NAL ENERGY CORPORATION

ANNUAL INFORMATION FORM

For the year ended December 31, 2010

March 31, 2011

NAL ENERGY CORPORATION
ANNUAL INFORMATION FORM
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GLOSSARY OF TERMS AND ABBREVIATIONS

Capitalized terms in this Annual Information Form have the meanings set forth below:

"**1331899**" means 1331899 Alberta ULC, an unlimited liability corporation incorporated under the laws of the Province of Alberta;

"**1380337**" means 1380337 Alberta Ltd., a corporation incorporated under the laws of the Province of Alberta and amalgamated with Spear and Tiberius to form NAL Energy GP;

"**1494705**" means 1494705 Alberta Ltd., a corporation incorporated under the laws of the Province of Alberta and amalgamated with Breaker to form BEL;

"**6.25% Debentures**" means the $115 million original aggregate principal amount of 6.25% convertible unsecured subordinated debentures of the Corporation due 2014;

"**6.75% Debentures**" means the $100 million original aggregate principal amount of 6.75% convertible extendible unsecured subordinated debentures of the Corporation due 2012;

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

"**ACE**" means NAL Petroleum (ACE) Ltd., a corporation formed upon the amalgamation of the predecessor of ACE, NAL GP, NAL Energy and 1331899 pursuant to the Arrangement;

"**Addison**" means Addison Energy Inc., a corporation amalgamated under the laws of the Province of Alberta;

"**Addison LP**" means Addison Energy Limited Partnership, a limited partnership formed under the laws of the Province of Alberta;

"**Administrative Services Agreement**" means the amended and restated administrative services and cost sharing agreement among the Manager, Resources, Manulife and the Corporation effective December 31, 2010;

"**Alberta Clipper**" means Alberta Clipper Energy Inc., a corporation amalgamated under the laws of the Province of Alberta;

"**Arrangement**" has the meaning ascribed thereto under the heading "NAL Energy Corporation – The Arrangement";

"**Banks**" means a syndicate of bank lenders to the Corporation;

"**BEL**" means NAL Petroleum (BEL) Ltd., a corporation formed upon the amalgamation of Breaker and 1494705 under the laws of the Province of Alberta;

"**Board of Directors**" means the board of directors of the Corporation;

"**boe**" means barrels of oil equivalent, determined approximately on the basis that six Mcf of natural gas is equivalent to one barrel of oil. The factor used to convert natural gas to oil equivalent is based upon energy content;

"**Breaker**" means Breaker Energy Ltd., a corporation incorporated under the laws of the Province of Alberta and amalgamated with 1494705 to form BEL;

"**Canadian GAAP**" means Canadian generally accepted accounting principles;

"**CBM**" means coalbed methane;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook;

"**Common Shares**" means the common shares in the capital of the Corporation;

"**Computershare**" means Computershare Trust Company of Canada, in its capacity as the transfer agent and registrar for the Common Shares, the 6.25% Debentures and the 6.75% Debentures;

"**Corporation**" means NAL Energy Corporation, a corporation incorporated under the laws of the Province of Alberta;

"**Debentureholder**s" means the holders, from time to time, of the Debentures;

"**Debentures**" means, collectively, the 6.75% Debentures and the 6.25% Debentures;

"**Debenture Trustee**" means Computershare Trust Company of Canada, in its capacity as trustee for the Debentureholders under the Note Indenture;

"**Debt Service Charges**" means all interest and principal repayments (which are not replaced by further borrowings) relating to borrowing of funds by the Corporation pursuant to the credit facilities made available by the Banks to the Corporation;

"**General and Administrative Expenses**" means costs incurred in the management and administration of the Corporation including, without limitation, (i) all reasonable costs and expenses related to the Corporation and its subsidiaries and paid directly to third parties by or on behalf of any such entity and (ii) all reasonable costs and expenses incurred by the Manager specifically for the Corporation and its subsidiaries, including, without limitation, auditing, accounting, bookkeeping, rent and other leasehold expenses, legal, land administration, engineering, travel, telephone, data processing, reporting, executive and management time and salaries;

"**Independent Director**" means a person who meets the requirements for independence set forth in section 1.4 of National Instrument 52-110 – *Audit Committees*;

"**Manager**" means NAL Resources Management Limited, a corporation incorporated under the laws of Canada;

"**Manulife**" means The Manufacturers Life Insurance Company;

"**McDaniel**" means McDaniel & Associates Consultants Ltd., independent petroleum engineers, Calgary, Alberta;

"**McDaniel Report**" means the report prepared by McDaniel setting forth certain information relating to the oil and natural gas reserves of the Properties of NAL and the present value of the estimated future net revenues associated with such reserves having a preparation date of March 8, 2011 and an effective date of December 31, 2010;

"**NAL Energy**" means NAL Energy Inc., a corporation amalgamated under the laws of the Province of Alberta;

"**NAL Energy GP**" means NAL Energy (General Partner) Inc., a corporation amalgamated under the laws of the Province of Alberta which was formed upon the amalgamation of the predecessor of NAL Energy GP and Addison;

"**NAL Energy LP**" means NAL Energy Limited Partnership, a limited partnership formed under the laws of the Province of Alberta;

"**NAL GP**" means NAL GP Ltd., a corporation formed upon the amalgamation of NAL GP Ltd. and Spearpoint under the laws of the Province of Alberta;

"**NAL Partnership**" means NAL Canada West Partnership, a general partnership formed under the laws of the Province of Alberta;

"**NAL Properties**" means NAL Properties Inc., a corporation incorporated under the laws of the Province of Alberta;

"**NGLs**" means natural gas liquids;

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

"**Note Indenture**" means the amended and restated note indenture dated December 31, 2010, between the Debenture Trustee and the Corporation, governing and setting forth the terms and conditions of the Debentures;

"**Probable Reserves**" means 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. At least 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved plus Probable Reserves is the targeted level of certainty;

"**Properties**" means royalties and the Working Interests held by NAL from time to time in petroleum and natural gas properties;

"**Proved Reserves**" means 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. At least 90% probability that the quantities actually recovered will equal or exceed the estimated Proved Reserves is the targeted level of certainty;

"**Reserves**" or "**reserves**" means estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: (i) analysis of drilling, geological, geophysical and engineering data; (ii) the use of established technology; and (iii) specified economic conditions generally accepted as being reasonable;

"**Resources**" means NAL Resources Limited, a corporation incorporated under the laws of the Province of Alberta;

"**SEDAR**" means the System for Electronic Document Analysis and Retrieval;

"**Shareholders**" means the holders from time to time of one or more Common Shares;

"**Spear**" means Spear Exploration Inc., a corporation incorporated under the laws of the Province of Alberta and which amalgamated with 1380337 and Tiberius to form NAL Energy GP;

"**Spearpoint**" means Spearpoint Energy Corp., a corporation incorporated under the laws of the Province of Alberta and which amalgamated with NAL GP Ltd. to form NAL GP;

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

"**Tiberius**" means Tiberius Exploration Inc., a corporation incorporated under the laws of the Province of Alberta and which amalgamated with 1380337 and Spear to form NAL Energy GP;

"**Trust**" means NAL Oil & Gas Trust;

"**Trust Unit**" means a fractional undivided interest in the Trust;

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

"**Unitholders**" means the holders from time to time of one or more Trust Units;

"**Ventures Trust**" means NAL Ventures Trust; and

"**Working Interest**" means the interest in a lease that carries with it the rights and obligations to develop and operate an oil or natural gas property.

ABBREVIATIONS

bbls	barrels	**Mcf**	thousand cubic feet
bbls/d	barrels per day	**Mcf/d**	thousand cubic feet per day
boe/d	barrels of oil equivalent per day	**MMcf**	million cubic feet
GJ	gigajoules	**MMcf/d**	million cubic feet per day
Mbbl	thousands of barrels	**MMbtu**	millions of British Thermal Units
Mboe	thousands of barrels of oil equivalent	**M$**	thousands of dollars
		MM$	millions of dollars

CONVERSION

In this Annual Information Form, certain measurements may be given in standard imperial or metric units only. The following table sets forth certain standard conversions:

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
barrels	cubic metres	0.159
cubic metres	barrels	6.293
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

Equivalency units such as boes may be misleading, particularly if used in isolation. A boe conversion ratio of six Mcf: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.

NON-CANADIAN GAAP FINANCIAL MEASURES

In addition to using financial measures prescribed by Canadian GAAP, references are made in this Annual Information Form to "netback", which is a measure that does not have any standardized meaning as prescribed by Canadian GAAP. Accordingly, the Corporation's use of such terms may not be comparable to similarly defined measures presented by other entities.

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

FORWARD-LOOKING INFORMATION

This Annual Information Form contains forward-looking information within the meaning of applicable Canadian securities legislation. Forward-looking information is typically identified by words such as "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "could", "plan", "intend", "should", "believe", "outlook", "project", "potential", "target" and similar words suggesting future events or future performance. In addition, statements relating to "reserves" are deemed to be forward-looking information as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities estimated and can be profitably produced in the future.

In particular, this Annual Information Form contains forward-looking information pertaining to the following, without limitation: the performance characteristics of NAL's crude oil and natural gas properties; crude oil and natural gas production levels; the size of, and future net revenues from, NAL's crude oil and natural gas reserves; projections of market prices and costs and the related sensitivity of distributions; supply and demand for crude oil and natural gas; expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development; NAL's future operating and financial results; treatment under governmental regulatory regimes and tax laws; capital expenditure programs; NAL's tax pools; operating costs; the amount of future asset retirement obligations; future liquidity and future financial capacity; future results from operations; payout ratios; cost estimates and royalty rates; drilling plans; tie-in of wells; and future development, exploration and acquisition activities and related expenditures.

With respect to forward-looking statements contained in this Annual Information Form, certain assumptions have been made regarding, among other things: future oil and natural gas prices; future capital expenditure levels; future oil and natural gas production levels; future exchange rates; the amount of future cash dividends; the cost of expanding NAL's property holdings; the ability to obtain equipment in a timely manner to carry out exploration and development activities; the ability to market oil and natural gas successfully to current and new customers; the impact of increasing competition; the ability to obtain financing on acceptable terms; and the ability to add production and reserves through acquisition, development and exploitation activities.

Although the Corporation believes that the expectations reflected in the forward-looking information contained in this Annual Information Form and the assumptions on which such forward-looking information is made, are reasonable, readers are cautioned not to place undue reliance on such forward-looking statements as there can be no assurance that the plans, intentions or expectations upon which the forward-looking information are based will occur. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated and which may cause NAL's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance. These risks and uncertainties include, without limitation: changes in commodity prices; unanticipated operating results or production declines; the impact of weather conditions on seasonal demand and the ability to execute NAL's capital program; risks inherent in oil and gas operations; incorrect assessments of the value of acquisitions and exploration and development programs; geological, technical, drilling and processing problems; the imprecision of reserve estimates; limited, unfavorable or no access to capital or credit markets; the impact of competitors; the lack of availability of qualified operating or management personnel; the inability to obtain industry partner and other third party consents and approvals, when required; failure to realize the anticipated benefits of acquisitions; general economic conditions in Canada, the United States and globally; fluctuations in foreign exchange or interest rates; changes in government regulation of the oil and gas industry, including environmental regulation; changes in royalty rates; changes in tax laws and incentive programs relating to the oil and gas industry; stock market volatility and fluctuations in market valuations; the Organization of the Petroleum Exporting Countries' ability to control production and balance global supply and demand for crude oil at desired price levels; political uncertainty, including the risk of hostilities in the petroleum producing regions of the world; and other risk factors discussed in other public filings of the Corporation, including this Annual Information Form.

The Corporation cautions that the foregoing list of factors that may affect future results is not exhaustive. The forward-looking information contained in this Annual Information Form is made as of the date of this Annual Information Form. The forward-looking information contained in this Annual Information Form is expressly qualified in its entirety by this cautionary statement. The Corporation does not undertake any obligation to publicly update or revise any forward-looking information to reflect new information, subsequent events or otherwise, except as required by applicable securities laws.

NAL ENERGY CORPORATION

The Arrangement

On December 31, 2010, the Trust converted from an income trust structure to a corporate structure (the "**Conversion**") pursuant to a statutory plan of arrangement under the ABCA (the "**Arrangement**") and since such time, the Corporation and its subsidiaries have carried on the business previously carried on by the Trust and its subsidiaries. The Arrangement was approved at the special meeting of the Unitholders held on December 16, 2010, with over 96% of the votes cast by Unitholders being voted in favor of the Arrangement. On December 17, 2010, the Alberta Court of Queen's Bench granted the final order required in connection with the Arrangement. Pursuant to the Arrangement, former Unitholders received one Common Share for each Trust Unit held and the obligations of the Trust for the Debentures were assumed by the Corporation. The Common Shares commenced trading on the TSX on January 6, 2011 under the trading symbol "NAE" and the Trust Units were de-listed.

Unless the context otherwise requires, all references in this Annual Information Form to "NAL" or to the "Corporation" or similar expressions for periods after December 31, 2010 refer to NAL Energy Corporation and, where the context requires, includes NAL Energy Corporation and all of its consolidated subsidiaries and any partnership of which NAL and/or its subsidiaries are the partners and for periods prior to December 31, 2010 refer to the Trust and, where the context requires, includes the Trust and all of its consolidated subsidiaries and any partnerships of which the Trust and/or its subsidiaries were the partners prior to the completion of the Arrangement.

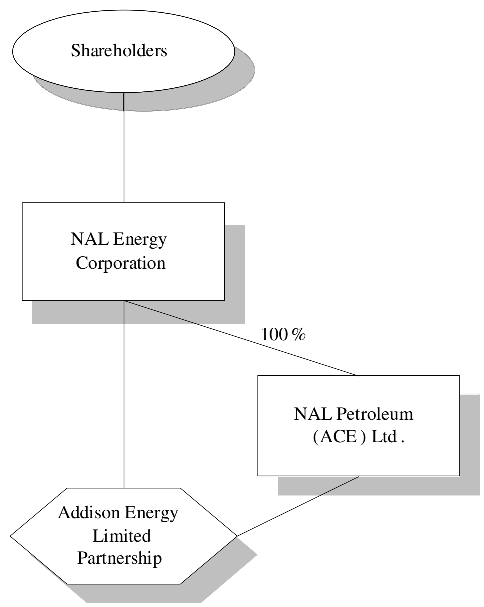
All references to dollar amounts in this Annual Information Form are in Canadian dollars, except where otherwise indicated.

Organization and Structure

NAL Energy Corporation

The Corporation was incorporated under the ABCA on November 1, 2010. The head and registered office of the Corporation is 1000, 550 – 6th Avenue S.W., Calgary, Alberta T2P 0S2.

The following diagram sets forth the organizational structure of the Corporation and its material subsidiaries as of the date hereof:



The following table provides the name, the percentage of voting securities owned or controlled, directly or indirectly, by the Corporation and the jurisdiction of incorporation, continuance, formation or organization of the Corporation's material subsidiaries as of January 1, 2011, the second effective date of the Arrangement:

	Percentage of voting securities owned or controlled by the Corporation (directly or indirectly)	Nature of Entity	Jurisdiction of Incorporation, Continuance, Formation or Organization (as applicable)
NAL Petroleum (ACE) Ltd.	100% (Directly)	Corporation	Alberta
Addison Energy Limited Partnership	100% (Directly and Indirectly)	Limited Partnership	Alberta

NAL Resources Management Limited

The Manager was incorporated under the *Canada Business Corporations Act* to manage oil and natural gas investments for major Canadian financial institutions. The Manager is engaged under the Administrative Services Agreement to manage the general and administrative affairs of NAL, to advise NAL with respect to the acquisition, development and disposition of oil and natural gas properties and to manage the Properties. See "NAL Resources Management Limited – Compensation". The Manager is a wholly owned subsidiary of Manulife. The head and registered office of the Manager is 1000, 550 – 6th Avenue S.W., Calgary, Alberta, T2P 0S2.

GENERAL DEVELOPMENT OF THE BUSINESS

NAL, a participant in the Canadian upstream oil and gas industry, engages in the acquisition, development, production and sale of crude oil, natural gas and natural gas liquids from pools located in its core areas of southeastern Saskatchewan, central Alberta, northeastern British Columbia and Lake Erie, Ontario.

Recent Developments

2010

Trust Unit Financing

On April 14, 2010, the Trust announced the closing of a public offering of 7,550,000 Trust Units at a price of $13.25 per Trust Unit, for aggregate gross proceeds of $100,037,500. The proceeds from the offering were used to repay indebtedness incurred in connection with certain acquisitions, to fund the Trust's expanded 2010 capital program and for general corporate purposes.

Internal Reorganization

On November 1, 2010, NAL Energy GP amalgamated with Addison to form NAL Energy GP.

Conversion into a Corporation

On December 31, 2010 and January 1, 2011, the Trust completed the Conversion. The Conversion was completed pursuant to the Arrangement and ultimately resulted in the Unitholders receiving one Common Share for each Trust Unit held. The Board of Directors and executive officers of the Corporation are comprised of the former members of the board of directors and executive officers of NAL Energy and the Manager continues to be the manager of the Corporation under the Administrative Services Agreement. Pursuant to or in connection with the Arrangement, the Trust, Ventures Trust, NAL Energy LP and NAL Partnership were wound-up and dissolved and NAL GP, ACE, 1331899 and NAL Energy were amalgamated to form ACE.

New Credit Facility

In connection with the Conversion, the credit facility was amended and restated to remove Ventures Trust and NAL Properties, as joint and several borrowers, and add the Corporation as the borrower. See "Borrowings – Credit Facilities".

2009

Reinstatement of Reinvestment Program

On March 11, 2009, the Trust announced that the reinvestment of distributions pursuant to the Trust's Premium Distribution™, Distribution Reinvestment and Optional Trust Unit Purchase Plan (the "**Trust DRIP**") would be reinstated effective with the March 2009 distribution payable on April 15, 2009.

Trust Unit Financing

On May 28, 2009, the Trust completed a public offering of 9,602,500 Trust Units at a price of $9.00 per Trust Unit for total gross proceeds of $86.4 million. The proceeds from the offering were added to the working capital of the Trust and used for general corporate purposes.

Acquisition of Alberta Clipper and Internal Reorganization

On June 1, 2009, the Trust completed its indirect acquisition of all of the issued and outstanding shares of Alberta Clipper for consideration of $36.6 million, before acquisition costs, consisting of the issuance of approximately 5.7 million Trust Units. The purchase also included the assumption of $78.9 million of Alberta Clipper bank debt resulting in a total purchase price of $115.5 million. The acquisition was completed by way of plan of arrangement under the ABCA. Upon completion of the plan of arrangement, Alberta Clipper changed its name to NAL Petroleum (ACE) Ltd. and divested a 50% working interest in substantially all of its oil and gas assets to Manulife for cash consideration of $54.3 million after closing adjustments.

On June 1, 2009, Alberta Clipper acquired a 99.9% partnership interest in NAL Partnership from Ventures Trust.

Acquisition of Spearpoint

On August 10, 2009, the Trust completed its indirect acquisition of all of the issued and outstanding shares of Spearpoint for total cash consideration of $10.6 million, before acquisition costs. Upon completion of the acquisition, Spearpoint divested a 40% working interest in substantially all of the oil and gas assets to Manulife for cash consideration of $6.8 million and transferred the remaining 60% working interest along with working capital to Addison LP for a partnership interest in Addison LP.

On December 1, 2009, Spearpoint amalgamated with NAL GP Ltd. and the amalgamated company continued as NAL GP Ltd.

