporation's real property and trade or business assets is (or was at any time during the five years prior to the disposition) attributable to U.S. real property interests. For this purpose, the Denali Assets are generally treated as real property located within the United States. Because these are the primary assets of US Opco, Can Holdco is expected to be subject to U.S. federal withholding and income taxation upon any disposition of the stock of US Opco. The applicable withholding tax is 10% of the gross proceeds from the disposition of the stock of US Opco, and the income tax is 35% of the gain realized by Can Holdco on such a disposition as determined for U.S. federal income tax purposes. In the event the tax withheld on a disposition exceeded the income tax due, Can Holdco would be entitled to request a refund of the excess by filing a U.S. tax return.

Any distribution from US Opco in excess of the amount treated as a dividend generally is treated as described above. As a result, the return of capital portion of any such distribution generally would be subject to a 10% U.S. withholding tax, even though Can Holdco would not recognize any gain with respect to such portion of a distribution. The portion of any distribution from US Opco that is treated as gain from the disposition of US Opco stock would be subject to the 10% withholding tax and the 35% income tax (with the tax withheld available as a credit against the income tax due).

***U.S. Federal Income Taxation of US Opco***

*Generally*

US Opco will be treated as a corporation for U.S. federal income tax purposes. US Opco is subject to U.S. federal income tax on its net taxable income, including the income related to the Denali Assets. In computing its net taxable income, US Opco is expected to be entitled to deduct interest paid on the US Opco Notes and certain other expenses incurred (such as intangible drilling and development costs and depletion) relating to its ownership of the Denali Assets.

*Interest Deductions*

The Trust, Can Holdco and US Opco will treat the US Opco Notes as debt of US Opco for U.S. federal income tax purposes. This treatment is supported by certain interest rate and debt feasibility studies and other analyses prepared on behalf of the Trust by its advisors. However, none of the Trust, Can Holdco or US Opco has requested or received an opinion of Vinson & Elkins L.L.P. regarding this treatment. The determination of whether the US Opco Notes are debt for U.S. federal income tax purposes is based on an analysis of all of the relevant facts and circumstances, and there is no clear authority characterizing a similar arrangement as debt for U.S. federal income tax purposes. Consequently, although the Trust, Can Holdco and US Opco will take the position that the US Opco Notes are debt for U.S. federal income tax purposes, there can be no assurance that this position will not be challenged by the IRS. If such a challenge were sustained, interest payments on the US Opco Notes would be recharacterized as non-deductible distributions with respect to US Opco's equity, and US Opco's net taxable income and thus its U.S. federal income tax liability would increase. If US Opco were liable for additional tax, the cash flow available for distribution to the Unitholders would be reduced, which could negatively impact the value of the Units. See "Risk Factors".

Assuming the US Opco Notes are treated as debt of US Opco for U.S. federal income tax purposes, the amount of deductible interest paid on such debt is subject to limitations. The amount of such interest must be consistent with the amount that would have been payable on a similar obligation at arm's length or the amounts actually paid may be recharacterized as a distribution on the equity of US Opco. In this regard, the Trust's advisors have conducted certain interest rate and debt feasibility studies in order to support the amount of interest payable by US Opco on the US Opco Notes. In addition to the arm's length limitation, Code Section 163(j) imposes a limitation on the amount of deductions for interest paid on such debt. In general, Code Section 163(j) limits a corporation's deductions for interest paid to related non-U.S. persons exempt from U.S. federal income tax in years that: (i) the debt-to-equity ratio of the corporation exceeds 1.5 to 1, and (ii) the corporation's net interest expense (i.e., the excess of interest expense over interest income) exceeds 50% of "adjusted taxable income." Adjusted taxable income is generally defined as the corporation's taxable income before net interest expense, depreciation, depletion and amortization. US Opco's debt-to-equity ratio will initially be approximately 1.8 to 1 and may exceed 1.5 to 1 for certain future taxable years. Any limitation on the amount of interest deductible by US Opco in respect of the US Opco Notes could increase the amount of U.S. federal income tax payable by US Opco. A recharacterization of a payment on the US Opco Notes as a distribution on equity generally would not only result in such payment being nondeductible but also would cause such payment to be subject to U.S. federal withholding tax. Any such taxes could reduce the amount of cash flow available for distribution to the Unitholders and could negatively impact the value of the Units. See "Risk Factors".

*Conduit Financing Rules*

Pursuant to applicable Treasury Regulations, the participation of one or more persons in a "conduit financing arrangement" may be disregarded by the IRS under certain circumstances. For this purpose, a "financing arrangement" means a series of transactions by which one person (the financing entity) advances money or other property and another person (the financed entity) receives money or other property, if the advance and receipt are effected through one or more other persons (intermediate entities) and there are "financing transactions" linking the financing entity, each of the intermediate entities, and the financed entity. If an intermediate entity is related to a financing or financed entity, the IRS can treat the participation of the intermediate entity as part of a conduit financing arrangement if (i) the participation of the intermediate entity in the financing arrangement reduces U.S. taxes and (ii) the participation of the intermediate entity in the financing arrangement is pursuant to a tax avoidance plan.

The US Opco Notes are financing transactions for this purpose. The Units may also be treated as financing transactions as a result of the rights of redemption of the holders. If the Units were considered financing transactions, the US Opco Notes and the Units would together (to the extent of the outstanding principal balance of the US Opco Notes) likely constitute a financing arrangement. Under the Treaty, interest paid to a qualified resident of Canada, such as the Trust, generally is exempt from U.S. federal withholding tax. In the absence of an applicable treaty or other exemption, interest paid by US Opco to a non-U.S. person is subject to a 30% U.S. federal withholding tax; thus, the participation of the Trust in a financing arrangement that includes the US Opco Notes may be found to reduce U.S. federal income taxes.

If financing transactions that include the US Opco Notes were treated as part of a conduit financing arrangement, and the participation of the Trust ignored, interest paid by US Opco to the Trust on the US Opco Notes could be subject to a 30% federal U.S. withholding tax, reducing the Trust's assets and cash available for distribution with respect to the Units.

Nevertheless, recharacterization and the resulting withholding tax should be avoided with respect to interest payments on the amount of US Opco Notes included within such an arrangement, to the extent such payments, if made directly to the Unitholders, would qualify for exemption from U.S. withholding tax under the Treaty (or other income tax treaty to which the United States is a party, to the extent applicable to payments to such Unitholder) and such Unitholders provide proper certifications regarding their qualification for benefits of the Treaty or otherwise qualify for an exemption from withholding tax (generally, IRS Form W-8BEN, Form W-9 or similar sufficient documentation).

The Trustee or Administrator may require any Unitholder, following a request by the Trustee or the Administrator, to furnish a Taxation Certification, and to use reasonable efforts to obtain a Taxation Certification from each beneficial unitholder holding Units in such Unitholder's name. If any Unitholder fails to furnish a Taxation Certification within 30 days following such a request or fails to use reasonable efforts to obtain a Taxation Certification from beneficial holders of Units, the Administrator may notify the Trustee, and upon notice by the Trustee to the non-complying Unitholder, redeem the Units held by any non-complying Unitholders at the Redemption Price in accordance with the terms of the Indenture.

While it is reasonable to assume that Unitholders will provide the necessary Taxation Certifications, no assurance can be given that such certifications will be provided. Accordingly, the failure to obtain the necessary Taxation Certifications could result in interest payments on the US Opco Notes being subject to a 30% U.S. withholding tax to the extent of any such failure.

# RISK FACTORS

The securities offered hereby should be considered speculative due to the nature of the Trust's business and the present stage of its development. The risks set out below are not an exhaustive description of all the risks associated with the Trust's business and the oil and natural gas business generally. A prospective investor should consider carefully the risk factors set out below. In addition, prospective investors should carefully review and consider all other information contained in this prospectus before making an investment decision. An investment in securities of the Trust should only be made by persons who can afford a significant or total loss of their investment.

There can be no assurance that an active trading market in the Units will develop or be sustained. The market price for the Trust's securities, including the Units, could be subject to wide fluctuations. Factors such as commodity prices, government regulation, interest rates, share price movements of the Trust's peer companies and competitors, as well as overall market movements, may have a significant impact on the market price of the securities of the Trust. The stock market has from time to time experienced extreme price and volume fluctuations, particularly in the oil and natural gas sector, which have often been unrelated to the operating performance of particular companies.

The following is a summary of certain risk factors relating to the businesses of the Trust, Can Holdco and US Opco, which prospective investors should carefully consider before deciding whether to purchase Units. Residents of the United States and other non-residents of Canada should have additional regard to the risk factors under the subheading "Risk Factors Applicable to Residents of the United States and Other Non-Residents of Canada".

The Trust is a limited purpose trust and is entirely dependent upon the operations and assets of US Opco through the Trust's indirect ownership of US Opco. Accordingly, the Trust's ability to pay distributions to Unitholders is dependent upon the ability US Opco and Can Holdco to meet their interest and principal obligations and expected levels of distribution payments to the Trust. US Opco's income will be derived from the production of oil, natural gas and NGLs from its U.S. resource properties and is susceptible to the risks and uncertainties associated with the oil and natural gas industry generally, and specifically in the U.S.

If the oil and natural gas reserves associated with the Denali Assets and other assets that may be acquired by US Opco are not supplemented through additional development or the acquisition of additional oil and natural gas properties, the ability of US Opco and Can Holdco to meet their obligations to the Trust and the ability of the Trust to pay distributions to Unitholders will be adversely affected.

## Risks Relating to the Business and Operations of the Trust and its Subsidiaries

***The Trust may not be able to achieve the anticipated benefits of the Acquisition and future acquisitions.***

The Trust intends to make acquisitions and dispositions of assets in accordance with the Trust's investment strategy. The price the Trust pays for the purchase of properties is based on engineering and economic estimates of the reserves made by Management and independent engineers modified to reflect technical and economic views. These assessments include a number of material factors and assumptions. Consequently, the reserves acquired may be less than expected, which could adversely impact cash flow from operating activities and distributions to Unitholders. Achieving the benefits of any acquisitions, including the Acquisition, depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner, as well as the ability to realize the anticipated growth opportunities and synergies, including operating expense reductions, from rationalizing operations and combining newly acquired assets with those of the Trust. The integration of newly acquired assets may require substantial Management effort, time and resources and may divert Management's focus from other strategic opportunities and operational matters, and may also result in the disruption of ongoing business, supplier, customer and employee relationships. The Trust will continually assess the value and contribution of assets that it holds. In this regard, assets may be disposed of from time to time so that Management can focus efforts and resources more efficiently. Depending on the state of the market for these types of assets, if disposed of, the Trust may realize less than their carrying value in the Trust's financial statements. There is no assurance that the Trust will be able to continue to complete acquisitions or dispositions of oil and natural gas properties which realize all the anticipated synergistic benefits.

***An incorrect assessment of value with respect to the Acquisition, or the acquisition of the Denali Reserved Interest, if applicable, could adversely affect the value of the Units and distributions to Unitholders***

The Acquisition and the acquisition of the Denali Reserved Interest, if applicable, will be based in large part on engineering and economic assessments made by independent reserve evaluators. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil, natural gas and NGLs, future prices of oil, natural gas and NGLs and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the Trust. All such assessments involve a measure of geological and engineering uncertainty that could result in lower production and reserves than anticipated. If actual production or reserves are less than expected, funds flow from operations and cash flow available for distribution to Unitholders could be negatively affected.

***US Opco may not achieve success in its planned development drilling programs and as a result may be unable to pay distributions at the planned initial distribution rate, or at all***

The ability of the Trust to make regular cash distributions to Unitholders following closing of the Acquisition will be entirely dependent on production from the Denali Assets. The level of distributions paid by the Trust may be decreased if US Opco is unsuccessful in maintaining production to the level anticipated by Management.

***Title to the Denali Assets and the Deep Rights cannot be assured***

The Trust cannot be certain of the title to the interests it is acquiring in the Acquisition. As is customary in the U.S. oil and natural gas industry, prior title reviews conducted at the direction of Denali focused primarily on currently productive wells and leasehold interests. Management has conducted a review of certain title opinions and historical royalty payment information pertaining to the Denali Assets provided by Denali regarding the ownership of certain producing wells and undeveloped leasehold acreage and a review of any restrictions on assignment set forth in the underlying oil and gas leases and commercial contracts made available by Denali. The leaseholds relating to the Deep Rights, having no production or reserves attributable to them, have only been subject to cursory and preliminary title review. All title opinions provided are limited to matters of record which were provided to the individual rendering the opinion. In each opinion, the examining attorney has assumed that each of the subject leases has not terminated as a result of lack of continuous operations on the tracts subject to the leases. Although Management has carried out these due diligence investigations to its commercial satisfaction, such investigations do not guarantee or certify that an unforeseen defect in the chain of title will not arise. Moreover, as is typical in U.S. oil and natural gas acquisition transactions, there are limited representations and warranties related to title to the Denali Assets enuring to US Opco's benefit in the Purchase and Sale Agreement, or otherwise. The existence of title deficiencies with respect to the interests it is acquiring in the Acquisition could reduce the value of those interests, result in the loss of attributed reserves or otherwise render the properties worthless, thus adversely affecting the distributions to Unitholders. US Opco does not obtain title insurance covering oil, natural gas and mineral leaseholds, which is generally not available in the U.S. Additionally, undeveloped leasehold acreage has greater risk of title defects than developed acreage. US Opco's inability or failure to cure title defects could render some locations undrillable or cause US Opco to lose its rights to some or all production from some of its properties, which could result in a reduction in proceeds available for distribution to Unitholders and the value of the Units may be reduced.

***There may be undisclosed liabilities associated with the Acquisition***

In connection with the Acquisition, there may be liabilities that the Administrator fails to discover or was unable to quantify in its due diligence investigations conducted prior to the Acquisition. US Opco may not be indemnified for some or all of these liabilities, which would negatively affect distributions to Unitholders.

***Declines in prices for oil, natural gas and/or NGLs will negatively affect the Trust's financial results and distributions***

The Trust's and its subsidiaries' operational results and financial condition, and therefore the amounts the Trust can pay to Unitholders as distributions, will be dependent on the prices received for oil, natural gas and NGLs. Prices for oil, natural gas and NGLs have exhibited extreme volatility over the past few years and monthly distributions may be similarly affected. For the five years ended December 31, 2011, the NYMEX–WTI oil price ranged from a high of US$145.31/bbl to a low of US$30.28/bbl, while the NYMEX–Henry Hub natural gas price ranged from a high of US$13.31/MMBtu to a low of US$1.83/MMBtu. Declines in prices for oil, natural gas and/or NGLs could result in reductions to, or elimination of, distributions to Unitholders. Prices for oil, natural gas and NGLs are determined by economic factors and, in the case of oil prices, political factors and a variety of additional factors beyond the Trust's control. These factors include economic conditions in the United States, Canada and worldwide; the actions of the Organization of Petroleum Exporting Countries; the nature and extent of domestic and foreign governmental regulation and taxation; political stability in the Middle East and elsewhere; internal capacity to produce natural gas in the United States from shale deposits; regional, domestic and foreign supply of oil and natural gas; risks of supply disruption; the price of foreign imports; weather conditions and seasonal trends; natural disasters; technological advances affecting energy consumption and energy supply; energy conservation and environmental measures; the price and availability of alternative fuel sources; and the availability of rigs, completion crews, and labor. Any substantial and extended decline in the prices of oil, natural gas and/or NGLs would have an adverse effect on the carrying value of US Opco proved plus probable reserves, net asset value, borrowing capacity, revenues, profitability and cash flows from operating activities and ultimately on the overall financial condition of the Trust and its subsidiaries, and therefore on the amounts to be distributed to Unitholders.

Natural gas prices in the U.S. have experienced a near continuous decrease in late 2011 and early 2012 due to increased domestic supply, largely from unconventional drilling in shale plays. Recent NYMEX-Henry Hub near month prices for natural gas have at times fallen below $2.00/MMBtu. Continued low prices or future further decreases in the natural gas market price could have a negative impact on revenues, profitability, cash flow and reserves values.

In addition, any extended decline in oil, natural gas and NGLs prices may cause Management to determine to postpone or cancel all or a portion of US Opco's development drilling program, which would affect future production levels and related cash flow.

***Estimated proved plus probable reserves are based on many assumptions that may turn out to be inaccurate, which, if adjusted downwards, could reduce distributions to the Unitholders and the value of the Units. There are numerous uncertainties inherent in estimating quantities of recoverable oil and natural gas reserves, including many factors beyond Management's control***

In general, estimates of economically recoverable oil and natural gas reserves, the future net revenues therefrom and finding and development costs relating thereto are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil, natural gas and NGLs, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. Changes in these assumptions or actual production expenses incurred and results of actual development could materially decrease reserve estimates. In addition, there could be errors made in the ownership and revenue and expense percentages furnished to the engineers for the purpose of preparing a reserve report. The reserves and production information contained in the Sproule Reserve Report is only an estimate and the actual production and ultimate reserves from the Denali Assets may be greater or less than the estimates prepared by Sproule. The Sproule Reserve Report has been prepared using certain commodity price assumptions which are described in the notes to the reserves tables under the heading "Reserves and Other Oil and Gas Information". If US Opco realizes lower prices for oil, natural gas or NGLs and these prices are substituted for the price assumptions utilized in that reserves report, the present value of estimated future net revenues for reserves and net asset value would be reduced and the reduction could be significant. The estimates in the Sproule Reserve Report are based in part on the timing and success of development activities Management intends to undertake in 2012 and future years in respect to the Denali Assets. The reserves and estimated future net revenues to be derived therefrom contained in the Sproule Reserve Report will be reduced in future years to the extent that such activities do not achieve the production performance set forth in the Sproule Reserve Report. Estimates of proved undeveloped and probable reserves are sometimes based upon volumetric calculations and upon analogy to similar types of reserves rather than 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 based upon production history and production practices will result in variations in the estimated reserves and such variations could be material. A material and adverse variance of actual production, revenues and expenditures from those underlying reserve estimates would have a material adverse effect on the financial condition, result of operations and cash flows of the Trust and would reduce cash distributions to Unitholders.

