balance

nal ENERGY

financial results 2011

contents

Abbreviations

bbls	barrels
bbls/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
Mbbl	thousands of barrels
Mboe	thousands of barrels of oil equivalent
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MMbtu	millions of British Thermal Units
D/CF	debt to cash flow
P+P	proved plus probable
Hz	horizontal
$MM	million dollars
$Cdn	Canadian dollars
$US	U.S. dollars
FX	foreign exchange

Conversion Factors

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	kilometers	1.609
kilometers	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

management's discussion & analysis

The following discussion and analysis ("MD&A") should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2011 of NAL Energy Corporation ("NAL" or the "Corporation"). It contains information and opinions on the Corporation's future outlook based on currently available information. All amounts are reported in Canadian dollars, unless otherwise stated. Where applicable, natural gas has been converted to barrels of oil equivalent ("boe") based on a ratio of six thousand cubic feet of natural gas to one barrel of oil. The boe rate is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a |value equivalency at the wellhead. The use of boes in isolation may be misleading.

Unless otherwise specifically stated, all financial information included and incorporated by reference in this MD&A is determined, for all periods prior to January 1, 2010, using Canadian generally accepted accounting principles in effect prior to January 1, 2010 and, for all periods beginning on and after January 1, 2010, using International Financing Reporting Standards ("IFRS") as adopted by the Canadian Accounting Standards Board.

NAL is primarily engaged in the exploration for, and the development and production of natural gas, natural gas liquids and crude oil in Western Canada. The Corporation resulted from a reorganization by plan of arrangement effective December 31, 2010 involving, among others, NAL Oil & Gas Trust (the "Trust"), the Corporation, and the security holders of the Trust (the "Reorganization").

Pursuant to the Reorganization, the Trust was restructured from an open-end unincorporated trust to NAL Energy Corporation, a publicly traded exploration and development corporation. Unitholders of the Trust received one common share of the Corporation for each trust unit held. The Corporation and its subsidiaries now carry on the business formerly carried on by the Trust and its subsidiaries.

The Reorganization to a corporation has been accounted for on a continuity of interest basis and accordingly, the consolidated financial statements for 2010 reflect the financial position, results of operations and cash flows as if the Corporation had carried on the business formerly carried on by the Trust.

References to NAL or the Corporation in this MD&A for periods prior to December 31, 2010 are references to the Trust and for periods after December 30, 2010 are references to NAL Energy Corporation. Additionally, NAL or the Corporation refers to shares, shareholders and dividends which are comparable to units, unitholders and distributions previously under the Trust.

Changes In Accounting Policies

On January 1, 2011, NAL adopted IFRS for financial reporting purposes, using a transition date of January 1, 2010. The financial statements for the year ended December 31, 2011, including required comparative information, have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IASB"). Previously, the Corporation prepared its interim and annual consolidated financial statements in accordance with Canadian generally accepted accounting principles ("previous CGAAP" or "CGAAP"). Unless otherwise noted, 2010 comparative information has been prepared in accordance with IFRS.

The adoption of IFRS has not had an impact on the Corporation's operations and strategic decisions. The most significant area of impact was to property, plant and equipment. Further information on the IFRS impacts is provided under the heading "Accounting Policies" in this MD&A, including reconciliations between previous CGAAP and IFRS net income, funds from operations and other financial metrics.

Non-IFRS Financial Measures

Throughout this MD&A, management uses the terms "funds from operations", "funds from operations per share", "payout ratio", "cash flow from operations per share", "net debt to trailing 12 month cash flow", "operating netback" and "cash flow netback". These are considered useful supplemental measures as they provide an indication of the results generated by the Corporation's principal business activities. Management uses the terms to facilitate the understanding of the results of NAL's operations. However, these terms do not have any standardized meaning as prescribed by IFRS. Investors should be cautioned that these measures should not be construed as an alternative to net income determined in accordance with IFRS as an indication of NAL's performance. NAL's method of calculating these measures may differ from other companies and, accordingly, they may not be comparable to measures used by other companies.

Funds from operations is calculated as cash flow from operating activities before changes in non-cash working capital less interest expense on bank debt and convertible debentures, excluding amortization on convertible debentures. Funds from operations does not represent operating cash flows or operating profits for the period and should not be viewed as an alternative to cash flow from operating activities calculated in accordance with IFRS. Funds from operations is considered by management to be a more meaningful key performance indicator of NAL's ability to generate cash to finance operations and to pay monthly dividends. Funds from operations per share and cash flow from operations per share are calculated using the weighted average shares outstanding for the period.

Payout ratio is calculated as dividends declared for a period as a percentage of either cash flow from operating activities or funds from operations; both measures are stated.

Net debt to trailing 12 months cash flow is calculated as net debt as a proportion of funds from operations for the previous 12 months. Net debt is defined as bank debt, plus convertible debentures at face value, plus working capital and other liabilities, excluding derivative contracts.

The following table reconciles cash flows from operating activities to funds from operations:

$(000s)	**2011**	**2010**
Cash flow from operating activities	258,801	274,606
Adjust for change in non-cash working capital	16,538	6,065
Less interest expense	(25,186)	(24,315)
Funds from operations	250,153	256,356

Forward-Looking Information

This MD&A contains forward-looking information as to the Corporation's internal projections, expectations and beliefs relating to future events or future performance. 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 forward-looking statements 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 MD&A contains forward-looking information pertaining to the following, without limitation: the amount and timing of cash flows and dividends to shareholders; reserves and reserves values; 2012 production; future tax treatment of the Corporation; the Corporation's tax pools; future oil and gas prices; operating, drilling and completions 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; future acquisition, development and exploration expenditures; and rates of return.

With respect to forward-looking statements contained in this MD&A and the press release through which it was disseminated, 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 that NAL intends to pay; the cost of expanding the Corporation's property holdings; the Corporation's ability to obtain equipment in a timely manner to carry out exploration and development activities; the Corporation's ability to market its oil and natural gas successfully to current and new customers; the impact of increasing competition; NAL's ability to obtain financing on acceptable terms; and NAL's ability to add production and reserves through its development and exploitation activities.

Although NAL believes that the expectations reflected in the forward-looking information contained in the MD&A and the press release through which it was disseminated, and the assumptions on which such forward-looking information are 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 is 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 NAL's ability to execute its capital program; risks inherent in oil and gas operations; 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; stock market volatility and market valuations; OPEC's 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 the Corporation's current Annual Information Form.

NAL cautions that the foregoing list of factors that may affect future results is not exhaustive. The forward-looking information contained in this MD&A is made as of the date of this MD&A. The forward-looking information contained in this MD&A is expressly qualified by this cautionary statement.

Structure Of The Business

On December 31, 2010, NAL Oil & Gas Trust completed a plan of arrangement whereby the unitholders of the Trust exchanged their trust units for common shares of NAL Energy Corporation on a one-to-one basis thereby effectively converting the Trust into a corporation ("Reorganization"). The Trust was dissolved and NAL Energy Corporation received all the assets and assumed all the liabilities of the Trust.

A partnership ("Partnership") that was indirectly owned jointly by the Corporation and Manulife Financial Corporation ("MFC") was dissolved on December 31, 2010. This Partnership held the assets acquired from the acquisitions of Tiberius Exploration Inc. ("Tiberius") and Spear Exploration Inc. ("Spear") in February 2008.

The Corporation, by virtue of being the owner of the general partner of the Partnership prior to December 31, 2010, was required to consolidate the results of the Partnership into its financial statements on the basis that the Corporation had control over the Partnership. The published financial information of the Corporation prior to December 31, 2010 reflects all the assets, liabilities, revenues and expenses of the Partnership, of which 50 percent are removed through the minority interest. The Corporation adjusted its financial statements on December 31, 2010 based on the dissolution of the Partnership to reflect its proportionate share of the Partnership's assets and liabilities.

NAL's conversion from a trust to a corporation did not change the Corporation's strategic or operational objectives.

Exploration & Development Activities

2011 Drilling Activity

	Crude Oil		Natural Gas		Service Wells		Dry & Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Operated wells	103	57.7	10	7.1	-	-	-	-	113	64.8
Non-operated wells	17	2.0	6	1.0	-	-	1	0.5	24	3.5
Total wells drilled[1]	120	59.7	16	8.1	-	-	1	0.5	137	68.3

(1) Includes drilling activity NAL participated in, but excludes third party revenue wells.

The Corporation has drilled 137 (68.3 net) wells during 2011, compared to 131 (61.4 net) in 2010. Of the total wells drilled in 2011, 120 (88 percent) targeted oil and natural gas liquids.

Southeast Saskatchewan

In Saskatchewan, 65 (30.1 net) horizontal oil wells were drilled during 2011. Activity was focused in the Greater Hoffer area (38), with 27 additional wells drilled in other operating areas including Alida (4), Nottingham (5), Bryant (3) and Steelman (2).