Convertible Debenture Financing

On December 3, 2009, the Trust completed a public offering of $115 million principal amount of 6.25% Debentures. The proceeds from the offering were used to repay outstanding bank indebtedness. See "Borrowings".

Acquisition of Breaker

On December 11, 2009, the Trust completed its indirect acquisition, through 1494705, of all of the issued and outstanding shares of Breaker for total consideration, before acquisition costs, of $308.5 million consisting of the issuance of approximately 24.8 million Trust Units. The acquisition also included the assumption of $94.5 million of Breaker bank debt. The acquisition was completed by way of plan of arrangement under section 193 of the ABCA. Upon the completion of the plan of arrangement, 1494705 and Breaker amalgamated to form BEL.

On December 31, 2009, Alberta Clipper and BEL were amalgamated to form ACE.

Further particulars in respect of the acquisition of Breaker are contained in the business acquisition report on Form 51-102F4 of the Trust dated January 21, 2010 (the "**Breaker Business Acquisition Report**"). The Breaker Business Acquisition Report may be accessed on SEDAR at www.sedar.com.

2008

Increase to Borrowing Amount under the Trust's Credit Facilities

During the second quarter of 2008, NAL's banking group was expanded by the addition of two new banks and the borrowing amount under the Trust's credit facilities was increased from $400 million to $450 million. See "Borrowings".

Acquisition of Spear and Tiberius

On February 27, 2008, the Trust completed its indirect acquisition, through 1380337, of all of the issued and outstanding shares of Spear and Tiberius for total consideration of $115.6 million, before acquisition costs, consisting of the issuance of approximately 2.4 million Trust Units and the payment of $86.12 million in cash. The acquisition was completed by way of plan of arrangement under section 193 of the ABCA. Upon completion of the plan of arrangement, 1380337, Spear and Tiberius were amalgamated to form NAL Energy GP.

On February 29, 2008, the petroleum and natural gas assets of NAL Energy GP were contributed to NAL Energy LP. At such time, NAL Energy LP was owned as to a 50% interest by each of NAL Energy GP and Manulife Property Limited Partnership ("**MPLP**"), a subsidiary entity of Manulife. MPLP acquired its 50% interest in NAL Energy LP by payment of one-half of the purchase price for Spear and Tiberius. Consequently, the total acquisition cost to the Trust of its 50% interest in the acquired properties was $57.8 million, before acquisition costs, comprised of the issuance of approximately 2.4 million Trust Units and the payment of $28.31 million in cash.

On March 1, 2008 NAL Energy LP granted a 49.5% net profits interest royalty to MPLP and a 49.5% net profits interest royalty to NAL Energy GP.

NAL Energy LP owned and operated interests in 5.25 sections of land in southeast Saskatchewan, adjacent to the Trust's Alida properties, the Trust's largest core area.

Internal Reorganization

On June 1, 2008, NAL Energy GP transferred its 49.5% net profits interest royalty on the assets of NAL Energy LP to NAL Energy in exchange for one preferred share of NAL Energy.

Suspension of Distribution Reinvestment Program

On October 9, 2008, the Trust suspended the Trust DRIP due to the then prevailing market conditions and the strength of the Trust's balance sheet. The Trust DRIP provided Unitholders the option to elect to reinvest distributions or make optional cash payments to acquire Trust Units from treasury at 95% of the average market price with no additional fees or commissions.

Business Strategy

The Manager's objective is to maximize cash flow consistent with the long-term growth and sustainability of the Corporation. In pursuing this objective, the Manager employs prudent oil and natural gas business and operating practices.

When considering the acquisition of oil and natural gas producing properties for NAL, the Manager focuses on properties that can either be operated by the Manager, or other acceptable operators, and that have a potential to increase cash flow and enhance the Corporation's value through exploitation. The Manager retains independent consultants to review the environmental history, facility design and physical integrity of significant properties considered by NAL before they are acquired.

Future capital expenditures are required to be made on an ongoing basis to sustain the production and cash flow of the Corporation and to increase recoveries from existing Properties.

The Manager regularly monitors the performance of the Properties. Where the Manager is not the operator of a Property, the Manager monitors the operator's activities on an ongoing basis and provides input to the operator where appropriate. The Manager may recommend the sale of Properties by NAL in the event certain Properties are assessed as being unable to contribute to the maximization of the long-term value of the Corporation or the Manager otherwise determines that the sale of certain Properties is in the best interest of the Shareholders. The Manager will use reasonable efforts to acquire replacement properties within the same calendar year in which the sale of any Properties is completed.

The Manager's activities are conducted in accordance with applicable laws with a view to the best interests of NAL.

PRINCIPAL PROPERTIES

Summary of Properties

The portfolio of Properties held by NAL as at December 31, 2010 include primarily long life, unitized and non-unitized oil and natural gas properties. All of NAL's properties are located in Canada, within the provinces of Alberta, Saskatchewan, British Columbia and Ontario. Over 95% of the Proved plus Probable Reserves of NAL are in the 23 principal areas described below. Unless otherwise stated, references to reserve volumes or production figures from the Properties are based on: (i) NAL's net Working Interest therein before deduction of applicable royalties; (ii) the total Proved plus Probable Reserves estimated in the McDaniel Report; and (iii) forecast price assumptions. **The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties due to the effects of aggregation.**

Garrington/Westward Ho/Cochrane, Alberta

This major producing area is located in central Alberta and consists of various oil and gas assets, including non-unit wells, operated units and non-operated units producing from the Edmonton, Cardium, Viking, Glauconitic, Ostracod and Elkton formations. This area was expanded in 2009 with the acquisition of additional properties and farm-in opportunities near Cochrane/Lochend. The Manager operates the majority of its production from all properties in this area, along with several oil batteries and compressor stations, with most of the gas being processed for sale at gas plants owned and operated by others.

Production from this area averaged 4,921 boe/d for 2010 as compared to 4,547 boe/d for 2009. Proved plus Probable Reserves in the McDaniel Report totaled 24,541 Mboe. This will be one of the most active areas for NAL in 2011, with approximately $77 million anticipated to be spent primarily on horizontal development drilling in the Cardium formation.

Sylvan Lake/Medicine River/Willesden Green, Alberta

In December 2010, the NAL group's acquisition of Enerplus assets supplemented its existing assets in the Sylvan Lake/Medicine River area. These assets include oil and gas wells producing from various formations, of Cretaceous, Jurassic, Mississippian and Devonian age, on unitized and non-unitized lands and at depths of 1,500 to 10,000 feet.

Production from this area is split between high quality crude oil and sweet natural gas. Over two-thirds of the production is operated by the Manager. Operating costs are relatively low because of the NAL group's ownership and control of infrastructure in the area, which includes three major gas plants and numerous compressors and batteries. Most of the NAL group's gas production in this area is processed at the Sylvan Lake Gas Plant, operated by the Manager. It is anticipated that NAL will spend approximately $8 million in this area in 2011, primarily on Pekisko, Mannville and Cardium development drilling.

Production from this area averaged 2,579 boe/d during 2010 as compared with 2,600 boe/d during 2009. Proved plus Probable Reserves in the McDaniel Report totaled 10,167 Mboe.

Drumheller, Alberta

The Drumheller area is located in southern Alberta east of the town of Drumheller. The area includes approximately 175 wells which produce primarily shallow sweet gas. Sweet oil is also produced from two oil pools in the area. Most of the gas in this area is processed in infrastructure that is operated by other producers. NAL plans to spend approximately $3 million drilling one horizontal well in the Banff formation in 2011.

Production from this area averaged 1,269 boe/d in 2010 as compared to 1,489 boe/d in 2009. Proved plus Probable Reserves in the McDaniel Report totaled 3,406 Mboe.

Brent/Hanna, Alberta

The Brent/Hanna area is located in southern Alberta near the town of Hanna. The Brent property includes approximately 235 wells which produce primarily shallow sweet gas and are processed through the 100% managed Brent Gas Plant. The Hanna property includes approximately 155 wells which produce primarily shallow sweet gas and are processed through the 100% managed Hanna Gas Plant. NAL plans to spend approximately $2 million to drill one oil well and one gas well in the Glauconitic formation in 2011.

Production from this area averaged 1,203 boe/d in 2010 as compared to 1,303 boe/d in 2009. Proved plus Probable Reserves in the McDaniel Report totaled 3,287 Mboe.

Pine Creek, Alberta

The Pine Creek area is located west of the city of Edmonton and northwest of the town of Edson. The majority of this property is operated by the Manager, and consists primarily of legacy assets acquired in the purchase of Addison in February 2005, along with significant access to undeveloped acreage acquired in the 2009 Spearpoint acquisition. This area also includes the Kakwa property acquired in 2009 as part of the Alberta Clipper acquisition.

This property historically produced a combination of oil and gas mainly from vertical wells in the Cardium sandstone. More recently, utilization of horizontal wells and multi-stage completion techniques have been employed to exploit the Cardium formation. Production in the Pine Creek area also originates from several other formations including the Cadomin, Gething, Bluesky, Wilrich, Notikewan, and Second White Specks. Several of these formations are emerging as candidates for horizontal drilling and multi-stage completion techniques.

NAL plans to invest approximately $19 million in Pine Creek in 2011, with the majority of the expenditure targeting horizontal wells in emerging gas resource plays.

Production from this area averaged 2,122 boe/d in 2010 as compared to 1,495 boe/d in 2009. Proved plus Probable Reserves in the McDaniel Report totaled 9,444 Mboe.

Lacombe/Nevis/Clive, Alberta

The Lacombe/Nevis/Clive area is located northeast of the city of Red Deer in central Alberta. The area includes approximately 140 wells which produce primarily shallow sweet gas from the Horseshoe Canyon CBM and Belly River zones. Most of the gas in this area is processed in infrastructure that is operated by other producers. NAL will be spending limited capital in this area in 2011.

Production from this area averaged 506 boe/d in 2010 as compared to 604 boe/d in 2009. Proved plus Probable Reserves in the McDaniel Report totaled 1,917 Mboe.

Joffre D-2 Unit, Alberta

ACE owns a 45.7% Working Interest in the Joffre D-2 Unit (the "**Joffre Unit**") which is located immediately northeast of Red Deer. The Manager is the operator of the Joffre Unit.

The Joffre Unit produces oil and sour gas from the Joffre Nisku D-2 pool, which was discovered at a depth of 7,000 feet in 1956 and was fully developed by 1960. The Joffre Unit, which covers 32 square miles, was formed in 1969 to implement a line drive waterflood scheme for pressure maintenance. NAL's interests in the Joffre Unit and surrounding wells have been sold subsequent to this reporting period, effective February 1, 2011.

Production from the Joffre Unit averaged 239 boe/d in 2010 as compared to 280 boe/d in 2009. Proved plus Probable Reserves in the McDaniel Report totaled 1,433 Mboe.

Irricana, Alberta

The Irricana property is located approximately 40 kilometres northeast of the city of Calgary and was acquired as part of the Breaker acquisition. The property includes approximately 80 wells and produces primarily sour oil and gas from the Wabamun formation. The facilities include an operated oil battery and compressor station, along with interests in two non-operated gas plants. The Manager operates over 95% of its production in the property. NAL plans to invest approximately $17 million on three horizontal drills in the Irricana Wabamun and two horizontal drills in the Crossfield Cardium in 2011.

Production from this area averaged 2,229 boe/d in 2010. Proved plus Probable Reserves in the McDaniel Report totaled 8,158 Mboe.

Provost*, *Alberta

The Provost area is located in south-east Alberta near the town of Provost and was acquired as part of the Breaker acquisition. The Manager operates essentially 100% of its production in the area, along with a 7 MMcf per day gas plant. The area includes approximately 100 wells and produces primarily oil from the Sparky formation and sweet gas from the Viking formation. NAL will be spending limited capital in this area in 2011.

Production from this area averaged 487 boe/d in 2010. Proved plus Probable Reserves in the McDaniel Report totaled 1,145 Mboe.

Millard Lake*, *Alberta

The Millard Lake property is located in east-central Alberta near the town of Wainwright and was acquired as part of the Breaker acquisition. The property includes approximately 25 wells and produces 17 degree API oil (reported as heavy oil in the McDaniel Report) from the Leduc formation. The Manager operates 100% of the property, including the oil battery at 1-24-45-4 W4M. NAL plans to invest approximately $4 million on four horizontal drills in the Leduc formation in 2011.

Production from this area averaged 352 boe/d in 2010. Proved plus Probable Reserves in the McDaniel Report totaled 1,402 Mboe.

East Prairie, Alberta

The East Prairie area is located southeast of the town of High Prairie. This property is operated by the Manager, and consists of assets acquired as part of the Breaker acquisition. The property is centered primarily on the East Prairie Métis Settlement ("**EPMS**"). ACE has a 100% operated Working Interest in the undeveloped lands while the Métis Settlement General Council and the EPMS collectively have a right to participate for a 25% Working Interest in proposed activity.

This property produces primarily natural gas and light oil from the Viking formation. A waterflood has been initiated on the Viking oil pool, and significant oil recovery upside exists with this waterflood. NAL plans to invest approximately $2 million in East Prairie in 2011 to optimize the waterflood and production handling capability in the Viking oil pool.

Production from this area averaged 620 boe/d in 2010. Proved plus Probable Reserves in the McDaniel Report totaled 1,152 Mboe.

Steelman, Saskatchewan

The Steelman properties are located approximately 18 miles northeast of city of Estevan in southeast Saskatchewan. The main oil production comes from Steelman Unit Nos. 2 and 3, in which Addison LP holds a 34.2% and 33.9% Working Interest, respectively. The Manager operates these units. Addison LP also owns a minor Working Interest in Steelman Unit No. 4, which is operated by Canadian Natural Resources Limited. In addition to the unitized production, Addison LP has Working Interests in producing non-unit wells in the area. The majority of the production is from the Midale and Frobisher formations, with minor production coming from older Birdbear, Winnipegosis, Silurian and Red River formations. For 2011, NAL plans to invest $6 million in the drilling of nine gross wells targeting the Midale and Frobisher formations.

Production from this area averaged 1,105 boe/d in 2010 as compared to 1,257 boe/d in 2009. Proved plus Probable Reserves in the McDaniel Report totaled 4,134 Mboe.

Alida Area (including the Alida Unit), Saskatchewan

With the acquisition of additional minor interests in May 2010, ACE and Addison LP own a combined 47.60% Working Interest share in the Alida Unit, which is located just north of the town of Alida in southeast Saskatchewan. The Manager has been the operator of the Alida Unit since 1990. Production is from the Mississippian Mission Canyon Group at an average depth of 3,550 feet. The Alida pool (unit and non-unit) was discovered in the mid-1950s and is geologically complex with numerous vertical and lateral discontinuities as evidenced by variations in oil and natural gas interfaces in different regions of the pool. The complexity of the reservoir lends itself to the application of horizontal technology. NAL plans to invest approximately $4 million for development drilling (six gross wells) and waterflood activities within the Alida area in 2011.

Production from this area averaged 1,698 boe/d in 2010 as compared to 1,839 boe/d in 2009. Proved plus Probable Reserves in the McDaniel Report totaled 4,263 Mboe.

Midale, Saskatchewan

The Midale properties are located approximately 24 miles northwest of Estevan. Addison LP owns a 50% Working Interest in, and the Manager operates, three voluntary units: Midale East Unit No. 1 and Midale South Unit Nos. 2 and 3. In addition, Addison LP holds a 0.12% Working Interest in the main Midale Unit which is operated by Apache Canada Ltd. and a 50% Working Interest in several non-unit oil wells in the area which it operates. Most of the oil production from the Midale properties is from the Midale formation and most of the volumes are associated with waterflood projects. NAL plans to invest approximately $3 million for Mississippian drilling as well as waterflood maintenance in 2011.

Production from this area averaged 647 boe/d in 2010 as compared to 669 boe/d in 2009. Proved plus Probable Reserves in the McDaniel Report totaled 2,215 Mboe.

Elswick/Hoffer/Hummingbird, Saskatchewan

During 2010, Addison LP expanded its landholdings west of the Elswick area and is actively developing some new oil plays at the Hoffer and Hummingbird areas. The primary target is the Ratcliffe formation, with additional potential in other Mississippian and Devonian age formations. These new areas are located 40 to 60 miles west of Estevan.

The Elswick properties are located approximately 27 miles northwest of Estevan. The main production comes from the Elswick Midale Beds Voluntary Unit No. 2 in which Addison LP owns, and the Manager operates, a 38.69% Working Interest and two waterflood projects operated by Devon Canada Corporation in which Addison LP holds a 12.5% Working Interest. Oil production is derived from Mississippian age formations. In 2011, Addison LP plans to invest approximately $30 to 35 million in development drilling, (35 gross wells) and related facilities, primarily focused in the Hoffer area.

Production from this area averaged 900 boe/d for 2010 as compared to 715 boe/d for 2009. Proved plus Probable Reserves in the McDaniel Report totaled 3,887 Mboe.

Star Valley, Saskatchewan

The Star Valley properties are located approximately 43 miles northeast of Estevan. The majority of the oil production comes from the Frobisher-Alida pool located in sections 13 and 14-6-9 W2M. Addison LP operates approximately half of the wells in the pool. NAL will be spending limited capital in this area in 2011.

Production from this area averaged 366 boe/d for 2010 as compared to 472 boe/d for 2009. Proved plus Probable Reserves in the McDaniel Report totaled 1,073 Mboe.

Nottingham Area (including Nottingham Unit), Saskatchewan

ACE and Addison LP own a combined 37.07% Working Interest share in the Nottingham Unit after the acquisition of additional minor interests in May 2010. The Manager is the operator of the Nottingham Unit. The

Manager also operates the Nottingham Gas Plant which processes most of the gas volumes produced in Nottingham area and several surrounding properties.

The Nottingham area produces oil from a depth of 3,500 feet in the Alida formation, a member of the Mississippian Mission Canyon Group. The oil pool was discovered in 1956 and the Nottingham Unit was formed in 1960 to maximize oil recovery, conserve solution natural gas and re-inject produced water. In 2009, the Nottingham Gas Plant expansion was completed, increasing the capacity to 18 MMcf/d. Plans for 2011 include approximately $6 million for drilling 12 gross development locations.

Production from this area averaged 652 boe/d in 2010 as compared to 627 boe/d in 2009. Proved plus Probable Reserves in the McDaniel Report totaled 1,795 Mboe.

Weyburn, Saskatchewan

The Weyburn properties are located approximately 70 miles southeast of the city of Regina. Addison LP owns a 50% Working Interest in the Weyburn Midale Beds Voluntary Unit No. 5, which the Manager operates, and a 25% Working Interest in the Weyburn Midale Voluntary Unit No. 10, which is operated by Enerplus Resources Fund. The remainder of the production in the area comes from a number of producing non-unit oil wells in which Addison LP holds mostly 50% Working Interests. Production is largely derived from the Midale formation with minor volumes coming from the Frobisher formation. The majority of the oil production is supported by waterflooding or the presence of natural water drive. There is not expected to be any capital investment for drilling in the area during 2011. Some of NAL's interests in this area, including its interests in Unit No. 5 and Unit No. 10, have been sold subsequent to this reporting period (effective February 1, 2011).

Production from this area averaged 353 boe/d for 2010 as compared to 337 boe/d for 2009. Proved plus Probable Reserves in the McDaniel Report totaled 997 Mboe.

Willmar, Saskatchewan

This Manager-operated oil field represents the main production acquired as part of the 2002 acquisition of Landex Exploration Ltd. Production is from the Frobisher formation, the same formation that NAL produces from in the neighboring Alida, Nottingham and Rosebank fields. Willmar is located about 20 miles west of NAL's core operations and NAL has a Working Interest of 100% in most of the producing wells. NAL is considering spending up to $5 million to drill four wells in this area in 2011.