***Denali has limited obligations in respect of claims under the Purchase and Sale Agreement***

The obligations of Denali in respect of certain claims under the Purchase and Sale Agreement relating to a breach by it of a representation, warranty, covenant or obligation are subject to an aggregate threshold of US$250,000 per claim. Additionally, Denali is only required to indemnify US Opco up to an aggregate limit of 100% of the unadjusted purchase price of the Acquisition. Denali is not required to provide credit support or retain in escrow any portion of the purchase price of the Acquisition following closing of the Acquisition in order to facilitate payment of any indemnity claims made by US Opco and there can be no assurance that Denali will have the financial capacity to perform its indemnity obligations under the Purchase and Sale Agreement after the closing of the Acquisition. See "Funding, Acquisition and Related Transactions – Acquisition – Purchase and Sale Agreement".

***The net present value of future net revenues attributable to US Opco's reserves will not necessarily be the same as the current market value of estimated reserves***

Potential investors and Unitholders should not assume that the net present value of future net revenues attributable to US Opco's reserves is the current market value of estimated reserves. Sproule based the estimated discounted future net revenues from proved plus probable reserves on certain commodity price assumptions, which assumptions are described in the notes to the reserves tables under the heading "Reserves and Other Oil and Gas Information". These future commodities price assumptions assume increasing future prices of natural gas and crude oil over the life of reserves which, in the case of natural gas, begin with 2012 prices substantially above current U.S. market prices for natural gas, which in recent months has declined for NYMEX-Henry Hub near month futures trading to below $2.00 per MMBtu. Actual future net revenues from US Opco's properties will be affected by factors such as:

- actual prices received for oil, natural gas and NGLs;
- actual cost of development and production expenditures;
- the amount and timing of actual production from US Opco's oil and natural gas properties; and
- changes in governmental regulations or taxation.

The timing of both production and incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing and amount of actual future net revenues from proved plus probable reserves, and thus their actual present value. In addition, the 10% discount factor used when calculating discounted future net revenues may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with the Trust or the oil and natural gas industry in general. Additionally, such calculation excludes a number of important costs that the Trust will actually incur, such as interest expense and general and administrative expenses.

***Increases in interest rates could increase the Trust's costs and reduce the Trust's income and ability to pay distributions***

There is a risk that interest rates will increase given the current historically low level of interest rates. An increase in interest rates could result in a significant increase in the amount paid by US Opco to service debt, including borrowings under the Credit Facilities, resulting in a decrease in cash available for distributions to Unitholders, and could impact the market price of the Units. In addition, increasing interest rates may put competitive pressure on the levels of distributable income paid by the Trust to Unitholders, increasing the level of competition for capital faced by the Trust, which could have a material impact on the trading price of the Units.

***The value of the Canadian dollar against the U.S. dollar will affect the Trust's results and distributions***

World oil prices are quoted in U.S. dollars and as all of the assets of US Opco will initially be located in the U.S., US Opco's oil, natural gas and NGLs revenues are also received in U.S. dollars.

The Trust and Can Holdco will receive distributions and interest from US Opco in U.S. dollars and the Trust pays distributions to Unitholders in Canadian dollars. The Trust also raises funds primarily in Canada from the sale of Units in Canadian dollars and invests indirectly through US Opco in U.S. oil and natural gas assets, using U.S. dollars. Thus, when the Canadian dollar increases in value against the U.S. dollar, the Trust's indirect investments in U.S. oil and natural gas assets will be less expensive; however, distributions received by the Trust directly or indirectly from US Opco will also be reduced. When the Canadian dollar decreases in value against the U.S. dollar, the Trust's indirect investments in U.S. oil and natural gas assets will be more expensive; however, distributions received by the Trust directly or indirectly from US Opco will increase.

***The global economy has not fully recovered and unforeseen events may negatively impact the financial condition of the Trust***

Market events and conditions including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions caused significant volatility to commodity prices over the last few years. These conditions have resulted in a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating 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 and trust valuations and may continue to impact the performance of the global economy going forward.

If the economic climate in the U.S. or the world generally deteriorates further, demand for petroleum products could diminish further and prices for oil and natural gas could decrease further, which could adversely impact the Trust's results of operations, liquidity and financial condition.

***The Trust's level of indebtedness may reduce financial flexibility***

US Opco will be required to comply with covenants under the documentation for the Credit Facilities. In the event that it does not comply with such covenants, access to capital could be restricted or repayment could be required on an accelerated basis by the lender, and the ability to make distributions to Unitholders may be restricted. The lender has security over substantially all of the assets of US Opco. If US Opco becomes unable to pay its debt service charges or otherwise commits an event of default that is not cured, the lender may foreclose on or sell US Opco's working interests in its properties. Amounts paid in respect of interest and principal on debt may reduce distributions. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service before payment of distributions or interest by US Opco to Can Holdco and the Trust, respectively, and by Can Holdco to the Trust. Certain covenants in the documentation for the Credit Facilities may also limit distributions. Although Management believes the Credit Facilities will be sufficient for the near term, there can be no assurance that the amount will be adequate for the Trust's future financial obligations including US Opco's future capital expenditure programs, or that additional funds will be able to be obtained. Failure to obtain financing necessary for US Opco's capital expenditure plans may result in a delay in development or production on US Opco's oil and natural gas properties and/or a decrease in distributions. For more information, see "Credit Facilities".

A high level of indebtedness increases the risk that the Trust and/or its subsidiaries may default on their debt obligations. The Trust's and its subsidiaries' ability to meet their debt obligations and to reduce their level of indebtedness depends on future performance. General economic conditions, oil and natural gas prices and financial, business and other factors affect operations and future performance. Many of these factors are beyond the Trust's and its subsidiaries' control. The Trust and its subsidiaries may not be able to generate sufficient cash flows to pay the interest on debt and future working capital or to repay all or part of their indebtedness and borrowings or equity financing may not be available to pay or refinance such debt on commercially reasonable terms. Factors that will affect the ability to raise cash through an offering of capital stock or a refinancing of debt include financial market conditions, the value of assets and performance at the time the Trust or any of its subsidiaries need capital. The occurrence of any of these events could have a material adverse effect on the Trust's and its subsidiaries' results of operations and financial condition, which in turn could negatively affect the amount of distributions paid to Unitholders.

In the event that the Operating Facility is not extended before August 10, 2013 (or such later date to be determined by US Opco and the lender in connection with the Operating Facility) all outstanding indebtedness thereunder will become repayable 366 days thereafter. There is also a risk that the Operating Facility will not be renewed for the same principal amount or on the same terms. Any of these events could materially adversely affect the ability of the Trust and its subsidiaries to fund ongoing operations and the ability of the Trust to distribute cash to Unitholders.

***The failure to complete the Asset Disposition may result in US Opco curtailing its capital expenditures which, in turn, may adversely affect its ability to pay distributions***

There is a risk that the proposed Asset Disposition will not be completed on the terms contemplated by the Asset Purchase Agreement, or at all, and as a result US Opco may not receive the expected proceeds from such sale. The Asset Purchase Agreement is subject to customary closing conditions. All amounts owing under the Bridge Facility will become payable upon the earlier of the closing of the Asset Disposition and October 15, 2012, at which time such facility will be terminated. In such circumstance, the Trust will have limited financial resources and there is no certainty that the Trust will be able to repay the amounts borrowed under the Bridge Facility as required by such termination and necessary in order to continue paying cash distributions on the issued Units, or to carry out its planned capital program without curtailing its capital expenditures. The occurrence of this event could have a material adverse effect on the Trust's and its subsidiaries' results of operations and financial condition, which in turn could negatively affect the amount of distributions paid to Unitholders.

***Future acquisition and development projects will require substantial capital expenditures. Trusts have historically relied on external sources of capital, borrowings and equity sales, and the Trust may be unable to obtain needed capital or financing on satisfactory terms, which could lead to expiration of leases or a decline in reserves***

The Trust's planned acquisition and development activities will be capital intensive. The Trust expects to make substantial capital expenditures in its business for the acquisition, development and production of oil and natural gas reserves. If adequate sources of capital are not available on attractive terms, or at all to fund planned capital expenditures, the Trust may not be able to fully implement its current drilling strategy. The actual amount and timing of future capital expenditures may differ materially from estimates as a result of, among other things, commodity prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments.

Changes in the Trust's financing needs may require it to alter capitalization substantially through the issuance of debt or additional Units. The issuance of additional debt may require that a portion of cash flows provided by operating activities be used for the payment of principal and interest on existing debt, thereby reducing the ability to use cash flows to fund working capital, capital expenditures, acquisitions and distributions. The issuance of additional Units could have a dilutive effect on the value of previously issued Units.

Future cash flows provided by operating activities and access to capital are subject to a number of variables, including:

- proved plus probable reserves;
- the level of oil, natural gas and NGLs US Opco is able to produce from existing wells;
- the prices at which oil, natural gas and NGLs are sold;
- the costs of developing and producing oil, natural gas and NGLs;
- the ability to acquire, locate and produce new reserves;
- the ability and willingness of the Trust's banks to lend; and
- the ability to access the equity and debt capital markets.

If the borrowing base under the Operating Facility or revenues decrease as a result of commodity prices, operating difficulties, declines in reserves or for any other reason, the Trust may have limited ability to obtain the capital necessary to sustain operations at current levels. If additional capital is needed, the Trust may not be able to obtain debt or equity financing on favourable terms, or at all. To the extent that external sources of capital become limited or unavailable or available only on onerous terms, the Trust's ability to make capital investments and maintain or expand existing assets and reserves may be impaired, which in turn could lead to a possible expiration of the Trust's leases and a decline in reserves. The Trust's assets, liabilities, business, financial condition, results of operations and distributions may be materially and adversely affected as a result. Alternatively, the Trust may issue additional Units at prices which may result in a decline in production per Unit and reserves per Unit or the Trust may wish to increase borrowings to finance significant acquisitions or development projects to accomplish its long term objectives on less than optimal terms or in excess of the optimal capital structure.

***In the future, US Opco may participate in hedging activities that reduce the realized prices received from sales of oil, natural gas and NGLs. This may require US Opco to provide collateral for hedging liabilities and may involve risk that counterparties may be unable to satisfy their obligations to US Opco***

In order to manage exposure to price volatility in marketing oil, natural gas and NGLs, US Opco may enter into oil, natural gas and NGLs price risk management arrangements for a portion of expected production. Commodity price hedging may limit the prices actually realized and therefore reduce revenues in the future. Commodity hedging activities could impact earnings in various ways, including recognition of certain mark-to-market gains and losses on derivative instruments. The fair value of commodity derivative instruments can fluctuate significantly between periods. In addition, commodity price risk management transactions may expose the Trust to the risk of financial loss in certain circumstances, including instances in which:

- production is less than expected;
- there is a widening of price differentials between delivery points for production and the delivery point assumed in the hedge arrangement; or
- the counterparties to these contracts fail to perform their obligations.

Hedging transactions involve the risk that counterparties, which are generally financial institutions, may be unable to satisfy their obligations. If any counterparties were to default on obligations under the hedging contracts or seek bankruptcy protection, it could have an adverse effect on US Opco's ability to fund planned activities and could result in a larger percentage of future production being subject to commodity price changes. The risk of counterparty default is heightened in a poor economic environment.

US Opco's obligations under future hedging arrangements may be secured by all or a portion of its reserves, the value of which must cover the fair value of the transactions outstanding under the facility by some multiple. If the collateral value falls below the coverage designated, US Opco would be required to post cash or letters of credit with the counterparties if US Opco does not have sufficient unencumbered oil and natural gas properties available to cover the shortfall. Future collateral requirements would be dependent to a great extent on oil and natural gas prices.

***Units may from time to time trade at a price that is less than the net asset value per Unit***

Net asset value from time to time will vary depending upon a number of factors beyond the Trust's control, including oil, natural gas and NGLs prices. The trading price of the Units from time to time is determined by a number of factors, some of which are beyond the Trust's control and such trading price may be greater or less than the net asset value.

***US Opco is committed to pay up to US$48 million with respect to the Deep Rights to which no reserves have been attributed, and there is no assurance that reserves will be attributed to or obtained from the Deep Rights***

US Opco is required to pay US$18 million over the next three years in respect of its 75% net revenue interest in the Deep Rights. In addition upon the occurrence of certain events, US Opco may be further obligated to acquire 100% of Denali Deep Rights Interests for US$30 million. The Deep Rights have not been attributed any reserves under the Sproule Reserve Report. While Management expects to implement a drilling program on the Deep Rights, there is no assurance that reserves will be attributed to or production will be obtained from the Deep Rights. Failure to attribute reserves to, or obtain production from, the Deep Rights may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects and its ability to maintain distributions.

***US Opco may be required to pay the Put Amount in respect of the Denali Deep Rights Interests and the timing of such payment could have an adverse impact on the Trust, distributions to Unitholders or the price of the Units***

In the event the put option in respect of the Denali Deep Rights Interests is triggered, US Opco would be required to pay US$30.0 million within 60 calendar days of such date. US Opco's ability to pay the Put Amount will depend on future operating performance and financial results, which will be subject, in part, to factors beyond the control of the Trust and US Opco, including commodity prices, interest rates and general economic, financial and business conditions. If US Opco is unable to satisfy the Put Amount, the Trust or US Opco may be required to: reduce cash distributions to Unitholders, obtain additional financing through the issue of equity or debt, draw down on the Operating Facility, sell some of US Opco's assets or operations, reduce or delay capital expenditures and/or acquisitions, or revise or delay Management's strategic plans. If the Trust or US Opco are required to take any of these actions, it could have an adverse impact on the business, financial condition and results of operation of the Trust and US Opco and could also have a material impact on the distributions to Unitholders and the price of the Units. In addition, there can be no assurance that the Trust or US Opco, as applicable, would be able to take any of these actions, that these actions would enable US Opco to satisfy the Put Amount or that these actions would be permitted under the terms of the Credit Facilities.

***Shortages or increases in costs of equipment, services and qualified personnel could delay the drilling of new wells and result in a reduction in the amount of cash flow available for distribution to Unitholders***

The demand for qualified and experienced personnel to conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with prices for oil, natural gas and NGLs, causing periodic shortages. Historically, there have been shortages of drilling rigs and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher prices for oil, natural gas and NGLs generally stimulate demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. Shortages of field personnel and equipment or price increases could significantly hinder the ability of third-party operators to drill new wells and delay completion of such wells, which could reduce future distributions to Unitholders.

***The generation of proceeds for distribution by the Trust depends in part on access to and the operation of gathering, transportation and processing facilities. Any limitation in the availability of those facilities could interfere with sales of oil, natural gas and NGLs production from the Denali Assets***

The amount of oil, natural gas and NGLs that may be produced and sold from wells located on any current or future property of US Opco is subject to the availability of gathering, transportation and processing facilities. Even where such facilities are available, services from such facilities are subject to curtailment in certain circumstances, such as inclement weather conditions, pipeline interruptions due to scheduled and unscheduled maintenance, failure of tendered oil, natural gas and NGLs to meet quality specifications of gathering lines or downstream transporters, or excessive line pressure which prevents delivery or physical damage to the gathering system or transportation system. The curtailments may vary from a few days to several months. In many cases, an operator is provided limited notice, if any, as to when production will be curtailed and the duration of such curtailments. If an operator, including US Opco, is forced to reduce production due to such a curtailment, the revenues of the Trust and the amount of cash distributions to Unitholders could be reduced due to the reduction of proceeds from the sale of production. Although the Denali Assets currently do not have any material production shut-in and do not shut in production on a routine basis as a result of lack of accessibility to transportation or lack of processing facilities, there can be no assurance this will be the case in the future.

Some wells may be drilled in locations that currently are not serviced by gathering and transportation pipelines or locations in which existing gathering and transportation pipelines do not have sufficient capacity to transport additional production. As a result, US Opco may not be able to sell the production from certain wells until the necessary gathering systems and/or transportation pipelines are constructed or until the necessary transportation capacity on an interstate pipeline is obtained. Any delay in the procurement of additional transportation capacity would delay the receipt of any proceeds that may be associated with production from such wells.