In the Greater Hoffer area, NAL drilled 16 (8.0 net) wells in the new Oungre/Neptune area, signed two farm-in agreements and purchased proprietary seismic which is expected to extend the Corporation's exposure to the new pool discoveries in this area. NAL continues to optimize drilling techniques at Hoffer and is working on a pressure maintenance scheme to enhance production performance.

Severe wet weather conditions in Saskatchewan impacted drilling throughout the second and third quarters of 2011. The protracted wet conditions affected drilling, tie-in, maintenance, trucking operations, and ultimately reduced the Corporation's productive capacity during that time.

For 2012, NAL currently has up to five drilling rigs operating in Saskatchewan during the first quarter and intends to drill 21 additional horizontal Mississippian oil wells during this period, largely focused in the Greater Hoffer, Alida-Nottingham and Midale areas.

Construction of the central gathering facility at Hoffer was completed and commenced operations at the end of January 2012. The battery ties-in production that was previously producing to single well oil batteries in the area, thereby reducing operating and transportation costs and improving reliability in bringing volumes to market. In addition, construction started in early 2012 on a new satellite facility at Oungre/Neptune to allow for the consolidation of trucking operations closer to infrastructure.

Alberta

In Alberta, NAL participated in drilling 66 (34.6 net) wells during 2011. Activity was focused on the Cardium for which 42 wells were drilled, including the six well program in Lochend. In addition, NAL executed a four well Wilrich program and infill oil drilling at Millard Lake, Hussar and Irricana.

NAL also undertook a farm-out program of its non-core acreage during 2011, on which 23 (3.0 net) third party revenue farm-out wells were drilled.

Cardium drilling at Garrington/Westward Ho continues to perform in-line with expectations. In addition, NAL drilled its first two Cardium wells at Willesden Green in late 2011 where it will continue to monitor results.

In 2011, NAL followed up on the successful 10-17-27-3W5 location at Lochend by drilling five more wells directly offsetting this location and obtained initial production rates as high as 800 boe per day. New-well production peaked in November at approximately 1,375 boe per day as flush volumes were tied in and declined to just over 1,200 boe per day in December. Since then, actual production history has validated the legitimacy of a regional "sweet-spot" and is now characterized by an internal type curve in which the 30 day initial production rate exceeds NAL's typical Cardium type curve by two to three times. At current crude oil prices, Lochend Cardium wells deliver payouts in eight to 12 months and recycle ratios of up to five times. In 2011, NAL acquired a large 3D seismic survey in the area in order to help define both, the extent of the sweet spot and controls on the distribution of the play. For 2012, NAL plans to double its drilling program at Cochrane/Lochend with approximately 15 locations planned. Drilling is expected to resume after break-up, with incremental production anticipated in the second half of 2012. During 2011, construction was completed on a battery at Cochrane, which provides additional liquids handling capacity.

In Pine Creek, NAL's fifth Wilrich well rig released in January 2012 and is expected to be on-stream prior to break up. NAL's previously completed four well Wilrich program continues to have more productive capability than available capacity on existing infrastructure.

NAL is planning to drill two wells with the major operator at Sawn Lake in 2012, following the acquisition of land in that area in 2011. The 16-10-92-13W5 location was spud in February 2012 and the closest offset wells to this location have produced 30-day initial production rates in excess of 400 boe per day.

Northeast British Columbia

In British Columbia, three (3.0 net) wells were drilled in the 100% working interest Fireweed property. Early in 2011, two high impact Doig horizontal wells were drilled with production test rates of approximately 1,475 boe per day and 1,600 boe per day. The third well was the first appraisal well for the Montney at Fireweed. The first Montney well came on stream in the fourth quarter of 2011 and delivered a 30 day initial production rate of approximately 1,000 boe per day with approximately 4 mmcf per day of natural gas and up to 100 bbls/mmcf of liquids. A second appraisal well commenced drilling prior to year end. Drilling of these two Montney wells has successfully preserved 11 contiguous sections that were scheduled to expire in December, 2011.

Lake Erie

During 2011, three (0.6 net) wells were drilled in the Corporation's non-operated property in Lake Erie.

Capital Expenditures

($000s)	**2011**	**2010**
Drilling, completions and production equipment	200,752	157,832
Plant and facilities	17,153	7,928
Seismic	5,568	1,955
Land[1]	20,612	31,703
Total exploration and development	244,085	199,418
Office equipment	1,818	2,106
Total capitalized expenditures before acquisitions	245,903	201,524
Property acquisitions	3,858	68,607
Proceeds on disposition	(32,841)	(22,178)
Total property acquisitions (dispositions) net	(28,983)	46,429
Total capitalized expenditures	216,920	247,953

(1) Land expenditures include lease rental charges

In 2011, capital expenditures, before property acquisitions and dispositions, totaled $245.9 million, an increase of 22 percent from $201.5 million in 2010. The increase of $44.4 million is largely attributable to an increase in drilling, completions and tie-in expenditures of $42.9 million, reflecting an increase in the number of net wells drilled from 61.4 in 2010 to 68.3 in 2011. Total drill, complete, equip and tie-in capital was focused primarily on oil and liquids operations, representing approximately 82 percent of total capital spending.

In addition, plant and facilities expenditures increased year-over-year by $9.2 million to $17.2 million in 2011. Significant projects in 2011 included the battery and related facilities in Hoffer and a gas gathering pipeline and facilities in Cochrane/Lochend.

NAL spent $20.6 million acquiring land during 2011, compared to $31.7 million in 2010. Acreage acquisitions were principally focused on Crown land sales in the Sawn Lake area of northern Alberta. NAL now holds an average 50 percent interest with a major operator in the area in over 32 sections of land prospective for the Slave Point carbonate. Production in the area is light sweet oil (approximately 40° API). Offsetting horizontal development in the area exhibits initial production rates in excess of 400 boe per day.

The total 2011 net property acquisitions and dispositions of $29 million relate primarily to non-core property dispositions.

Production

Average Daily Production Volumes

	2011	2010
Oil (bbl/d)	10,587	11,349
Natural gas (Mcf/d)	90,302	92,403
NGLs (bbl/d)	2,701	2,696
Oil equivalent (boe/d)	28,338	29,446

Production volumes of 28,338 boe per day in 2011 are approximately 1,100 boe per day lower than last year. The majority of the shortfall is related to lower oil production in Saskatchewan which was caused by severe wet weather during the second and third quarters.

Drilling of the 2012 capital program commenced in early January, with volumes anticipated to come on stream late in the first and early in the second quarters.

Production Weighting

	2011	2010
Oil	37%	39%
Natural gas	53%	52%
NGLs	10%	9%

Oil and natural gas liquids totaled 47 percent of production with natural gas at 53 percent of production during 2011. The Corporation's oil and liquids weighting is one percentage point lower than for 2010 and is attributable primarily to the weather-related interruptions in Saskatchewan which curtailed oil volumes.

Revenue

Revenue(1) ($000s)	2011	2010
Oil	342,160	305,462
Gas	116,611	134,193
NGL's	65,753	51,222
Sulphur	1,742	160
Total revenue	526,266	491,037
$/boe	50.88	45.69

(1) Oil, natural gas and natural gas liquid sales less transportation costs and prior to royalties and hedging.

Gross revenue from oil, natural gas and natural gas liquids sales, after transportation costs and prior to hedging, totaled $526.3 million for 2011, an increase of seven percent from 2010. The increase was attributable to an 11 percent increase in the average realized price per boe, partially offset by a four percent decrease in production and a two percent decrease in relative oil weighting in production. The increase in realized prices reflects higher West Texas Intermediate ("WTI") prices and differentials, partially offset by a stronger Canadian dollar and lower AECO prices in 2011.

Pricing

Average Pricing (net of transportation charges)

	2011	2010
Liquids		
WTI (US$/bbl)	95.12	79.54
NAL average oil (Cdn$/bbl)	88.54	73.74
NAL natural gas liquids (Cdn$/bbl)	66.70	52.05
Natural Gas (Cdn$/mcf)		
AECO – daily spot	3.63	4.00
AECO – monthly	3.67	4.13
NAL Western Canada natural gas	3.51	3.94
NAL Lake Erie natural gas	4.46	5.04
NAL average natural gas	3.54	3.98
NAL Oil Equivalent before hedging (Cdn$/boe – 6:1)	50.88	45.69
Average Foreign Exchange Rate (US$/Cdn$)	0.9892	1.0301

Oil Marketing

NAL markets its crude oil based on refiners' posted prices at Edmonton, Alberta and Cromer, Manitoba adjusted for transportation and the quality of crude oil at each field battery. The refiners' posted prices are influenced by the WTI benchmark price, transportation costs, exchange rates and the supply / demand balance of particular crude oil quality streams during the year.