Production from this area averaged 591 boe/d for 2010 as compared to 507 boe/d for 2009. Proved plus Probable Reserves in the McDaniel Report totaled 1,480 Mboe.

Rosebank, Saskatchewan

The Rosebank property is located in southeast Saskatchewan adjacent to the Nottingham Unit. The Manager is operator of the property.

The Rosebank field was discovered in the mid-1950s and produces from the Mississippian Mission Canyon Group from average depths of approximately 3,500 feet. There is no drilling or recompletion work planned for 2011.

Production from this area averaged 312 boe/d in 2010 as compared to 368 boe/d in 2009. Proved plus Probable Reserves in the McDaniel Report totaled 1,025 Mboe.

Sukunka, British Columbia

This property, which is located in northeast British Columbia, was acquired as part of the acquisition of Seneca Energy Canada Inc., bringing exploration opportunities with potential to add significant volumes for NAL. NAL's Working Interest varies from 6% to 33% (averaging 18.4%) on a large land block of over 145,000 gross acres. NAL has an interest in compression/pipeline facilities in this area. Gas production is processed for sale at a gas plant operated by others. There is no drilling planned for this area for 2011.

Production from this area averaged 2,104 boe/d for 2010 as compared to 2,340 boe/d in 2009. Proved plus Probable Reserves in the McDaniel Report totaled 3,734 Mboe.

Fireweed, British Columbia

The Fireweed area is located approximately 85 kilometres northwest of the city of Fort St. John. This property is operated by the Manager and consists of assets acquired in the Breaker acquisition. NAL has a 100% Working Interest in all of its production in this property, along with compression/dehydration facilities. The gas is processed for sale at a gas plant operated by others.

This property produces primarily liquids-rich natural gas from the Doig formation. Production from this property has historically been obtained with vertical wells. Recently, horizontal wells have been drilled and multi-stage completion techniques employed in the Doig formation, which has resulted in improvements in well deliverability. NAL plans to invest approximately $17 million in Fireweed in 2011 to conduct horizontal drilling with multi-stage completions.

Production from this area averaged 2,350 boe/d in 2010. Proved plus Probable Reserves in the McDaniel Report totaled 7,742 Mboe.

Lake Erie, Ontario

ACE owns an average 20% Working Interest share in a large block of natural gas producing acreage underlying Lake Erie on the Ontario side of the Canada-United States border. The area comprises a succession of properties approximately 200 miles in extent. Dundee Energy Limited Partnership ("**Dundee Energy**") operates the interests.

This extensive natural gas producing area consists of relatively shallow natural gas reservoirs producing from geologic formations of Silurian and Devonian age at depths of 1,300 to 2,000 feet below the bottom of Lake Erie. Water depths average about 50 feet, but in some areas exceed 100 feet. The offshore wells are all completed with wellheads on the lake bottom that are connected to extensive pipeline gathering systems. There are no offshore production structures, as the natural gas is processed at onshore facilities that compress and dehydrate the natural gas before it is marketed to local natural gas distribution companies.

Dundee Energy and its partners own and operate five vessels that are used in the Lake Erie operations, and also contract tug boats and diving vessels as required for additional support services. The operated vessels include a drilling barge, a well servicing barge, a jack-up platform that houses a compressor unit, a service boat to assist with well stimulations, and a dive/supply boat. These vessels typically work through the summer and fall months to drill, complete and tie-in new wells, perform workovers on existing wells as required, abandon depleted wells, install new pipelines and optimize production from the various natural gas pools. There is no drilling program identified for 2011, however, approximately $2 million is anticipated to be spent on maintenance and recompletion activities.

Production from this area averaged 527 boe/d in 2010 as compared to 549 boe/d in 2009. Proved plus Probable Reserves in the McDaniel Report totaled 2,880 Mboe.

Production

Average Daily Production Volumes and Netbacks

The average daily production volumes and netbacks for NAL for 2010 are set out below:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter(1)	Annual Average(1)
Daily Production (1)					
Light and Medium Oil (bbl)	11,788	11,643	11,404	11,469	11,575
NGLs (bbl)	2,777	2,812	2,650	2,635	2,718
Natural Gas (Mcf)	93,328	90,928	92,518	93,314	92,522
Oil equivalent (boe 6:1)	30,120	29,609	29,473	29,657	29,713
Average Pricing, net of transportation charges, before hedging					
Oil ($/bbl)	76.43	71.52	70.78	76.42	73.74
Natural Gas ($/Mcf)	5.01	3.87	3.49	3.56	3.98
NGLs ($/bbl)	55.02	53.78	47.65	51.59	52.05
Operating Netback ($/boe)					
Production Revenue, net of transportation costs	50.49	45.10	42.69	44.43	45.69
Royalties, net	(8.54)	(8.85)	(7.83)	(7.75)	(8.25)
Operating Expenses	(10.81)	(10.98)	(11.72)	(10.21)	(10.93)
Other Income	0.16	0.04	0.12	0.20	0.13
Operating Netback, before hedging	31.30	25.31	23.26	26.67	26.64
Hedging Gains	0.63	2.18	4.20	2.49	2.37
Operating Netback, after hedging	31.93	27.49	27.46	29.16	29.01

Note:

(1) Average Daily Production Volumes before Reorganization.

Selected Reserves Information

The following tables set forth certain information relating to the consolidated oil and natural gas reserves of NAL and the present value of the estimated future net cash flow associated with such reserves as at December 31, 2010. The information set forth below is derived from the McDaniel Report, which has been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101 and the COGE Handbook. **All evaluations of future net cash flows are stated prior to any provision for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. Future net revenues have been presented on both a before and after tax basis. It should not be assumed that the estimated future net cash flow shown below is representative of the fair market value of the Properties. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGL and natural gas reserves may be greater than or less than the estimates provided herein.**

All references to natural gas in this report include solution gas from oil wells, plus CBM volumes where applicable. The total solution gas reserves represent approximately eight percent of NAL's total Proved plus Probable Reserves on a boe basis, and are not considered material in terms of being reported separately from other natural gas reserves. Similarly, the total CBM reserves represent less than two percent of NAL's total Proved plus Probable Reserves on a boe basis, and are not considered material in terms of being reported separately from other gas reserves. Additionally, NAL's solution gas and CBM volumes are produced, treated and sold in a similar manner to other natural gas volumes, and as such have no specific characteristics requiring separate reporting. Heavy oil volumes have been included in the McDaniel Report, as the Millard Lake property that was acquired with the Breaker acquisition produces oil with a density of approximately 16.8 degrees API, which is within the range defined as heavy oil under NI 51-101 reporting requirements.

In accordance with the requirements of NI 51-101, the Report on Reserves Data by Independent Qualified Reserves Evaluator on Form 51-101 F2 and the Report of Management and Directors on Oil and Gas Disclosure on Form 51-101 F3 are attached as Appendices "A" and "B" hereto, respectively.

Numbers in the following tables may not add exactly due to rounding.

SUMMARY OF OIL AND GAS RESERVES AND NET PRESENT VALUE OF FUTURE NET REVENUE as of December 31, 2010

FORECAST PRICES AND COSTS

	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
PROVED								
Developed Producing	23,566	20,738	381	330	183,606	160,406	6,170	4,338
Developed Non-Producing	125	108	20	16	5,122	4,095	138	97
Undeveloped	3,601	3,252	400	331	26,205	21,821	769	617
TOTAL PROVED	27,292	24,098	801	677	214,933	186,322	7,076	5,052
PROBABLE	12,731	11,184	638	504	97,325	84,039	3,365	2,467
TOTAL PROVED PLUS PROBABLE	40,023	35,282	1,439	1,181	312,258	270,361	10,441	7,519

	NET PRESENT VALUE OF FUTURE NET REVENUE									
	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)
PROVED										
Developed Producing	1,870	1,414	1,142	964	839	1,743	1,340	1,096	933	818
Developed Non-Producing	27	18	13	10	8	20	14	10	8	7
Undeveloped	206	136	93	64	44	153	99	66	43	27
TOTAL PROVED	2,103	1,569	1,249	1,039	891	1,916	1,452	1,172	985	852
PROBABLE	1,156	659	429	302	225	859	486	313	218	160
TOTAL PROVED PLUS PROBABLE	3,260	2,228	1,678	1,341	1,115	2,775	1,938	1,484	1,203	1,012

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2010

FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	NET ROYALTIES* (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	WELL ABANDONMENT COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Proved Reserves	4,499,420	658,478	1,437,673	189,504	110,525	2,103,240	187,641	1,915,599
Proved Plus Probable Reserves	6,947,313	1,011,062	2,132,040	420,339	124,263	3,259,609	485,067	2,774,542

* Net royalties include Crown, freehold and overriding royalties, as well as mineral taxes, net profits interest payments and Saskatchewan Capital surcharges.

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2010

FORECAST PRICES AND COSTS

PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$)	UNIT VALUE* ($/bbl)
Light and Medium Crude Oil (including solution gas and other by-products)		
Proved Producing	780,459	39.07
Proved Non-Producing	2,091	28.24
Proved Undeveloped	70,652	21.73
Total Proved	853,202	36.61
Probable	290,048	26.62
Total Proved plus Probable	1,143,251	33.43
Heavy Oil		
Proved Producing	10,190	30.84
Proved Non-Producing	324	20.82
Proved Undeveloped	5,955	17.99
Total Proved	16,469	24.33
Probable	11,617	23.07
Total Proved plus Probable	28,086	23.79
Natural Gas (including by-products but excluding solution gas from oil wells)		($/mcf)
Proved Producing	351,843	2.62
Proved Non-Producing	10,663	2.65
Proved Undeveloped	16,644	1.00
Total Proved	379,150	2.45
Probable	127,059	1.83
Total Proved plus Probable	506,209	2.26

* Unit values are calculated using the 10% discount rate divided by the Major Product Type Net reserves for each group.

Notes:

(1) The economic evaluation is based on royalty rates and incentive programs in effect as of the date of evaluation.

(2) "Gross Reserves" means the Working Interest share of remaining recoverable reserves before the deduction of royalties, and without including any royalty interests.

(3) "Net Reserves" means the Working Interest share of remaining recoverable reserves less all lessor and overriding royalties and interests owned by others, plus NAL's royalty interests in reserves.

(4) The net cumulative cash flow forecasts are after direct lifting costs, freehold royalties, Crown mineral taxes and future investments but before income taxes. An allowance for future well abandonment costs for all Working Interest wells was included, however, no allowance was made for the abandonment of any facilities.

(5) "Royalties" refers to royalties paid to others. The royalties deducted from the reserves are based on the percentage royalty calculated by applying the applicable royalty rate or formula. In the case of Crown sliding scale royalties that are dependent on selling prices, the price forecasts for the individual properties in question have been employed.

(6) "Reserves" are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on analysis of drilling, geological, geophysical and engineering data, the use of established technology, and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates.

(7) "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. At least a 90% probability that the quantities actually recovered will equal or exceed the estimated Proved Reserves is the targeted level of certainty.

(8) "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. At least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved plus Probable Reserves is the targeted level of certainty.

(9) "Proved 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.

(10) "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.

(11) "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. This category includes reserves for wells that were recently drilled and completed, but were in the process of being tied in for production as of the evaluation date of the reserves report.

(12) "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 classification (Proved, Probable, possible) to which they are assigned.

(13) The pricing assumptions used in the McDaniel Report with respect to net cumulative cash flow as well as the inflation rates used for operating costs are set forth below.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS as of December 31, 2010

FORECAST PRICES AND COSTS*

	OIL				NATURAL GAS	NATURAL GAS LIQUIDS		
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40^0 API ($Cdn/bbl)	Hardisty Heavy 12^0 API ($Cdn/bbl)	Cromer Medium 29.3^0 API ($Cdn/bbl)	AECO Spot Price ($Cdn/MMbtu)	Edmonton NGL Mix ($Cdn/bbl)	INFLATION RATES (%/Year)	EXCHANGE RATE ($US/Cdn)
2010 act.	79.40	77.45	62.30	73.75	4.15	61.00	2.0	0.971
Forecast								
2011	85.00	84.20	66.70	77.20	4.25	61.40	2.0	0.975
2012	87.70	88.40	68.70	80.40	4.90	64.50	2.0	0.975
2013	90.50	91.80	68.60	82.50	5.40	67.30	2.0	0.975
2014	93.40	94.80	70.80	85.20	5.90	69.80	2.0	0.975
2015	96.30	97.70	73.00	87.90	6.35	72.30	2.0	0.975
2016	99.40	100.90	75.40	90.70	6.75	74.90	2.0	0.975
2017	101.40	102.90	76.90	92.50	7.10	76.50	2.0	0.975
2018	103.40	104.90	78.40	94.30	7.40	78.20	2.0	0.975
2019	105.40	107.00	80.00	96.20	7.60	79.80	2.0	0.975
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.975

* All forecast prices are from McDaniel's published year-end forecasts. Price escalation rates after the year 2019 are approximate.

NAL's weighted average historical prices for 2010, net of transportation charges, were $3.98/Mcf for natural gas, $73.74/bbl for crude oil and $52.05/bbl for natural gas liquids.

**RECONCILIATION OF
COMPANY GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE**

FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL			HEAVY OIL			ASSOCIATED AND NON-ASSOCIATED GAS		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2009	27,721	12,241	39,962	825	837	1,662	215,257	92,182	307,439
Extensions & Improved Recovery	1,500	3,761	5,261	0	0	0	4,339	16,733	21,072
Technical Revisions	1,765	(3,210)	(1,445)	95	(198)	(103)	21,841	(10,670)	11,171
Discoveries	10	27	37	0	0	0	124	70	194
Acquisitions	798	217	1,015	0	0	0	7,982	1,856	9,838
Dispositions	(511)	(283)	(794)	0	0	0	(611)	(473)	(1,084)
Economic Factors	0	(22)	(22)	0	0	0	(562)	(2,373)	(2,935)
Production	(3,991)	0	(3,991)	(120)	0	(120)	(33,437)	0	(33,437)
December 31, 2010	27,292	12,731	40,023	801	638	1,439	214,933	97,325	312,258

In the table above, the Extensions and Improved Recovery category represents infill drilling and development activities that added incremental reserves above what had previously been booked. The Technical Revisions category includes performance adjustments and movement of reserves between categories (e.g. from Probable to Proved). In addition, a number of successful new wells drilled during the year resulted in reserves being upgraded from Proved Undeveloped to Proved Developed, with no net change to the Proved Reserves estimates.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (typically the drilling, completion and tie-in of one or more wells) is required to render them capable of production.

The following table sets forth the Proved Undeveloped Reserves and the Probable Undeveloped Reserves, each by product type, attributed to NAL in the three most recent financial years and, in the aggregate, before that time.

PROVED UNDEVELOPED RESERVES

YEAR	LIGHT AND MEDIUM OIL (Mbbl)		HEAVY OIL (Mbbl)		NATURAL GAS (MMcf)		NATURAL GAS LIQUIDS (Mbbl)	
	1st Attributed	Cumulative at Year End (1)	1st Attributed	Cumulative at Year End (1)	1st Attributed	Cumulative at Year End (1)	1st Attributed	Cumulative at Year End (1)
2007		595		0		4,691		83
2008	653	738	0	0	2,152	5,620	94	101
2009	3,571	3,654	499	499	23,404	27,742	744	775
2010	2,091	3,601	0	400	6,025	26,205	253	769

Note:

(1) Cumulative at Year End = Residual Cumulative of Previous Year plus 1st Attributed.

PROBABLE UNDEVELOPED RESERVES

YEAR	LIGHT AND MEDIUM OIL (Mbbl)		HEAVY OIL (Mbbl)		NATURAL GAS (MMcf)		NATURAL GAS LIQUIDS (Mbbl)	
	1st Attributed	Cumulative at Year End (1)	1st Attributed	Cumulative at Year End (1)	1st Attributed	Cumulative at Year End (1)	1st Attributed	Cumulative at Year End (1)
2007		1,418		0		8,695		231
2008	2,761	3,361	0	0	4,733	10,110	271	435
2009	2,711	5,078	695	695	30,195	37,688	907	1,192
2010	2,311	5,838	0	495	13,475	43,612	364	1,365

Note:

(1) Cumulative at Year End = Residual Cumulative of Previous Year plus 1st Attributed.

Proved Undeveloped Reserves are assigned to development drilling locations that NAL has identified for the current budget year plus the following three years, and that have a sufficiently high degree of certainty to be booked as Proved Undeveloped Reserves. The independent evaluator reviews all drilling locations and assigns reserves to the Proved or Probable Undeveloped categories as appropriate. The identified wells, or equivalent locations, are all expected to be drilled within the next four years and the estimated capital costs to drill, complete, equip and tie-in all wells are included in the evaluation. The Proved Undeveloped Reserves that are planned for development beyond the next two years generally represent continuation of multi-well drilling programs that extend beyond a two year time frame. The reserves assigned to the Proved Undeveloped category are a conservative estimate of the expected recovery from those wells.

Probable Undeveloped Reserves are assigned to development drilling locations that have a higher risk than the Proved Undeveloped locations but meet the criteria for booking as Probable Undeveloped Reserves. Some Probable Undeveloped Reserves are also assigned for additional recovery from wells that have Proved Undeveloped Reserves assigned. The identified wells, or equivalent locations, are all expected to be drilled within the next four years and the estimated capital costs to drill, complete, equip and tie-in all wells are included in the evaluation. The Probable Undeveloped Reserves that are planned for development in the third and fourth years generally represent follow-up drilling locations that are part of multi-well programs which include some drilling within the next two years, or locations that are being phased in over time to optimize NAL's capital budget. The reserves assigned for total Proved plus Probable represent the most likely estimate of the recovery from wells in the undeveloped category.

Significant Factors or Uncertainties

There are no significant factors or uncertainties to report beyond the usual risks related to reserves reporting which are outlined earlier in this report.

Future Development Costs

The following table outlines development costs deducted in the estimation of future net revenue based on forecast prices and costs, calculated using no discount and a 10% discount rate.

	2011 (MM$)		2012 (MM$)		2013 (MM$)		2014 (MM$)		2015 (MM$)		Remaining (MM$)		Total (MM$)	
RESERVE CATEGORY	0%	10%	0%	10%	0%	10%	0%	10%	0%	10%	0%	10%	0%	10%
Proved Reserves	90.0	85.8	86.2	74.7	6.9	5.5	4.0	2.9	0.3	0.2	2.1	0.8	189.5	169.9
Proved Plus Probable Reserves	126.9	121.0	150.2	130.2	98.1	77.3	40.6	29.1	0.3	0.2	4.2	1.4	420.3	359.2

NAL expects to source funding for future development costs through internally generated cash flows and, if management deems necessary, through existing lines of credit or through equity or debt financing. The future costs of financing are not expected to impact the future development of reserves.

Finding and Development Costs

Details on NAL's finding and development costs are provided in Appendix "D" attached hereto.

Other Oil and Gas Information

Oil and Gas Properties and Wells

NAL's important properties, plants and facilities are described above under "- Summary of Properties".

A small amount (less than 3%) of NAL's Proved plus Probable reserves is in the non-producing category. A portion of those reserves represent volumes assigned to wells that were drilled or recompleted in the latter part of the year and were not yet tied-in for production as of the effective date of the reserves evaluation. Most of those volumes are expected to be brought on production during the upcoming year. There are also some non-producing reserves assigned for future recompletions planned for wells that are currently producing from other horizons. In addition, some small volumes of natural gas reserves are assigned to the non-producing category for gas cap volumes located structurally above producing oil formations. These gas volumes will be produced once the majority of the recoverable oil has been produced and approval received for concurrent production of the gas cap.