The ability to deliver natural gas into third party natural gas pipeline facilities is directly impacted by the gas quality specifications required by those pipelines. In 2006, FERC issued a policy statement on provisions governing gas quality and interchangeability in the tariffs of interstate gas pipeline companies and a separate order declining to set generic prescriptive national standards. FERC strongly encouraged all natural gas pipelines subject to its jurisdiction to adopt, as needed, gas quality and interchangeability standards in their FERC gas tariffs modeled on the interim guidelines issued by a group of industry representatives, headed by the Natural Gas Council ("**NGC+ Work Group**"), or to explain how and why their tariff provisions differ. Management does not believe that the adoption of the NGC+ Work Group's gas quality interim guidelines by a pipeline that either directly or indirectly interconnects with US Opco's facilities would materially affect its operations. Management has no way to predict, however, whether FERC will approve of gas quality specifications that materially differ from the NGC+ Work Group's interim guidelines for such an interconnecting pipeline.

***Certain oil and natural gas leases and agreements to be acquired by US Opco may require consents for transfer which, if not obtained, could result in those leases or agreements being omitted from the Acquisition with a corresponding downward adjustment to the purchase price for the Denali Assets, and possible loss of reserves and future cash flow.***

Certain oil and natural gas leases and agreements relating to the Denali Assets require consent from third parties prior to being transferred to US Opco. The terms of a number of consents require that the consent not be unreasonably withheld and, as a result, Management believes such consents should be obtainable. Other consents required in connection with the Acquisition may not be obtained by Denali prior to the closing of the Acquisition, if obtained at all. The Purchase and Sale Agreement contains provisions for the removal of leases comprising the Denali Assets that cannot be transferred to US Opco due to a lack of required consents and provide a corresponding reduction in the applicable purchase price. Leases requiring consents may have reserves and future production attributed to them in the Sproule Reserve Report, and such reserves and future production have not been fully identified and quantified by US Opco. The failure of Denali to obtain consents associated with leases with significant reserves and future production, or otherwise of significant value, and the subsequent adjustment and elimination of such Denali Assets from the leases to be conveyed to US Opco pursuant to the Purchase and Sale Agreement, could adversely impact revenue of US Opco and cash available for distribution by the Trust.

***Failure of third parties to meet their contractual obligations may have a material adverse affect on the Trust's financial condition***

The Trust is exposed to third party credit risk through contractual arrangements with current or future joint venture partners, third party operators, marketers of its oil and natural gas production and other parties. Poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in ongoing capital programs, potentially delaying such programs and the results thereof until the Trust finds a suitable alternative partner.

***US Opco's business is heavily regulated and such regulation increases its costs and may adversely affect its financial condition***

Oil and natural gas operations (including land tenure, exploration, development, production, refining, transportation and marketing) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Regulation increases costs. In order to conduct oil and natural gas operations, licenses from various governmental authorities are required. There can be no assurance that US Opco will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake. See "The Industry".

***Income tax laws or other laws may in the future be changed or interpreted in a manner that adversely affects the Trust and its Unitholders***

The Trust intends to continue at all times to qualify as a "unit trust" and a "mutual fund trust" for purposes of the Tax Act. There can be no assurance that Canadian federal income tax laws and the administrative policies and assessing practices of the CRA respecting mutual fund trusts will not be changed in a manner that adversely affects the Unitholders. Should the Trust cease at any time to qualify as a mutual fund trust under the Tax Act, the income tax considerations described under the heading "Canadian Federal Income Tax Considerations" would be materially and adversely different in certain respects.

The SIFT Rules apply to a trust that is a SIFT trust. If the SIFT Rules were to apply to the Trust, they could have an adverse impact on the Trust and on the distributions received by the Unitholders. The Trust will not be a SIFT trust for the purposes of these rules by virtue of not holding any "non-portfolio property" (as defined in the Tax Act), based on its investment restrictions. There can be no assurance that there will not be changes to the SIFT Rules or to the administrative policies or assessing practices which will adversely affect the Trust and its Unitholders.

***Canadian tax laws may be changed or certain tax positions taken by the Trust and its subsidiaries may be challenged***

The income of the Trust and the Trust Subsidiaries must be computed in accordance with Canadian and U.S. laws, as applicable, and the Trust and Can Holdco are subject to Canadian tax laws. There can be no assurance that Canadian federal income tax laws, the judicial interpretation thereof or the administrative and assessing practices and policies of the CRA and the Department of Finance (Canada) will not be changed in a manner that adversely affects Unitholders. Any such change could increase the amount of tax payable by the Trust or Can Holdco or could otherwise adversely affect Unitholders by reducing the amount available to pay distributions or changing the tax treatment available to Unitholders in respect of such distributions.

There can be no assurance that the taxation authorities will not seek to challenge certain tax positions taken by the Trust and its subsidiaries. In particular, Can Holdco will be required to include in calculating its income all dividends received on its US Opco shares (which, pursuant to proposed amendments to the Tax Act, will include any distributions received by Can Holdco on its US Opco shares, except distributions received on a liquidation of US Opco or a redemption of US Opco shares). Can Holdco should be entitled to a deduction equal to the amount of such dividends derived from US Opco's earnings from carrying on an active business in the U.S., provided that the central management and control of US Opco is, at all times, exercised in the U.S. The result of this income inclusion and corresponding deduction is that Can Holdco should not be subject to tax on dividends received by Can Holdco from US Opco. If this deduction was denied, Can Holdco would be subject to Canadian income tax on the dividends from US Opco, which could adversely affect the financial position of Can Holdco and the Trust and reduce the amount of cash available for distribution to Unitholders.

Can Holdco's entitlement to designate dividends paid to the Trust from the funds received from US Opco as eligible dividends under the Tax Act may depend on Can Holdco being controlled, directly or indirectly, in any manner whatever, by one or more or a combination of non-resident persons, public corporations or corporations having a class of listed shares. If Can Holdco designates a dividend as an eligible dividend in excess of the amounts it is entitled to designate (referred to as an "excessive eligible dividend designation" within the meaning of the Tax Act), Can Holdco would be subject to an additional tax under the Tax Act on the excess amount, which would reduce the amount of cash available for distribution to the Trust.

***The Trust, Can Holdco and US Opco are subject to United States tax laws***

There can be no assurance that U.S. federal income tax laws and Internal Revenue Service and Department of the Treasury administrative and legislative policies respecting the U.S. federal income tax consequences described herein will not be changed, possibly on a retroactive basis, in a manner that adversely affects the Unitholders. In particular, any such change could increase the amount of U.S. federal income tax or withholding tax payable by US Opco, Can Holdco or the Trust, reducing the amount of distributions which the Trust would otherwise receive and thereby reducing the amount available to pay distributions to Unitholders.

***Future tax measures could impact the Trust***

There can be no assurance that future revisions to Canadian or United States domestic tax law, or to the terms of the Treaty, will not result in an adverse change to the tax treatment of the operations of US Opco, the amounts paid by US Opco to Can Holdco and the Trust or a denial of treaty benefits to Can Holdco or the Trust with respect to such payments.

***A successful IRS contest of the U.S. federal income tax positions taken may adversely affect the market for the Units, and the cost of an IRS contest will reduce cash flow available for distribution to Unitholders***

The IRS may adopt tax positions that differ from the positions taken by the Trust, Can Holdco and US Opco, including the position that the interest on the US Opco Notes is deductible or not subject to withholding tax. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions taken by the Trust, Can Holdco and US Opco. A U.S. court may not agree with some or all of the positions taken. Any contest with the IRS may materially and adversely impact the after-tax cash flow of US Opco, the cash flow available for distribution to Unitholders and the price at which the Units trade.

As discussed above in "U.S. Federal Income Taxation of the Trust, Can Holdco and US Opco – U.S. Federal Income Taxation of US Opco – Conduit Financing Rules", the US Opco Notes held by the Trust are financing transactions and the Units may also be treated as a financing transaction as a result of the rights of redemption of the Unitholders. If the Units were considered financing transactions, the US Opco Notes and the Units would together likely constitute a financing arrangement under the conduit financing rules. If Taxation Certifications are not provided by Unitholders, certain interest payments on the US Opco Notes could be subject to a 30% U.S. withholding tax. While it is reasonable to assume that Unitholders will provide the necessary Taxation Certifications, no assurance can be given that such certifications will be provided. Accordingly, the failure to obtain the necessary Taxation Certifications could result in interest payments to the Trust on the US Opco Notes being subject to a 30% U.S. withholding tax to the extent of any such failure.

***Potential U.S. legislative and regulatory actions could increase costs, reduce revenue and cash flow from oil and natural gas sales, reduce liquidity or otherwise alter the way the Trust conducts its business***

The activities of exploration and production companies operating in the United States are subject to extensive regulation at the federal, state and local levels. Changes to existing laws and regulations or new laws and regulations such as those described below could, if adopted, have an adverse effect on the Trust's business. Specifically, U.S. federal budget proposals, and certain legislation introduced in the U.S. Congress, would repeal the expensing of intangible drilling costs, repeal the percentage depletion allowance and increase the amortization period of geological and geophysical expenses currently available to independent producers of oil and natural gas. These changes, if enacted, would make it more costly to explore for and develop oil and natural gas reserves. In addition, substantive changes to Code Section 163(j) and related legislation have been proposed in the past that, if adopted, would negatively affect US Opco's ability to take certain interest deductions. Any such changes could negatively impact cash flows, the cash flow available for distribution to the Unitholders, the amount of distributions to Unitholders and the value of the Units. The Trust is unable to predict whether any changes, or other proposals to such laws, ultimately will be enacted. Any such changes would negatively impact cash flows and the cash flow available for distribution to Unitholders and could negatively impact the amount of any distributions to Unitholders and the value of the Units.

***New U.S. regulation of derivatives trading could reduce hedging opportunities and negatively affect the Trust's results***

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "**Dodd-Frank Act**") was signed into law by the President of the U.S. on July 21, 2010, and the provisions of the Dodd-Frank Act generally were effective beginning 360 days from the date of enactment, on July 16, 2011. Provisions that require further rulemaking will not take effect until at least 60 days after publication of the related final rule. The SEC and the CFTC have not completed all of the rulemaking the Dodd-Frank Act directs them to carry out. The regulators have granted temporary relief from the general effective date for various requirements of the Dodd-Frank Act, and also have indicated they may phase in implementation of various requirements of the new rules. In the future, the Trust may use over the counter derivative markets for its oil and natural gas derivative contracts. The Dodd-Frank Act could reduce liquidity in the energy futures markets. Such changes could materially reduce hedging opportunities and negatively affect revenues and cash flow during periods of low commodity prices.

***Climate change legislation or regulations restricting emissions of "GHG" could result in increased operating costs and reduced demand for the oil and natural gas produced***

On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other GHGs present a danger to public health and the environment. Based on these findings, the EPA has adopted regulations under existing provisions of the federal *Clean Air Act* that require a reduction in emissions of GHGs from motor vehicles and also requires construction and operating permit reviews of GHG emissions from certain large stationary sources. The EPA's rules relating to emissions of GHGs from large stationary sources of emissions are currently subject to a number of legal challenges, but the federal courts have thus far declined to issue any injunctions to prevent the EPA from implementing, or requiring state environmental agencies to implement, the rules. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified GHG emission sources in the United States including, among others, certain onshore oil and natural gas processing facilities on an annual basis. Both houses of Congress have from time to time considered legislation to reduce emissions of GHGs and almost one-half of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of GHGs. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHGs from, US Opco's equipment and operations could require US Opco to incur costs to reduce emissions of GHGs associated with operations or could adversely affect demand for the oil and natural gas that is produced by US Opco. These developments could have a significant adverse effect on the business in which the Trust or its subsidiaries will invest.

***Acquiring, developing and exploring for oil and natural gas involves many risks, which even a combination of experience, knowledge and careful evaluation may not be able to overcome***

The Trust's business plan contemplates acquisitions of additional producing properties and developmental drilling, and the Trust's future financial condition and results of operations will depend on the success of these activities. Oil and natural gas acquisition, development and production activities are subject to numerous risks beyond the Trust's control.

These risks include, but are not limited to; encountering unexpected formations or pressures; premature declines of reservoirs; blow-outs; craterings (sanding in or watering out of a well); equipment malfunctions; failures and other accidents; toxic gas releases; uncontrollable flows of oil, natural gas or well fluids; pipeline or tank ruptures or spills; pipe or cement failures and casing collapses; problems from waterflood operations, including surface discharges of contaminated water; lost or damaged drilling and service tools; loss of drilling fluid circulation; adverse weather conditions; pollution; other environmental risks; natural disasters; explosions, blowouts and fires; oil, natural gas or produced water releases or spills; delays in payments between parties caused by operational or economic matters; delays imposed or resulting from compliance with regulatory requirements including permitting; and shortages of or inability to secure materials or labour (including shortages of or inability to obtain rigs, completion crews or water for hydraulic fracturing activities). These risks will continue as the Trust undertakes more developmental drilling. Although the Trust will maintain insurance in accordance with customary industry practice, it is not fully insured against all of these risks. Continuing production from a property, and to some extent the marketing of production therefrom, are largely dependent upon the ability of the operator of the property. Third parties may operate a small portion of the Denali Assets being acquired in the Acquisition and may operate other properties the Trust acquires in the future. Returns on assets operated by third parties depend upon a number of factors outside the Trust's control. To the extent the operators fail to perform these functions properly, operating income may be reduced. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects and its ability to maintain distributions.

***Distributions on Units are variable and may be reduced or suspended entirely***

The actual cash flow available for distribution to Unitholders is dependent on the amount of cash flow paid to the Trust by its operating entities and can vary significantly from period to period for a number of reasons, including among other things: (i) the operating entities' operational and financial performance (including fluctuations in the quantity of their oil, natural gas and NGLs production and the sales price that they realize for such production (after hedging contract receipts and payments)); (ii) fluctuations in the costs to produce oil, natural gas and NGLs, including royalty burdens, and to administer and manage the Trust and its subsidiaries; (iii) the amount of cash required or retained for debt service or repayment; (iv) amounts required to fund capital expenditures and working capital requirements; (v) foreign currency exchange rates and interest rates; and (vi) other obligations and liabilities such as environmental, contractual or legal liabilities and obligations. These amounts are subject to the discretion of the Board, which will regularly evaluate the Trust's distribution payout with respect to anticipated cash flows, debt levels, capital expenditure plans and amounts to be retained to fund acquisitions and expenditures. In addition, the Trust's level of distributions per Unit will be affected by the number of outstanding Units and other securities that may be entitled to receive cash distributions. Distributions may be increased, reduced or suspended entirely depending on the Trust's operations and the performance of its assets. The market value of the Units may deteriorate if the Trust is unable to meet distribution expectations in the future and such deterioration may be material.

***The Board has discretion in the payment of distributions and may not choose to maintain distributions in certain circumstances***

The Trust Indenture provides that all of the distributable income of the Trust, as the case may be at the end of any calendar month, including December 31, shall be declared payable and distributed to the Unitholders of record on the last day of each such calendar month. These distributions are enforceable by the Unitholders of record. However, if this amount is not determined and declared payable in accordance with the rules of the TSX, the right to receive this income will trade with the Units. The Trust Indenture provides that this distributable income is allocated to Unitholders for tax purposes and to the extent a Unitholder trades Units in this period, they will be allocated such income but will have disposed of their right to receive such distribution. The Trust Indenture also provides for the consolidation of the Units to the pre-distribution number of Units after any *pro rata* distribution of additional Units to all Unitholders. Accordingly, the Trust Indenture allows for the payment of distributions in a form other than cash and Unitholders may have taxable income and cash taxes payable in excess of the amount of cash distributions they receive from the Trust.

***The Trust is participating in larger projects which may delay expected revenue from operations***

The Denali Assets are located primarily in a concentrated area of Texas. US Opco plans to undertake development activities in respect of the Denali Assets and may also undertake a variety of development activities in respect of any additional properties that are acquired. Project delays may impact expected revenues from operations. Significant project cost over-runs could make a project uneconomic. US Opco's ability to execute projects and market oil, natural gas and NGLs depends upon numerous factors beyond Management's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of water supplies and/or disposal facilities;
- reductions in prices for oil, natural gas and/or NGLs;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- changes in regulations;

- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Trust (through its subsidiaries) could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil, natural gas and/or NGLs that is produced.

***The Trust's business is difficult to evaluate because it has no operating history***

Until the successful completion of this Offering and the Acquisition, the Trust will have no assets or operating history. Management faces challenges and uncertainties in financial planning as a result of the unavailability of historical data and uncertainties regarding the nature, scope and results of the Trust's future activities. New companies must develop successful business relationships, establish operating procedures, hire staff, install management information and other systems, establish facilities and obtain licenses, as well as take other measures necessary to conduct their intended business activities. Management may not be successful in implementing its business strategies or in completing the development of the infrastructure necessary to conduct business as planned. In the event that the Trust's development plan is not completed or is delayed, operating results will be adversely affected and operations will differ materially from the activities described in this prospectus. As a result of industry factors or factors relating specifically to the Trust, Management may have to change methods of conducting business, which may cause a material adverse effect on results of operations and financial condition.