NAL's average oil price was $88.54 per barrel in 2011 compared to $73.74 in 2010. The 20 percent increase in realized price was driven by a 20 percent increase in the WTI price (US$/bbl) and an increase in crude oil differentials over the comparable period, partially offset by a four percent increase in the value of the Canadian dollar. The crude oil differential was 94 percent, an increase of four percentage points from 2010. The strong differential for Canadian light sweet and sour crude grades was largely due to the tight supply conditions in core refining regions. The differential is calculated as realized price as a percentage of the WTI price stated in Canadian dollars.

For 2011, natural gas liquids averaged $66.70/bbl, an increase of 28 percent from 2010.

Natural Gas Marketing

Approximately 73 percent of NAL's current gas production is sold under marketing arrangements tied to the Alberta monthly or daily spot price ("AECO"), with the remaining 27 percent tied to NYMEX or other indexed reference prices.

NAL averaged $3.54/Mcf in 2011, an 11 percent decrease from the $3.98/Mcf realized in 2010. The decrease in natural gas prices was attributable to a nine percent and 11 percent decrease in the benchmark AECO daily and monthly spot prices, respectively.

Prices for Lake Erie natural gas decreased to $4.46/Mcf in 2011, compared to $5.04/Mcf in 2010, a decrease of 12 percent. Lake Erie production of 3.0 mmcf per day accounted for three percent of the Corporation's natural gas production in 2011, as compared to 3.2 mmcf per day in 2010. Natural gas sales from the Lake Erie property generally receive a higher price due to the proximity of the Ontario and northeastern U.S. markets.

Risk Management

NAL employs risk management practices to assist in managing cash flows and to support capital programs and dividend payments. NAL currently has derivative contracts in place to assist in managing the risks associated with commodity prices, interest rates and foreign exchange rates.

NAL's commodity hedging policy currently provides authorization for management to hedge up to 60 percent of forecasted revenue, net of royalties for up to 24 months. Management's practice is to layer in hedges up to 24 months forward, with greater volumes hedged in the current 12 month forward period. The execution of NAL's commodity hedging program utilizes a combination of swaps and collars. As at December 31, 2011, NAL had several financial WTI oil contracts and AECO natural gas contracts in place.

NAL's interest rate hedging policy currently provides authorization to hedge up to 50 percent of outstanding bank debt for periods of up to five years. As at December 31, 2011, NAL had several interest rate swaps outstanding with a total notional value of US$100 million.

NAL's foreign exchange hedging policy currently provides authorization to hedge up to 50 percent of its U.S. dollar exposure for periods of up to 24 months. As at December 31, 2011, NAL had several exchange rate contracts outstanding with a total notional value of US$168 million.

All derivative contract counterparties are Canadian chartered banks in the Corporation's lending syndicate.

All derivative contracts are recorded on the balance sheet at fair value based upon forward curves at December 31, 2011. Changes in the fair value of the derivative contracts are recognized in net income for the period.

Fair value is calculated at a point in time based on an approximation of the amounts that would be received or paid to settle these instruments, with reference to forward prices at December 31, 2011. Accordingly, the magnitude of the unrealized gain or loss will continue to fluctuate with changes in commodity prices, interest rates and foreign exchange rates.

The fair value of the derivatives at December 31, 2011 was a net liability of $5.6 million, comprised of a $6.7 million liability on oil contracts, a $2.5 million liability on foreign exchange contracts and a $0.9 million liability on interest rate swaps, partially offset by a $4.5 million asset on natural gas contracts.

The gain / loss on all forward derivative contracts is as follows:

Gain / (Loss) on Derivative Contracts

($000s)	2011	2010
Unrealized gain (loss):		
Crude oil contracts	8,641	(2,467)
Natural gas contracts	2,890	(2,318)
Interest rate swaps	(1,655)	(1,755)
Exchange rate swaps	(5,594)	(875)
Unrealized gain (loss)	4,282	(7,415)
Realized gain (loss):		
Crude oil contracts	(14,342)	(4,353)
Natural gas contracts	5,221	23,349
Interest rate swaps	(528)	(1,057)
Exchange rate swaps	5,445	6,507
Realized gain (loss)	(4,204)	24,446
Gain (loss) on derivative contracts	78	17,031

For the year ended December 31, 2011, income includes an unrealized gain of $4.3 million, resulting from the change in the fair value of the derivative contracts during the period from an unrealized loss of $9.9 million at December 31, 2010 to an unrealized loss of $5.6 million at December 31, 2011. The unrealized gain was comprised of an $8.6 million unrealized gain on crude oil contracts and a $2.9 million unrealized gain on natural gas contracts, partially offset by a $1.6 million unrealized loss on interest rate swaps and a $5.6 million unrealized loss on foreign exchange swaps.

The following is a summary of the realized gains and losses on risk management contracts:

Realized Gain / (Loss) on Derivative Contracts

	2011	2010
Commodity contracts:		
Average crude volumes hedged (bbl/d)	5,876	6,189
Crude oil realized loss ($000s)	(14,342)	(4,353)
Gain (loss) per bbl hedged ($)	(6.69)	(1.93)
Average natural gas volumes hedged (GJ/d)	19,831	37,570
Natural gas realized gain ($000s)	5,221	23,349
Gain per GJ hedged ($)	0.72	1.70
Average BOE hedged (boe/d)	9,009	12,124
Total realized commodity contracts gain (loss) ($000s)	(9,121)	18,996
Gain (loss) per boe hedged ($)	(2.77)	4.29
Gain (loss) per boe ($)	(0.88)	1.77
Interest rate swaps realized loss ($000s)	(528)	(1,057)
Loss per boe ($)	(0.05)	(0.10)
Exchange rate swaps realized gain ($000s)	5,445	6,507
Gain per boe ($)	0.52	0.61
Total realized gain (loss) ($000s)	(4,204)	24,446
Gain (loss) per boe ($)	(0.41)	2.27

NAL has the following interest rate risk management contracts outstanding:

Interest Rate Contract	Remaining Term	Amount (millions)[1]	Corporation Fixed Rate	Counterparty Floating Rate
Swaps-floating to fixed	Jan 2012 – Jan 2013	$22.0	1.3850%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Jan 2012 – Jan 2014	$22.0	1.5100%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Jan 2012 – Mar 2013	$14.0	1.8750%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Jan 2012 – Mar 2014	$14.0	1.9850%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Jan 2012 – Mar 2013	$14.0	1.8500%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Jan 2012 – Mar 2014	$14.0	1.9300%	CAD-BA-CDOR (3 months)

(1) Notional debt amount.

NAL has the following U.S. dollar / Canadian dollar foreign exchange option contracts outstanding.

Fixed Rate (USD/CAD)	Notional (US) per month	Term	Counterparty Floating Rate
0.9954	$2.0 MM	Jan 1, 2012 to Dec 31, 2012	BofC Monthly Average Noon Rate
1.0565	$1.5 MM	Jan 1, 2012 to Dec 31, 2012	BofC Monthly Average Noon Rate

NAL has a monthly commitment to settle the above fixed rates against the Bank of Canada monthly average noon rate.

Option Payout Range (USD/CAD)	Notional (US) per month	Term	Counterparty Floating Rate	Monthly Premium Received (CAD)
$0.93 - $1.03	$2.0 MM	Jan 1, 2012 to Dec 31, 2012	BofC Monthly Average Noon Rate	$40K
$0.90 - $1.15	$1.0 MM	Jan 1, 2013 to Sep 30, 2013	BofC Monthly Average Noon Rate	$40K

When the monthly average noon spot foreign exchange rate is outside the payout range, the monthly premium received is forfeited. NAL is committed to selling the above listed U.S. dollars at the upper payout range value for that month when the average noon spot foreign exchange rate exceeds the payout range.

Option Fixing Range (USD/CAD)	Notional (US) per month	Term	Counterparty Floating Rate
$0.97 - $1.04	$1.0 MM	Jan 1, 2012 to Dec 31, 2012	BofC Monthly Average Noon Rate

When the monthly average noon spot foreign exchange rate exceeds the option fixing range, NAL is committed to selling the above listed U.S. dollars at the lower option fixing range rate for that month. To the extent the monthly average spot foreign exchange rate is below the option fixing range, NAL is committed to selling the above listed U.S. dollars at the lower option fixing range rate. When the monthly average noon spot foreign exchange rate falls within the option fixing range, NAL has no commitment to sell U.S. dollars.