As at December 31, 2010, NAL had an interest in approximately 7,437 gross (2,405.3 net) producing and non-producing oil and natural gas wells as shown in the following table. For purposes of this table, multiple completions within a single well have been excluded such that each well bore is only counted once.

	PRODUCING		**NON-PRODUCING**(3)	
	Gross (1)	Net (2)	Gross(1)	Net(2)
CRUDE OIL WELLS				
Alberta	1,228	554.3	165	68.8
Saskatchewan	2,424	512.9	552	107.3
Ontario	0	0.0	0	0.0
British Columbia	3	0.2	1	0.1
NATURAL GAS WELLS				
Alberta	1,987	874.8	333	119.7
Saskatchewan	1	0.5	58	2.5
Ontario	520	104.0	60	12.0
British Columbia	82	40.7	23	7.5
TOTAL	**6,245**	**2,087.4**	**1,192**	**317.9**

Notes:

(1) "Gross" wells mean the total number of wells in which NAL had an interest as at December 31, 2010.
(2) "Net" wells means the number of wells obtained by aggregating NAL's Working Interest in each of the gross wells as at December 31, 2010.
(3) Includes injection wells.

Properties with No Attributed Reserves

The following table sets forth the gross and net acres of unproved properties held by NAL and the net area of unproved property for which NAL's rights to explore, develop and exploit are scheduled to expire during the next year. A portion of the expiring lands are expected to be held by production and development activities, and therefore the net expiring area for the upcoming year is expected to be less than shown below.

LOCATION	UNPROVED PROPERTIES (acres)		
	Gross	Net	Net Area to Expire
Alberta	583,754	297,204	66,032
Saskatchewan	232,084	115,088	5,366
Ontario	512,327	101,953	9,347
British Columbia	190,936	49,819	10,403
TOTAL	**1,519,101**	**564,064**	**91,148**

Forward Contracts

NAL has entered into certain financial commodity price hedge arrangements for 2011 as disclosed in the annual financial statements for the year ended December 31, 2010. These financial contracts are not incorporated into the reserves evaluation in the McDaniel Report. NAL's position relative to these financial contracts will be disclosed in each quarterly report for 2011.

Abandonment & Reclamation Costs

Future abandonment and reclamation costs have been estimated based on actual costs incurred to date by NAL for abandonment and reclamation activities. Costs to abandon approximately 1,900 net wells totaling $124.3 million (inflated cost, undiscounted) net of salvage value are included in the estimate of future net revenue in the Proved plus Probable case of the McDaniel Report. The cost after discounting the net cash flow at 10% per year is $32.1 million. Additional costs for future lease reclamation, facility abandonments and the abandonment of additional non-producing or service wells not included in the McDaniel Report are estimated to be $294.3 million (inflated cost, undiscounted). After discounting the net cash flow at 10% per year, these additional costs total $92.8 million. NAL's estimated abandonment and reclamation costs for the next three years, inflated and undiscounted, total $29.4 million.

Tax Horizon

The Corporation is a taxable entity under the Tax Act. The Corporation's estimated consolidated tax pool balances as at December 31, 2010 total approximately $1.4 billion. These tax pools can be used to reduce NAL's taxable income and tax payable.

Costs Incurred

The following table outlines costs incurred during the financial year ended December 31, 2010:

NATURE OF COST	AMOUNT (MM$)
Acquisition Costs (Net of Dispositions)	
Proved	24.4
Unproved	46.0
Exploration Costs	12.6
Development Costs	164.3
Office Equipment	2.1
TOTAL	**249.4**

Exploration and Development Activities

The following table summarizes the results of exploration and development activities during the financial year ended December 31, 2010.

	GROSS	NET
DEVELOPMENT WELLS		
Gas	16	6.35
Oil	102	48.39
Service	2	1.50
Dry	0	0
EXPLORATORY WELLS		
Gas	0	0
Oil	11	5.16
Service	0	0
Dry	0	0
TOTAL WELLS	**131**	**61.40**

NAL has a planned 2011 capital program with development expenditures budgeted at approximately $200-230 million. The development capital consists of approximately $175 million to drill, complete and tie-in new wells, $15 million for plant and facilities capital and $10 million for land and seismic. Approximately 85% of the total development capital expenditures are budgeted for oil properties in Alberta and Saskatchewan and the remainder for strategic natural gas drilling in Alberta and British Columbia. In total, NAL expects to participate in the drilling of 139 (73 net) wells during 2011.

Production Estimates

The following table summarizes the volume of production for total Proved and total Proved plus Probable reserves estimated for 2011 using forecast prices and costs. The volumes reported are gross company interest volumes before deduction of royalties payable.

	ESTIMATED PRODUCTION	
	Total Proved	Total Proved plus Probable
Light and Medium Crude Oil (Mbbl)	3,887.8	4,171.9
Heavy Oil (Mbbl)	112.6	165.4
Natural Gas (MMcf)	33,184.6	34,888.5
Natural Gas Liquids (Mbbl)	961.4	1,016.0

INDUSTRY CONDITIONS

Government Regulation

The oil and natural gas industry is subject to extensive controls and regulations imposed by various levels of government. In western Canada, the various provincial governments have legislation and regulations that govern land tenure, royalties, production rates, environmental protection, the prevention of waste and other matters. Although it is not expected that any of these controls and regulations will affect the operations of NAL in a manner materially different than they would affect other oil and natural gas producers of similar size, the controls and regulations should be considered carefully by investors in the oil and natural gas industry. Outlined below are some of the principal aspects of legislation and regulations governing the oil and natural gas industry. All current legislation is a matter of public record and the Manager is unable to predict what additional legislation or amendments may be enacted.

Pricing and Marketing – Oil

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

Pricing and Marketing – Natural Gas

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

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

Pipeline Capacity

As a result of recent pipeline additions and expansions, an excess of natural gas pipeline capacity exists in western Canada, which provides for the ability to deliver all current production to natural gas sales markets.

Recent and ongoing expansions of existing crude oil pipelines combined with the commissioning of a new, larger diameter oil pipeline leaves the Western Canadian Sedimentary Basin with sufficient take-away capacity to deliver product to oil markets for the foreseeable future.

Land Tenure

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

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

Provincial Royalties and Incentives

General

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

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

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

Alberta

The Alberta government implemented a new oil and gas royalty framework effective January 2009. The new framework established new royalties for conventional oil, natural gas and bitumen that are linked to price and production levels and apply to both new and existing conventional oil and gas activities and oil sands projects. Under the framework, the formula for conventional oil and natural gas royalties uses a sliding rate formula, dependant on the market price and production volumes. Royalty rates for conventional oil range from 0% to 50%. Natural gas royalty rates range from 5% to 50%.

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

The Deep Oil Exploration Program (the "**DOEP**") and the Natural Gas Deep Drilling Program (the "**NGDDP**") are two programs that became effective on January 1, 2009. These programs provide upfront royalty adjustments to new wells. To qualify for such royalty adjustments under the DOEP, exploration wells must have a vertical depth greater than 2,000 metres with a Crown interest and must be spudded after January 1, 2009. These oil wells qualify for a royalty exemption on either the first $1,000,000 of royalty or the first 12 months of production. The NGDDP applies to wells producing at a true vertical depth greater than 2,500 metres. The NGDDP has an escalating royalty credit in line with progressively deeper wells from $625 per meter to a maximum of $3,750 per meter and there are additional benefits for the deepest wells. Both the DOEP and the NGDDP are five year programs. Any wells spudded after December 31, 2013, or any wells that choose the transition option, will not qualify under either program. No royalty adjustments will be granted under either the DOEP or the NGDDP after December 31, 2018. On May 27, 2010 the NGDDP was amended, retroactive to May 1, 2010, by reducing the minimum qualifying depth to 2,000 metres and including wells drilled into pools discovered prior to 1985, among other changes.

On March 3, 2009, the Alberta government announced a three-point incentive program. This incentive program includes a drilling royalty credit for new oil and natural gas wells drilled between April 1, 2009 and March 31, 2010, providing a $200-per-metre-drilled royalty credit to companies on a sliding scale based on their production levels from the previous year. There is also a new well incentive program that provides a maximum 5% royalty rate for the first 12 months of production from new wells that begin producing oil or natural gas between April 1, 2009 and March 31, 2010 to a maximum of 50,000 barrels of oil or 500 million cubic feet of natural gas. As of June 25, 2009, the Alberta government has extended these two programs to March 31, 2011. The Province of Alberta will also invest $30 million in a fund committed to abandonment and reclamation projects where there is no legally responsible or financially able party to deal with the clean-up of inactive wells.

On March 11, 2010, the Alberta government announced its intention to adjust royalty rates effective January 1, 2011. This adjustment includes making the incentive program royalty rate of 5% on new natural gas and conventional oil wells a permanent feature of the royalty system with the time and volume limits discussed above. The maximum royalty rate was be reduced from the current levels of 50% to 40% for conventional oil and to 36% for natural gas. The transitional royalty framework for oil and gas will continue until December 31, 2013 as announced but no new wells will be allowed to select transitional royalty rates effective January 1, 2011; wells that have selected the transitional royalty rates will be allowed to switch to the new rates effective January 1, 2011. Royalty curves incorporating the changes announced on March 11, 2010 were released on May 27, 2010. The royalty adjustments are subject to certain risks and uncertainties, including changes to existing legislation and the regulation and development of proprietary software to support the calculation and collection of royalties.

In conjunction with the release of the new royalty curves on May 27, 2010 the Alberta government also announced its Emerging Resources and Technology Initiative intended to accelerate new technologies and encourage the development of unconventional resources. Among other initiatives, the following changes were announced:

- CBM wells will receive a maximum royalty rate of 5% for 36 producing months up to 750 million cubic feet of production, retroactive to wells that began producing on or after May 1, 2010;
- Horizontal gas wells will receive a maximum royalty of 5% for 18 producing months up to 500 million cubic feet of production, retroactive to wells that commenced drilling on or after May 1, 2010; and
- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well, retroactive to wells that commenced drilling on or after May 1, 2010.

The Emerging Resources and Technology Initiative will be reviewed in 2014 and the Government of Alberta has committed to provide industry three years notice if it intends to discontinue the program.

Saskatchewan

Natural Gas

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

Each month, the royalty rates are adjusted based on the level of the Provincial Average Gas Price ("**PGP**") established by the Province monthly. The PGP represents the weighted average fieldgate price (expressed in $/1,000m^3) received by producers during the month for the sale of all gas subject to royalty. Crown royalty on the production volume is calculated on each individual well using the applicable royalty rate to the volume of gas produced by each well on a monthly basis.

At the present time, the operator must elect to use either the PGP or the Operator Average Gas Price ("**OGP**") for purposes of valuing the Crown's royalty share of the production volume from each well. The OGP is determined each month by the operator and represents the weighted average fieldgate price ($/1,000m^3) received by the operator for sales of gas during the month. The Crown royalty share is calculated by multiplying the Crown royalty volume determined for each well by the wellhead value of the gas for the month. On June 14, 2010 the Province of Saskatchewan announced that it will eliminate the option of using the OGP for purposes of valuing the Crown's royalty share of the production volume from each well commencing from the fall of 2011, and will require use of the PGP. The proposed changes may require further consultation and there may be modifications introduced prior to the implementation of such changes.

Conventional Oil

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

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

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

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

- An incentive volume for exploratory gas wells drilled on or after October 1, 2002 and for horizontal gas wells drilled on or after June 1, 2010 and before April 1, 2013. A lower royalty rate applies (2.5%) to natural gas produced from such wells up to 25 million cubic metres.

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

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

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

British Columbia

The British Columbia royalty regime for natural gas produced on Crown lands is price-sensitive and determined by a sliding scale formula based on a reference price, which is the greater of the producer price and a prescribed minimum price. The Government of British Columbia determines the producer price by averaging the actual selling prices for gas sales with shared characteristics for each company minus applicable costs. Natural gas in British Columbia is classified as either "conservation gas" (produced in association with oil) or "non-conservation gas" (not produced in association with oil). There are three royalty categories applicable to non-conservation gas, which are dependent on the date on which title was acquired from the Crown and on the date on which the well was drilled. The royalty rate may also be impacted by the select price, a parameter in the royalty rate formula to account for inflation. The base royalty rate for non-conservation gas ranges from 9% to 15%. A lower base royalty rate of 8% is applied to conservation gas as an incentive to produce gas that might otherwise have been flared. The royalty rate may be reduced for low productivity wells.

The British Columbia royalty regime for oil is dependent on type and age of the oil and quantity produced. Oil is classified as "old", "new" or "third tier" depending on the discovery date of the pool from which the oil is produced, and a different formula is used to determine the royalty rate depending on the classification. Royalty rates are further varied depending on production. Lower royalty rates apply to low productivity wells and third tier oil (produced from pools discovered after June 1, 1998) to reflect the increased cost of exploration and extraction.

The Government of British Columbia has also introduced a number of oil and natural gas royalty reduction and credit incentive programs to encourage oil and gas exploration and development in British Columbia. The following incentive programs are currently in effect:

- A temporary royalty rate of 2% for the first 12 months of production is available for new wells drilled between September 1, 2009 and June 30, 2010 and brought on production before December 31, 2010.

- The Summer Royalty Program provides a royalty credit of 10% of drilling and completion costs to a maximum of $100,000 for qualifying wells spudded between April 1 and November 30 of each year.

- The Deep Royalty Program and Deep Re-Entry Royalty Program provide royalty credits for qualifying deep vertical wells with a true vertical depth greater than 2,500 meters (8,202 feet) and horizontal wells with a true vertical depth greater than 1,900 meters (6,234 feet), which spud on or after January 1, 2009, and for deep re-entry wells with a true vertical depth greater than 1,900 meters (6,234 feet) and a re-entry date after December 31, 2003. The royalty credit is calculated according to the measured (drilled) depth of the qualifying well and associated drilling costs.

- The Deep Discovery Royalty Program provides for a three-year royalty holiday or 283,000,000 m^3 (10,000 MMcf) of royalty-free gas production, whichever comes first, for qualifying deep discovery wells with a true vertical depth greater than 4,000 meters (13,123 feet) that have finished drilling after November 2003 and whose surface locations are at least 20 kilometres (12.4 miles) away from the surface location of any well in a recognized pool of the same formation.

- The Coalbed Gas Royalty Program provides a royalty reduction for Coalbed gas wells with average daily production less than 17,000 m^3 (0.6 MMcf/d) as well as a royalty credit for Coalbed gas wells equal to $50,000 for wells drilled on Crown land and a tax credit equal to $30,000 for Coalbed gas wells drilled on freehold land.

- The Marginal Royalty Program provides a royalty reduction for low productivity natural gas wells with an average monthly production rate of under 25,000 m^3 (0.88 MMcf/d) during the first 12 months of production and an average daily production rate of less than 23 m^3 (0.80 MMcf/d) for every meter (3.3 feet) of depth to the applicable zone.

- The Ultra-Marginal Royalty Program provides additional royalty breaks for low productivity shallow natural gas wells with a true vertical depth of less than 2,300 meters (7,546 feet), an average monthly production volume of under 60,000 m^3 (2,130 MMcf) during the first 12 months of production and an average daily production rate of less than 11.5 m^3 (0.4 MMcf/d) for development wells or 17 m^3 (0.6 MMcf/d) for exploratory wildcat wells, for every 100 meters (328 feet) of depth to the applicable zone.

- The Net Profit Royalty Program targets the development and commercialization of technically complex resources in British Columbia, such as coalbed gas, tight gas, shale gas, enhanced oil recovery or resources that are remote from existing infrastructure, and provides for a reduction in initial royalty rates while a producer is recovering capital costs in exchange for higher royalty rates once these costs have been recovered. The program allows for the calculation of royalties based on the net profits of a particular project.

- The Infrastructure Royalty Credit Program provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects. The Government of British Columbia announced that $120 million in royalty credits was allocated to this program for 2011.

Ontario

In Ontario, the Crown royalty rate for oil and gas is 12.5%, based on monthly production and the full sale price of the oil or gas received at the point of sale.

Greenhouse Gases and Industrial Air Pollutants

Kyoto Protocol, Copenhagen Accord and Cancun Agreement

Canada is a signatory to the United Nations Framework Convention on Climate Change (the "**Convention**") and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nation-wide emissions of carbon dioxide, methane, nitrous oxide and other greenhouse gases ("**GHG**"). However, the Government of Canada has concluded that Canada will not meet its commitment to the Kyoto Protocol and has been developing an alternative strategy for reducing Canada's GHG emissions. From December 6 to 18, 2009, government leaders and representatives from approximately 170 countries met in Copenhagen, Denmark (the "**Copenhagen Conference**") to attempt to negotiate a successor to the Kyoto Protocol, which expires in 2012. The primary result of the Copenhagen Conference was the Copenhagen Accord, which represents a broad political consensus rather than a binding international treaty like the Kyoto Protocol and has not been endorsed by all participating countries. The Copenhagen Accord reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. Although Canada has committed under the Copenhagen Accord to reducing its GHG emissions by 17% from 2005 levels by 2020, the Copenhagen Accord does not establish binding GHG emissions reduction targets. The Copenhagen Accord calls for a review of implementation of its stated goals before 2016. In late 2010, another climate change conference was held in Cancun, Mexico but, like the Copenhagen Accord, it did not result in a binding treaty. The Cancun Agreement does recognize that global reductions in GHG emissions are required to limit global temperature increases to less than 2°C and that the parties should consider limiting any increase to less than 1.5°C.

Federal

The Government of Canada previously released the *Regulatory Framework for Air Emissions*, updated March 10, 2008 by *Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions* (collectively, the "**Regulatory Framework**"), for regulating GHG emissions by proposing mandatory emissions intensity reduction obligations on a sector by sector basis. Legislation to implement the Regulatory Framework had been expected to be put in place, but the federal government has delayed the release of any such legislation and potential federal requirements in respect of GHG emissions are unclear. In 2009, the Government of Canada announced its commitment to work with the provincial governments to implement a North America-wide 'cap and trade' system for GHG emissions, in cooperation with the United States. On January 30, 2010, the Government of Canada announced its new target to reduce overall Canadian GHG emissions by 17% below 2005 levels by 2020, from the previous target of 20% from 2006 levels by 2020, to align itself with the GHG emission reduction goals of the United States.

The Government of Canada currently proposes to enter into equivalency agreements with provinces to establish a consistent regulatory regime for GHGs, but the success of any such plan is uncertain, possibly leaving overlapping levels of regulation. It is uncertain whether either federal GHG regulations or an integrated North American 'cap and trade' system will or will not be implemented, or what obligations might be imposed under any such system. As the details of the implementation of any federal legislation for GHGs have not been announced, the effect on NAL's operations cannot be determined at this time.