***US Opco has limited experience in drilling wells in the Eagle Ford Shale oil formation and limited information regarding reserves and decline rates in this area. Wells drilled in this area are more expensive and more susceptible to mechanical problems in drilling and completion techniques than wells using conventional drilling***

US Opco has limited experience in the drilling and completion of Eagle Ford Shale wells, including limited horizontal drilling and completion experience. The Sproule Reserve Report assumes a significant amount of drilling by US Opco in the Eagle Ford Shale over the next four years. Other operators in this play may have significantly more experience in the drilling and completion of these wells, including the drilling and completion of horizontal wells. In addition, US Opco has limited information with respect to the ultimate recoverable reserves and production decline rates in these areas due to their limited histories. The wells drilled in the Eagle Ford Shale formation are primarily horizontal and require more artificial stimulation, which makes them more expensive to drill and complete. The wells also are more susceptible to mechanical problems associated with the drilling and completion of the wells, such as casing collapse and lost equipment in the wellbore due to the length of the lateral portions of these unconventional wells. The fracturing of these formations will be more extensive and complicated than fracturing geological formations in conventional areas of operation.

***US Opco only operates in Texas and expansion outside of such state or into new business activities may increase its risk exposure***

Upon the completion of this Offering and the Acquisition, all reserves and production will be located in Texas. The Trust's business plan contemplates acquisitions and development through its subsidiaries of additional reserves and production primarily in the U.S. In addition, the Trust Indenture does not limit activities to oil and natural gas production and development, allowing the Trust to acquire and own assets or property in connection with gathering, processing, transporting, extracting, buying, storing or selling oil, natural gas, NGLs or other related products, in connection with other forms of energy and related businesses, or in connection with such other investments as the Trustee may determine. Expansion of activities into new areas may present new additional risks or alternatively, significantly increase the exposure to one or more of the present risk factors which may adversely affect the Trust's future operational and financial conditions.

***Oil and natural gas reserves are a depleting resource, and production from these reserves will diminish over time***

The oil, natural gas and NGLs reserves attributable to the Denali Assets are, and any properties subsequently acquired by the Trust will likely be, depleting assets, which means that the reserves of oil, natural gas and NGLs attributable to the properties owned by the Trust will decline over time. As a result, the quantity of oil, natural gas and NGLs produced from such properties will decline over time.

Future well maintenance may affect the quantity of proved reserves that can be economically produced from the properties to which the wells relate. The timing and size of these projects will depend on, among other factors, the market prices of oil, natural gas and NGLs. If the operators of such wells do not implement maintenance projects when warranted, the future rate of production decline of proved reserves may be higher than the rate currently expected by the Trust or estimated in the reserve reports.

Distributions by the Trust of distributable cash in respect of properties, absent commodity price increases or cost effective acquisition and development activities, will decline over time in a manner consistent with declining production from typical oil, natural gas and NGLs reserves. Future oil and natural gas reserves and production, and therefore the Trust's cash flows from operating activities, will be highly dependent on successfully exploiting the Trust's reserves base and acquiring additional reserves. Without reserves additions through acquisition or development activities, reserves and production may decline over time as existing reserves are depleted. There can be no assurance that the Trust will be successful in developing or acquiring additional reserves on terms that meet investment objectives.

***The Trust's growth strategy depends on the successful acquisition of additional oil and natural gas reserves. The Trust may be subject to risks in connection with acquisitions and the integration of significant acquisitions may be difficult***

The overall business strategy of the Trust contemplates future acquisition and development of conventional oil and natural gas producing properties. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future prices for oil, natural gas and NGLs and their appropriate differentials;
- development and operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, Management anticipates undertaking a review of the subject properties that is generally consistent with industry practices. Management's review may not reveal all existing or potential problems nor will it permit Management to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. US Opco may not be entitled to contractual indemnification for environmental liabilities and may acquire properties on an "as is" basis.

Significant acquisitions and other strategic transactions may involve other risks, including:

- diversion of Management's attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;
- challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of US Opco while carrying on its ongoing business;
- difficulty associated with coordinating geographically separate organizations; and
- challenge of attracting and retaining personnel associated with acquired operations.

The process of integrating operations could cause an interruption of, or loss of momentum in, the activities of US Opco's business. Management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage the business. If Management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, the Trust's business could suffer.

***The future use of hydraulic fracturing may be subject to new or more stringently enforced existing laws and regulations that could adversely affect the Trust's results***

Vast quantities of oil, natural gas and NGLs deposits exist in deep shale and other formations. It is customary in the oil and natural gas industry to recover oil, natural gas and NGLs from these deep shale formations through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Hydraulic fracturing is the process of creating or expanding cracks, or fractures, in formations underground where water, sand and other additives are pumped under high pressure into the formation. These formations are generally geologically separated and isolated from fresh ground water supplies by protective rock layers. The Trust's current business strategy contemplates developing the Austin Chalk formation in the Denali Assets without the use of hydraulic fracturing to stimulate production from any horizontal wells, although this technique may be more routinely used during future drilling activities. Hydraulic fracturing, however, will be an important component of drilling operations in the Eagle Ford Shale oil formation. Certain environmental and other non-governmental groups have suggested that additional federal, state and local laws and regulations may be needed to more closely regulate the hydraulic fracturing process, and have made claims that hydraulic fracturing techniques are harmful to surface water and drinking water sources. On April 17, 2012, the EPA approved final regulations under the *Clean Air Act* that, among other things, require the reduction in VOCs emitted from natural gas wells by requiring the use of green completions on all gas wells hydraulically-fractured or re-fractured after January 1, 2015. Moreover, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities using diesel under the SDWA's Underground Injection Control Program and on May 4, 2012, issued draft guidance for *Safe Drinking Water Act* permits issued to oil and natural gas exploration and production operators using diesel during hydraulic fracturing. At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with initial results of the study anticipated to be available by late 2012 and final results by 2014. In the interim, however, the EPA has utilized its existing SDWA enforcement authorities to order actions and potentially to pursue penalties against some oil and natural gas producers where EPA believes their activities may have impacted groundwater. Also, for the second consecutive session, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Moreover, the EPA has announced that it will develop effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, have or are evaluating various other aspects of hydraulic fracturing, with the U.S. Department of the Interior proposing regulations on May 4, 2012 that would require oil and natural gas producers to publicly disclose their hydraulic fracturing chemicals in connection with their drilling of wells on federal and Indian lands and also would strengthen standards for well-bore integrity and the management of fluids that return to the surface during and after fracturing operations on federal and Indian lands. These studies or reviews, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the *Safe Drinking Water Act* or other regulatory mechanisms. In addition, some states have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations. In June 2011, Texas adopted a law and has since adopted regulations that require the disclosure to the RRC and the public of certain information regarding the substances used in the hydraulic fracturing process. Certain states are also considering temporary moratoriums on hydraulic fracturing activities until further studies can be completed. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for the operators to perform fracturing to stimulate production from tight formations. Restrictions on hydraulic fracturing also could reduce the amount of oil, natural gas and NGLs that are ultimately produced in commercial quantities from the Trust's properties. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, the Trust's business and operations and the properties in which the Trust has an interest could be subject to additional permitting requirements, and also to attendant permitting delays, increased operating and compliance costs and process prohibitions.

***Operations are subject to hazards and unforeseen interruptions for which the Trust may not be adequately insured***

There are a variety of operating risks inherent in the wells, gathering systems and associated facilities to be acquired by US Opco, such as leaks, explosions, mechanical problems and natural disasters, all of which could cause substantial financial losses. Any of these or other similar occurrences could result in the disruption of operations, substantial repair costs, personal injury or loss of human life, significant damage to property, environmental pollution, impairment of operations and substantial revenue losses. The location of the wells, gathering systems and associated facilities to be acquired by US Opco near populated areas, including residential areas, commercial business centers and industrial sites, could significantly increase the level of damages resulting from these risks.

The Trust is not fully insured against all risks. Generally, pollution and environmental risks are not fully insurable. In addition, Management may elect not to obtain insurance if it believes that the cost of available insurance is excessive relative to the perceived risks presented. Therefore, losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Moreover, insurance may not be available in the future at commercially reasonable costs and on commercially reasonable terms. Losses and liabilities from uninsured and underinsured events and a delay in the payment of insurance proceeds could adversely affect the Trust's business, financial condition, results of operations and ability to make distributions to Unitholders.

***The Trust has the authority to impose restrictions on the issuance or transfer of Units to a non-resident of Canada***

The Trust intends to comply with the requirements under the Tax Act for a "unit trust" and "mutual fund trust" at all relevant times such that it maintains its status of a unit trust and a mutual fund trust for purposes of the Tax Act. Under current law, a mutual fund trust may lose its status under the Tax Act as a "mutual fund trust" if it can reasonably be considered that the trust was established or is maintained primarily for the benefit of non-residents of Canada (including partnerships owned in whole or in part by non-residents), except in limited circumstances. Among those circumstances are that all or substantially all of the mutual fund trust's property is not "taxable Canadian property", as defined by the Tax Act.

As a result of the Trust's investment restrictions, the Trust is not expected to hold any taxable Canadian property and should not be subject to the Tax Act's non-resident ownership restrictions. However, in the event that the Trust determines that such non-resident restrictions apply, the Trustee has various powers that can be used for the purpose of monitoring and controlling the extent of non-resident ownership of the Units. See "Description of the Trust – Limitations on Non-Resident Ownership".

If restrictions on issuances of Units by the Trust to non-residents are imposed by the Trust the ability of the Trust to raise financing for future acquisitions or operations could be negatively affected. In addition, the fact that such restrictions may be implemented in the future may limit the ability of Unitholders to sell their Units at the best price, and could discourage certain categories of investors from purchasing Units in the open market, which could negatively affect the liquidity of the Units and the future market price for Units.

***The nature of the Trust's assets exposes it to significant costs and liabilities with respect to environmental and occupational health and safety matters***

Environmental and occupational health and safety requirements applicable to oil and natural gas production activities can create significant costs and liabilities. These costs and liabilities could arise under a wide range of U.S. federal, state and local environmental and worker health and safety laws and regulations, including agency interpretations of the foregoing and governmental enforcement policies, which have become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and to a lesser extent, issuance of injunctions to limit or cease operations. In addition, claims for damages to persons or property may result from environmental and other impacts of operations.

Strict, joint and several liabilities may be imposed under certain environmental laws, which can result in liability for the conduct of others as well as for consequences of a party's own actions that were in compliance with all applicable laws at the time the conduct occurred or actions were taken. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements or well construction, drilling, completion or water management activities could require significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on its results of operations, competitive position or financial condition. If the Trust is not able to recover the resulting losses through insurance or increased revenues, the ability to make distributions to Unitholders could be adversely affected. See “The Industry – Environmental, Health and Safety Regulation”.

***Competition in the oil and natural gas industry is intense, making it more difficult to acquire properties, market oil, natural gas and NGLs and secure trained personnel***

US Opco’s ability to acquire and develop additional reserves in the future will depend on the ability to evaluate and select suitable properties and consummate the acquisition of those properties, to effectively market oil, natural gas and NGLs and to secure equipment and trained personnel in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many competitors possess and employ financial, technical and personnel resources substantially greater than the Trust’s. Those companies may be able to pay more for productive oil and natural gas properties or to identify, evaluate, bid for and purchase a greater number of properties than the Trust’s financial or personnel resources permit. Furthermore, these companies may also be better able to withstand the financial pressures of unsuccessful drilling attempts, sustained periods of volatility in financial markets and generally adverse global and industry-wide economic conditions, and may be better able to absorb the burdens resulting from changes in relevant laws and regulations, which would adversely affect competitive position. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel. The cost to attract and retain qualified personnel has increased over the past few years due to competition and may increase substantially in the future. The Trust may not be able to compete successfully in the future in acquiring and developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on the Trust’s business.

***Success depends in large measure on certain key personnel and the Trust’s ability to retain its key personnel***

The loss of certain key personnel could delay the completion of certain projects or otherwise have a material adverse effect on the Trust. Unitholders will be dependent on Management in respect of the administration and management of all matters relating to the Trust’s properties, the Units and the safekeeping of its primary workspace and computer systems.

***Acreage must be drilled before lease expiration, generally within two to five years, in order to hold the acreage by production. In the highly competitive market for acreage, failure to drill sufficient wells in order to hold acreage will result in a substantial lease renewal cost, or if renewal is not feasible, loss of US Opco’s lease and prospective drilling opportunities***

If US Opco acquires leasehold that is not held by production, it must establish production prior to the expiration of the applicable lease or renew the lease to prevent expiration. The cost to renew leases may increase significantly, and US Opco may not be able to renew such leases on commercially reasonable terms or at all. As such, US Opco’s actual drilling activities may materially differ from current expectations, which could adversely affect the ability to pay distributions.

***The Trust may incur losses as a result of title defects in the properties in which US Opco invests***

Industry practice in the U.S. for acquiring undrilled or non-producing oil and natural gas leases or interests does not typically involve retaining lawyers to examine the title to the mineral interest and instead relies upon the judgment of oil and natural gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office or using available field notes, run sheets or title abstracts before attempting to acquire a lease in a specific mineral interest.

Prior to the drilling of an oil or natural gas well, however, it is the normal practice in the industry for the operator of the well to obtain a preliminary title review by a lawyer, law firm or other land professional to ensure there are no obvious defects in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct defects in the marketability of the title, and such curative work entails expense. Failure to cure any title defects may adversely impact the ability in the future to increase production and reserves.

There can be no assurance that the Trust will not suffer a monetary loss from title defects or title failure. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in assignment of leasehold rights in properties in which US Opco holds an interest, it may suffer a financial loss.

### Risks Relating to the Trust's Structure and Ownership of Units

***Distributions do not represent a "yield" and are not comparable to debt instruments and rights of redemption have limited liquidity***

Units will have no value when reserves from the properties owned by the Trust can no longer be economically produced and, as a result, distributions do not represent a "yield" in the traditional sense and are not comparable to bonds or other fixed yield securities, where investors are entitled to a full return of the principal amount of debt on maturity in addition to a return on investment through interest payments. Distributions represent a blend of return of Unitholders' initial investment and a return on Unitholders' initial investment. Unitholders have a limited right to require a repurchase of their Units, which is referred to as a redemption right. It is anticipated that the redemption right will not be the primary mechanism for Unitholders to liquidate their investment. The right to receive cash in connection with a redemption is subject to material limitations. Any securities which may be distributed in specie to Unitholders in connection with a redemption may not be listed on any stock exchange and a market may not develop for such securities and such securities may be illiquid. In addition, there may be resale restrictions imposed by law upon the recipients of the securities pursuant to the redemption right. See "Description of the Trust – Redemption at the Option of Unitholders".

***The Units do not represent a traditional investment in the oil and natural gas sector and should not be viewed by investors as shares in a corporation***

The Units represent a fractional interest in the Trust. Corporate law does not govern the Trust and the rights of Unitholders. As Unitholders, Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring oppression or derivative actions. The rights of Unitholders are specifically set forth in the Trust Indenture. In addition, trusts are not defined as recognized entities within the definitions of legislation such as the *Bankruptcy and Insolvency Act* (Canada), the *Companies' Creditors Arrangement Act* (Canada) and in some cases the *Winding Up and Restructuring Act* (Canada). As a result, in the event of an insolvency or restructuring, a Unitholder's position as such may be quite different than that of a shareholder of a corporation. The Trust's sole assets will be the Can Holdco Shares and the US Opco Notes. The price per Unit is a function of anticipated distributable income, the properties acquired by the Trust and the ability to effect long-term growth in value. The market price of the Units will be sensitive to a variety of market conditions including, but not limited to, interest rates and the ability to acquire suitable oil and natural gas properties. Changes in market conditions may adversely affect the trading price of the Units.

The Units are not "deposits" within the meaning of the *Canada Deposit Insurance Corporation Act* (Canada) and are not insured under the provisions of that Act or any other legislation. Furthermore, the Trust is not a trust company and, accordingly, is not registered under any trust and loan company legislation as the Trust does not carry on or intend to carry on the business of a trust company.

***Unitholder limited liability is subject to contractual and statutory assurances which may have some enforcement risks***

The Trust Indenture provides that no Unitholder will be subject to any liability in connection with the Trust or its obligations and affairs and, in the event that a court determines Unitholders are subject to any such liabilities, the liabilities will be enforceable only against, and will be satisfied only out of the Trust's assets. Pursuant to the Trust Indenture, the Trust will indemnify and hold harmless each Unitholder from any costs, damages, liabilities, expenses, charges and losses suffered by a Unitholder resulting from or arising out of such Unitholder not having such limited liability. The Trust Indenture provides that all written instruments signed by or on behalf of the Trust must contain a provision to the effect that such obligation will not be binding upon Unitholders personally. Personal liability may also arise in respect of claims against the Trust that do not arise under contracts, including claims in tort, claims for taxes and possibly certain other statutory liabilities. The possibility of any personal liability of this nature arising is considered unlikely. The *Income Trusts Liability Act* (Alberta) provides that a Unitholder will not be, as a beneficiary, liable for any act, default, obligation or liability of the trustee that arises after the legislation came into force. The Trust's operations will be conducted, upon the advice of counsel, in such a way and in such jurisdictions as to avoid as far as possible any material risk of liability on Unitholders for claims against the Trust.