Fade-in Level (USD/CAD)	Strike Price (USD/CAD)	Participation Level (USD/CAD)	Notional (US) per month	Term	Counterparty Floating Rate
$0.92	$0.985	$1.03	$2.0 MM	Jan 1, 2012 to Dec 31, 2012	BofC Monthly Average Noon Rate
$0.91	$1.0075	$1.05	$1.5 MM	Jan 1, 2012 to Dec 31, 2012	BofC Monthly Average Noon Rate
$0.935	$1.00	$1.05	$0.5 MM	Jan 1, 2012 to Dec 31, 2012	BofC Monthly Average Noon Rate
$0.92	$1.012	$1.0625	$0.5 MM	Jan 1, 2012 to Dec 31, 2012	BofC Monthly Average Noon Rate
$0.92	$0.995	$1.035	$1.0 MM	Jan 1, 2012 to Dec 31, 2012	BofC Monthly Average Noon Rate
$0.93	$1.04	$1.075	$0.5 MM	Jan 1, 2012 to Dec 31, 2012	BofC Monthly Average Noon Rate
$0.90	$1.065	$1.15	$1.0 MM	Jan 1, 2013 to Sept 30, 2013	BofC Monthly Average Noon Rate

NAL is committed to sell U.S. dollars on a monthly basis at the strike price. If the Bank of Canada monthly average noon rate is below the fade-in level or between the strike and participating level, NAL has no commitment to sell U.S. dollars.

NAL has the following commodity risk management contracts outstanding:

Crude Oil	Q1-12	Q2-12	Q3-12	Q4-12	Q1-13	Q2-13	Q3-13	Q4-13
US$ Collar Contracts								
$US WTI Collar Volume (bbl/d)	900	900	700	700	-	-	-	-
Bought Puts – Average Strike Price ($US/bbl)	101.11	101.11	101.43	101.43	-	-	-	-
Sold Calls – Average Strike Price ($US/bbl)	117.07	117.07	117.66	117.66	-	-	-	-
US$ Swap Contracts								
$US WTI Swap Volume (bbl/d)	7,115	7,200	7,000	7,000	500	500	500	500
Average WTI Swap Price ($US/bbl)	97.30	97.44	97.36	97.36	100.95	100.95	100.95	100.95
Total Oil Volume (bbl/d)	8,015	8,100	7,700	7,700	500	500	500	500
US$ Option Contracts								
Sold Call Options – Volume (bbl/d)	-	-	-	-	2,000	2,000	2,000	2,000
Average WTI Strike Price (US$/bbl)	-	-	-	-	110	110	110	110
Premium Received ($/bbl/d)	-	-	-	-	10.33	10.33	10.33	10.33

Certain swap contracts for calendar 2012 for a total of 1,500 bbl per day, with an average price of $102.30, contain extendible call options into calendar 2013. The extendible call option provides the counterparty with the option to extend the contract into calendar 2013 under the same price and volumetric terms. The counterparty can exercise this option any time before December 31, 2012.

Natural Gas	Q1-12	Q2-12	Q3-12	Q4-12	Q1-13	Q2-13	Q3-13	Q4-13
Collar Contracts								
AECO Collar Volume (GJ/d)	-	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Bought Puts & Average Strike Price ($Cdn/GJ)	-	2.50	2.50	2.50	2.50	2.50	2.50	2.50
Sold Calls & Average Strike Price ($Cdn/GJ)	-	3.05	3.05	3.05	3.05	3.05	3.05	3.05
Swap Contracts								
AECO Swap Volume (GJ/d)	24,000	7,000	7,000	5,674	2,000	2,000	2,000	2,000
AECO Average Price ($Cdn/GJ)	3.98	3.77	3.77	3.69	2.81	2.81	2.81	2.81
Total Natural Gas Volume (GJ/d)	24,000	9,000	9,000	7,674	4,000	4,000	4,000	4,000

In 2012, the Corporation has outstanding hedge contracts averaging 7,878 bbl per day of oil and 12,396 GJ's per day of natural gas.

Royalty Expenses

	2011	2010
Royalties ($000s)	89,907	86,485
As a % of revenue	17.1	17.6
$/boe	8.69	8.05

Crown, freehold and overriding royalties totaled $89.9 million in 2011, up from $86.5 million in 2010. Expressed as a percentage of gross sales net of transportation costs, the net royalty rate was 17.1 percent, comparable to the 17.6 percent experienced in 2010. Both years include prior period royalty amendments which include annual gas cost allowance adjustments. Excluding the impact of these amendments, the royalty rate would be 17.5 percent in 2011 compared to 17.3 percent in 2010. The increase in royalty rates is primarily attributable to higher commodity prices in 2011 as compared to 2010.

For the year ended December 31, 2011, 47 percent of crude oil production and 70 percent of natural gas production was from Alberta.

Operating Costs

	2011	2010
Operating costs ($000s)	124,209	111,911
As a % of revenue	23.6	22.8
$/boe	12.01	10.41

Operating costs were $124.2 million in 2011, $12.3 million higher than 2010, representing an increase of 11 percent year-over-year. Operating costs in 2011 were $12.01 per boe compared to $10.41 per boe in 2010.

The increase in operating costs year-over-year is primarily attributable to repairs and maintenance, workovers and fluid hauling associated with the flooding and wet weather conditions in Saskatchewan, an increase in property taxes and increased repairs, workovers and utility costs in other operating areas.

Operating Netback

	2011	2010
Average Daily Production		
Oil (bbl/d)	10,587	11,349
Gas (Mcf/d)	90,302	92,403
NGLs (bbl/d)	2,701	2,696
Total (boe/d)	28,338	29,446
Revenue[1]		
Oil ($/bbl)	88.54	73.74
Gas ($/Mcf)	3.54	3.98
NGLs ($/bbl)	66.70	52.05
Total ($/boe)	50.88	45.69
Royalties		
Oil ($/bbl)	(17.67)	(14.62)
Gas ($/Mcf)	(0.14)	(0.36)
NGLs ($/bbl)	(17.20)	(13.95)
Total ($/boe)	(8.69)	(8.05)
Operating Expenses		
Oil ($/bbl)	(14.55)	(11.51)
Gas ($/Mcf)	(1.80)	(1.68)
NGLs ($/bbl)	(8.64)	(7.80)
Total ($/boe)	(12.01)	(10.41)
Other Income[2]		
Oil ($/bbl)	0.14	0.21
Gas ($/Mcf)	0.01	0.01
NGLs ($/bbl)	0.10	0.15
Total ($/boe)	0.08	0.13
Operating Netback, Before Hedging		
Oil ($/bbl)	56.46	47.82
Gas ($/Mcf)	1.61	1.95
NGLs ($/bbl)	40.96	30.45
Total ($/boe)	30.26	27.36
Hedging Gains/(Losses)[3]		
Oil ($/bbl)	(2.30)	0.52
Gas ($/Mcf)	0.16	0.69
NGLs ($/bbl)	-	-
Total ($/boe)	(0.36)	2.38
Operating Netback, After Hedging		
Oil ($/bbl)	54.16	48.34
Gas ($/Mcf)	1.77	2.64
NGLs ($/bbl)	40.96	30.45
Total ($/boe)	29.90	29.74

(1) Net of transportation charges.
(2) Excludes interest on notes with MFC.
(3) Realized hedging gains/losses on commodity and exchange rate derivative contracts.

For the year-ended December 31, 2011, NAL's operating netback before hedging was $30.26 per boe, an increase of 11 percent from $27.36 per boe in 2010. The increase was due to higher revenues, as a result of higher commodity prices, partially offset by increased royalty expenses and operating costs per boe. Realized hedging losses, related to commodity and exchange rate derivative contracts, were $0.36 for the year ended December 31, 2011, as compared to a gain of $2.38 per boe in 2010. The loss in 2011 was attributable to increased oil hedging losses due to higher crude oil prices and lower natural gas hedging gains due to lower volumes hedged in 2011.

General & Administrative Expenses

	2011	2010
G&A expenses ($000s)	25,873	25,697
$/boe	2.50	2.39
As a % of revenue	4.9	5.2
Per share ($)	0.17	0.18

General and administrative ("G&A") expenses include direct costs incurred by the Corporation plus the reimbursement of the G&A expenses incurred by NAL Resources Management Limited (the "Manager") on the Corporation's behalf.

For the year ended December 31, 2011, G&A expenses were $25.9 million, comparable with the $25.7 million in 2010. G&A expense per boe was $2.50 in 2011, compared to $2.39 in 2010. The increase in the boe rate was attributable to lower volumes in 2011.

Share-Based Incentive Compensation Plan

	2011	2010
Share-based compensation ($000s):	(1,077)	4,632
As a % of revenue	(0.2)	0.9
$/boe	(0.10)	0.43
Per share ($)	(0.01)	0.03

The employees of the Manager are all members of a share-based incentive plan (the "Plan"). The Plan results in employees of the Manager receiving cash compensation based upon the value and overall return of a specified number of notional common shares of the Corporation. The Plan consists of Restricted Share Units ("RSUs") and Performance Share Units ("PSUs"). One third of the amount of each RSU grant vests on November 30 in each of the three years after the date of grant. PSUs vest on November 30, three years from the date of grant. Dividends paid on the Corporation's outstanding common shares during the vesting period are assumed to be paid on the awarded notional shares and reinvested in additional notional shares on the date of distribution. Upon vesting, the employee is entitled to a cash payout based on the share price at the date of vesting of the units held. In addition, PSUs have a performance multiplier which is based on the Corporation's performance relative to its peers and may range from zero to two times the market value of the notional common shares at vesting.