Alberta

Alberta currently regulates GHG emissions under the *Climate Change and Emissions Management Act*, the Specified Gas Reporting Regulation (the "**SGRR**"), which imposes GHG emissions reporting requirements, and the Specified Gas Emitters Regulation (the "**SGER**"), which imposes GHG emissions limits. Under the SGRR, GHG emissions of 100,000 tonnes or more from a facility in any year must be reported to Alberta Environment. Alberta Environment has publicly announced its intention to lower this reporting threshold for facilities to 50,000 tonnes of GHG emissions annually. The SGER applies to facilities in Alberta that have produced 100,000 or more tonnes of GHG emissions in 2003 or any subsequent year and requires reductions in GHG emissions intensity (i.e. the quantity of GHG emissions per unit of production) from emissions intensity baselines that are established in accordance with the SGER. The SGER distinguishes between "established" facilities that completed their first year of commercial operation before January 1, 2000, or have completed eight years of commercial operation, and "new" facilities that have completed their first year of commercial operation on December 31, 2000 or a subsequent year and have completed less than eight years of commercial operation. Generally, the baseline for an established facility reflects the average of emissions intensity in 2003, 2004, and 2005, and for a new facility emissions intensity in the third year of commercial operation. For an established facility, the required reduction in GHG emissions is 12% from its baseline, and such reduction must be maintained over time. For a new facility, the reduction requirement from its baseline is phased in by annual 2% increments beginning in the fourth year of commercial operation until the maximum 12% reduction requirement imposed on established facilities is reached.

There are three ways to comply with the SGER reduction requirements: (i) actual physical reductions in GHG emissions intensity; (ii) purchase of Alberta-based emission offset credits and/or emission performance credits; or (iii) purchase of fund credits at a cost of $15 per tonne of GHG emissions, with the proceeds going to the Government of Alberta's Climate Change and Emissions Management Fund. Compliance reports for facilities subject to the SGER are due to Alberta Environment on March 31 annually. The Government of Alberta previously announced in its 2008 Provincial Energy Strategy that it may modify the SGER and implement stricter standards.

In addition, Alberta facilities must currently report emissions of industrial air pollutants and comply with obligations imposed in permits and under environmental regulations.

Saskatchewan

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

British Columbia

Pursuant to the *Greenhouse Gas Reduction Targets Act*, the Province of British Columbia has set a goal of reducing its GHG emissions to 33% below 2007 levels by 2020, with interim targets of 6% below 2007 levels by 2012 and 18% below 2007 levels by 2016. The provincial government is required under that legislation to report every second year on the amount of reductions achieved in the province. In June 2008, British Columbia released its Climate Action Plan, which outlines a number of strategies and initiatives to take B.C. approximately 73% towards meeting the goal of reducing greenhouse gas emissions by 33% below 2007 levels by 2020. The province has also enacted framework legislation providing for a provincial cap and trade system and has imposed GHG emissions reporting requirements under the *Greenhouse Gas Reduction (Cap and Trade) Act* and the Reporting Regulation. Additionally, British Columbia has implemented a carbon tax on the purchase or use of fossil fuels within the province, starting at $10/tonne of CO_2e emissions from the combustion of each fuel commencing on July 1, 2008 and rising by $5 per year to $30/tonne in 2012. Requirements that may be imposed in British Columbia may have operational or financial adverse consequences for NAL's business.

British Columbia is a partner in the Western Climate Initiative ("**WCI**") which is an organization made up of four Canadian provinces (B.C., Manitoba, Ontario, and Quebec) and seven states (Arizona, California, Montana, New Mexico, Oregon, Utah and Washington). The WCI is working towards implementing a regional cap-and-trade program that is expected to come into effect by 2012.

Ontario

The Province of Ontario has not implemented GHG emission reduction legislation at this time. Ontario's Climate Change Action Plan calls for a 6% reduction by 2014 and a 15% reduction by 2020 from 1990 levels. Ontario plans to achieve these reductions with the implementation of a cap and trade system and by phasing out coal-fired electrical power plants, among other measures.

The *Environmental Protection Act* was recently amended to include provisions to enable a cap and trade system and as of January 1, 2010 emitters of more than 25,000 tonnes of CO_2e per year must report their emissions to the government pursuant to *Ontario Regulation 452/09* (*Ontario Greenhouse Gas Emissions Reporting*).

Ontario is a partner in the Western Climate Initiative ("**WCI**") which is an organization made up of four Canadian provinces (B.C., Manitoba, Ontario, and Quebec) and seven states (Arizona, California, Montana, New

Mexico, Oregon, Utah and Washington). The WCI is working towards implementing a regional cap-and-trade program that is expected to come into effect by 2012.

Environmental Regulation

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

In Alberta, environmental compliance is governed by the *Alberta Environmental Protection and Enhancement Act*. In Saskatchewan, environmental compliance is governed by the *Environmental Management and Protection Act*. Applicable environmental legislation in British Columbia is the *Environmental Assessment Act* and in Ontario, the *Environmental Protection Act*.

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

NAL believes that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. While NAL believes that it is in substantial compliance with applicable environmental laws and regulations in effect at the present time and that continued compliance with existing requirements will not have a material adverse impact on NAL, it cannot give any assurance that it will not be adversely affected in the future. NAL has established internal guidelines to be followed in order to comply with environmental laws and regulations in the jurisdictions in which it operates. NAL employs an environmental, health, and safety department whose responsibilities include providing assurance that its operations are carried out in accordance with applicable environmental guidelines and safety precautions. Although NAL maintains pollution insurance against the costs of cleanup operations, public liability, and physical damage, there is no assurance that such insurance will be adequate to cover all such costs or that such insurance will continue to be available in the future.

The total future asset retirement obligation is estimated by the Manager based on the Corporation's net ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities, estimated costs to remediate, reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. The net present value of the Corporation's asset retirement obligations is estimated to be $144.7 million as at December 31, 2010 based on a total undiscounted amount of cash flows required to settle its undiscounted (unescalated) asset retirement obligations of $418.6 million. These expenditures are expected to be made over the next 43 years with the majority of the costs incurred between 2012 and 2034. The Corporation's credit-adjusted risk-free rate of 8 to 9% and an inflation rate of 2% were used to calculate the present value of the asset retirement obligations.

During 2010, the Trust incurred $6.6 million of abandonment and environmental expenditures, which were paid from the Trust's funds from operations.

DESCRIPTION OF CAPITAL STRUCTURE

The authorized capital of the Corporation consists of an unlimited number of Common Shares and a number of preferred shares (the "**Preferred Shares**") limited to a maximum number equal to not more than one-half of the Common Shares issued and outstanding at the time of issuance of such Preferred Shares. The following is a summary of the rights, privileges, restrictions and conditions attaching to the Common Shares and Preferred Shares.

Description of the Common Shares

Each Common Share entitles the holder to one vote at all meetings of shareholders of the Corporation, except meetings at which only holders of a specified class of shares are entitled to vote. Subject to the prior rights and privileges attaching to any other class of shares of the Corporation, holders of Common Shares have the right to receive any dividend declared by the Board of Directors on the Common Shares and the right to receive the remaining property and assets of the Corporation upon dissolution.

As of December 31, 2010 and March 8, 2011 there were 147,248,494 and 147,625,687 Common Shares issued and outstanding, respectively.

Description of the Preferred Shares

The Preferred Shares may at any time and from time to time be issued in one or more series, each series to consist of such number of shares as may, before the issue thereof, be determined by the Board of Directors, provided that the number of Preferred Shares of all series shall be limited in number to an amount equal to not more than one-half of the Common Shares issued and outstanding at the time of issuance of such Preferred Shares. Subject to the provisions of the ABCA, the Board of Directors may fix from time to time, before the issue thereof, the designation, rights, privileges, restrictions and conditions attaching to each series of the Preferred Shares.

As of December 31, 2010 and March 8, 2011 there were no Preferred Shares issued and outstanding.

DISTRIBUTION RECORD AND DIVIDEND POLICY

The following monthly distributions were paid by the Trust on each Trust Unit for the three most recently completed financial years:

For the Month Ended	Distributions per Trust Unit ($)	Payment Date
January 31, 2008	0.16	February 15, 2008
February 29, 2008	0.16	March 17, 2008
March 31, 2008	0.16	April 15, 2008
April 30, 2008	0.16	May 15, 2008
May 30, 2008	0.16	June 16, 2008
June 30, 2008	0.16	July 15, 2008
July 31, 2008	0.16	August 15, 2008
August 31, 2008	0.16	September 15, 2008
September 30, 2008	0.16	October 15, 2008
October 31, 2008	0.16	November 17, 2008
November 30, 2008	0.16	December 15, 2008
December 31, 2008	0.16	January 15, 2009
January 31, 2009	0.11	February 16, 2009
February 28, 2009	0.11	March 16, 2009
March 31, 2009	0.09	April 15, 2009
April 30, 2009	0.09	May 15, 2009
May 31, 2009	0.09	June 15, 2009
June 30, 2009	0.09	July 15, 2009
July 31, 2009	0.09	August 17, 2009
August 31, 2009	0.09	September 15, 2009
September 30, 2009	0.09	October 15, 2009
October 31, 2009	0.09	November 16, 2009

For the Month Ended	Distributions per Trust Unit	Payment Date
November 30, 2009	0.09	December 15, 2009
December 31, 2009	0.09	January 15, 2010
January 31, 2010	0.09	February 15, 2010
February 28, 2010	0.09	March 15, 2010
March 31, 2010	0.09	April 15, 2010
April 30, 2010	0.09	May 17, 2010
May 31, 2010	0.09	June 15, 2010
June 30, 2010	0.09	July 15, 2010
July 31, 2010	0.09	August 16, 2010
August 31, 2010	0.09	September 15, 2010
September 30, 2010	0.09	October 15, 2010
October 31, 2010	0.09	November 15, 2010
November 30, 2010	0.09	December 15, 2010
December 31, 2010	0.09	January 17, 2011

The historical distributions described above may not be reflective of future dividends, which are subject to review by the Board of Directors taking into account the prevailing circumstances at the relevant time. See "Risk Factors".

General

The Corporation currently declares cash dividends on a monthly basis to Shareholders of record on the 22nd day of the applicable month, provided that if the 22nd day is not a Business Day, then the record date for such dividend payment will be the immediately following Business Day, and paying such dividends on the 15th day of the month immediately following, provided that if the 15th day is not a Business Day, then such payment will be made on the immediately following Business Day. Monthly dividends are currently paid in the amount of $0.07 per Common Share, such dividend payment representing an annual dividend of $0.84 per Common Share. The Corporation designates dividends paid as "eligible dividends" for Canadian federal income tax purposes, which are anticipated to qualify for the enhanced federal dividend tax credit in Canada. However, no assurance can be given that dividends will be designated as "eligible dividends".

The Board of Directors will continue to assess dividend levels, taking into consideration commodity prices, internal capital reinvestment opportunities, the forecast cash flow of NAL, financial market conditions, the availability of financing and taxability.

Notwithstanding the foregoing, the amount and timing of any dividends payable by the Corporation will be at the discretion of the Board of Directors from time to time. The amount may vary depending on, among other things, the Corporation's earnings, financial requirements for the Corporation's operations, the satisfaction of solvency tests imposed by the ABCA for the declaration and payment of dividends and other conditions existing from time to time. In addition, the Board of Directors may alter the timing for the declaration and payment of dividends from monthly to quarterly or other periods of frequency. No assurance can be given that the Corporation will continue to pay dividends in the future.

Restrictions on Dividends

The ability of the Corporation to pay cash dividends to Shareholders may be directly affected in certain events and as a result of certain restrictions, including, but not limited to restrictions in the Corporation's credit facilities. The terms of the documents governing the Corporation's credit facilities contain provisions that in effect ensure that the lenders have priority as to payment over the Shareholders in respect to the assets and income of the Corporation and its subsidiaries. Amounts due and owing to the lenders under the credit facilities must be paid before any dividends can be paid to Shareholders. This relative priority of payments could result in a temporary or permanent interruption of dividends to Shareholders. See "Borrowings – Credit Facilities" and "Risk Factors – Debt Service".

In addition, the ABCA provides that a corporation shall not declare or pay a dividend if there are reasonable grounds for believing that (i) the corporation is, or would after the payment be, unable to pay its liabilities as they become due, or (ii) the realizable value of the corporation's assets would thereby be less than the aggregate of its liabilities and stated capital of all classes.

MARKET FOR SECURITIES

Common Shares

The outstanding Common Shares of the Corporation are listed and posted for trading on the TSX under the symbol "NAE". Prior to the Conversion, the Trust Units were listed and posted for trading under the symbol "NAE.UN" on the TSX. The following table sets forth the price range and trading volumes for the Trust Units during the most recent financial year ended December 31, 2010:

Date	High ($)	Low ($)	Monthly Trading Volume
January	$14.95	$12.75	14,554,538
February	$13.44	$12.50	9,712,464
March	$13.94	$12.67	12,849,375
April	$13.57	$12.35	12,496,683
May	$12.80	$9.68	15,611,632
June	$11.49	$10.51	9,800,231
July	$11.40	$10.32	8,628,917
August	$11.33	$9.80	10,551,430
September	$11.63	$10.62	12,492,505
October	$12.95	$11.57	12,763,522
November	$12.94	$12.00	10,357,124
December	$13.11	$11.95	8,646,608

6.75% Debentures

The outstanding 6.75% Debentures are listed and posted for trading on the TSX under the symbol NAE.DB.

The following table sets forth the price range and trading volumes of the 6.75% Debentures traded on the TSX during the most recent financial year ended December 31, 2010:

Date	High ($)	Low ($)	Monthly Trading Volume
January	$110.00	$103.50	1,020,000
February	$107.50	$106.00	474,000
March	$107.50	$104.50	645,000
April	$106.50	$104.75	862,000
May	$105.50	$102.70	743,000
June	$105.00	$102.80	768,000
July	$105.50	$104.00	1,187,000
August	$105.80	$103.60	767,000
September	$106.00	$103.85	551,000
October	$107.00	$104.30	406,000
November	$107.50	$104.00	624,000
December	$105.00	$103.50	150,000

6.25% Debentures

The outstanding 6.25% Debentures are listed and posted for trading on the TSX under the symbol NAE.DB.A.

The following table sets forth the price range and trading volumes of the 6.25% Debentures traded on the TSX during the most recent financial year ended December 31, 2010:

Date	High ($)	Low ($)	Monthly Trading Volume
January	$105.75	$104.00	2,135,500
February	$106.00	$104.00	2,106,000
March	$105.50	$103.50	2,685,000
April	$105.00	$100.55	3,938,000
May	$104.25	$100.75	2,817,000
June	$103.75	$102.15	738,000
July	$105.00	$103.00	4,436,000
August	$104.75	$103.10	3,651,000
September	$106.45	$103.25	2,058,000
October	$106.00	$104.25	1,015,000
November	$106.00	$104.00	707,000
December	$105.75	$103.77	463,000

BORROWINGS

Credit Facilities

At December 31, 2010, the Corporation had bank borrowings outstanding in the amount of $267 million.

As of January 1, 2011 the Corporation has a revolving term credit facility and a revolving working capital facility in an aggregate amount of up to $550 million. The credit facilities are extendible, revolving facilities and will revolve until April 30, 2011 at which time each is extendible for a further 364-day revolving period upon agreement between the Corporation and the Banks. The facilities consist of a $535 million production facility and a $15 million working capital facility. The credit facilities are fully secured by first priority security interests in all present and after acquired properties and assets of the Corporation and its subsidiaries. The purpose of the facilities is to fund ongoing working capital requirements and for general corporate purposes of the Corporation and its subsidiaries. Scheduled principal repayments to the Banks are not required at this time. Should principal repayments become mandatory, and in the absence of refinancing arrangements, the Corporation would be required to repay the production facility in five equal quarterly installments commencing May 1, 2012 concluding with a final residual payment in May 2013. If the working capital facility is not extended then it will be repayable in full 2 years from such date. As the available lending limits of the facility are based on the Banks' interpretation of the Corporation's reserves and future commodity prices, there can be no assurance that the amount of available facility will not decrease at the next scheduled review on April 19, 2011.

The Corporation's credit facilities contain restrictions on its and its subsidiaries' ability to make distributions, including the declaration or payment of any dividend or the payment of interest on the Debentures. See "Risk Factors – Debt Service" and "Distribution Record and Dividend Policy".

Convertible Debentures

General

Pursuant to the Arrangement, all of the covenants and obligations of the Trust with respect to the Debentures were assumed by the Corporation in accordance with the terms of the Note Indenture.

The 6.75% Debentures mature on August 31, 2012 and bear interest at an annual rate of 6.75% payable semi-annually in arrears on February 28 and August 31 in each year. The 6.75% Debentures are direct obligations of the Corporation and are not secured by any mortgage, pledge, hypothec or other charge. The 6.75% Debentures were issued under, and are governed by, the Note Indenture. The 6.75% Debentures are listed and posted for trading on the TSX under the symbol NAE.DB.

The 6.25% Debentures mature on December 31, 2014 and bear interest at an annual rate of 6.25% payable semi-annually in arrears on June 30 and December 31 in each year. The 6.25% Debentures are direct obligations of the Corporation and are not secured by any mortgage, pledge, hypothec or other charge. The 6.25% Debentures were issued under, and are governed by, the Note Indenture. The Debentures are listed and posted for trading on the TSX under the symbol NAE.DB.A.

Conversion Privilege

The 6.75% Debentures are convertible, at the Debentureholder's option, into fully paid and non-assessable Common Shares at any time prior to the close of business on the earlier of their maturity date and the business day immediately preceding the date specified by the Corporation for redemption of the 6.75% Debentures, at a conversion price of $14.00 per Common Share, being a conversion rate of 71.4286 Common Shares for each $1,000 principal amount of 6.75% Debentures. Debentureholders converting their 6.75% Debentures will receive an amount in cash equal to any accrued and unpaid interest thereon. The 6.75% Debentures may not be converted during the three business days preceding February 28 and August 31 in each year, as the registers of the Debenture Trustee will be closed during such periods. The Note Indenture provides for the adjustment of the conversion price for the 6.75% Debentures upon the occurrence of certain events. No fractional Common Shares will be issued on any conversion of the 6.75% Debenture but in lieu thereof the Corporation shall satisfy fractional interests by a cash payment equal to the current market price of any fractional interest.

The 6.25% Debentures are convertible, at the Debentureholder's option, into fully paid and non-assessable Common Shares at any time prior to the close of business on the earlier of their maturity date and the business day immediately preceding the date specified by the Corporation for redemption of the 6.25% Debentures, at a conversion price of $16.50 per Common Share, being a conversion rate of 60.6061 Common Share for each $1,000 principal amount of 6.25% Debentures. Debentureholders converting their 6.25% Debentures will receive an amount in cash equal to any accrued and unpaid interest thereon. The 6.25% Debentures may not be converted during the three business days preceding June 30 and December 31 in each year, as the registers of the Debenture Trustee will be closed during such periods. The Note Indenture provides for the adjustment of the conversion price for the 6.25% Debentures upon the occurrence of certain events. No fractional Common Shares will be issued on any conversion of the 6.25% Debenture but in lieu thereof the Corporation shall satisfy fractional interests by a cash payment equal to the current market price of any fractional interest.

Redemption and Purchase

As of September 1, 2010, the 6.75% Debentures may be redeemed in whole or in part from time to time at the option of the Corporation on not more than 60 days' and not less than 30 days' prior notice, at a redemption price of $1,050 per 6.75% Debenture on or after September 1, 2010 and on or before August 31, 2011 and at a price equal to $1,025 per 6.75% Debenture on or after September 1, 2011 and before maturity, in each case, plus accrued and unpaid interest thereon, if any. In the case of redemption of less than all of the 6.75% Debentures, the 6.75% Debentures to be redeemed will be selected by the Debenture Trustee on a *pro rata* basis or in such other manner as the Debenture Trustee deems equitable, subject to the approval of the TSX, if applicable.