**Risk Factors Applicable to Residents of the United States and Other Non-Residents of Canada**

***Persons not resident in Canada may have difficulty enforcing civil remedies***

The Trust and Can Holdco are organized under the laws of Alberta, Canada and have their principal place of business in Canada. US Opco is organized under the laws of the State of Delaware. Most of the Trust's, and Can Holdco's directors and officers and the representatives of the experts who provide services to the Trust (such as its auditors and its independent reserve engineers), and all of the assets held directly by the Trust and all or a substantial portion of the assets of such persons are located in Canada. As a result, it may be difficult for investors in the United States to effect service of process within the United States upon such directors, officers and representatives of experts who are not residents of the United States or to enforce against them judgments of the United States courts based upon civil liability under the United States federal securities laws or the securities laws of any state within the United States. There is doubt as to the enforceability in Canada against the Trust and Can Holdco or against any of their respective directors, officers or representatives of experts (to the extent applicable) who are not residents of the United States, in original actions or in actions for enforcement of judgments of United States courts of liabilities based solely upon the United States federal securities laws or securities laws of any state within the United States.

***There are differences in reporting practices in Canada and the United States***

The Trust reports its production and reserve quantities in accordance with Canadian practices and specifically in accordance with NI 51-101. These practices are different from the practices used to report production and to estimate reserves in reports and other materials filed with the Securities and Exchange Commission by companies in the United States. The Trust incorporates additional information with respect to production and reserves which is either not generally included or prohibited under rules of the Securities and Exchange Commission and practices in the United States. The Trust follows the Canadian practice of reporting gross production and reserve volumes (before deduction of Crown and other royalties); however, it also follows the United States practice of separately reporting reserve volumes on a net basis (after the deduction of royalties and similar payments). The Trust also follows the Canadian practice of using forecast prices and costs when estimating reserves; whereas the Securities and Exchange Commission requires that prices and costs be averaged for the 12 months ended as of the date of the Sproule Reserve Report. Included in this prospectus are estimates of proved and proved plus probable reserves. Probable reserves are higher risk and are generally believed to be less likely to be accurately estimated or recovered than proved reserves. The Securities and Exchange Commission generally prohibits the inclusion of estimates of probable reserves in filings made with it. This prohibition does not apply to the Trust as a Canadian foreign private issuer.

As a consequence of the foregoing, the reserve estimates and production volumes in this prospectus may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

***There is additional taxation applicable to non-residents***

Net income of the Trust, other than certain net realized capital gains, distributed to non-residents will be subject to withholding tax under the Tax Act at a 25% rate, subject to reduction under an applicable income tax treaty.

An additional 15% Canadian withholding tax also applies to the return of capital portion of distributions made to non-resident unitholders for publicly traded trusts whose trust units derive more than 50% of their value from any combination of real property situated in Canada, "Canadian resource property" (as defined in the Tax Act), or "timber resource property" (as defined in the Tax Act). The Trust and its affiliates do not expect to hold any of the properties referred to above, and accordingly, the additional withholding tax should not apply to the Trust and its Unitholders. There can be no assurance that Canadian tax laws or international tax treaties will not be changed in a manner which adversely affects the rate of withholding on distributions of the Trust's capital and/or income.

If the Trust ceases to qualify as a "mutual fund trust" for purposes of the Tax Act, non-resident Unitholders may be subject to Canadian tax (subject to any treaty relief) on gains realized on a disposition of Units if such Units constitute "taxable Canadian property" as defined in the Tax Act. However, Units will generally not constitute "taxable Canadian property" unless in the 60 month period preceding the disposition date more than 50% of the value of the Units was derived, directly or indirectly, from "real or immovable property situated in Canada", "Canadian resource property" (as defined in the Tax Act), "timber resource property" (as defined in the Tax Act) and/or options and interests in any of the foregoing. Given the anticipated holdings of the Trust and its affiliates, it is not expected that the Units will constitute "taxable Canadian property"; however, no assurances can be given in this regard.

***Non-resident Unitholders will be subject to additional foreign exchange risk***

The Trust's distributions are declared in Canadian dollars and converted to foreign denominated currencies at the spot exchange rate at the time of payment. As a consequence, investors are subject to foreign exchange risk. To the extent that the Canadian dollar strengthens with respect to their currency, the amount of the distribution will be reduced when converted to their home currency.

## LEGAL PROCEEDINGS AND REGULATORY ACTION

Management is not aware of any material outstanding, threatened or pending litigation as at the date hereof by or against the Trust, Can Holdco, US Opco, the Administrator or any other direct or indirect subsidiaries of the Trust.

There have not been any penalties or sanctions imposed against the Trust by a court relating to provincial and territorial securities legislation or by a securities regulatory authority, nor have there been any other penalties or sanctions imposed by a court or regulatory body against the Trust, and the Trust has not entered into any settlement agreements before a court relating to provincial and territorial securities legislation or with a securities regulatory authority.

## EXEMPTIONS FROM CERTAIN DISCLOSURE REQUIREMENTS

The Trust applied to the Alberta Securities Commission, as principal regulator on behalf of the securities regulatory authorities in the other provinces of Canada (other than Ontario), and to the Ontario Securities Commission, for exemptive relief from Sections 32.2 and 32.3 of Form 41-101F1 – *Information Required in a Prospectus* ("**Form 41-101F1**"), as prescribed under National Instrument 41-101 – *General Prospectus Requirement*s. Those sections require that the Trust include in this prospectus annual financial statements for each of the three most recently completed financial years of the Denali Assets, being the years ended December 31, 2011, December 31, 2010 and December 31, 2009 and comparable interim financial statements for the most recent interim period of the Denali Assets ended more than 45 days before the date of this prospectus, being March 31, 2012 and 2011. The Trust will indirectly acquire the Denali Assets pursuant to the Purchase and Sale Agreement. Initially, the Denali Assets will comprise the principal undertaking of the Trust and may therefore be viewed as the primary business of the Trust pursuant to Section 32.1(b) of Form 41-101F1. The Trust sought exemptive relief from the requirements to include in this prospectus the financial statements described above.

The Trust has instead included: (i) audited Consolidated Statement of Financial Position as at June 30, 2012 and the Consolidated Statements of Comprehensive Loss, Changes in Unitholders' Equity and Cash Flows for the period from the date of establishment on January 31, 2012 to June 30, 2012; and (ii) audited Operating Statements Containing Gross Revenues, Royalties and Production Taxes and Operating Expenses for the Denali Assets for the years ended December 31, 2011, 2010 and 2009 and unaudited Operating Statements Containing Gross Revenues, Royalties and Production Taxes and Operating Expenses for the Denali Assets for the three month periods ended March 31, 2012 and 2011 (collectively, the "**Financial Statements**").

The Trust has also applied for exemptive relief from Section 4.2 of National Instrument 52-107 – *Acceptable Accounting Principles and Auditing Standards*, which requires that the Financial Statements included in this prospectus (for periods ending on or before December 31, 2010) be prepared in accordance with Canadian generally accepted accounting principles as contained in Part V of the CICA Handbook. The Trust has adopted IFRS in respect of the Operating Statements Containing Gross Revenues, Royalties and Production Taxes and Operating Expenses comprising part of the Financial Statements, in accordance with the Canadian Securities Administrator's Staff Notice 52-321 – *Early Adoption of International Financial Reporting Standards, Use of U.S. GAAP and Reference to IFRS-IASB*, and has prepared the Financial Statements in accordance with IFRS. Management believes it has carefully assessed the readiness of its staff, the Board, audit committee, auditors, investors and other market participants for the adoption of IFRS for the presentation of the Operating Statements Containing Gross Revenues, Royalties and Production Taxes and Operating Expenses comprising part of the Financial Statements in connection with the Offering.

In addition, the Trust applied for exemptive relief from Section 5.5 of Form 41-101F1, which requires that the Trust include oil and gas reserve disclosure in accordance with Form 51-101F1, together with reports in Form 51-101F2 and Form 51-101F3, each under National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities*, with an effective date as at the most recent date for which the prospectus includes an audited balance sheet of the issuer. The Trust sought exemptive relief from the requirements to include oil and gas reserve disclosure at that effective date and has instead included oil and gas reserve disclosure in such forms with an effective date of December 31, 2011. A Sproule December 31, 2011, price forecast was used in the Sproule Reserve Report.

The issuance by the Alberta Securities Commission of a final receipt for this prospectus constitutes evidence of the granting of relief from the foregoing requirements in all jurisdictions in Canada.

## AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of the Trust are PricewaterhouseCoopers LLP, Chartered Accountants, 111 – 5th Avenue S.W., Suite 3100, Calgary, Alberta, T2P 5L3. PricewaterhouseCoopers LLP has advised they are independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

The transfer agent and registrar for the Units is Computershare Trust Company of Canada, at its principal offices in Calgary, Alberta and Toronto, Ontario where transfers of securities may be recorded.

## EXPERTS

Certain legal matters relating to the distribution of the Units will be passed upon by Bennett Jones LLP on behalf of the Trust, Can Holdco and the Administrator, by Vinson & Elkins L.L.P., on behalf of US Opco, and by Blake, Cassels & Graydon LLP, on behalf of the Underwriters. As at the date hereof, the partners and associates of each of Bennett Jones LLP, Vinson & Elkins L.L.P. and Blake, Cassels & Graydon LLP who participated in or were in a position to directly influence the preparation of the opinions of their respective firms, as respective groups, beneficially own, directly or indirectly, less than 1% of the outstanding Units, and such groups respectively each own less than 1% of the outstanding securities of any associate or affiliate of the Trust.

No person or company whose profession or business gives authority to a report, valuation, statement or opinion made by such person or company and who is named in this prospectus as having prepared or certified a part of this prospectus, or a report, valuation, statement or opinion described in this prospectus, has received or shall receive a direct or indirect interest in any securities or other property of the Trust or any associate or affiliate of the Trust.

As at the date hereof, the principals of Sproule, independent engineering consultants to the Administrator, do not beneficially own, directly or indirectly, any of the outstanding Units, and such group owns less than 1% of the outstanding securities of any associate or affiliate of the Trust.

PricewaterhouseCoopers LLP has advised they are independent with respect to the Trust within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

## MATERIAL CONTRACTS

Copies of the following documents, once executed, will be available for inspection during normal business hours at the Administrator's office, Suite 500, 321 – 6$^{th}$ Avenue S.W. Calgary, Alberta, T2P 3H3 and at the offices of Bennett Jones LLP, 4500 Bankers Hall East, 855 – 2nd Street S.W. in Calgary, Alberta, T2P 4K7 during the period of distribution, or at any time after closing of the Offering on the SEDAR website at www.sedar.com.

1. Trust Indenture. See "Description of the Trust".
2. Administrative Services Agreement. See "Administration of the Trust – Administrative Services Agreement".
3. Services Agreement. See "Administration of the Trust – Services Agreement with Aston Hill".
4. The US Opco Notes. See "Description of US Opco – The US Opco Notes".
5. Voting Agreement. See "Voting Agreement".
6. Underwriting Agreement. See "Plan of Distribution".
7. Purchase and Sale Agreement. See "Funding, Acquisition and Related Transactions".
8. Credit agreement relating to the Credit Facilities. See "Credit Facilities".

## RIGHTS OF WITHDRAWAL AND RESCISSION

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus and any amendment. In several of the provinces, the securities legislation further provides a purchaser with remedies for rescission, or, in some jurisdictions, revisions of the price or damages, if the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that such remedies for rescission, revisions of the price or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province for the particulars of these rights or consult with a legal advisor.

## AUDITORS' CONSENT

We have read the prospectus of Argent Energy Trust (the "**Trust**") dated August 1, 2012 qualifying the distribution of 21,230,000 trust units of the Trust. We have complied with Canadian generally accepted auditing standards for an auditor's involvement with offering documents.

We consent to the use in the above-mentioned prospectus of our report to the directors of Argent Energy Ltd., as administrator of the Trust (the "**Administrator**"), on the Consolidated Statement of Financial Position of the Trust as at June 30, 2012 and the Consolidated Statements of Comprehensive Loss, Changes in Unitholders' Equity and Cash Flows from establishment of the Trust on January 31, 2012 to June 30, 2012. Our report is dated August 1, 2012.

We also consent to the use in the above-mentioned prospectus of our report to the directors of the Administrator on the Operating Statements Containing Gross Revenues, Royalties and Production Taxes and Operating Expenses pertaining to the Denali Assets for each of the years in the three-year period ended December 31, 2011. Our report is dated August 1, 2012.

Calgary, Alberta
August 1, 2012

(signed) "*PricewaterhouseCoopers LLP*"
Chartered Accountants

# APPENDIX A

# FINANCIAL STATEMENTS OF THE TRUST

## INDEPENDENT AUDITOR'S REPORT

**To the Directors of Argent Energy Ltd., as administrator of Argent Energy Trust**

We have audited the accompanying consolidated financial statements of Argent Energy Trust, which comprise the consolidated statement of financial position as at June 30, 2012 and the consolidated statements of comprehensive loss, changes in unitholders' equity and cash flows for the period from the date of establishment on January 31, 2012 to June 30, 2012 and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

### Management's responsibility for the consolidated financial statements

Management of Argent Energy Ltd., on behalf of Argent Energy Trust, is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

### Auditor's responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

### Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Argent Energy Trust as at June 30, 2012 and its financial performance and its cash flows for the period from the date of establishment on January 31, 2012 to June 30, 2012 in accordance with International Financial Reporting Standards.

(signed) "*PricewaterhouseCoopers LLP*"

**Chartered Accountants**
Calgary, Alberta
August 1, 2012

**Argent Energy Trust**

**Consolidated Statement of Financial Position**
**As at June 30, 2012**
**(All amounts in Canadian dollars, unless otherwise stated)**

| | June 30 2012 |
|---|---|
| | $ |
| **Assets** | |
| **Current** | |
| Cash and cash equivalents | 817,038 |
| Other receivables | 156,972 |
| Prepaid expenses | 27,500 |
| Deferred costs | 2,578,055 |
| Total current assets | 3,579,565 |
| **Non-current** | |
| Property, plant and equipment (Note 4) | 6,773 |
| **Total Assets** | 3,586,338 |
| **Liabilities and Unitholders' Liabilities** | |
| **Current Liabilities** | |
| Accounts payable and accruals | 2,102,453 |
| Total current liabilities | 2,102,453 |
| **Unitholder's Equity** | |
| Unitholders' capital (Note 5) | 2,975,742 |
| Deficit | (1,491,857) |
| | 1,483,885 |
| **Total Liabilities and Shareholders' Equity** | 3,586,338 |

*The accompanying notes are an integral part of these consolidated financial statements.*

*Subsequent events (Note 9)*

*Approved on behalf of the board of the Administrator, Argent Energy Ltd.*

*"Eric Tremblay"*
Director – Eric Tremblay

*"William Robertson"*
Director – William Robertson

**Argent Energy Trust**

**Consolidated Statement of Comprehensive Loss**
**For the period from establishment on January 31, 2012 to June 30, 2012**
**(All amounts in Canadian dollars, unless otherwise stated)**

| | For the period from January 31, 2012 to June 30, 2012 $ |
|---|---|
| **Expenses** | |
| Employee salaries and benefits | 769,856 |
| Audit, accounting and tax fees | 350,307 |
| Engineering and environmental | 78,633 |
| Legal fees | 126,680 |
| Business development and travel costs | 92,204 |
| Rent and utilities | 34,768 |
| Other | 39,409 |
| **Net Loss and Comprehensive Loss for the period** | (1,491,857) |
| **Net Loss per Unit** | |
| Basic and diluted | (2.78) |

*The accompanying notes are an integral part of these consolidated financial statements.*

## Argent Energy Trust

### Consolidated Statement of Changes in Unit Holders' Equity
### For the period from establishment on January 31, 2012 to June 30, 2012
### (All amounts in Canadian dollars, unless otherwise stated)

| | For the period from January 31, 2012 to June 30, 2012 |
|---|---|
| **Number of trust units outstanding** | |
| Issued on initial organization on January 31, 2012 (Note 5) | 1 |
| Repurchased by the Trust on February 3, 2012 (Note 5) | (1) |
| Units issued for private placement (Note 5) | 600,000 |
| Outstanding at the end of period | 600,000 |
| **Unitholders capital** | |
| Balance at beginning of period | - |
| Proceeds from private placement (Note 5) | $3,000,000 |
| Private placement issuance costs | ($24,258) |
| Balance at end of period | $2,975,742 |
| **Deficit** | |
| Balance at beginning of period | - |
| Net loss for the period | ($1,491,857) |
| Balance at end of period | ($1,491,857) |
| Total equity | $1,483,885 |

*The accompanying notes are an integral part of these consolidated financial statements.*

**Argent Energy Trust**

**Consolidated Statement of Cash Flows**
**For the period from establishment on January 31, 2012 to June 30, 2012**
**(All amounts in Canadian dollars, unless otherwise stated)**

| | For the period from January 31, 2012 to June 30, 2012 $ |
|---|---|
| **Operating Activities** | |
| Net Loss for the period | (1,491,857) |
| Adjustments for non-cash items: | |
| Amoritzation | 1,130 |
| | (1,490,728) |
| Change in non-cash working capital (Note 6) | (660,073) |
| **Net cash from operating activities** | (2,150,801) |
| **Investing Activities** | |
| Acquisition of property, plant and equipment | (7,903) |
| **Net cash used in investing activities** | (7,903) |
| **Financing Activities** | |
| Proceeds from private placement, net of issuance costs (Note 5) | 2,975,742 |
| **Net cash from financing activities** | 2,975,742 |
| Change in cash and cash equivalents | 817,038 |
| Cash and cash equivalents, beginning of period | - |
| **Cash and cash equivalents, end of period** | 817,038 |

*The accompanying notes are an integral part of these consolidated financial statements.*

## 1. Reporting Entity

Argent Energy Trust (the "Trust") is an unincorporated open-ended limited purpose trust established under the laws of the Province of Alberta on January 31, 2012. The Trust was settled by the initial unitholder subscribing for one (1) trust unit of the Trust for $5.00. The unit was repurchased by the Trust on February 3, 2012. The Trust was established to initially indirectly acquire an interest in non-Canadian oil and gas assets through Argent Energy (Canada) Holdings Inc. ("Can Holdco") and Argent Energy (US) Holdings Inc. ("US Opco") (see Note 5).