During 2011, the Corporation has recorded a reduction of $1.1 million for share-based incentive compensation that reflects a decrease in the share price and PSU performance multipliers, partially offset by the impact of vesting during the year. The share price decreased by 39 percent, from $12.95 at December 31, 2010, to $7.88 at December 31, 2011. A decrease in share price results in previously accrued amounts being reversed.

On a full year basis, the Corporation has recorded a reduction of $1.1 million compared to an expense of $4.6 million in 2010. The year-over-year decrease was a reflection of a 39 percent decrease in share price during 2010 compared to a six percent decrease in share price during 2010.

At December 31, 2011, the share price used to determine share-based incentive compensation was $7.88. The closing share price of the Corporation on the Toronto Stock Exchange on March 6, 2012 was $7.27.

The calculation of share-based compensation expense is made at the end of each quarter based on the quarter end share price and estimated performance factors. The compensation charges relating to the units granted are recognized over the vesting period based on the share price, number of RSUs and PSUs outstanding, and the expected performance multiplier. As a result, the expense recorded in the accounts will fluctuate over-time.

At December 31, 2011, the Corporation recorded a total accumulated liability of $4.7 million for share-based incentive compensation, of which $2.6 million was paid in January 2012. The remaining balance represents the Corporation's estimated liability for the share-based incentive plan as at December 31, 2011, with $0.8 million recorded as a current liability (total current liability $3.4 million), as it is payable in December 2012, and $1.3 million is a long-term liability, as it is payable in December 2013 and 2014.

Related Party Transactions

The Corporation is managed by the Manager. The Manager is a wholly-owned subsidiary of Manulife Financial Corporation ("MFC") and also manages NAL Resources Limited ("NAL Resources"), another wholly-owned subsidiary of MFC. NAL Resources and the Corporation maintain ownership interests in many of the same oil and natural gas properties in which NAL Resources is the joint operator. As a result, a significant portion of the net operating revenues and capital expenditures during the year are based on joint amounts from NAL Resources. These transactions are in the normal course of joint operations and are measured using the fair value established through the original transactions with third parties.

The Manager provides certain services to the Corporation and its subsidiary entities pursuant to an administrative services and cost sharing agreement. This agreement requires the Corporation to reimburse the Manager at cost for G&A and share-based compensation expenses incurred by the Manager on behalf of the Corporation, calculated on a unit of production basis. The agreement does not provide for any base or performance fees to be payable to the Manager.

The Corporation paid $22.2 million (2010 - $21.7 million) for the reimbursement of G&A expenses during 2011. The Corporation also pays the Manager its share of share-based incentive compensation expense when cash compensation is paid to employees under the terms of the Plan, of which $6.9 million was paid, representing shares that vested on November 30, 2010 (2010 - $6.8 million).

At December 31, 2011 the Corporation owed the Manager $3.7 million for the reimbursement of G&A and had a receivable from NAL Resources of $9.4 million, relating to operating revenues less capital expenditures.

Interest & Debt

	2011	2010
Interest on bank debt ($000s)[1]	12,616	11,794
Interest on convertible debentures ($000s)	12,570	12,521
Amortization on convertible debentures ($000s)	(2,356)	-
Total interest before interest rate hedges($000)	22,830	24,315
Loss on interest rate swaps ($000s)	528	1,057
Total interest after interest rate hedges ($000s)	23,358	25,372
Bank debt outstanding at period end ($000s)	327,170	266,965
Convertible debentures at period end ($000s)[2]	197,164	199,520
$/boe:		
Interest on bank debt	1.22	1.10
Interest on convertible debentures	1.22	1.17
Amortization on convertible debentures	(0.23)	-
Loss on interest rate swaps	0.05	0.10
Total interest after interest rate hedges	2.26	2.37

(1) Excludes interest rate hedge impact.
(2) Debt component of the debentures, as reported on the balance sheet.

Interest on bank debt includes interest rate charges on borrowings, plus a standby fee, a stamping fee and the fee for renewal.

For the year ended December 31, 2011, interest on bank debt increased $0.8 million to $12.6 million, compared to $11.8 million in 2010 due to higher average debt levels, partially offset by lower effective interest rates. Average outstanding debt for the 12 months ended December 31, 2011 increased to $284.4 million, $55.7 million higher than the $228.7 million outstanding for 2010. The effective interest rate averaged 4.44 percent in 2011, compared to 5.16 percent in 2010. The decrease in the rate from 2010 is attributable to lower overall borrowing rates in the market.

NAL's interest is calculated based upon a floating rate, before the effect of any interest rate swaps.

Interest on convertible debentures was consistent year-over-year, at $12.6 million for the years ended December 31, 2011 and 2010. Interest represents the interest on the 2007 convertible debentures at 6.75 percent and the interest on the 2009 convertible debentures at 6.25 percent.

Amortization of the debt premium was $2.4 million for the year ended December 31, 2011 (2010 - nil). During 2010, the convertible debentures were recorded at fair value resulting in no accretion or amortization (refer to "Capital Resources and Liquidity" in this MD&A for further information).

Cash Flow Netback

($/boe)	2011	2010
Operating netback, after hedging	29.90	29.74
G&A expenses, including share-based incentive compensation	(2.40)	(2.82)
Interest on bank debt and convertible debentures[1]	(2.43)	(2.26)
Interest on notes with MFC[2]	-	-
Realized loss on interest rate swaps	(0.05)	(0.10)
Cash flow netback	25.02	24.56

(1) Excludes non-cash amortization on convertible debentures.
(2) Reported as other income.

For the year ended December 31, 2011, NAL's cash flow netback was $25.02 per boe, a two percent increase from $24.56 per boe in 2010. The increase was due to a higher operating netback after hedging, lower G&A expenses, including share-based incentive compensation, and lower realized losses on interest rate swaps, partially offset by higher interest charges.

Gains On Oil & Gas Properties

	2011	2010
Gains on oil and gas properties ($000s)	26,046	17,596
As a % of revenue	4.9	3.6
$/boe	2.52	1.64

Gains on oil and gas properties include gains recognized relating to the disposition of oil and gas properties, on property swaps and on farm-outs. A gain on disposition of properties is computed as the difference between sales proceeds and the net book value. A gain on a property swap is computed as the difference between the net book value of the properties given up and the fair value of the properties received. A gain on a farm-out agreement is recognized as the difference between the carrying value of the undeveloped land farmed-out and the estimated fair value of the interest retained (royalty or working interest) under the farm-out agreement.

The gain on disposition of oil and gas properties for the year ended December 31, 2011 was $26.0 million, compared to $17.6 million in 2010. Included in 2011 was $15.6 million relating to the disposal of certain non-core properties, $2.3 million relating to a property swap and $8.1 million relating to farm-out agreements.

Depletion, Accretion Of Asset Retirement Obligations & Impairment

	2011	2010
Depletion ($000s)	193,376	200,787
Depletion rate per boe ($)	18.70	18.68
Accretion of asset retirement obligation ($000s)	10,123	11,006
Impairment ($000s)	101,996	32,804

Depletion of oil and natural gas properties, including the capitalized portion of the asset retirement obligations, and depreciation of equipment is provided for on a unit-of-production basis using estimated proved plus probable reserves volumes.

For the year ended December 31, 2011, depletion on property, plant and equipment was $18.70 per boe, comparable to the $18.68 per boe in 2010.

Accretion on asset retirement obligation was $10.1 million in 2011, an eight percent decrease from $11.0 million in 2010, due to the dispositions of properties.

Impairment of $102.0 million has been recorded for the year ended December 31, 2011 (2010 – $32.8 million). Impairment is recognized if the carrying amount of PP&E is greater than its recoverable amount, and it is calculated on a cash generating unit basis ("CGU") (see "Accounting Policies" in this MD&A for more information). A CGU is the lowest level at which there are identifiable cash inflows. NAL has determined that it has nine CGUs. The impairment in 2011 occurred in four natural gas CGUs, due to lower gas prices, and one crude oil CGU, due to revisions to reserve volumes and future costs, compared to December 31, 2010. If gas prices recover and the fair value of assets increases, NAL is required to reverse any impairment previously recognized in net income, net of what depletion would have been had the asset not been impaired, and increase the carrying value of the CGU to which it relates. The reversal cannot exceed the amount previously written off, net of assumed depletion.

The depletion rate will fluctuate period-over-period depending on the amount and type of capital expenditures and the amount of reserves added.

Taxes

For the year ended December 30, 2011, NAL had a deferred tax recovery of $3.0 million compared to $29.9 million in 2010.