The 6.25% Debentures are not redeemable on or before December 31, 2012, except in certain limited circumstances as set forth in the Note Indenture. On or after January 1, 2013 and prior to maturity, the 6.25% Debentures may be redeemed in whole or in part from time to time at the option of the Corporation on not more than 60 days' and not less than 30 days' prior notice, at a redemption price of $1,050 per 6.25% Debenture on or after January 1, 2013 and on or before December 31, 2013 and at a price equal to $1,025 per 6.25% Debenture on or after January 1, 2014 and before maturity, in each case, plus accrued and unpaid interest thereon, if any. In the case of redemption of less than all of the 6.25% Debentures, the 6.25% Debentures to be redeemed will be selected by the Debenture Trustee on a *pro rata* basis or in such other manner as the Debenture Trustee deems equitable, subject to the approval of the TSX, if applicable.

Payment upon Redemption or Maturity

On redemption or at maturity, the Corporation is required to repay the indebtedness represented by the Debentures by paying to the Debenture Trustee in lawful money of Canada an amount equal to the aggregate redemption price of the outstanding Debentures which are to be redeemed or the principal amount of the outstanding Debentures which have matured, as the case may be, together, with accrued and unpaid interest thereon, if any. The Corporation may also, at its option, on not more than 60 days and not less than 40 days' (30 days' in the case of the 6.25% Debentures) prior notice in respect of a payment of the redemption price, and not more than 60 days' and not less than 40 days' prior notice in respect of a payment of the principal amount on maturity, and in each case subject to applicable regulatory approval, elect to satisfy its obligation to pay the redemption price of the Debentures which are to be redeemed or the principal amount of the Debentures which have matured, as the case may be, by issuing Common Shares to the holders of such Debentures. Any accrued and unpaid interest thereon will be paid in cash.

The number of Common Shares to be issued will be determined by dividing the aggregate redemption price of the outstanding Debentures which are to be redeemed or the principal amount of the outstanding Debentures which have matured, as the case may be, by 95% of the current market price on the date fixed for redemption or the maturity date, as the case may be. No fractional Common Shares will be issued on redemption or maturity but in lieu thereof the Corporation shall satisfy fractional interests by a cash payment equal to the current market price of any fractional interest. The term "current market price" is defined in the Note Indenture to mean the volume weighted average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending five trading days prior to the date fixed for redemption or the maturity date, as the case may be. The volume weighted average trading price will be determined by dividing the aggregate sale price of all Common Shares sold on the TSX during the 20 consecutive trading days by the total number of Common Shares so sold.

Subordination

The payment of the principal of, and interest on, the Debentures is subordinated and postponed in right of payment, as set forth in the Note Indenture to the prior payment in full of all Senior Indebtedness of the Corporation, including indebtedness to trade creditors of the Corporation. "Senior Indebtedness" of the Corporation is defined in the Note Indenture as the principal of and premium, if any, and interest on and other amounts in respect of all indebtedness of the Corporation (whether outstanding as at the date of the Note Indenture or thereafter incurred), other than indebtedness evidenced by the Debentures and all other existing and future debentures or other instruments of the Corporation which, by the terms of the instrument creating or evidencing the indebtedness, is expressed to be *pari passu* with, or subordinate in right of payment to, the Debentures.

The Note Indenture provides that in the event of any insolvency or bankruptcy proceedings, or any receivership, liquidation, reorganization or other similar proceedings relative to the Corporation, or to its property or assets, or in the event of any proceedings for voluntary liquidation, dissolution of the Corporation, whether or not involving insolvency or bankruptcy, or any marshalling of the assets and liabilities of the Corporation, then those holders of Senior Indebtedness, including any indebtedness to trade creditors, will receive payment in full before the Debentureholders will be entitled to receive any payment or distribution of any kind or character, whether in cash, property or securities, which may be payable or deliverable in any such event in respect of any of the Debentures or any unpaid interest accrued thereon.

Change of Control of the Corporation

Within 30 days following the occurrence of a change of control of the Corporation involving the acquisition of voting control or direction over 66 2/3% or more of the outstanding Common Shares by any person or group of persons acting jointly or in concert (a "**Change of Control**"), the Corporation will be required to make an offer in writing to purchase, in whole or in part, the Debentures then outstanding (the "**Debenture Offer**"), at a price equal to 101% of the principal amount thereof plus accrued and unpaid interest (the "**Debenture Offer Price**").

If 90% or more of the aggregate principal amount of the Debentures outstanding on the date of the giving of notice of the Change of Control have been tendered to the Corporation pursuant to the Debenture Offer, the Corporation will have the right to redeem all the remaining Debentures at the Debenture Offer Price. Notice of such redemption must be given by the Corporation to the Debenture Trustee within 10 days following the expiry of the Debenture Offer, and as soon as possible thereafter, by the Debenture Trustee to the holders of the Debentures not tendered pursuant to the Debenture Offer.

Interest Payment Option

The Corporation may elect, subject to regulatory approval, to satisfy its obligation to pay all or any part of the interest on the Debentures by delivering sufficient Common Shares to the Debenture Trustee to satisfy all or the part, as the case may be, of the interest payment obligation in accordance with the Note Indenture. The Note Indenture provides that, upon such election, the Debenture Trustee shall accept delivery of Common Shares, accept bids with respect to, and consummate sales of, such Common Shares, and use the proceeds received to satisfy the interest payment obligation for the Debentures.

Events of Default

The Note Indenture provides that an event of default ("**Event of Default**") in respect of the Debentures will occur if any one or more of the following described events has occurred and is continuing with respect to such Debentures: (i) failure for 10 days to pay interest on such Debentures when due; (ii) failure to pay principal or premium, if any, on such Debentures when due, whether at maturity, upon redemption, by declaration or otherwise; (iii) default in the observance or performance of any material covenant or condition of the Note Indenture and continuance of such default for a period of 30 days after notice in writing has been given by the Debenture Trustee to the Corporation specifying such default and requiring the Corporation to rectify the same; or (iv) certain events of bankruptcy, insolvency or reorganization of the Corporation under bankruptcy or insolvency laws. If an Event of Default has occurred and is continuing, the Debenture Trustee may, in its discretion, and shall upon request of holders of not less than 25% of the principal amount of the Debentures then outstanding under the Note Indenture, declare the principal of and interest on all outstanding Debentures to be immediately due and payable. In certain cases, the holders of more than 50% of the principal amount of all Debentures then outstanding under the Note Indenture may, on behalf of the holders of all such Debentures, waive any Event of Default and/or cancel any such declaration upon such terms and conditions as such holders of Debentures shall prescribe.

Offers for Debentures

The Note Indenture contains provisions to the effect that if an offer is made for the Debentures which is a take-over bid for such Debentures within the meaning of the *Securities Act* (Alberta) and not less than 90% of the Debentures (other than Debentures held at the date of the take-over bid by or on behalf of the offeror or associates or affiliates of the offeror) are taken up and paid for by the offeror, the offeror will be entitled to acquire the Debentures held by the Debentureholders who did not accept the offer on the terms offered by the offeror.

Modification

The rights of the Debentureholders as well as any other series of debentures that may be issued under the Note Indenture may be modified in accordance with the terms of the Note Indenture. For that purpose, among others, the Note Indenture contains certain provisions which will make binding on all Debentureholders resolutions passed at meetings of the Debentureholders by votes cast thereat by holders of not less than 66 2/3% of the principal amount of the Debentures present at the meeting or represented by proxy, or rendered by instruments in writing signed by the holders of not less than 66 2/3% of the principal amount of the Debentures then outstanding. In certain cases, the modification will, instead or in addition, require assent by the holders of the required percentage of Debentures of each particularly affected series.

Limitation on Issuance of Additional Debentures

The Note Indenture provides that the Corporation shall not issue additional convertible debentures of senior or equal ranking to the Debentures if the principal amount of all issued and outstanding convertible debentures of the Corporation exceeds 25% of the Total Market Capitalization of the Corporation immediately after the issuance of such additional convertible debentures. The term "Total Market Capitalization" is defined in the Note Indenture as the total principal amount of all issued and outstanding debentures of the Corporation which are convertible at the option of the holder into Common Shares plus the amount obtained by multiplying the number of issued and outstanding Common Shares by the current market price of the Common Shares on the relevant date.

NAL RESOURCES MANAGEMENT LIMITED

Background

The Manager provides ongoing advisory, management and administrative services to institutional investors (including insurance companies) in the Canadian petroleum and natural gas industry. The Manager's responsibilities include operatorship of many of its clients' direct Working Interests, the design and implementation of exploitation and development programs, the ongoing maintenance of properties and financial reporting. The Manager also supervises properties under its administration that it does not operate and participates in joint venture decisions such as annual budgets, development proposals and capital expenditure approvals. It also participates in routine financial audits of operators to ensure compliance with relevant operating agreements. It is the Manager's policy not to purchase any petroleum and natural gas properties for its own account.

The primary duties of the Manager under the Administrative Services Agreement are to: (i) manage the Corporation; (ii) provide management services for the economic and efficient exploitation of oil and natural gas properties; (iii) operate oil and natural gas properties which NAL is entitled to operate and monitor the activities of third party operators; (iv) recommend, carry out and monitor property acquisitions and dispositions and exploitation and development programs for NAL; (v) negotiate, execute and amend, on behalf of NAL, all exploitation and development agreements, operating agreements, working agreements, farm-in and farm-out agreements, leases and other documents relating to the exploitation of the oil and natural gas properties as may be advisable; (vi) recommend and, subject to the direction of NAL, negotiate banking arrangements for NAL; and (vii) provide office space, office furnishings and equipment and personnel necessary for the proper administration of the assets of NAL.

The Administrative Services Agreement also provides that the obligations of the Manager under the agreement shall extend to the management of all oil and gas properties owned by NAL's subsidiaries, as well as to the management of the general administrative affairs of such subsidiaries as contemplated by the Administrative Services Agreement.

The Manager employs approximately 350 employees and 117 consultants on a full and part-time basis.

Compensation

Pursuant to the Administrative Services Agreement, the Manager is entitled to reimbursement for its General and Administrative Expenses in providing management and administrative services to NAL. General and Administrative Expenses are generally allocated to NAL by the Manager on a unit of production basis. Costs and expenses including, without limitation, management time incurred by the Manager in connection with the design and implementation of exploitation and development programs, are charged on an actual time expended basis. The Manager no longer receives any base or performance fees from NAL.

From January 1, 2010, to December 31, 2010, NAL reimbursed the Manager an aggregate of $13.9 million for General and Administrative Expenses incurred in managing NAL and $7.1 million for share-based compensation.

DIRECTORS AND OFFICERS

The name, municipality of residence, position with the Corporation and principal occupation of each of the directors and executive officers of the Corporation are as follows:

Name and Municipality of Residence	Position Held	Principal Occupation	Director Since
Irvine J. Koop (1)(2)(3) Calgary, Alberta, Canada	Chairman of the Board of Directors	Retired Petroleum Executive	March 1996
Andrew B. Wiswell Calgary, Alberta, Canada	President & Chief Executive Officer, Director	President & Chief Executive Officer of the Manager	May 2005
Kelvin B. Johnston (1)(2)(3) Calgary, Alberta, Canada	Director	Vice President, Corporate Development of Lakeview Energy Ltd. and President of Wylander Crude Corp.	May 19, 2010
Barry D. Stewart (1)(2)(3)(4) Calgary, Alberta. Canada	Director	Retired Petroleum Executive	May 2002
Gordon Lackenbauer(1)(2)(3)(4) Calgary, Alberta, Canada	Director	Retired Investment Banking Executive	July 2006

Name and Municipality of Residence	Position Held	Principal Occupation	Director Since
Donald R. Ingram[(1)(2)(3)(4)] Calgary, Alberta, Canada	Director	Retired Petroleum Executive	May, 2009
William J. Eeuwes Toronto, Ontario, Canada	Director	Senior Vice President & Managing Director of Manulife Capital	December 2008
Keith A. Steeves Calgary, Alberta, Canada	Vice President, Finance & Chief Financial Officer	Vice President, Finance & Chief Financial Officer of the Manager	-
Marlon J. McDougall Calgary, Alberta, Canada	Vice President, Operations & Chief Operating Officer	Vice President, Operations & Chief Operating Officer of the Manager	-
John C. Koyanagi Calgary, Alberta, Canada	Vice President, Business Development	Vice President, Business Development of the Manager	-
John H. Kousinioris Calgary, Alberta, Canada	Corporate Secretary	Partner, Bennett Jones LLP	-

Notes:

(1) Independent Director.
(2) Member of Audit Committee.
(3) Member of Reserves Committee.
(4) Member of Corporate Governance, Environment, Health & Safety Committee.

Directors of the Corporation hold office for a term expiring not later than the close of the next annual meeting of the Corporation following their election.

Each of the foregoing directors and executive officers has had the same principal occupation for the previous five years except for Irvine Koop who was Chairman and Chief Executive Officer of IKO Resources Inc. from 2001 to January 2008; Gordon Lackenbauer who was Deputy Chairman of BMO Nesbitt Burns prior to his retirement; Kel Johnston who was President and Chief Executive Officer of Alberta Clipper from 2005 to 2009; Donald Ingram who was Senior Vice President, Midstream & Refined Products of Husky Energy Inc. from 2000 to 2008; Keith Steeves who was Corporate Financial Officer of Irving Oil Limited from 2004 to 2006; Marlon McDougall who held a variety of positions with Northrock Resources Ltd. including, most recently, as Vice President, Operations until December 2006; and John Koyanagi who was Managing Director at Canaccord Enermarket from 2006 to 2008.

Except as provided below, the directors and executive officers of the Corporation, as a group, beneficially own, directly or indirectly, or exercise control or direction over 202,550 Common Shares, being less than 1% of the Common Shares currently issued and outstanding. William Eeuwes is an officer of Manulife which holds 1,592,357 Common Shares or approximately 1.079% of the Common Shares currently issued and outstanding.

NAL Resources Management Limited

The name, municipality of residence, position with the Manager and principal occupation of each of the directors and executive officers of the Manager are as follows:

Name and Municipality of Residence	Position Held	Principal Occupation	Director Since
William Eeuwes Toronto, Ontario, Canada	Chairman of the Board of Directors	Senior Vice President & Managing Director of Manulife Capital	February 2009
Irvine J. Koop(1) Calgary, Alberta, Canada	Director	Retired Petroleum Executive	September 2006
Andrew B. Wiswell Calgary, Alberta, Canada	Director, President & Chief Executive Officer	President & Chief Executive Officer	May 2005
Kevin J.E. Adophe Toronto, Ontario, Canada	Director	Chief Operating Officer, Investments of Manulife Financial and President & Chief Executive Officer of Manulife Real Estate	May 2007
Barry D. Stewart Calgary, Alberta, Canada	Director	Retired Petroleum Executive	September 2006
Kelvin B. Johnston(1) Calgary, Alberta, Canada	Director	Vice President, Corporate Development of Lakeview Energy Ltd. and President of Wylander Crude Corp.	May 19, 2010
Keith A. Steeves Calgary, Alberta, Canada	Vice President, Finance & Chief Financial Officer	Vice President, Finance & Chief Financial Officer	-
Marlon J. McDougall Calgary, Alberta, Canada	Vice President, Operations & Chief Operating Officer	Vice President, Operations & Chief Operating Officer	-
John C. Koyanagi Calgary, Alberta, Canada	Vice President, Business Development	Vice President, Business Development	-
Alicia K. Quesnel Calgary, Alberta, Canada	Corporate Secretary	Partner, Burnet, Duckworth & Palmer LLP	

Note:

(1) On May 19, 2010, Mr. Koop resigned as a director of NAL Resources Management Limited and Mr. Johnston was appointed in his place.

Directors of the Manager hold office for a term expiring not later than the close of the next annual meeting of the Manager following their election.

Each of the foregoing directors and officers has had the same principal occupation for the previous five years except for Irvine Koop who was Chairman and Chief Executive Officer of IKO Resources Inc. from 2001 to January 2008; Kel Johnston who was President and Chief Executive Officer of Alberta Clipper from 2005 to 2009; Keith Steeves who was Chief Financial Officer of Irving Oil Limited from 2004 to 2006; Marlon McDougall who held a variety of positions with Northrock Resources Ltd. including, most recently, as Vice President, Operations until December 2006; and John Koyanagi who was Managing Director at Canaccord Enermarket from 2006 to 2008.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

To the knowledge of the Corporation, no directors or executive officers of the Corporation: (a) are, as at the date hereof, or have been, within the 10 years before the date hereof, a director, chief executive officer or chief financial officer of any company, including NAL and any personal holding companies, that, (i) was subject to a 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 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 (ii) 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; (b) are, as at the date hereof, or have been within 10 years before the date hereof, a director or executive officer of any company, including NAL and any personal holding companies, 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 (c) have, within the 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director or executive officer, except as set forth below.

William J. Eeuwes was a director of a private company, Micro-Optics Development Corp. until April 2003. Within a year after his resignation as a director, that company was subject to a court appointed trustee and filed for court protection under insolvency statutes.

AUDIT COMMITTEE

The full text of the audit and risk management committee charter is included in Appendix C of this Annual Information Form.

Composition of the Audit Committee

The audit committee of the Corporation consists of five members: Messrs. Irvine J. Koop, Barry D. Stewart, Gordon S. Lackenbauer, Donald R. Ingram and Kel B. Johnston. The Board of Directors has determined that each member of the audit committee is "independent" and "financially literate", as such terms are defined in National Instrument 52-110 – *Audit Committees.*

Relevant Education and Experience

In addition to each member's general business experience, the education and experience of each Audit Committee member that is relevant to the performance of his responsibilities as an Audit Committee member is outlined below:

Irvine J. Koop

Mr. Koop is the Chairman of the Board of Directors and a retired petroleum executive. From 2001 to 2008, he was Chairman and Chief Executive Officer of IKO Resources Inc. From 1993 to 1995, he was President and Chief Executive Officer of Numac Energy Inc., an exploration and production company. From 1996 to 2001, Mr. Koop was a senior executive with Westcoast Energy Inc., from where he retired in 2001 as Executive Vice President, President and Chief Executive Officer, Pipelines and Midstream. Mr. Koop is also a director of Compton Petroleum Corporation and a past Chair of the Canadian Energy Research Institute. He was the inaugural Chairman of CAPP in 1991. He holds a Bachelor of Science in Mechanical Engineering from the University of Manitoba and has completed the Advanced Management Program at the Wharton School of Business.

Barry D. Stewart

Mr. Stewart is a retired petroleum executive. Previously, Mr. Stewart was Executive Vice President, In-Situ and International Oil of Suncor Energy Inc. from 2000 to 2001 and from 1991 to 1999, was Executive Vice President, Exploration & Production with Suncor Energy Inc. He is the Past Chairman of the board of the Center for Affordable Water and Sanitation Technology and is a director and chairman of the board of Newalta Inc. Mr. Stewart has a Bachelor of Science in Engineering Physics from Queen's University.

Gordon S. Lackenbauer

Mr. Lackenbauer was Deputy Chairman of BMO Nesbitt Burns, and brings significant financial expertise to his position, including a background in energy, capital markets, and mergers and acquisitions. He currently serves as a director of TransAlta Corporation.

Donald R. Ingram

Mr. Ingram is an independent businessman. Prior thereto, Mr. Ingram was Senior Vice President, Midstream & Refined Products of Husky Energy Inc., a fully integrated oil and gas company, from August 2000 until August 2008. From 2002 until 2008, Mr. Ingram was also Chairman and a Director of Sultran Ltd., a sulphur logistics and transportation company. He currently serves as chairman of the board of SilverBirch Energy Corporation and is a director and chairman of the audit committee of Greenfields Petroleum Corporation.