The registered office address of the Trust is Suite 500, 321 – 6th Ave SW, Calgary, Alberta

Pursuant to the terms of an Administrative Services Agreement, Argent Energy Ltd. (the "Administrator"), a corporation formed under the laws of the Province of Alberta on June 9, 2011, is the Administrator of the Trust and performs all general and administrative services that are or may be required or advisable, from time to time, for the Trust.

The consolidated financial statements have been approved by the directors of Argent Energy Ltd., as administrator of the Trust, on August 1, 2012.

The Trust has no history of earnings or operations prior to January 31, 2012; though on January 31, 2012 it assumed the general and administrative expenses amounting to $966,336 that were incurred prior to establishment by a predecessor trust.

## 2. Basis of Preparation

The consolidated financial statements of the Trust have been prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board, and are presented in Canadian dollars, which is the Trust's functional currency. The consolidated financial statements have been prepared under the historical cost convention, as modified by the revaluation of land and buildings, available-for-sale financial assets, and financial assets and financial liabilities (including derivative instruments) at fair value through profit or loss, if applicable.

The preparation of consolidated financial statements in conformity with IFRS requires the use of certain critical accounting estimates. It also requires management to exercise its judgment in the process of applying the Trust's accounting policies.

## 3. Significant accounting policies

***Cash and cash equivalents***

Cash and cash equivalents are comprised of cash on hand and short term investments with a term of maturity of three months or less.

***Trust Capital***

Trust units will be classified as equity. Incremental costs directly attributable to the issue of trust units are recognized as a deduction from equity, net of any tax effects.

***Deferred Costs***

Deferred costs represent registration and other regulatory fees, underwriting costs and brokerage fees, amounts paid to lawyers, accountants, investment bankers and other professional advisors and fees and commissions paid to agents, brokers and dealers, directly attributable to the issuance of units as part of the Trust's initial public offering (IPO) on the Toronto Stock Exchange. Upon successful completion of the IPO, these costs will be accounted for as a deduction from equity, net of any related income tax benefit. If the IPO does not proceed, these costs will be expensed.

***Property, plant and equipment***

Property, plant and equipment are stated at cost, less accumulated depreciation. The initial cost of an asset comprises its purchase price or construction, being the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

Property, plant and equipment are tested for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. For the purpose of measuring recoverable amounts, assets are grouped at the lowest levels for which there are separately identifiable cash flows (cash-generating units or CGUs). The recoverable amount is the higher of an asset's fair value less costs to sell and value in use (being the present value of the expected future cash flows of the relevant asset or CGU). An impairment loss is recognized for the amount by which the asset's carrying amount exceeds its recoverable amount.

***Depreciation***

Furniture and equipment are depreciated over their estimated remaining lives using the straight line method of depreciation, being over 5 years for furniture and over 3 years for computer equipment.

Gains and losses on disposal of an item of property, plant and equipment are determined by comparing the proceeds from disposal with the carrying amount with any gain or loss recognized in earnings.

***Financial Instruments***

Financial assets and financial liabilities are recognized when the Trust becomes a party to the contractual provisions of the instrument. The Trust derecognizes a financial liability when its contractual obligations are discharged or cancelled or expire.

Financial assets and liabilities are offset and the net amount presented in the statement of financial position when, and only when, the Trust has a legal right to offset the amounts and intends either to settle on a net basis or to realize the asset and settle the liability simultaneously.

Financial assets or liabilities are classified as either financial assets or liabilities at fair value through profit or loss, loans and receivables, available for sale financial assets, or other liabilities as appropriate. When financial instruments are recognized initially, they are measured at fair value plus, in the case of investments not at fair value through profit or loss, transaction costs. The fair value of financial assets and other liabilities is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At June 30, 2012, the fair value of these balances approximated their carrying value due to their short term maturity.

***Financial assets and liabilities at fair value through profit or loss***

A financial asset or liability is classified in this category if acquired principally for the purpose of selling or repurchasing in the short-term.

Financial instruments in this category are recognized initially and subsequently at fair value. Transaction costs are expensed in the statement of comprehensive loss. Gains and losses arising from changes in fair value are presented in the statement of comprehensive loss within other gains and losses in the period in which they arise. The Trust does not currently hold any financial assets or liabilities at fair value through profit or loss.

***Loans and receivables***

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. Loans and receivables are initially recognized at the amount expected to be received, less, when material, a discount to reduce the loans and receivables to fair value. Subsequently, loans and receivables are measured at amortized cost using the effective interest method less a provision for impairment.

The Trust has classified its cash and cash equivalents and other receivables as loans and receivables.

At each reporting date, the Trust assesses whether there is objective evidence that a financial asset is impaired. If such evidence exists, the amount of loss is measured as the difference between the asset's carrying amount and the present value of estimated cash flows discounted at the financial asset's original effective interest rate. The carrying amount of the asset is reduced and the amount of the loss is recognized in the statement of comprehensive loss.

***Financial liabilities at amortized cost***

Financial liabilities at amortized cost include accounts payable and accrued liabilities. Accounts payable and accrued liabilities are initially recognized at the amount required to be paid, less, when material, a discount to reduce the payables to fair value. Subsequently, trade payables are measured at amortized cost using the effective interest method.

***Consolidation***

The financial statements consolidate the accounts of Argent Energy Trust ("Trust") and its subsidiaries. Subsidiaries are those entities which the Trust controls by having the power to govern the financial and operating policies. Subsidiaries are fully consolidated from the date on which control is obtained by Trust and are de-consolidated from the date that control ceases. Intercompany transactions, balances, income and expenses, and profits and losses are eliminated. Changes in the parent company's ownership interest in subsidiaries that do not result in a loss of control are accounted for as equity transactions.

***Per Unit information***

Basic per Unit information is computed by dividing the earnings (loss) by the weighted average number of units outstanding during the reporting period. Diluted earnings per unit are determined by adjusting the profit or loss attributable to unitholders of the Trust and the weighted average number of trust units outstanding for the effects of dilutive instruments.

***Accounting standards issued but not yet adopted***

New standards, amendments and interpretations issued but not effective for the financial year beginning on or after January 1, 2012 and not early adopted.

IFRS 9, *Financial instruments*, addresses the classification, measurement and recognition of financial assets and financial liabilities. IFRS 9 was issued in November 2009 and October 2010. It replaces the parts of IAS 39 that relate to the classification and measurement of financial instruments. IFRS 9 requires financial assets to be classified into two measurement categories: those measured as at fair value and those measured at amortized cost. The determination is made at initial recognition. The classification depends on the entity's business model for managing its financial instruments and the contractual cash flow characteristics of the instrument. For financial liabilities, the standard retains most of the IAS 39 requirements. The main change is that, in cases where the fair value option is taken for financial liabilities, the part of a fair value change due to an entity's own credit risk is recorded in other comprehensive income rather than the income statement, unless this creates an accounting mismatch. The Trust is yet to assess IFRS 9's full impact and intends to adopt IFRS 9 no later than the accounting period beginning on or after January 1, 2013.

IFRS 10, *Consolidated Financial Statements*, replaces the guidance on control and consolidation in IAS 27, *Consolidated and Separate Financial Statements*, and SIC-12, *Consolidation – Special Purpose Entities*. IFRS 10 changes the definition of control under IFRS so that the same criteria are applied to all entities to determine control. The Trust is yet to assess IFRS 10's full impact and intends to adopt IFRS 11 no later than the accounting period beginning on or after January 1, 2013.

IFRS 11, *Joint Arrangements*, replaces IAS 31 *Interests in Joint Ventures*, IFRS 11 reduces the types of joint arrangements to two: joint ventures and joint operations. IFRS 11 requires the use of equity accounting for interests in joint ventures, eliminating the existing policy choice of proportionate consolidation for jointly controlled entities under IAS 31. Entities that participate in joint operations will follow accounting much like that for jointly controlled operations under IAS 31. The Trust is yet to assess IFRS 11's full impact and intends to adopt IFRS 11 no later than the accounting period beginning on or after January 1, 2013.

IFRS 12, *Disclosures of Interests in Other Entities*, sets out the disclosure requirements for entities reporting under IFRS 10 and IFRS 11, and replaces the disclosure requirements currently found in IAS 28, *Investments in Associates*. The Trust is yet to assess IFRS 12's full impact and intends to adopt IFRS 12 no later than the accounting period beginning on or after January 1, 2013.

There are no other IFRS or the IFRS Interpretations Committee (formerly called the IFRIC) interpretations that are not yet effective that would be expected to have a material impact on the Trust.

***Current and Deferred Income Tax***

Income tax expense will comprise current and deferred tax. Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. The effect of any change in income tax rates is recognized in the current period income.

Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

Argent Energy Trust is a taxable entity under the Income Tax Act (Canada) ("Tax Act") and is currently taxable only on income that is not distributed or distributable to the unitholders. The Trust will at no time be a SIFT trust as defined in the Tax Act provided it complies with its investment restrictions. Investment restrictions contained in the formation documents provide that the Trust and its subsidiaries will only invest in entities that qualify as a "portfolio investment entity" and will not hold any "non-portfolio property" or "taxable Canadian property", each as defined in the Tax Act. It also qualifies as a "mutual fund trust" within the meaning of the Tax Act and will not be subject to the limit on non-resident ownership in the Tax Act as it will not own any "taxable Canadian property" as defined in the Tax Act.

As at June 30, 2012, the Trust has a gross amount of losses of $1,491,857 for which income tax benefits have not been recognised.

4. **Property, Plant and Equipment**

| | Computer Equipment | Furniture & Fixtures | Total |
|---|---|---|---|
| | $ | $ | $ |
| **Cost or deemed cost:** | | | |
| Balance at beginning of period | - | - | - |
| Additions | 5,089 | 2,813 | 7,902 |
| **Balance at June 30, 2012** | 5,089 | 2,813 | 7,902 |
| **Depreciation** | | | |
| Balance at beginning of period | - | - | - |
| Depreciation for the period | 848 | 281 | 1,129 |
| **Balance at June 30, 2012** | 848 | 281 | 1,129 |
| Carrying amounts: | | | |
| At establishment | - | - | - |
| **At June 30, 2012** | 4,241 | 2,532 | 6,773 |

5. **Trust Units**

**Authorized**

At June 30, 2012 the Trust was authorized to issue an unlimited number of units.

**Issued**

On establishment of the Trust on January 31, 2012, an initial trust unit was issued for consideration of $5.00. Concurrent with the closing of the Trust's initial private placement on February 3, 2012, as described below, the Trust repurchased the initial trust unit issued for consideration of $5.00. The initial trust unit issued was classified as a liability and recorded at amortized cost.

On February 3, 2012, the Trust completed a private placement of 153,000 units at $5.00 per unit, for gross proceeds of $765,000. On February 13, 2012, the Trust completed a private placement of 220,000 units at $5 per unit, for gross proceeds of $1,100,000. On February 27, 2012 and February 29, 2012, the Trust completed private placements of 217,000 units and 10,000 units respectively, at $5.00 per unit for gross proceeds of $1,135,000.

During the period from establishment to June 30, 2012 the Trust issued a total of 600,000 trust units for gross proceeds of $3,000,000. Issuance costs incurred in relation to the offering were $24,258.

6. **Supplemental cash flow information**

Changes in non-cash working capital from operating activities is comprised of:

| | For the period from January 31, 2012 to June 30, 2012 |
|---|---|
| | $ |
| **Source/(use) of cash** | |
| Other receivables | (156,972) |
| Prepaid expenses | (27,500) |
| Deferred costs | (2,578,055) |
| Accounts payable and accruals | 2,102,454 |
| **Change in non-cash working capital** | (660,073) |
| Related to: | |
| Operating activities | (660,073) |
| Investment activities | - |
| **Change in non-cash working capital** | (660,073) |

No interest or income taxes were paid in the period to June 30, 2012.

**7. Loss per Unit**

Basic loss per unit is calculated as follows:

| | For the period from January 31, 2012 to June 30, 2012 |
|---|---|
| Net loss for the period | $1,491,857 |
| Effect of trust units issued | 537,298 |
| Weighted average number of units – basic | 537,298 |
| Basic and diluted loss per unit | $2.78 |

Diluted loss per unit is equal to basic loss per unit as there are no dilutive instruments outstanding.

**8. Capital Disclosures**

The Trust's objectives when managing capital are to ensure the Trust will have sufficient financial capacity, liquidity, and flexibility to fund the Trust's operations, growth, and proposed acquisition and development of oil and gas assets. The Trust is dependent upon external funding for these activities through a combination of debt and equity.

The Trust's objectives when managing capital are: (i) to maintain a flexible capital structure, which optimizes the cost of capital at acceptable risk; (ii) to maintain sufficient working capital to sustain expected monthly distributions to unitholders; and (iii) to maintain investor, creditor and market confidence in order to sustain the future development of the business. The Trust's unit capital is not subject to external restrictions.

**9. Subsequent Events**

On May 10, 2012, the Trust filed a preliminary prospectus qualifying the distribution of trust units of the Trust in an initial public offering. On June 12, 2012, the Trust filed an amended and restated preliminary prospectus qualifying the distribution of trust units of the Trust in an initial public offering. On July 13, 2012 the Trust filed a second amended and restated preliminary prospectus qualifying the distribution of trust units of the Trust in an initial public offering.

On August 1, 2012, the Trust filed a final prospectus which qualified the distribution of 21,230,000 trust units of the Trust in an initial public offering. Concurrent with the final prospectus, the Trust and its subsidiaries entered into several agreements related to the initial public offering and the purchase of a 100% working interest in certain oil and natural gas assets held by Denali Oil & Gas Partners II, LP and Denali Oil & Gas Partners III, LLC (collectively "Denali"), in South Texas. These related agreements include, but are not limited to, the purchase and sale agreement that was entered into with Denali on May 23, 2012, as amended on June 11, 2012 and July 12, 2012, such purchase and sale being expected to close on August 10, 2012.

## APPENDIX B

## OPERATING STATEMENTS CONTAINING GROSS REVENUES, ROYALTIES AND PRODUCTION TAXES AND OPERATING EXPENSES FOR THE DENALI ASSETS

# INDEPENDENT AUDITOR'S REPORT

**To the Directors of Argent Energy Ltd., as administrator of Argent Energy Trust**

We have audited the accompanying operating statements containing gross revenues, royalties and production taxes and operating expenses of the Denali Assets for the years ended December 31, 2011, 2010 and 2009, and the related notes, which comprise a summary of significant accounting policies and other explanatory information (together the "operating statements").

## Management's responsibility for the operating statements

Management of Argent Energy Ltd., on behalf of Argent Energy Trust, is responsible for the preparation of the operating statements of the Denali Assets as described in Note 1 and for such internal control as management determines is necessary to enable the preparation of the operating statements that are free from material misstatement, whether due to fraud or error.

## Auditor's responsibility

Our responsibility is to express an opinion on the operating statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the operating statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the operating statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the operating statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation of the operating statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the operating statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

## Opinion

In our opinion, the operating statements of the Denali Assets for the years ended December 31, 2011, 2010 and 2009 are prepared in all material respects in accordance with the financial reporting framework as described in Note 1.

## Emphasis of matter

The operating statements of the Denali Assets for the three month periods ended March 31, 2012 and 2011 are unaudited.

(signed) "*PricewaterhouseCoopers LLP*"

**Chartered Accountants**
Calgary, Alberta
August 1, 2012

**Denali Assets**

**Operating Statements containing Gross Revenues, Royalties and Production Taxes and Operating Expenses**

| | Three Months Ended March 31, 2012 US$ (unaudited) | Three Months Ended March 31, 2011 US$ (unaudited) |
|---|---|---|
| Oil, Natural Gas and Natural Gas Liquids Sales | 5,444,808 | 6,897,570 |
| Royalties and Production Taxes | (1,393,887) | (1,664,106) |
| Net Revenues | 4,050,921 | 5,233,464 |
| Operating Expenses | (756,041) | (1,557,870) |
| | 3,294,880 | 3,675,594 |

| | Year Ended December 31, 2011 US$ | Year Ended December 31, 2010 US$ | Year Ended December 31, 2009 US$ |
|---|---|---|---|
| Oil, Natural Gas and Natural Gas Liquids Sales | 29,163,580 | 21,063,802 | 8,906,926 |
| Royalties and Production Taxes | (7,323,145) | (5,989,472) | (2,223,908) |
| Net Revenues | 21,840,435 | 15,074,330 | 6,683,018 |
| Operating Expenses | (5,386,952) | (2,933,882) | (2,272,075) |
| | 16,453,483 | 12,140,448 | 4,410,943 |

*The accompanying notes are an integral part of these operating statements.*

# Denali Assets

## Notes to Operating Statements containing Gross Revenues, Royalties and Production Taxes and Operating Expenses For the years ended December 31, 2011, 2010 and 2009 and the three months ended March 31, 2012 and 2011.