Estimated Tax Pools ($ millions)	2011	2010
Canadian exploration expense	91	57
Canadian development expense	516	376
Canadian oil and gas property expense	398	456
Undepreciated capital costs	245	251
Other (including loss carry forwards)	136	279
Total estimated tax pools	1,386	1,419

As at December 31, 2011, the Corporation's (including all subsidiaries) estimated tax pools (unaudited) available for deduction from future taxable income approximated $1.4 billion, of which approximately 29 percent represented COGPE, 18 percent represented UCC, and the remaining balance consisted of CEE, CDE, share issue costs and non-capital loss carry forwards.

Based upon current commodity prices and capital spending levels, the Corporation is not likely to be taxable for many years.

Net Income (Loss)

($000's)	2011	2010
Net income (loss)	(11,034)	59,025

Net income is a measure impacted by both cash and non-cash items. The largest non-cash items impacting the Corporation's net income are depletion, unrealized gains or losses on derivative contracts, gains or losses on property, plant and equipment, deferred income taxes and impairment losses/reversal.

Net loss for the year ended December 31, 2011 of $11.0 million was $70.0 million less than the net income of $59.0 million in 2010. The decrease in net income in 2011 was attributable to increased impairment ($69.2 million), a decreased gain on derivative contracts ($17.0 million), increased operating costs ($12.3 million) and a decreased tax recovery ($27.7 million). This was offset by increased revenues net of royalties ($31.0 million), decreased interest charges ($1.5 million), lower share based incentive compensation ($5.7 million), decreased depletion ($7.4 million) and a higher gain on disposition ($8.5 million).

Capital Resources & Liquidity

	2011	2010
Shareholders' equity ($000s)	796,725	895,750
Bank debt ($000s)	327,170	266,965
Working capital deficit (surplus)[1] ($000s)	36,210	43,337
Net debt excluding convertible debentures	363,380	310,302
Convertible debentures ($000s)[2]	194,744	194,744
Net debt ($000s)	558,124	505,046
Net debt excluding convertible debentures to trailing 12-month cash flow[3]	1.45	1.21
Total net debt to trailing 12-month cash flow[3]	2.23	1.97
Common shares outstanding (000s)	151,107	147,248

(1) Working capital and other liabilities, excluding derivative contracts, current amount of convertible debentures and note with MFC.
(2) Convertible debentures included at face value.
(3) Calculated as net debt divided by funds from operations for the previous 12 months.

The capital structure of the Corporation is comprised of common shares, bank debt and convertible debentures.

As at December 31, 2011, NAL had 151,106,917 common shares outstanding, compared with 147,248,494 common shares as at December 31, 2010. The increase from December 31, 2010 is attributable to 2,700,000 shares issued under the Corporation's dividend reinvestment program ("DRIP") and 1,158,423 shares issued at prevailing market prices pursuant to the Corporation's equity distribution agreement as outlined in the Prospectus Supplement of the Corporation dated June 20, 2011.

Under the DRIP, shareholders may elect to reinvest dividends or make optional cash payments to acquire common shares from treasury at 95 percent of the average market price with no additional fees or commissions. The operation of the DRIP was reinstated effective with the March 2009 distribution payable on April 15, 2009, following suspension of the program in October 2008. Participation in the DRIP has averaged 21 percent during the year.

As at December 31, 2011, the Corporation had net debt of $558.1 million (net of working capital and other liabilities, excluding derivative contracts) including convertible debentures at face value of $194.7 million. Excluding the convertible debentures, net debt was $363.4 million, compared with $310.3 million at December 31, 2010. The increase in net debt, excluding convertible debentures, of $53.1 million during 2011 is attributable to increased bank debt of $60.2 million, offset by a positive change in the working capital deficit of $7.1 million.

Bank debt outstanding was $327.2 million at December 31, 2011, compared with $267.0 million as at December 31, 2010. Of the $327.2 million outstanding at December 31, 2011, $1.3 million was outstanding under the working capital facility with the remainder under the production facility.

At the end of the 2011, the Corporation had a net debt (excluding convertible debentures) to 12 months trailing cash flow ratio of 1.45 times and a total net debt (including convertible debentures) to 12 months trailing cash flow ratio of 2.23 times.

During the year, the Corporation amended its $550 million credit facility to a fixed maturity date, set at April 30, 2014. The Corporation can apply at any time for an extension of the latest maturity date to a business day not later than three years from April 30th of the year in which the request for the extension was made. The facility consists of a $535 million production facility and a $15 million working capital facility. The credit facility is fully secured by first priority security interests in all present and after acquired properties and assets of the Corporation and its subsidiary and affiliated entities. The purpose of the facility is to fund property acquisitions and capital expenditures.

The Corporation has two series of convertible debentures outstanding as at December 31, 2011.

The Corporation has outstanding $79.7 million principal amount of 6.75 percent convertible extendible unsecured subordinated debentures. Interest on these debentures is paid semi-annually in arrears, on February 28 and August 31, and the debentures are convertible at the option of the holder, at any time, into fully paid common shares at a conversion price of $14.00 per common share. The debentures mature on August 31, 2012 at which time they are due and payable. The debentures are redeemable by the Corporation at a price of $1,025 per debenture before August 31, 2012. On redemption or maturity, the Corporation may opt to satisfy its obligation to repay the principal by issuing common shares. If all of the outstanding debentures were converted at the conversion price, an additional 5.7 million common shares would be required to be issued. On maturity, these debentures will be funded from the proceeds from the issuance of convertible debentures that occurred in February 2012, as described below.

In addition, the Corporation has outstanding $115 million principal amount of 6.25 percent convertible unsecured subordinated debentures. Interest on the debentures is paid semi-annually in arrears, on June 30 and December 31, and the debentures are convertible at the option of the holder, at any time, into fully paid common shares at a conversion price of $16.50 per common share. The debentures mature on December 31, 2014 at which time they are due and payable. The debentures are redeemable by the Corporation at a price of $1,050 per debenture on or after January 1, 2013 and on or before December 31, 2013, and at a price of $1,025 per debenture on or after January 1, 2014 and on or before December 31, 2014. On redemption or maturity, the Corporation may opt to satisfy its obligation to repay the principal by issuing common shares. If all of the outstanding debentures were converted at the conversion price, an additional 7.0 million common shares would be required to be issued.

Subsequent to December 31, 2010, the convertible debentures were classified as debt on the balance sheet with a portion of the proceeds allocated to equity, representing the value of the conversion feature. Prior to December 31, 2010, as a trust, the convertible debentures were fair valued and had no equity portion assigned. As a Corporation, and as the debentures are converted to common shares, a portion of the debt and equity amounts are transferred to Share Capital. The debt balance amortizes over time to the principal amount owing on maturity. The amortization of the debt premium and the interest paid to debenture holders are reflected each period as part of the line item "interest and amortization on convertible debentures" in the consolidated statement of income.

The Corporation recognized $2.4 million (2010 - nil) of amortization of the debt premium in 2011.

As at March 6, 2012, the Corporation had 151,895,063 common shares and $344.7 million in convertible debentures outstanding. The increase in common shares outstanding since December 31, 2011, is attributable to the DRIP and 300,000 shares issued at prevailing market prices pursuant to the Corporation's equity distribution agreement outlined in the Prospectus Supplement dated June 20, 2011. Net proceeds were $2.2 million, after commission of $0.1 million. In addition, subsequent to year end, the Corporation issued $150 million principal amount of 6.25 percent convertible unsecured subordinated debentures, at a price of $1,000 per debenture. Interest on these debentures is paid semi-annually in arrears on March 31 and September 30, and the debentures are convertible at the option of the holder at any time into common shares at a conversion price of $9.90 per share. The debentures mature on March 31, 2017.

Funds from Operations

	2011	2010
Cash flow from operating activities ($000s)	258,801	274,606
Cash flow from operating activities per share ($)	1.74	1.91
Payout ratio based on cash flow from operating activities	48%	57%
Funds from operations ($000s)	250,153	256,356
Funds from operations per share ($)	1.68	1.78
Payout ratio based on funds from operations	50%	61%

As stated in the non-IFRS measures section of this MD&A, NAL uses funds from operations as a key performance indicator to measure the ability of the Corporation to generate cash from operations and to pay dividends.

For the year ended December 31, 2011, funds from operations decreased by $6.2 million to $250.2 million from $256.4 million in 2010. The two percent decrease was attributable to a decrease in net realized gains on derivative contracts ($28.7 million), from a gain of $24.4 million in 2010 to a loss of $4.2 million in 2011, increased operating costs ($12.3 million), partially offset by increased revenues net of royalties ($31.0 million) and decreased share-based incentive compensation ($5.7 million).

Capital expenditures of the Corporation and the dividends paid in any given period may exceed funds from operations. This shortfall is financed from a combination of debt and equity.

The Corporation renewed its bank line of $550 million of which $327.2 million was drawn at December 31, 2011, leaving available capacity of $222.8 million.