Kelvin B. Johnston

Mr. Johnston is an executive with over 25 years of experience as founder, president, chief executive officer and director of various public and private companies in Canada. Mr. Johnston has been President of Wylander Crude Corp., a private oil and gas company, since July 2006, and Vice President, Corporate Development of Lakeview Energy Ltd., a private oil and gas company, since June 2009. From July 2005 until June 2009, Mr. Johnston was President and Chief Executive Officer of Alberta Clipper. From May 2004 to July 2005, Mr. Johnston was Vice-President, Exploration of Thunder Energy Ltd., an oil and gas company. Prior thereto, Mr. Johnston served in various capacities at Husky Oil Ltd., Startech Energy Inc., Impact Energy Inc., Mustang Resources Ltd. and Peerless Energy Inc. Mr. Johnston has a Bachelor of Science (Hons.) degree in Geology from the University of Manitoba and a Masters degree in Economics from the University of Calgary. He currently serves as a director of Small Explorers and Producers Association of Canada (SEPAC).

Pre-Approval Policies and Procedures

The Corporation has adopted policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by KPMG LLP. The audit committee approves an annual budget for the provision of a specified list of audit and permitted non-audit services that the audit committee believes to be typical, recurring or otherwise likely to be provided by KPMG LLP.

The audit committee must approve any unbudgeted non-audit services, with the Chairman of the audit committee having the authority to approve any unbudgeted non-audit expenditure up to a specified quarterly maximum of $25,000. The Chairman is to report any such approvals at the next quarterly audit committee meeting.

External Auditor Services Fees

The following table provides information about the fees billed to NAL Energy for professional services rendered by KPMG LLP during fiscal 2010 and 2009:

($ thousands)	**2010**	**2009**
Audit Fees(1)	183	160
Audit-Related Fees(2)	79	72
Tax Fees(3)	0	2.5
All Other Fees(4)	277	390
Total	539	624.5

Notes:

(1) Audit fees consist of fees for the audit of the Corporation's annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements.

(2) Audit-related fees consist of fees for assurance and related services that are reasonably related to the performance of the audit or review of the Corporation's financial statements and are not reported as Audit Fees. During fiscal 2010 and 2009, the services provided in this category included review of quarterly financial statements.

(3) Tax fees consist of fees for tax compliance services, tax advice and tax planning.

(4) During fiscal 2010 and 2009, the services provided in this category included information circular review, prospectus review and review and discussion of IFRS position papers.

RISK FACTORS

Volatility of Oil and Natural Gas Prices

NAL's results of operations and financial condition are dependent on the prices received for its oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, which are beyond the control of NAL. These factors include, but are not limited to, global energy policy, including the ability of the Organization of the Petroleum Exporting Countries to set and maintain production levels for oil, geopolitical conditions, worldwide economic conditions, weather conditions, the supply and price of foreign oil and natural gas, the level of consumer demand, the price and availability of alternative fuels, the proximity to and capacity of transportation facilities, the effect of worldwide energy conservation measures, and government regulation.

Any decline in oil or natural gas prices could have a material adverse effect on NAL's operations, financial condition, Proved reserves and the level of expenditures for the development of the oil and natural gas reserves. Management of NAL may enter into hedging or derivative transactions on a portion of overall production at certain times to manage the risk associated with oil and natural gas price fluctuations. Dividend levels will therefore be sensitive to prevailing oil and natural gas prices.

Reserves Replacement (Sustainability)

NAL's area of business focus is the Western Canadian Sedimentary Basin, which is a mature basin with significant natural production declines. NAL's future oil and natural gas reserves and production, and therefore its cash flow, will depend upon its success in acquiring and/or developing additional reserves. If NAL fails to add reserves by acquiring or developing them, NAL's reserves and production will decline over time as current reserves are produced. When oil and gas from NAL's properties can no longer be economically produced and marketed, the Common Shares will have no value unless additional reserves have been acquired or developed. If NAL is unable to raise capital on favourable terms, NAL may not be able to add to or maintain its reserves. If NAL uses its cash flow to acquire or develop reserves, it will reduce the amount of cash available to be distributed to Shareholders.

There is strong competition in all aspects of the oil and gas industry, including reserve acquisitions. NAL will actively compete for reserve acquisitions and skilled industry personnel with other oil and gas companies and organizations. However, no assurance can be given that NAL will be successful in acquiring additional reserves on terms that meet its objectives and, to the extent that NAL is not successful in adding acquisitions, production and reserves will decline over time.

Future oil and natural gas exploration may involve unprofitable efforts, not only from unsuccessful wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Purchase of Reserves

The purchase price for petroleum or natural gas interests will be based on engineering and economic assessments made by independent engineers. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, future prices of oil and natural gas 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 Manager or NAL. In particular, changes in the prices of, and markets for, oil and natural gas from those anticipated at the time of making such assessments will affect the return on and value of the Common Shares. In addition, all such assessments involve a measure of geological and engineering uncertainty, which could result in lower production and reserves than anticipated.

Although title reviews are conducted prior to any purchase of significant resource assets, such reviews cannot guarantee that an unforeseen defect in the chain of title will not arise to defeat the Corporation's title to certain assets. Such defects could reduce the amount of cash flow, possibly resulting in lower dividends to Shareholders which could result in a lower market price of the Common Shares.

Uncertainty of Reserve Estimates

The value of the Common Shares will depend upon, among other things, the Corporation's reserves. In making strategic decisions, the Manager and the Corporation rely upon reports prepared by NAL's independent reserve engineers and NAL's own internal estimates. Estimating future production and reserves is inherently uncertain. Ultimately, actual production, revenues and expenditures for the underlying properties will vary from estimates and those variations could be material. Changes in the prices of, and markets for, oil and natural gas from those anticipated at the time of making such assessments will affect the return on, and value of, the Common Shares. The reserve and cash flow information contained herein represent estimates only.

Petroleum engineers consider many factors and make assumptions in estimating reserves. If any of these factors and assumptions prove to be inaccurate, NAL's actual results may vary materially from its reserve estimates. Many of these factors are subject to change and are beyond NAL's control. In particular, changes in the prices of, and markets for, oil and natural gas from those anticipated at the time of making such assessments will affect the return on, and value of, the Common Shares. In addition, all such assessments involve a measure of geological and engineering uncertainty that could result in lower production and reserves than anticipated. A portion of NAL's reserves are classified as "undeveloped" and are subject to greater uncertainty than reserves classified as "developed".

In accordance with normal industry practices, NAL engages independent petroleum engineers to conduct a detailed engineering evaluation of the Corporation's oil and gas properties for the purpose of estimating its reserves as part of the year-end reporting process. As a result of that evaluation, NAL may increase or decrease the estimates of its reserves. Any significant reduction to the estimates of NAL's reserves resulting from any such evaluation could have a material adverse effect on the value of the Common Shares.

Marketability of Oil and Natural Gas Production

The marketability of NAL's production depends in part upon the availability, proximity and capacity of gas gathering systems, pipelines and processing facilities. United States federal and state and Canadian federal and provincial regulation of oil and gas production and transportation, general economic conditions, and changes in supply and demand could adversely affect NAL's ability to produce and market oil and natural gas. If market factors dramatically change, the financial impact on NAL could be substantial. The availability of markets is beyond the Corporation's control.

Debt Service

The Corporation has a revolving term credit facility and a revolving working capital facility in an aggregate amount of up to $550 million. A total of $267 million was drawn as of December 31, 2010. 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 dividends. Although the Manager and the Corporation believe that the existing credit facilities are sufficient for immediate requirements, there can be no assurance that the amount will be adequate for the future financial obligations of the Corporation and its subsidiaries or that additional funds will be obtainable.

The Banks have security over substantially all of the assets of the Corporation and its subsidiaries. If NAL becomes unable to pay its Debt Service Charges or otherwise commits an event of default such as bankruptcy, the Banks may foreclose on or sell the assets, and the net proceeds of sale will be allocated firstly to the repayment of Bank debt and the remainder, after paying all creditors of the Corporation and its subsidiaries, will be payable to the Corporation.

The Corporation's credit facilities contain restrictions on its and its subsidiaries' ability to make distributions, including the declaration or payment of any dividend or the payment of interest on the Debentures when (i) a default or event of default under the bank credit facilities has occurred and is continuing or would reasonably be expected to occur as a result of such payment; or (ii) outstanding loans under the bank credit facilities exceed the borrowing base set by the lenders thereunder until such time as such outstanding loans are reduced below the borrowing base. The borrowing base is generally re-determined by the lenders on a semi-annual basis and may be re-determined at other times, including upon the acquisition or disposition of assets beyond certain defined limits. See "Borrowings – Credit Facilities".

Availability of Future Financing

The Corporation may find it necessary in the future to obtain additional debt or equity financing to support ongoing operations, to undertake capital expenditures, to repay existing indebtedness or to undertake acquisitions or other business combination transactions. There can be no assurance that additional financing will be available to the Corporation when needed or on terms acceptable or favourable to the Corporation. The Corporation's inability to raise financing to support ongoing operations or to fund capital expenditures, acquisitions, debt repayments or other business combination transactions could limit the Corporation's growth and may have a material adverse effect upon the Corporation.

Conditions of the Credit Markets

The ability to make scheduled payments on or to refinance debt obligations depends on the financial condition and operating performance of the Corporation, which is subject to prevailing economic and competitive conditions and to certain financial, business and other factors beyond its control. The credit markets have recently experienced and continue to experience adverse conditions. Continuing volatility in the credit markets may increase costs associated with debt instruments due to increased spreads over relevant interest rate benchmarks, or affect the ability to access those markets of the Corporation or third parties it seeks to do business with. The Corporation may be unable to maintain a level of cash flow from operating activities sufficient to permit it to pay the principal, premium, if any, and interest on its indebtedness.

In addition, there has been substantial uncertainty in the capital markets and access to financing is uncertain. These conditions could have an adverse effect on the industry in which the Corporation operates and its business, including future operating results.

Amount of Future Dividends

The amount of future cash dividends, if any, will be subject to the discretion of the Corporation's board of directors and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, the availability of external sources of capital, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends. Depending on these and various other factors, many of which will be beyond the control of the board of directors and the Manager, the Corporation will change its dividend policy from time to time and as a result, future cash dividends could be reduced or suspended entirely. The market value of the Common Shares may deteriorate if the Corporation reduces or suspends the amount of the cash dividends that it pays in the future and such deterioration may be material. Furthermore, the future treatment of dividends for tax purposes will be subject to the nature and composition of the Corporation's dividends and potential legislative and regulatory changes.

Operational Matters

Continuing production from a property, and to some extent the marketing of production therefrom, are dependent upon the ability of the operator of the property. To the extent the operator fails to perform these functions properly or becomes insolvent, revenue may be reduced. Payments from production generally flow through the operator. Where the Manager is not the operator, there is a risk of delay and additional expense in receiving such revenues. Any delay in payment along the production chain could adversely affect the amount of cash available for the payment of dividends.

The operation of the wells located on properties not operated by the Manager are generally governed by operating agreements which typically require the operator to conduct operations in a good and workman-like manner. Operating agreements generally provide, however, that the operator will have no liability to the other non-operating working interest owners for losses sustained or liabilities incurred, except such as may result from gross negligence or wilful misconduct. In addition, third-party operators are generally not fiduciaries with respect to the Corporation or Shareholders. As owner of working interests in properties not operated by the Manager, the Corporation will generally have a cause of action for damages arising from a breach of the operator's duty. Therefore, Shareholders will be dependent upon the Corporation, as owner of the working interest, to enforce such rights.

The operation of oil and natural gas wells involves a number of operating and natural hazards, which may result in blowouts, environmental damage and other unexpected or dangerous conditions resulting in damage to NAL and possible liability to third parties. The Manager and NAL will maintain liability insurance, where available, in amounts consistent with industry standards. Business interruption insurance may also be purchased for selected facilities to the extent such insurance is available. The Manager and NAL may become liable for damages arising from such events against which they cannot insure or against which they may elect not to insure because of high premium costs or other reasons. Costs incurred to repair such damage or pay such liabilities will reduce the amount of cash available for the payment of dividends.

Environmental and Health and Safety Risks

Compliance with environmental and human health and safety laws and regulations could materially increase the Corporation's costs of operations. The Corporation may incur substantial capital and operating costs to comply with increasingly complex laws and regulations covering the protection of the environment and human health and safety. In particular, the Corporation may be required to incur significant costs to comply with legislation and regulations to reduce emissions of greenhouse gases into the air. See "Industry Conditions – Environmental Regulation".

Competition in Energy Industry

There is strong competition relating to all aspects of the oil and gas industry. NAL will actively compete for capital, undeveloped lands, reserve acquisitions, skilled industry personnel, access to service equipment, access to processing facilities and pipeline and refining capacity against much larger, well-established oil and natural gas companies, many of which have significantly greater technical and financial resources than NAL. NAL may not be able to compete successfully with some of these larger, well-established competitors. As a result, there can be no assurance that NAL will be successful in developing additional reserves or acquiring additional reserves on terms that meet the Corporation's investment criteria.

Currency Exchange Rates

The Corporation's operating costs, including costs of production, are generally paid in Canadian dollars. World oil prices are quoted in U.S. dollars and the price Canadian producers receive is therefore affected by the Canadian/U.S. dollar exchange rate that will fluctuate over time. A material increase in the value of the Canadian dollar may negatively impact the Corporation's production revenue. A decline in the value of the Canadian dollar relative to the United States dollar provides a competitive advantage to United States companies in acquiring Canadian oil and gas properties and may make it more difficult for NAL to replace reserves through acquisitions.

Risks Associated with Changes to Accounting Policies

In January 2006, the Canadian Institute of Chartered Accountants' Accounting Standards Board ("**AcSB**") adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, the AcSB confirmed in February 2008 that International Financial Reporting Standards ("**IFRS**") will replace Canadian GAAP in 2011 for Canadian publicly accountable enterprises. While IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences that must be evaluated.

The implementation of IFRS may result in significant adjustments to the Corporation's financial results, which could negatively impact its business, including increasing the risk of failing a financial covenant contained within the Corporation's credit facilities. At this time, NAL cannot reasonably quantify the full impact that adopting

IFRS will have on its financial position and future results. For information regarding the impact that IFRS will have on the Corporation's accounting policies and financial statements, see the Corporation's 2010 MD&A filed on SEDAR.

Hedging Activities

To the extent that the Corporation has engaged, or in the future engages, in risk management activities related to commodity prices and foreign exchange rates, through entry into oil or natural gas price commodity contracts and foreign exchange contracts or otherwise, the Corporation may be subject to unfavourable price changes and credit risks associated with the counterparties with which it contracts.

Risks Affecting the Trading Price of Common Shares

The Corporation may issue additional Common Shares in the future for acquisitions or to directly or indirectly fund capital expenditure requirements now or hereafter owned directly or indirectly by the Corporation. Such additional Common Shares may be issued without the approval of Shareholders. Shareholders have no pre-emptive rights in connection with such additional issues. The Corporation has discretion in connection with the price and the other terms of the issue of such additional Common Shares.

The market price of the Common Shares is sensitive to a variety of market based factors including, but not limited to, interest rates, foreign exchange rates and the comparability of the Common Shares to other yield-oriented securities. Any changes in these market-based factors may adversely affect the trading price of the Common Shares.

Changes in Legislation

The oil and gas industry in Canada is subject to federal, provincial and municipal legislation and regulation governing such matters as land tenure, prices, royalties, production rates, environmental protection controls, the exportation of crude oil, natural gas and other products, as well as other matters. The industry is also subject to regulation by governments in such matters as the awarding or acquisition of exploration and production rights, oil sands or other interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields and mine sites (including restrictions on production) and possibly expropriation or cancellation of contract rights.

Government regulations may change from time to time in response to economic or political conditions. The exercise of discretion by governmental authorities under existing regulations, the implementation of new regulations or the modification of existing regulations affecting the crude oil and natural gas industry could reduce demand for crude oil and natural gas or increase the Corporation's costs, either of which would have a material adverse impact on NAL. See "Industry Conditions".

Third Party Credit Risk

NAL is exposed to third party credit risk through its contractual arrangements with current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to NAL, such failures could have a material adverse effect on NAL and its cash flow from operations. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in NAL's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

Risks Associated with Terrorist Activities

Energy sector participants, including NAL, are a potential target for terrorists. The possibility that infrastructure facilities may be direct targets of, or indirectly affected by, an act of terror and the implementation of security measures as a precaution against possible terrorist attacks will result in increased costs to the Corporation's business.

Experience of the Manager

Shareholders will be entirely dependent on the Manager in respect of administration of all matters relating to NAL for so long as the Administrative Services Agreement remains in force. Moreover, the Corporation's operations are highly dependent on the executive officers and management employees of the Manager; the unexpected loss of the services of any of these individuals could have a detrimental effect on the operations, financial condition, results of operation and prospects of the Corporation. The contributions of the existing management team to our immediate and near term operations are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that NAL will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Increased activity within the oil and gas sector can increase the cost of goods and services and make it more difficult to attract and retain qualified professional staff. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of management.

Potential Conflicts of Interest

There may be situations in which the interests of the Manager will conflict with those of the Shareholders. Neither the Manager, nor its management, will carry on their full-time activities on behalf of NAL and, when acting on behalf of others, may at times act in contradiction to or in competition with the interests of NAL. In resolving such conflicts the Manager is obliged to act in good faith with a view to the best interests of Shareholders.

Circumstances may arise where members of the Board of Directors and the Corporation's subsidiaries are directors or officers of corporations which are in competition with the interests of NAL. No assurances can be given that opportunities identified by such board members will be provided to NAL.

Possible Negative Tax Consequences for Previous Transactions

The business and operations of the Trust prior to the completion of the Arrangement were complex and the Trust executed a number of significant financings, business combinations, acquisitions and dispositions over the course of its history. The computation of income taxes payable as a result of these transactions involves many complex factors as well as the Corporation's interpretation of relevant tax legislation and regulations. As part of the Arrangement, and prior to the dissolution of the Trust, the Corporation assumed all of the obligations and liabilities of the Trust. The Corporation believes that the provision for income tax is adequate and in accordance with Canadian GAAP and applicable legislation and regulations. However, there are a number of tax filing positions that can still be the subject of review by taxation authorities who may successfully challenge the Corporation's interpretation of the applicable tax legislation and regulations, with the result that additional taxes could be payable by the Corporation. Any increase in tax liability would reduce the net assets of and funds available to the Corporation.

CONFLICTS OF INTEREST

There may be situations in which the interests of the Manager will conflict with those of Shareholders. The Manager expects to acquire oil and natural gas properties on behalf of persons other than the Shareholders, including Manulife. The Manager may manage and administer such additional properties, as well as enter into other types of energy-related management and advisory activities. Thus, neither the Manager, nor its management, will carry on their full-time activities on behalf of Shareholders and, when acting on behalf of others, may at times act in contradiction to or in competition with the interests of Shareholders.

In resolving such conflicts, decisions will be made on a basis consistent with the objectives and funds of each group of interested parties and the time limitations on investment of such funds, all consistent with the duty of the Manager to deal fairly and in good faith with each such group of persons. In the event that the interests of the Manager are in conflict with those of the Shareholders, the Manager is obliged to make decisions acting in good faith, having regard to the best interests of Shareholders and in a manner that would not contravene its fiduciary obligations to Shareholders.

Oil and natural gas properties will occasionally be made available for purchase in areas where the Manager's clients will hold interests. In such circumstances, the Manager shall provide each of its clients, including the Corporation and its subsidiaries and Manulife, with the opportunity to participate in the acquisition of such properties on a pro rata basis.