### 1. Basis of Presentation

The Operating Statements containing Gross Revenues, Royalties and Production Taxes and Operating Expenses (the "Operating Statements") include the operating results relating to the operations of certain oil and gas properties (the "Denali Assets") to be acquired by Argent Energy (US) Holdings Inc. ("US Opco"), an indirect wholly-owned subsidiary of Argent Energy Trust, pursuant to the Purchase and Sale Agreement between US Opco and Denali Oil & Gas Partners II, LP ("Denali II") and Denali Oil & Gas Partners III, LLC ("Denali III"), dated May 23, 2012, as amended on June 11, 2012 and July 12, 2012.

The line items in the Operating Statements have been prepared in all respects using accounting policies that are permitted by International Financial Reporting Standards applicable to publicly accountable enterprises, with such accounting policies applying to those line items as if such line items were presented as part of a complete set of financial statements. The line items comprising the Operating Statements are presented in accordance with a reporting framework prescribed by securities regulatory authorities that requires the presentation of a schedule of gross revenues, royalties and production taxes and operating expenses.

Accordingly, the Operating Statements include the following line items: oil and natural gas liquid sales, royalties and production taxes, and operating expenses related to the Denali Assets and do not include any provision for depletion and depreciation, asset retirement obligations, capital costs, impairment of properties, general and administrative expense or income taxes (including Texas franchise taxes) as these amounts are based on the consolidated operations of Denali II and Denali III of which the Denali Assets to be acquired form only a part.

### 2. Summary of Significant Accounting Policies

***Revenue Recognition***

Revenue associated with sales of crude oil, natural gas and natural gas liquids is recognized upon transfer of title, which is when the risk of ownership passes to the purchaser and physical delivery occurs.

***Royalties and Production Taxes***

Royalties in the United States are paid, pursuant to a lease agreement, to the owners of the mineral rights which can include private citizens, state governments or the federal government. Royalties can also be granted out of the lessee's interest in the lease (often referred to as an overriding royalty). Royalty obligations are recorded at the time the production is sold and are calculated in accordance with the applicable lease agreements.

Production taxes in the U.S. are recorded at the time transfer of title occurs. Production taxes are calculated in accordance with the applicable regulations and are paid to the state government on mineral production based on the value and/or quantity of production. Under certain circumstances, reduced tax rates or exemptions from production taxes are granted by a state government after production commences, whereby credits are granted for previously paid taxes. These tax credits are recorded at the time they are approved by the state government. Net production taxes incurred were US $629,374 and US $384,389 in the years ended December 31, 2011 and 2010, respectively, and a net credit of US $319,984 in the year ended December 31, 2009, and net production taxes incurred were US $164,851 (unaudited) and US $32,480 (unaudited) for the three months ended March 31, 2012 and 2011, respectively.

***Operating Expenses***

Operating expenses include amounts incurred on extraction of the product to the surface, transporting, field storage, operating and maintaining wells and related equipment and facilities. Operating expenses relating to equipment, facilities and material furnished by the operator are recorded at cost. Operating expenses also include field labour, insurance, maintenance, repairs, property taxes, utilities, supplies and allocated overhead on certain wells in accordance with the joint operating agreement.

***Joint interest operations***

The Operating Statements only reflect the proportionate interest acquired by US Opco for those properties operated through joint interest operations.

## APPENDIX C

## FORM 51-101F2 REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

To the Board of Directors of Argent Energy Ltd. (the “Administrator”), as administrator of Argent Energy Trust (the “Trust”):

1. We have evaluated the reserves data of the proposed acquisition by the Trust of certain petroleum and natural gas reserves of Denali Oil & Gas Partners II, LP and Denali Oil & Gas Partners III, LLC (hereinafter collectively referred to as “Denali Oil & Gas Partners, LLC”) as at December 31, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenue in US dollars as at December 31, 2011, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the management of the Administrator (“Management”). Our responsibility is to express an opinion on the reserves data based on our evaluation.

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

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

4. The following table sets forth the estimated future net revenue in US dollars (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 Trust’s proposed acquisition of certain petroleum and natural gas reserves evaluated by us as of December 31, 2011, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on Management and the board of directors of the Admistrator:

| | | | Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate) US Dollars | | | |
|---|---|---|---|---|---|---|
| **Independent Qualified Reserves Evaluator or Auditor** | **Description and Preparation Date of Evaluation Report** | **Location of Reserves (Country)** | **Audited (M$US)** | **Evaluated (M$US)** | **Reviewed (M$US)** | **Total (M$US)** |
| Sproule . . . . . . . . . . . . . . . | Evaluation of Select P&NG Reserves of Denali Oil & Gas Partners, LLC for Argent Energy Trust As of December 31, 2011 (US dollars), prepared January to April 2012 | United States | | | | |
| **Total** . . . . . . . . . . . . . . . . . | | | **Nil** | **182,888** | **Nil** | **182,888** |

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

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

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

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
April 27, 2012

*"Robert R. Warholm"*

Robert R. Warholm, P.Eng.
Manager, Engineering and Partner

*"Attila A. Szabo"*

Attila A. Szabo, P.Eng.
Senior Petroleum Engineer and Partner

*"Matthew J. Tymchuk"*

Matthew J. Tymchuk, P.Eng.
Petroleum Engineer

*"Ian K. Kirkland"*

Ian K. Kirkland, P.Geol.
Senior Petroleum Geologist and Associate

*"Victor Verkhogliad"*

Victor Verkhogliad, P.Geol.
Senior Petroleum Geologist

*"Tony K. Wong"*

Tony K. Wong, P.Geol.
Senior Petroleum Geologist and Partner

*"Alec Kovaltchouk"*

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

*"Harry J. Helwerda"*

Harry J. Helwerda, P.Eng., FEC
Executive Vice-President and Director

## APPENDIX D

## FORM 51-101F3 REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND NATURAL GAS DISCLOSURE

Management of Argent Energy Ltd., as administrator (the "Administrator") of Argent Energy Trust (the "Trust"), is responsible for the preparation and disclosure of information with respect to the Trust's oil and gas activities in accordance with securities regulatory requirements. This information is made up solely of the reserves data in respect to the Trust's proposed acquisition, through Argent Energy (US) Holdings Inc., to acquire the Denali Assets, as defined and further described in the accompanying prospectus, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the reserves data in respect to the Trust's proposed acquisition of the Denali Assets. The report of the independent qualified reserves evaluator is presented on the preceding page. The Reserves & Environment, Health & Safety Committee (the "**Committee**") of the board of directors of the Administrator has:

(a) reviewed the Trust's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservations; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Committee has reviewed the Trust's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Committee has approved:

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

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

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

Dated: May 10, 2012.

(signed) *"Brian Prokop"*
Chief Executive Officer and Director

(signed) *"Sean Bovingdon"*
Chief Financial Officer

(signed) *"Glen Schmidt"*
Director

(signed) "*William Robertson*"
Director

## APPENDIX E

## AUDIT COMMITTEE CHARTER

## Argent Energy Ltd.

## Audit Committee Charter

### General

Argent Energy Ltd. (the "**Corporation**") is the administrator of Argent Energy Trust (the "**Trust**") and as such, the board of directors of the Corporation (the "**Board of Directors**") is responsible for the stewardship of the affairs of the Trust and the Trust's direct and indirect subsidiary entities (together with the Corporation and the Trust, the "**Argent Group**"), for the benefit of the unitholders of the Trust (the "**Unitholders**"). The Board of Directors has established an Audit Committee (the "**Committee**") the primary role of which is to assist the Board of Directors in fulfilling its oversight responsibilities regarding the following matters:

1. the integrity, accuracy and completeness of the Trust's consolidated financial statements and related management discussion and analysis ("**MD&A**");
2. the design and implementation of an effective system of internal financial controls and disclosure controls and procedures of the Argent Group;
3. the selection (subject to approval by the Unitholders), engagement and monitoring of the activities of the Trust's external auditor;
4. the Argent Group's risk management strategy;
5. the Argent Group's compliance with legal, statutory and regulatory requirements as they relate to financial statements and taxation matters; and
6. any additional duties set out in this Charter or otherwise delegated to the Committee by the Board of Directors.

While the Committee has the responsibilities and powers set forth in this Charter, the role of the Committee is oversight. It is not the duty of the Committee to plan or conduct audits or to determine that the Trust's consolidated financial statements are complete and accurate and are in accordance with Canadian generally accepted accounting principles applicable to publicly accountable enterprises being International Financial Reporting Standards as adopted by the Canadian Accounting Standards Board ("**IFRS**"). These are the responsibility of senior financial management of the Corporation (the "**Management**") on behalf of the Trust and it is the responsibility of the Trust's external auditor to express an opinion on the Trust's consolidated financial statements based on their audit.

### Composition and Operation

The Board of Directors will in each year appoint a minimum of three (3) directors ("**Directors**") as members of the Committee. All members of the Committee shall be "independent" Directors as such term is defined in Sections 1.4 and 1.5 of National Instrument 52-110 – *Audit Committees*, such that each member of the Committee shall have no direct or indirect material relationship with the Argent Group that could, in the view of the Board of Directors, be reasonably expected to interfere with the exercise of his or her independent judgment.

The Board of Directors will in each year appoint a chairman of the Committee (the "**Committee Chair**"). In the Committee Chair's absence, or if the position is vacant, the Committee may select another member as Committee Chair. The Committee Chair will have the right to exercise all powers of the Committee between meetings but will attempt to involve all other members of the Committee as appropriate prior to the exercise of any powers and will, in any event, advise all other members of the Committee of any decisions made or powers exercised.

All members of the Committee shall be financially literate. While the Board of Directors shall determine the definition of and criteria for financial literacy, this shall, at a minimum, include the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Trust's financial statements.

Directors who are not members of the Committee may attend all or any part of meetings of the Committee, but shall not be entitled to vote on any questions before the Committee. Other than members of the Board of Directors, entitlement to attend all or any portion of any Committee meeting shall be determined by the Committee Chair or by the members of the Committee.

## Mandate

The Committee's duties and responsibilities include, but are not limited to, the following matters:

### *Financial Reporting and Disclosure*

In connection with the financial reporting and disclosure obligations of the Trust, the Committee will:

1. review the audited consolidated annual financial statements of the Trust as prepared by Management in conjunction with the external auditors, the related MD&A and the associated press releases for submission to the Board of Directors for approval;
2. review the unaudited consolidated quarterly financial statements of the Trust as prepared by Management, the related MD&A and the associated press releases for submission to the Board of Directors for approval;
3. review with Management and the external auditor, significant accounting practices employed by the Argent Group and disclosure issues, including complex or unusual transactions, judgement-related areas such as the financial implications of reserves or estimates, and significant changes to accounting principles, with a view to gaining reasonable assurance that the accounting policies and critical accounting estimates are appropriate and that the financial statements are accurate within reasonable levels of materiality, are complete, do not contain any misrepresentations and present fairly the Trust's financial position and results of operations in accordance with IFRS;
4. review and assess any new or proposed developments in accounting and reporting standards that may affect or have an impact on the Trust;
5. confirm through discussions with Management and the external auditor that Canadian IFRS and all applicable laws or regulations related to financial reporting and disclosure have been complied with;
6. review any unresolved significant issues between Management and the external auditor that could affect the financial reporting or internal controls of the Argent Group;
7. review any actual or anticipated litigation or other events, including tax assessments, which could have a material current or future effect on the Trust's consolidated financial statements, and the disclosure of such in the financial statements;
8. discuss with Management the effect of any off-balance sheet transactions, arrangements, obligations and other relationships with unconsolidated entities or other persons that may have a material current or future effect on the Trust's financial condition, changes in financial condition, results of operations, liquidity, capital expenditures, capital resources, or significant components of revenues and expenses;
9. review and discuss with the Chief Executive Officer and Chief Financial Officer of the Corporation the procedures undertaken in connection with the Chief Executive Officer and Chief Financial Officer certifications for the annual and/or quarterly filings with applicable securities regulatory authorities;
10. review disclosures made by the Chief Executive Officer and Chief Financial Officer to the Corporation during their certification process for annual and/or quarterly financial statements with applicable securities regulatory authorities about any significant deficiencies in the design or operation of internal controls which adversely affect the Argent Group's ability to record, process, summarize and report financial data or any material weaknesses in the internal controls, and any fraud involving management or other employees of the Argent Group or the Corporation who have a significant role in the Argent Group's internal controls; and
11. review or satisfy itself that adequate procedures are in place for the review of the Trust's public disclosure of financial information extracted from the Trust's financial statements and periodically assess the adequacy of those procedures.

### *Oversight of Internal Controls*

The Committee will:

1. monitor the quality and integrity of the Argent Group's system of internal controls, disclosure controls and management information systems through discussions with Management and the external auditor;
2. oversee the system of internal controls by:
   (a) consulting with the external auditor regarding the effectiveness of the Argent Group's internal controls;
   (b) monitoring policies and procedures for internal accounting, financial controls and management information, electronic data controls and computer security;
   (c) obtaining from Management adequate assurances that all statutory payments and withholdings have been made; and
   (d) taking other actions as considered necessary;
3. oversee investigations of alleged fraud and illegality relating to the Argent Group's finances and any resulting actions; and
4. establish procedures for the receipt, retention and treatment of complaints received by the Argent Group regarding accounting, internal accounting controls or auditing matters, the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters and for the protection from retaliation of those who report such complaints in good faith.

### *External Auditor Appointment and Removal*

The Committee will:

1. recommend the appointment or replacement of the external auditor to the Board of Directors, who will consider the recommendation prior to submitting the nomination to the Unitholders for their approval;
2. review Management's plans for an orderly transition to a new external auditor, if required;
3. pre-approve, in accordance with applicable law, any non-audit services to be provided to the Trust by the external auditor, with reference to compatibility of the service with the external auditors' independence and, where appropriate, delegate to one or more members of the Committee the authority to grant pre-approvals of non-audit services with the members of the Committee being informed of any such pre-approvals at the next regularly scheduled meeting of the Committee; and
4. review and approve the Argent Group's hiring policies regarding partners, employees and former partners and employees of the present and former external auditor.

### *External Auditor Liaison*

The external auditor will report directly to the Committee and will be accountable to the Committee and the Board of Directors, as representatives of the Unitholders.

In its role as liaison with the external auditor, the Committee will:

1. be directly responsible for overseeing the work of the external auditor engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Trust, including the resolution of any disagreements between Management and the external auditor regarding financial reporting;
2. review all material written communications between the external auditor and the Argent Group, including any post-audit management letter containing the recommendations of the external auditor, Management's response and, subsequently, follow up on identified weaknesses; and
3. meet with the external auditor independently from Management at least annually to discuss and review specific issues and any significant matters that the auditor may wish to bring to the Committee for its consideration.

### *External Auditor Review*

The Committee will:

1. review with Management, and make recommendations to the Board of Directors, regarding the fee related to the audit. In making a recommendation with respect to the fee, the Committee shall consider the number and nature of reports issued by the external auditor, the quality of internal controls, the size, complexity and financial condition of the Argent Group, and the extent of other support provided by the Argent Group and Management to the external auditor;
2. review with Management the terms of the external auditors' engagement, accountability, experience, qualifications and performance;
3. evaluate the performance of the external auditor;
4. review the audit plan and scope of the external audit with the external auditor and Management, and consider the nature and scope of the planned audit procedures prior to the commencement of the audit;
5. discuss with the external auditor any significant changes required in the approach or scope of their audit plan, Management's handling of any proposed adjustments identified by the external auditor, and any actions or inactions by Management that limited or restricted the scope of their work;
6. review, independently from Management, the results of the annual external audit, the audit report thereon and the auditors' review of the related MD&A, and discuss with the external auditor the quality (not just the acceptability) of accounting principles used, any alternative treatments of financial information that have been discussed with Management, the ramifications of their use and the auditors' preferred treatment, and any other material communications with Management;
7. engage the external auditor to review all interim financial statements and review the results of the auditors' review of the interim financial statements and the auditors' review of the related MD&A independently of and without Management present;
8. review any other matters related to the external audit that are to be communicated to the Committee under generally accepted auditing standards or that relate to the external auditor;
9. review with Management and the external auditor any correspondence with regulators or governmental agencies, employee complaints or published reports that raise material issues regarding the Argent Group's financial statements or accounting policies; and
10. at least annually, and before the external auditor issues its report on the annual financial statements, review and confirm the independence of the external auditor through discussions with the auditor on their relationship with the Argent Group, including details of all non-audit services provided. Consider the safeguards implemented by the external auditor to minimize any threats to their independence, and take action to eliminate all factors that might impair, or be perceived to impair, the independence of the external auditor. Consider the number of years the lead audit partner has been assigned to the Corporation, and consider whether it is appropriate to recommend to the Board of Directors a policy of rotating the lead audit partner more frequently than every seven years, as is required under the rules of the Canadian Public Accountability Board.