For 2012, the Corporation expects to continue to execute its active hedging program. Currently, full year average crude oil volumes of 7,878 bbls per day are hedged at an average price of US$97.37 per bbl on fixed price contracts and an average floor price of $101.25 per bbl on collared contracts. For natural gas, 2012 average volumes of 12,396 GJ per day are hedged at an average price of $3.88 per GJ ($4.09 per Mcf) on fixed contracts and at an average floor of $2.50 per GJ ($2.64 per Mcf) on collared contracts.

NAL's capital program is designed to be scalable and flexible in response to commodity prices and market conditions. The Corporation, through the Manager, operates approximately 95 percent of the assets to which the capital program is directed, allowing for significant flexibility over the scale and timing of the program.

Fluctuations in commodity prices, market conditions or potential growth opportunities may make it necessary to adjust planned capital expenditures and/or dividend levels.

Asset Retirement Obligation

At December 31, 2011, the Corporation reported an asset retirement obligation ("ARO") balance of $130.1 million ($149.0 million as at December 31, 2010) for future abandonment and reclamation of the Corporation's oil and gas properties and facilities. The ARO balance was increased by $10.1 million from accretion expense, $0.8 million for liabilities incurred and revisions to estimates, and was reduced by $22.9 million for property dispositions and $6.9 million for actual abandonment and reclamation expenditures incurred during the year ended December 31, 2011.

Variable Interest Entities

NAL has no variable interest entities.

Contractual Obligations

Joint Venture Agreement:

Effective April 20, 2009, the Corporation and MFC entered into a joint venture agreement with a senior industry partner. The arrangement consists of a three year commitment to spend $50 million to earn an interest in freehold and Crown acreage. The Corporation has a 65 percent interest in this agreement and MFC a 35 percent interest and therefore the Corporation's net commitment is $32.5 million. The agreement is exclusive and structured to be extendible for up to an additional six years for a total potential commitment of $150 million ($97.5 million net to the Corporation) to earn an interest in over 150 sections (97.5 net) of freehold and Crown acreage. If the capital spending commitments are not met, interests in the freehold and Crown acreage will not be earned and the Corporation will not be required to pay unspent commitment amounts to the senior industry partner. As at December 31, 2011, the Corporation had spent $26.1 million under this agreement.

Farm-in Agreement:

Effective January 2012, the Corporation and MFC renegotiated a prior farm-in agreement with a senior industry partner, which resulted in the replacement of the original agreement with a new agreement. The renegotiated arrangement consists of a four year capital commitment to December 2015, for a total of $50 million, of which at least $10 million must be spent each year. The Corporation has a 60 percent interest in this agreement and MFC a 40 percent interest. The agreement provides the opportunity to earn an interest in approximately 280 gross sections (182 net) of undeveloped Cardium rights and other zones of interest in Alberta held by the partner. If the capital spending commitments are not met, interest in the acreage will not be earned and the Corporation will not be required to pay any unspent amounts under the agreement.

Other:

NAL has entered into several contractual obligations as part of conducting day-to-day business. NAL has the following remaining commitments for the next five years:

($000s)	2012	2013	2014	2015	2016
Office lease[1]	2,182	2,168	2,126	2,126	-
Office lease – Clipper and Breaker[2]	2,211	364	-	-	-
Transportation agreement	4,068	2,019	574	72	19
Processing agreement[3]	197	184	-	-	-
Convertible debentures[4]	79,744	-	115,000	-	-
Bank debt	-		327,170	-	-
Total	88,402	4,735	444,870	2,198	19

(1) Represents the full amount of office lease commitments, including both base rent and operating costs, in relation to the lease held by the Manager, of which the Corporation is allocated a pro rata share (currently approximately 60 percent) of the expense on a monthly basis.
(2) Represents the full amount of office lease assumed with the acquisitions of Clipper and Breaker. MFC is obligated to reimburse the Corporation for 50 percent of the Clipper obligation under a base price adjustment clause.
(3) Represents gas processing agreements with take or pay components.
(4) Principal amount.

Quarterly Information

	2011				2010			
($000s, except per share and production amounts)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue, net of royalties[1]	104,910	124,524	131,104	82,391	85,689	101,257	106,332	136,209
Per share ($)	0.70	0.72	0.88	0.56	0.58	0.69	0.74	0.99
Cash flow	67,818	69,103	60,897	60,983	69,401	87,586	50,066	68,248
Per share ($)	0.45	0.46	0.41	0.41	0.47	0.60	0.35	0.50
Funds from operations[2]	68,393	64,752	60,381	56,626	61,311	59,709	62,084	73,253
Per share ($)	0.45	0.44	0.41	0.38	0.42	0.41	0.43	0.53
Net income (loss)	(53,886)	11,087	33,275	(1,510)	(19,936)	6,806	22,918	49,237
Per share ($)								
basic	(0.36)	0.07	0.22	(0.01)	(0.14)	0.05	0.16	0.36
diluted	(0.36)	0.07	0.22	(0.01)	(0.14)	0.05	0.15	0.34
Average oil equivalent production (boe/d – 6:1)	29,795	28,752	26,758	28,024	28,596	29,222	29,334	29,819

(1) Represents revenue, net of royalties, plus gain (loss) on derivative contracts.
(2) Represents cash flow from operating activities prior to the change in non-cash working capital items.

Selected Annual Information

($000s except per share amounts) Years ended December 31	2011	2010	2009[3]
Oil, natural gas and liquid sales[1]	526,266	491,037	361,087
Net income (loss)	(11,034)	59,025	9,200
Net income (loss) per share	(0.07)	0.41	0.09
Net income (loss) per share – diluted	(0.07)	0.41	0.09
Dividends paid and declared	125,018	155,777	120,153
Dividends paid or declared per share	0.84	1.08	1.12
Total assets	1,561,204	1,638,101	1,609,450
Total liabilities	764,479	742,351	715,258
Long term debt[2]	443,297	466,485	408,690
Shareholders' equity	796,725	895,750	894,192
Number of common shares outstanding at year-end	151,107	147,248	137,471

(1) Represents oil, natural gas and natural gas liquid sales, less transportation costs and prior to royalties and hedging.
(2) Includes bank debt and convertible debentures.
(3) As computed under previous CGAAP.

Fourth Quarter Review

Capital Expenditures & Exploration & Development Activities

Fourth Quarter Drilling Activity

	Crude Oil		Natural Gas		Service Wells		Dry & Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Operated wells	18	8.7	-	-	-	-	-	-	18	8.7
Non-operated wells	9	1.2	-	-	-	-	-	-	9	1.2
Total wells drilled[1]	27	9.9	-	-	-	-	-	-	27	9.9

(1) Includes drilling activity NAL participated in, but excludes third party revenue wells.

The Corporation spent $31.7 million on drilling, completions and tie-in operations during the fourth quarter of 2011, compared to $19.4 million during the corresponding period of 2010, and drilled 27 (9.9 net) wells, compared to 23 (8.6 net) wells during the same period in 2010. All wells drilled in the fourth quarter were oil wells.

Capital expenditures before property acquisitions and dispositions for the fourth quarter of 2011 totaled $40.3 million, compared to $25.5 million in the same period of 2010. The increase of $14.8 million, is largely attributable to increased drilling, completions and tie-in activities ($12.3 million) with the balance of the increase related to facilities expenditures ($2.9 million), partially offset by a decrease in land expenditures ($0.3 million).

Production

Fourth quarter production of 29,795 boe per day is four percent higher than the production of 28,596 boe per day in the same period of 2010 due to higher crude oil volumes, primarily a result of the 2011 oil focused drilling program. Fourth quarter 2011 production has been positively impacted by flush volumes and attributable to the tie-in of the six wells from the Lochend Cardium program.

Total volumes increased 1,043 boe per day from the third quarter of 2011, continuing the positive growth trend, primarily in oil production, from the second quarter 2011 production, which was limited by facility constraints and wet weather related production outages. Oil volumes increased by approximately 13 percent quarter-over-quarter to average 11,755 bbls per day. This increase is a result of volumes coming back on-stream in Saskatchewan, and the impact of a successful 2011 Cardium drilling program primarily in the Lochend and Westward Ho areas as well as consistent results in the Corporation's Mississippian light oil drilling program.

Revenue

Gross revenue from oil, natural gas and natural gas liquids sales, after transportation costs and prior to hedging, totaled $144.8 million for the three months ended December 31, 2011, 24 percent higher than the fourth quarter of 2010. The increase was due to a 19 percent increase in the average realized price per boe, a four percent increase in production volumes and a three percent increase in relative oil weighting in the production. The 19 percent increase in realized price was driven by a 20 percent increase in the realized crude oil price, a 40 percent increase in the realized natural gas liquids price, partially offset by a 13 percent decrease in the realized natural gas price. The increase in realized prices reflects higher WTI prices and a weaker Canadian dollar, partially offset by lower AECO spot prices.

Pricing

NAL's fourth quarter average realized Canadian crude oil price per barrel, net of transportation costs and excluding hedging, was $91.84, compared to $76.42 for the corresponding quarter of 2010. The increase in realized price quarter-over-quarter of 20 percent, or $15.42/bbl, was primarily driven by a 10 percent increase in the WTI price (US$/bbl), an increase in crude oil differentials over the comparable period, and a one percent decrease in the value of the Canadian dollar.