Although the Manager will provide advisory and management services to the Corporation, the Board of Directors will supervise the management of the business and affairs of the Corporation, and make all final decisions relating to: (i) operations; (ii) the acquisition and disposition of properties; (iii) capital expenditures; (iv) borrowing; and (v) the payment of dividends.

Properties will not be acquired from officers or directors of the Manager or persons not at arm's length with such persons at prices which are greater than fair market value, nor will Properties be sold to officers or directors of the Manager or persons not at arm's length with such persons at prices which are less than fair market value in each case as established by an opinion of an independent financial advisor and approved by the independent members of the Board of Directors. There may be circumstances where certain transactions may also require the preparation of a formal valuation and the affirmative vote of Shareholders in accordance with the requirements of Multilateral Instrument 61-101 - *Protection of Minority Security Holders in Special Transactions*.

Circumstances may arise where members of the Board of Directors serve as directors or officers of corporations which are in competition to the interests of NAL. No assurances can be given that opportunities identified by such board members will be provided to NAL.

LEGAL PROCEEDINGS

The Corporation is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Corporation's favor, the Corporation does not currently believe that the outcome of any pending or threatened proceedings related to these or other matters, or the amounts which the Corporation may be required to pay by reason thereof, would have a material adverse impact on its financial position, results of operations or liquidity.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares is Computershare Trust Company of Canada at its principal offices in the cities of Montreal, Toronto, Calgary and Vancouver. Computershare Trust Company of Canada is also the trustee and registrar and transfer agent for the Debentures at its principal offices in the cities of Toronto and Calgary.

INTERESTS OF EXPERTS

KPMG LLP, Chartered Accountants, is the auditor of the Corporation and such firm has prepared an opinion with respect to the Trust's consolidated financial statements as at and for the fiscal year ended December 31, 2010. KPMG LLP is independent in accordance with the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

Information relating to reserves in this Annual Information Form was calculated by McDaniel as independent qualified reserves evaluators. The principals of McDaniel, as a group, own beneficially, directly or indirectly, less than one percent of the Corporation's securities.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business or otherwise disclosed in this Annual Information Form, the only material contracts outstanding are the following:

1. the Administrative Services Agreement;
2. the Note Indenture; and
3. the amended and restated credit agreement dated January 1, 2011, as amended and supplemented, governing the credit facilities of the Corporation.

Each of these documents is accessible on SEDAR at www.sedar.com.

ADDITIONAL INFORMATION

Additional information relating to the Corporation is available on SEDAR at www.sedar.com.

Additional information, including directors' remuneration and indebtedness, principal holders of the Common Shares and securities authorized for issuance under equity compensation plans, will be set forth in the Corporation's information circular for the Annual Meeting of Shareholders to be held on May 25, 2011.

Additional financial information is contained in the annual consolidated financial statements of the Trust for the year ended December 31, 2010.

APPENDIX A

FORM 51-101F2
REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES
EVALUATOR

To the board of directors of NAL Energy Corporation (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.

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

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us, for the year ended December 31, 2010, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management:

Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) (M$)			
		Audited	Evaluated	Reviewed	Total
March 8, 2011	Canada	-	1,677,546	-	1,677,546

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

6. We have no responsibility to update our 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. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

March 8, 2011, Calgary, Alberta, Canada.

McDaniel & Associates Consultants Ltd.

(Signed) P. A. Welch, P. Eng.
President & Managing Director

APPENDIX B

FORM 51-101F3
REPORT OF
MANAGEMENT AND DIRECTORS ON
RESERVES DATA AND OTHER INFORMATION

Management of NAL Energy Corporation (the "Corporation") is responsible for the preparation and disclosure of information with respect to the oil and gas activities of the Corporation in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Corporation has

(a) reviewed the Corporation's procedures for providing information to the independent qualified reserves 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 reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

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

(a) the content and filing with 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. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(Signed) Andrew B. Wiswell
President and Chief Executive Officer

(Signed) Keith A. Steeves
Vice President, Finance & Chief Financial Officer

(Signed) Irvine J. Koop
Director

(Signed) Barry D. Stewart
Director

March 8, 2011

APPENDIX C

NAL Energy Corporation

Audit and Risk Management Committee Charter

Effective December 31, 2010

NAL Energy Corporation

Audit and Risk Management Committee Charter

General

The board of directors (the "**Board of Directors**") of NAL Energy Corporation (the "**Corporation**") has established, an Audit and Risk Management Committee (the "**Committee**"). The primary role of the Committee is to assist the Board of Directors in fulfilling its oversight responsibilities regarding the following:

1. the accuracy and completeness of the Corporation's consolidated financial statements and related management discussion and analysis ("**MD&A**");

2. the internal control and financial reporting systems of the Corporation and its direct and indirect subsidiary entities (the "**NAL Group**");

3. the selection (subject to approval by the shareholders of the Corporation (the "**Shareholders**")), engagement and monitoring of the activities of the Corporation's external auditor;

4. the NAL Group's risk management strategy;

5. the NAL Group's compliance with legal and regulatory requirements; and

6. any additional duties set out in this mandate 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 NAL Group's financial statements are complete and accurate and are in accordance with Canadian GAAP or IFRS as applicable and as the case may be. These are the responsibility of the NAL Resources Management Limited (the "**Manager**") and the Corporation's external auditor.

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 National Instrument 52-110 – *Audit Committees*, such that each member of the Committee shall have no direct or indirect relationship with the NAL Group or the Manager that could, in the view of the Board of Directors, reasonably 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 NAL Group'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.

Financial Reporting and Disclosure

In connection with the financial reporting and disclosure obligations of the NAL Group, the Committee will:

1. review the audited annual financial statements of the NAL Group as prepared by the Manager 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 quarterly financial statements of the NAL Group as prepared by the Manager, the related MD&A and the associated press releases for submission to the Board of Directors for approval;

3. review with the Manager and the external auditor, significant accounting practices employed by the NAL Group and disclosure issues, including complex or unusual transactions, judgmental areas such as reserves or estimates, significant changes to accounting principles, and alternative treatments under GAAP or IFRS, as the case may be, for material transactions, 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, complete, do not contain any misrepresentations and present fairly the NAL Group's financial position and results of operations in accordance with GAAP or IFRS, as the case may be;

4. review and assess any new or proposed developments in accounting and reporting standards that may affect or have an impact on the Corporation;

5. confirm through discussions with the Manager and the external auditor that GAAP or IFRS, as the case may be, and all applicable laws or regulations related to financial reporting and disclosure have been complied with;

6. review any unresolved significant issues between the Manager and the external auditor that could affect the financial reporting or internal controls of the NAL Group;

7. review any actual or anticipated litigation or other events, including tax assessments, which could have a material current or future affect on the Corporation's financial statements, and the manner in which these have been disclosed in the financial statements;

8. discuss with the Manager 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 affect on the Corporation'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 Corporation'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 NAL Group or the Manager who have a significant role in the NAL Group's internal controls; and

11. review or satisfy itself that adequate procedures are in place for the review of the Corporation's public disclosure of financial information extracted from the Corporation'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 NAL Group's system of internal control, disclosure controls and management information systems through discussions with the Manager and the external auditor;

2. oversee the system of internal control, by:

   (a) consulting with the external auditor regarding the effectiveness of the NAL Group's internal controls;

   (b) monitoring policies and procedures for internal accounting, financial control and management information, electronic data control and computer security;

   (c) obtaining from the Manager 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 NAL Group's finances and any resulting actions; and

4. establish procedures for the receipt, retention and treatment of complaints received by the NAL Group regarding accounting, internal accounting controls or auditing matters, the confidential, anonymous submission by employees of the Corporation and/or the Manager of concerns regarding questionable accounting or auditing matters and for the protection from retaliation of those who report such complaints in good faith.

Monitor the Internal Audit Function

The Committee will:

1. regularly monitor the responsibilities, performance and effectiveness of the internal audit function for the NAL Group; and

2. review annually the Manager's internal audit plan for the NAL Group.

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 Shareholders 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 Corporation by the external auditor, with reference to compatibility of the service with the external auditor's 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 NAL 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 Shareholders. In its role as liaison with the external auditor the Committee will:

1. resolve any disagreements between management and the external auditor regarding financial reporting;

2. review all material written communications between the external auditor and the NAL 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 the Manager and without management of the Manager present 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 the Manager, and make recommendations to the Board of Directors, regarding the compensation of the external auditor. In making a recommendation with respect to compensation, 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 NAL Group, and the extent of other support provided by the NAL Group and the Manager to the external auditor;

2. review with the Manager the terms of the external auditor's 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;

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 the Manager that limited or restricted the scope of their work;

6. review, independently from the Manager and without representatives of the Manager present, the results of the annual external audit, the audit report thereon and the auditor's 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 the Manager, the ramifications of their use and the auditor's preferred treatment, and any other material communications with the Manager;

7. engage the external auditor to review all interim financial statements and review the results of the auditor's review of the interim financial statements and the auditor's review of the related MD&A independently of and without representatives of the Manager 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 the Manager and the external auditor any correspondence with regulators or governmental agencies, employee complaints or published reports that raise material issues regarding the NAL 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 NAL 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 five 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 NAL Group's risk management policies and procedures with respect to the NAL Group's principal business risks;

2. review with management, at least annually, the NAL Group's major risk exposures and the steps taken by the Manager to monitor and control such exposures;

3. review and monitor the results of the Manager'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 NAL Group's insurance program.

Regulatory Compliance

The Committee will review with the Manager the Corporation's relationship with regulators and the timeliness and accuracy of the NAL Group's filings with regulatory authorities.

Related Party Transactions

The Committee will review with the Manager 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 NAL Group respecting accounting, internal accounting controls or auditing matters and the confidential anonymous submission by employees of the Corporation or the Manager of concerns regarding questionable accounting or auditing matters.

Board of Directors Relationship and Reporting

The Committee will:

1. review and assess the adequacy of the Committee mandate annually and submit such amendments as the Committee proposes to the Corporate Governance and Environment, Health and Safety Committee of the Board of Directors;

2. oversee appropriate disclosure of the Committee mandate, and other information required to be disclosed by applicable securities laws, in the Corporation's annual information form and all other applicable disclosure documents, including any management information circular distributed in connection with the solicitation of proxies from Shareholders; and

3. report regularly to the Board of Directors on Committee activities, issues and related recommendations.

<u>Administrative Matters</u>

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. 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. Any member of the Committee may be removed or replaced at any time 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 Shareholders 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 NAL Group or the Manager 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, 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 may be given to the external auditor and shall be given in respect of meetings relating to the annual audited financial statements. 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 Shareholders of the Corporation.

8. The Committee shall report to the Board of Directors on such matters and questions relating to the financial position of the NAL 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 NAL Group, and to discuss such books and records that are in any way related to the financial position of the NAL Group with the officers and employees of the NAL Group and the Manager and the external auditor of the NAL Group.

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 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.

<u>Experts and Advisors</u>

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. The Committee may also request any officer or employee of the NAL Group or the Manager to attend a meeting of the Committee or to meet with any members of, or consultants or advisors to, the Committee.

APPENDIX D

FINDING AND DEVELOPMENT COSTS

Finding and development ("**F&D**") costs are reported below for both Proved and Proved plus Probable ("**P+P**") reserves, in each case after eliminating the effects of acquisitions and dispositions and including changes in future development costs as per NI 51-101 guidelines. For reference, the reconciliation of Gross Working Interest reserves (before deduction of royalties and excluding any wells or properties in which NAL has only a royalty interest) is shown below. The total boe reserves changes in the Improved Recovery and Technical Revisions categories of the reconciliation table are used in the F&D calculation. A negligible amount of the reserves changes in those categories was attributable to the current year activity within the properties acquired in 2010.

Numbers in the following tables may not add exactly due to rounding.

RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPAL PRODUCT TYPE

FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL		HEAVY OIL		ASSOCIATED AND NON-ASSOCIATED GAS		NATURAL GAS LIQUIDS		TOTAL BOE	
FACTORS	Proved (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mboe)	Proved Plus Probable (Mboe)
December 31, 2009	27,721	39,962	825	1,662	215,257	307,439	6,968	10,131	71,391	102,994
Improved Recovery*	1,511	5,277	0	0	3,901	18,332	154	674	2,314	9,006
Technical Revisions	1,765	(1,445)	95	(103)	21,841	11,171	652	287	6,152	600
Acquisitions	798	1,015	0	0	7,982	9,838	324	396	2,453	3,050
Dispositions	(511)	(794)	0	0	(611)	(1,084)	(45)	(70)	(658)	(1,044)
Production	(3,991)	(3,991)	(120)	(120)	(33,437)	(33,437)	(977)	(977)	(10,661)	(10,661)
December 31, 2010	27,292	40,023	801	1,439	214,933	312,258	7,076	10,441	70,991	103,946

* Improved Recovery includes extensions, discoveries, infill drilling, well recompletions and economic factors.

The capital spending of $200.9 million used in the F&D calculation for 2010 represents the Corporation's total expenditures for drilling, completion and production equipment, plant and facility costs (including maintenance capital items that supported NAL's base production volumes), plus seismic and land costs, capitalized general and administrative and stock-based incentive costs. The capital spent on land was considerably higher in 2010 versus previous years, at approximately $24 million (versus $6 million in 2009), as the Corporation continues to position itself for future development opportunities. The majority of the $24 million was spent on Crown land sales in the Pine Creek area where NAL continues to pursue some emerging gas development plays. A negligible amount of incremental capital was spent within the producing properties that were acquired in 2010, so the total capital spending amount used for the F&D calculation is the same as that used for the Finding, Development and Acquisition ("FD&A") calculation in the section which follows.

As shown in the table below, the F&D costs for 2010 were $21.41 per boe for Proved and $22.60 per boe for P+P reserves.

The F&D calculations for each of the three most recent financial years, and a weighted average for the three-year period, are also summarized in the tables below. It should be noted that the aggregate of the development costs incurred during the year and the change in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year. As such, the three-year weighted average, with changes tracked over time, provides a useful indicator of capital effectiveness as it relates to reserves development. The weighted average F&D costs for the three-year period from 2008 through 2010 were $17.92 per boe for Proved and $18.80 per boe for P+P reserves.

2010				
		Actual Spending During 2010	Change in Estimated Future Development Costs	Total
Capital (M$)	Proved	200,931	(19,647)	181,285
	Proved + Probable	200,931	16,158	217,089
		Improved Recovery	Technical Revisions	Total
Reserves (Mboe)	Proved	2,314	6,152	8,466
	Proved + Probable	9,006	600	9,606
F&D ($/boe)	Proved			21.41
	Proved + Probable			22.60

2009				
		Actual Spending During 2009	Change in Estimated Future Development Costs	Total
Capital (M$)	Proved	129,360	54,115	183,474
	Proved + Probable	129,360	57,790	187,150
		Improved Recovery	Technical Revisions	Total
Reserves (Mboe)	Proved	4,602	5,303	9,905
	Proved + Probable	8,570	1,910	10,480
F&D ($/boe)	Proved			18.52
	Proved + Probable			17.86

2008				
		Actual Spending During 2008	Change in Estimated Future Development Costs	Total
Capital (M$)	Proved	132,730	2,020	134,750
	Proved + Probable	132,730	36,051	168,781
		Improved Recovery	Technical Revisions	Total
Reserves (Mboe)	Proved	3,770	5,736	9,505
	Proved + Probable	7,849	2,542	10,392
F&D ($/boe)	Proved			$14.18
	Proved + Probable			$16.24

3-YEAR WEIGHTED AVERAGE				
		Actual Spending Over 3 Years	Change in Estimated Future Development Costs	Total
Capital (M$)	Proved	463,021	36,488	499,509
	Proved + Probable	463,021	109,998	573,020
		Improved Recovery	Technical Revisions	Total
Reserves (Mboe)	Proved	10,686	17,191	27,877
	Proved + Probable	25,425	5,052	30,478
F&D ($/boe)	Proved			17.92
	Proved + Probable			18.80

FINDING, DEVELOPMENT AND ACQUISITION COSTS

A significant part of NAL's business activity in any given year is the acquisition and, to a lesser degree, the disposition of Properties. In order to provide a more representative measure of NAL's total capital spending as it relates to reserves development, finding, development and acquisition ("**FD&A**") costs are reported including the effects of acquisitions and dispositions. During 2010, NAL completed approximately $48 million of net property acquisitions.

The FD&A calculation uses the total boe reserves changes in the Improved Recovery and Technical Revisions categories from the reconciliation table above, as well as the reserves acquired and disposed. The capital spending of $200.9 million includes all of the items discussed in the F&D calculation in the previous section. The same capital spending applies to the F&D and the FD&A calculation for 2010 because a negligible amount of incremental capital was spent within the acquired properties during 2010. The changes in estimated future development costs from the reserves report are also included in the FD&A calculation.

The resulting FD&A costs for 2010 were $22.37 per boe for Proved and $22.85 per boe for P+P reserves. The weighted average FD&A costs for the three-year period from 2008 through 2010 were $24.77 per boe for Proved and $21.86 per boe for P+P reserves. These three year averages provide an appropriate longer-term measure of the NAL's overall capital spending effectiveness.

2010						
		Actual Spending During 2010	Change in Estimated Future Development Costs	Acquisitions	Dispositions	Total Including A&D
Capital (M$)	Proved	200,931	(19,647)	70,401	(22,178)	229,508
	Proved + Probable	200,931	16,158	70,401	22,178	265,312
		Improved Recovery	Technical Revisions	Acquisitions	Dispositions	Total Including A&D
Reserves (Mboe)	Proved	2,314	6,152	2,453	(658)	10,261
	Proved + Probable	9,006	600	3,050	(1,044)	11,612
FD&A ($/boe)	Proved					22.37
	Proved + Probable					22.85

2009						
		Actual Spending During 2009	Change in Estimated Future Development Costs	Acquisitions	Dispositions	Total Including A&D
Capital (M$)	Proved	132,336	155,937	501,079	(17,521)	771,831
	Proved + Probable	132,336	246,532	501,079	(17,521)	862,426
		Improved Recovery	Technical Revisions	Acquisitions	Dispositions	Total Including A&D
Reserves (Mboe)	Proved	5,123	5,303	18,006	(740)	27,692
	Proved + Probable	9,428	1,910	28,169	(887)	38,620
FD&A ($/boe)	Proved					27.87
	Proved + Probable					22.33

2008						
		Actual Spending During 2008	Change in Estimated Future Development Costs	Acquisitions	Dispositions	Total Including A&D
Capital (M$)	Proved	148,527	4,710	67,594	0	220,831
	Proved + Probable	148,527	48,496	67,594	0	264,617
		Improved Recovery	Technical Revisions	Acquisitions	Dispositions	Total Including A&D
Reserves (Mboe)	Proved	3,897	5,663	1,818	0	11,378
	Proved + Probable	7,747	2,213	3,499	0	13,459
FD&A ($/boe)	Proved					19.41
	Proved + Probable					19.66

3-YEAR WEIGHTED AVERAGE						
		Actual Spending Over 3 Years	Change in Estimated Future Development Costs	Acquisitions	Dispositions	Total Including A&D
Capital (M$)	Proved	481,795	141,001	639,074	(39,700)	1,222,170
	Proved + Probable	481,795	311,185	639,074	(39,700)	1,392,354
		Improved Recovery	Technical Revisions	Acquisitions	Dispositions	Total Including A&D
Reserves (Mboe)	Proved	11,334	17,118	22,277	(1,398)	49,331
	Proved + Probable	26,181	4,723	34,718	(1,931)	63,691
FD&A ($/boe)	Proved					24.77
	Proved + Probable					21.86