### *Risk Management*

The Committee will:

1. review and assess the adequacy of the Argent Group's risk management policies and procedures with respect to the Argent Group's principal business risks;
2. review with Management, at least annually, the Argent Group's major risk exposures and the steps taken by Management to monitor and control such exposures;
3. review and monitor the results of Management's commodity price, financial and credit exposure management activities including oil and natural gas, foreign currency and interest rate hedging activities and the use of derivative instruments;

4. review and assess the adequacy of the implementation of appropriate systems to mitigate and manage the risks, and report regularly to the Board of Directors; and
5. review the Argent Group's insurance program.

***Regulatory Compliance***

The Committee will review with Management the Trust's relationship with regulators and the timeliness and accuracy of the Trust's filings with regulatory authorities.

***Related Party Transactions***

The Committee will review with Management all related party transactions and the development of policies and procedures related to those transactions.

***Complaint Procedures***

The Committee will establish and review procedures relating to the receipt, retention and treatment of complaints received by the Argent Group respecting accounting, internal accounting controls or auditing matters and the confidential anonymous submission by employees of concerns regarding questionable accounting or auditing matters.

***Board of Directors Relationship and Reporting***

The Committee will:

1. report regularly to the Board of Directors on Committee activities, issues and related recommendations;
2. oversee appropriate disclosure of the Committee mandate, and other information required to be disclosed by applicable securities laws, in the Trust's annual information form and all other applicable disclosure documents, including any management information circular distributed in connection with the solicitation of proxies from Unitholders; and
3. conduct an annual review and assessment of its performance, including compliance with this Charter and its role, duties and responsibilities, and submit such report to the Board of Directors.

**Administrative Matters**

The following general provisions shall have application to the Committee:

1. A quorum of the Committee shall be the attendance of two (2) members thereof present in person or by telephone or other telecommunication device that permits all persons participating in the meeting to speak and hear each other. No business may be transacted by the Committee except at a meeting of its members at which a quorum of the Committee is present or by a resolution in writing signed by all the members of the Committee.
2. The Board may at any time remove or replace any member of the Committee and may fill any vacancy in the Committee, by resolution of the Board of Directors. If and whenever a vacancy shall exist on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, each member of the Committee shall hold such office until the close of the annual meeting of Unitholders next following the date of appointment as a member of the Committee or until a successor is duly appointed.
3. The Committee may invite such officers, directors and employees of the Argent Group or the Corporation, as it may see fit, from time to time to attend at meetings of the Committee and to assist thereat in the discussion of matters being considered by the Committee. The external auditor is to appear before the Committee when requested to do so by the Committee.
4. The time and place for the Committee meetings, the calling and the procedure at such meetings shall be determined by the Committee having regard to the by-laws of the Corporation.

5. The Committee shall meet a minimum of four (4) times a year.

6. The Committee Chair shall preside at all meetings of the Committee. In the absence of the Committee Chair or in the event of a vacancy in the position of the Committee Chair, the other members of the Committee shall appoint a representative amongst them to act as Committee Chair for that particular meeting.

7. Notice of meetings of the Committee shall be given to the external auditor. The external auditor has the right to appear before and to be heard at any meeting of the Committee. Upon the request of the external auditor, the Committee Chair shall convene a meeting of the Committee to consider any matters which the external auditor believes should be brought to the attention of the Directors or Unitholders.

8. The Committee shall report to the Board of Directors on such matters and questions relating to the financial position of the Argent Group as the Board of Directors may from time to time refer to the Committee.

9. The members of the Committee shall, for the purpose of performing their duties, have the right to inspect all the books and records of the Argent Group, and to discuss such books and records that are in any way related to the financial position of the Trust with the officers and employees of the Argent Group and the external auditor of the Trust.

10. The Committee shall meet, in separate, non-management, *in camera* sessions at each regularly scheduled meeting.

11. Minutes of the Committee meetings shall be recorded and maintained. The Committee Chair will report to the Board of Directors on the activities of the Committee and/or the minutes of the Committee meetings will be promptly circulated to the Directors or otherwise made available at the next meeting of Directors.

12. The external auditors shall report directly to the Committee and the external auditors and internal auditors (if any) shall have a direct line of communication to the Committee through its chair and may bypass management if deemed necessary. The Committee, through its chair, may contact directly any employee in the Corporation as it deems necessary, and any employee may bring before the Committee any matter involving questionable, illegal or improper financial practices or transactions.

**Duties and Reliance**

In exercising their powers and discharging their duties under this charter and applicable law, each member of the Committee must:

1. act honestly and in good faith with a view to the best interests of the Corporation and the Argent Group (on a consolidated basis); and

2. exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.

Each member of the Committee will be entitled to reasonable reliance, or reliance in good faith, on:

1. financial statements of the Trust represented to the member of the Committee by an officer of the Corporation or in a written report of the external auditor of the Argent Group to reflect fairly the financial condition of the Argent Group;

2. the Argent Group's disclosure compliance system and on the Corporation's officers, employees and others whose duties would in the ordinary course have given them knowledge of the relevant facts; and

3. a report, statement or opinion of an expert, being a person or company whose profession gives authority to a statement made in a professional capacity by the person or company including, without limitation, an accountant, actuary, appraiser, auditor, engineer, financial analyst, geologist or lawyer.

In order to carry out its duties, the Committee may retain or appoint, at the Corporation's expense, such independent counsel and other experts and advisors, as it deems necessary and may set and pay the compensation for any counsel or advisor so engaged. The Committee may also request any officer or employee of the Corporation or the Argent Group to attend a meeting of the Committee or to meet with any members of, or consultants or advisors to, the Committee.

**APPENDIX F**

**ADMINISTRATOR BOARD OF DIRECTORS' MANDATE**

**Argent Energy Trust**
**Argent Energy Ltd.**

**Board of Directors' Charter**

## General

Argent Energy Ltd. (the "**Corporation**") is the administrator of Argent Energy Trust (the "**Trust**") and as such, the board of directors of the Corporation (the "**Board of Directors**") is responsible for the stewardship of both the affairs of the Trust and the Trust's direct and indirect subsidiary entities (collectively, the "**Argent Group**"), and the activities of management of the Corporation in the conduct of the day to day business, all for the benefit of the unitholders of the Trust (the "**Unitholders**").

The primary responsibilities of the Board of Directors are to:

- enhance and preserve long term Unitholder value;
- approve the strategy of the Argent Group to ensure the long term success of the Argent Group;
- oversee the business and affairs of the Argent Group in accordance with the terms of all applicable laws; and
- ensure that the Argent Group meets its obligations on an ongoing basis and operates in a reliable and safe manner.

In performing its functions, the Board of Directors shall also consider the legitimate interests of other stakeholders in the Argent Group such as employees, customers and communities.

## Composition and Operation

The Board of Directors will consist of a minimum of three (3) members up to the stipulated maximum number of members as prescribed by the Corporation's articles. No more than one-half of the members of the Board of Directors may be non-residents of Canada. A majority of the Board of Directors shall be "independent" directors as such term is defined in National Instrument 52-110 – *Audit Committees*, such that they shall have no direct or indirect material relationship with the Argent Group or the Corporation that could, in the view of the Board of Directors, be reasonably expected to interfere with the exercise of his or her independent judgment. The Board of Directors will in each year appoint a chairman of the Board of Directors (the "**Chair**") and may, if required or if determined to be appropriate by the Board of Directors, appoint a lead director from among the independent Directors (the "**Lead Director**"). The Board of Directors will analyze the application of the "independent" standard to individual members of the Board of Directors on an annual basis and disclose that analysis.

The Board of Directors operates by delegating certain of its authorities to management and committees and by reserving certain powers to itself. The Board of Directors retains the responsibility of managing its own affairs, including selecting its Chair, nominating candidates for election to the Board of Directors, constituting committees of the full Board of Directors and determining the compensation of directors of the Corporation ("**Directors**"). Subject to the articles and by-laws of the Corporation and all applicable laws, the Board of Directors may constitute, seek the advice of and delegate powers, duties and responsibilities to committees of the Board of Directors.

## Mandate

In addition to the primary responsibilities of the Board of Directors outlined above, the Board of Directors' duties shall include, but not be limited to, the following matters:

***Oversight and Overall Responsibility***

In fulfilling its responsibility for the stewardship of the affairs of the Argent Group, the Board of Directors shall be specifically responsible for:

1. providing leadership and vision in supervising the management of the Argent Group in the best interests of Unitholders;
2. promoting a culture of integrity within the Argent Group and overseeing management in the ethical conduct of business by the Argent Group;
3. overseeing the development of, and approving, the Argent Group's goals and objectives and the strategy for their achievement, including providing oversight and guidance on the strategic issues facing the Argent Group and on the implementation of appropriate business plans to effect the Argent Group's strategy;
4. monitoring the Argent Group's progress towards the execution of its strategy and the attainment of its goals and objectives;
5. approving the audited annual financial statements and the unaudited consolidated interim financial statements and the notes and management's discussion and analysis accompanying such financial statements for the Trust;
6. reviewing the process undertaken with respect to the annual engineering evaluation of the oil and natural gas properties of the Argent Group and approving such annual engineering evaluation in accordance with the requirements of National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities;
7. reviewing and approving material transactions involving the Argent Group including the establishment of the Trust's distribution policy, the payment of distributions, the issuance of securities, acquisitions and dispositions of material assets by the Argent Group and material capital expenditures by the Argent Group;
8. approving the significant policies and procedures by which the Argent Group is operated and monitoring compliance with such policies and procedures;
9. monitoring the activities of management on behalf of the Argent Group, to ensure that the operations of the Argent Group are at all times in compliance with applicable laws and regulations, including applicable environmental laws and legislation;
10. monitoring management's programs and policies for the health and safety of employees in the workplace;
11. requiring that the Argent Group sets high environmental standards in its operations and is in compliance with environmental laws and legislation;
12. monitoring the operation of the Trust's communication policies to ensure that the Trust is able to communicate effectively with Unitholders, other stakeholders and the public generally;
13. approving the timely reporting of any developments that have a significant and material impact on the value of the Argent Group;
14. verifying that the Argent Group, through management, has implemented adequate internal controls and management information systems, monitoring the integrity of such systems and obtaining assurances on a regular basis that the systems are designed and operating effectively; and
15. making regular assessments of the Board of Directors' effectiveness, as well as the effectiveness and contributions of each Board Committee and each Director.

In fulfilling these obligations, the Board of Directors shall:

1. act honestly and in good faith with a view to the best interests of the Argent Group (on a consolidated basis);

2. exercise the care, diligence and skill that responsible, prudent people would exercise in comparable circumstances; and
3. act in accordance with its obligations contained in the Corporation's articles and by-laws, trust indenture, and the administrative services agreement between the Corporation and the Trust, as may be amended, restricted or modified from time to time, and all relevant legislation and regulations.

***Appointment and Monitoring of Senior Management of the Corporation***

The Board of Directors has the responsibility to appoint the Chief Executive Officer and President of the Corporation, to monitor and assess the performance of the Chief Executive Officer and President, to approve the Chief Executive Officer's and President's compensation and to provide advice and counsel in the execution of the Chief Executive Officer's and President's duties.

The Board of Directors also has the responsibility to approve the appointment of all other executive officers of the Corporation.

The Board of Directors also has the responsibility, to the extent feasible, to satisfy itself as to the integrity of the President and the Chief Financial Officer and other corporate officers such that there is a culture of integrity throughout the organization.

***Risk Management***

The Board of Directors has the responsibility to understand the principal risks of the business in which the Argent Group is engaged, to achieve a proper balance between risks incurred and the potential return to Unitholders, and to confirm that there are systems in place which effectively monitor and manage those risks with a view to the long-term viability of the Argent Group.

***Public Disclosure***

The Board of Directors, together with management, has overall responsibility for the Corporation's disclosure obligations. As a result it must:

1. verify that the Argent Group has in place policies and programs to enable the Trust to communicate effectively with Unitholders, other stakeholders and the public generally;
2. verify that the financial performance of the Argent Group is adequately reported to Unitholders, other stakeholders and regulators on a timely and regular basis;
3. verify that the financial results are reported fairly and in accordance with Canadian generally accepted principles for publicly accountable enterprises (being International Financial Reporting Standards, as adopted by the Canadian Accounting Standards Board); and
4. report annually to Unitholders on its stewardship of the affairs of the Argent Group for the preceding year.

***Code of Business Conduct***

The Board of Directors shall be responsible to adopt a "Code of Business Conduct" for the Argent Group which shall address:

1. conflicts of interests;
2. the protection and proper use of the Argent Group's assets and opportunities;
3. the confidentiality of information;
4. fair dealing with the various stakeholders of the Argent Group;
5. compliance with laws, rules and regulations; and
6. the reporting of any illegal or unethical behavior.

The Board of Directors shall oversee compliance with the Argent Group's Code of Business Conduct (or a similar policy) by the Directors and the officers of the Corporation, authorize any waiver granted in connection with this policy, and confirm with management the appropriate disclosure of any such waiver.

***Whistleblower Policy***

The Board of Directors shall be responsible to adopt a Whistleblower Policy for the Argent Group which shall provide the Corporation's employees and consultants with a mechanism by which they can raise concerns regarding accounting or audit matter concerns, grave misconduct or the potential violation of any law relating to fraud, free of any discrimination, retaliation or harassment.

***Other Duties***

The Board of Directors may perform any other activities consistent with this Mandate, the articles and by-laws of the Corporation and any other governing laws as the Board of Directors deems necessary or appropriate including, but not limited to:

1. calling meetings of the Board of Directors at such time and place and providing notice of such meetings to all members of the Board of Directors in accordance with the by-laws of the Corporation;

2. ensuring that Board of Directors meetings are properly attended by Directors;

3. ensuring that a majority of Directors is present in order to transact any business;

4. ensuring that all decision making at Board of Directors meetings is made by a majority of votes, and in the event that decisions are made by written resolution, that such resolution is signed by all of the Directors; and

5. ensuring that the Board of Directors functions independently of management and holds meetings without management or non-independent Directors being in attendance.

## CERTIFICATE OF THE TRUST AND THE PROMOTER

Dated: August 1, 2012

This prospectus constitutes full, true and plain disclosure of all material facts relating to the securities offered by this prospectus as required by the securities legislation of each of the provinces of Canada.

**ARGENT ENERGY TRUST**
By: Argent Energy Ltd., as Administrator of the Trust

By: (signed) "*Brian Prokop*"
Chief Executive Officer

By: (signed) "*Sean Bovingdon*"
Chief Financial Officer

**On Behalf of the Board of Directors of Argent Energy Ltd., the Administrator of Argent Energy Trust**

By: (signed) "*Glen Schmidt*"
Director

By: (signed) "*John Brussa*"
Director

**BY THE PROMOTER**
Aston Hill Financial Inc.

By: (signed) "*Eric Tremblay*"
Chief Executive Officer

By: (signed) "*Larry Titley*"
Chief Financial Officer

By: (signed) "*Catherine Best*"
Director

By: (signed) "*Bruce Calvin*"
Director

## CERTIFICATE OF THE UNDERWRITERS

Dated: August 1, 2012

To the best of our knowledge, information and belief, this prospectus constitutes full, true and plain disclosure of all material facts relating to the securities offered by this prospectus as required by the securities legislation of each of the provinces of Canada.

| **SCOTIA CAPITAL INC.** | **CIBC WORLD MARKETS INC.** | **RBC DOMINION SECURITIES INC.** |
|---|---|---|
| By: (signed) "*Cameron Goldade*" | By: (signed) "*John M. Peltier*" | By: (signed) "*Darrell Law*" |

| **BMO NESBITT BURNS INC.** | **TD SECURITIES INC.** |
|---|---|
| By: (signed) "*Shane Fildes*" | By: (signed) "*Robi Contrada*" |

| **CANACCORD GENUITY CORP.** | **NATIONAL BANK FINANCIAL INC.** |
|---|---|
| By: (signed) "*Karl B. Staddon*" | By: (signed) "*Craig Langpap*" |

| **ACUMEN CAPITAL FINANCE PARTNERS LIMITED** | **ALTACORP CAPITAL INC.** | **CORMARK SECURITIES INC.** |
|---|---|---|
| By: (signed) "*Myja Miller*" | By: (signed) "*Gurdeep Gill*" | By: (signed) "*Dion Degrand*" |

| **DESJARDINS SECURITIES INC.** | **DUNDEE SECURITIES LTD.** | **FIRSTENERGY CAPITAL CORP.** | **GMP SECURITIES L.P.** |
|---|---|---|---|
| By: (signed) "*Alex Shegelman*" | By: (signed) "*Aaron Unger*" | By: (signed) "*Erik B. Bakke*" | By: (signed) "*Dan Tsubouchi*" |

ARGENT
ENERGY TRUST