For the fourth quarter of 2011, NAL's crude oil price differential was 95 percent, an increase of six percentage points from the comparable period in 2010.

Natural gas liquids averaged $72.37/bbl in the fourth quarter of 2011, a 40 percent increase from the $51.59/bbl realized in 2010.

For the three months ended December 31, 2011, the Corporation's natural gas sales averaged $3.10/Mcf compared to $3.56/Mcf in the comparable period of 2010, a decrease of 13 percent. The year-over-year decrease in gas prices was attributable to a 12 percent and a three percent decrease in the benchmark AECO daily and monthly spot prices, respectively.

Prices for Lake Erie natural gas decreased to $4.17/Mcf in the fourth quarter of 2011, compared to $4.64/Mcf in 2010, a decrease of 10 percent. Lake Erie production of 3.1 mmcf per day accounted for three percent of the Corporation's natural gas production in the fourth quarter of 2011, the same as in the comparable period of 2010. Natural gas sales from the Lake Erie property generally receive a higher price due to the proximity of the Ontario and northeastern U.S. markets.

Risk Management

Realized losses on derivative contracts were $0.9 million for the fourth quarter of 2011, compared to a gain of $6.4 million in the corresponding quarter of 2010. The decrease is attributable to increased realized losses on crude oil contracts and lower natural gas realized gains.

During the fourth quarter, an average of 6,001 bbl/d of crude was hedged, resulting in a realized loss of $3.2 million. In addition, 27,000 GJ/d of natural gas were hedged, resulting in a realized gain of $1.8 million, and foreign exchange rate contracts resulted in a realized gain of $0.6 million, which were partially offset by realized losses on interest rate contracts of $0.1 million.

Fourth quarter income for 2011 includes a $16.7 million unrealized loss on derivatives resulting from the change in the fair value of the derivative contracts during the quarter from an unrealized gain of $11.0 million at September 30, 2011 to an unrealized loss of $5.6 million at December 31, 2011. The $16.7 million unrealized loss was comprised of a $25.2 million unrealized loss on crude oil contracts, offset by a $2.0 million unrealized gain on natural gas contracts, a $0.5 million unrealized gain on interest rate swaps and an $6.0 million unrealized gain on foreign exchange swaps.

Royalty Expenses

Crown, freehold and overriding royalties totaled $24.0 million for the three months ended December 31, 2011. Expressed as a percentage of gross sales net of transportation costs, before gain/loss on derivative contracts, the net royalty rate was 16.6 percent for the quarter ended December 31, 2011, a decrease from 16.9 percent in the comparable period of 2010. Both periods include prior period royalty amendments which include annual gas cost allowance adjustments. Excluding the impact of these amendments, the royalty rate would be 17.3 percent in 2011 compared to 17.1 percent in 2010. The increase in royalty rates is primarily attributable to higher commodity prices in 2011 as compared to 2010.

Royalties increased to $8.74 per boe for the fourth quarter of 2011, an increase of 16 percent compared to the fourth quarter of 2010, reflecting higher commodity prices on a year-over-year basis.

Operating Costs

Operating costs were $37.7 million in the fourth quarter of 2011, an increase of $12.1 million, or 47 percent, from the comparable period in 2010. On a per boe basis, operating costs increased to $13.76 per boe for the quarter ended December 31, 2011, up 42 percent from $9.72 per boe for the quarter ended December 31, 2010. The increase in operating costs in the fourth quarter of 2011 is primarily the result of prior period adjustments. Excluding the impact of these amendments, the operating costs would be $29.8 million or $10.87 on a boe basis.

Operating Netback

For the quarter ended December 31, 2011, NAL's operating netback before hedging gains was $30.41 per boe, an increase of 11 percent from $27.38 per boe for the quarter ended December 31, 2010. The increase was due to higher revenues, a result of higher commodity prices, partially offset by increased royalty expense and operating costs per boe. Realized hedging losses, related to commodity and exchange rate derivative contracts, were $0.29 per boe in the fourth quarter of 2011, as compared to a gain of $2.49 per boe in 2010.

General & Administrative Expenses

For the three months ended December 31, 2011, G&A expenses were $5.2 million, compared to $7.4 million in the same quarter of 2010. G&A expense per boe was $1.89 in the quarter, as compared to $2.81 for the same period in 2010. The decrease in G&A year-over-year was primarily due to corporate conversion costs included in the fourth quarter of 2010, relating to the conversion from a trust to a corporation on December 31, 2010.

Share-Based Incentive Compensation Plan

During the fourth quarter of 2011, the Corporation recorded a $0.3 million charge for share-based incentive that reflects an increase in the share price and the impact of vesting, partially offset by a decrease in PSU performance multipliers since September 30, 2011. The share price of the Corporation increased by two percent, from $7.70 at September 30, 2011 to $7.88 at December 31, 2011. An increase in share price results in previously accrued amounts being increased.

Share-based incentive compensation decreased from $3.0 million in the fourth quarter of 2010 to $0.3 million in 2011. The year-over-year decrease was a reflection of a smaller increase in the share price during the fourth quarter of 2011 compared to the fourth quarter of 2010 (from $11.53 at September 30, 2010 to $12.95 at December 31, 2010).

Interest

Interest on bank debt for the fourth quarter of 2011 was $3.3 million, an increase of $0.1 million from $3.2 million for the comparable period in 2010 due to higher average debt levels, partially offset by lower effective interest rates. Average outstanding bank debt for the fourth quarter of 2011 was $312.4 million, $60.6 million higher than the $251.8 million outstanding for the fourth quarter of 2010, driven primarily by lower average bank debt in 2010 due to $94.5 million raised in an equity financing in the second quarter of 2010, net of issue costs. NAL's effective interest rate averaged 4.23 percent during the fourth quarter of 2011, compared to 5.06 percent during the corresponding period in 2010.

Cash Flow Netback

For the quarter ended December 31, 2011, NAL's cash flow netback was $25.70 per boe, a nine percent increase from $23.58 per boe for the comparable period in 2010. The increase was due to a higher operating netback after hedging, lower G&A expenses, including share-based incentive compensation, lower interest charges per boe and lower realized losses on interest rate swaps.

Gains on Oil & Gas Properties

The gain on disposition of oil and gas properties for the three months ended December 31, 2011 was $10.6 million compared to $6.4 million in the corresponding period of 2010. Included in the fourth quarter gain of 2011 was $8.1 million relating to farm-out agreements and $2.3 million relating to a property swap.

Depletion, Accretion of Asset Retirement Obligation and Impairment

For the quarter ended December 31, 2011, depletion on property, plant and equipment was $18.42 per boe, two percent higher than $18.10 per boe for the same period in 2010.

Accretion on asset retirement obligation was $2.5 million for the fourth quarter in 2011, an eight percent decrease from $2.8 million for the comparable period of 2010 due to the disposition of properties.

Impairment of $84.0 million has been recorded in the fourth quarter of 2011, reflecting a decrease in natural gas prices and revisions to reserve volumes and future costs since September 30, 2011 (2010 - $26.2 million).

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Impairment of $84.0 million has been recorded in the fourth quarter of 2011, reflecting a decrease in natural gas prices and revisions to reserve volumes and future costs since September 30, 2011 (2010 - $26.2 million).

Net Loss

Net loss for the fourth quarter of 2011 was $53.9 million compared to $22.0 million for the corresponding period in 2010. The decrease of $31.9 million was mainly due to increased impairment ($57.8 million), increased operating costs ($12.1 million), an increased loss on derivative contracts ($3.7 million) and increased depletion ($2.9 million). This was offset by increased revenues net of royalties ($23.5 million), decreased G&A costs including share based incentive compensation ($4.9 million), increased gains on property, plant and equipment ($4.2 million), increased tax recovery ($11.0 million) and a positive fair value adjustment on convertible debentures in 2010 ($0.8 million).

Funds from Operations

For the three months ended December 31, 2011, funds from operations amounted to $68.4 million compared with $61.3 million for the corresponding period in 2010. The 12 percent increase was primarily due to increased revenues net of royalties ($23.5 million) and decreased G&A costs including share-based incentive compensation ($4.9 million), partially offset by increased operating costs ($12.1 million) and a decrease in the realized gain on derivative contracts ($7.3 million).

Disclosure Controls & Procedures ("DC&P")

The Chief Executive Officer and the Chief Financial Officer are responsible for establishing and maintaining disclosure controls and procedures ("DC&P"), as such term is defined in National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109"), for NAL. They have, as at the financial year ended December 31, 2011, designed such DC&P, or caused them to be designed under their supervision, to provide reasonable assurance that information required to be disclosed by NAL in its annual filings, interim filings or other reports filed or submitted by NAL under applicable securities legislation is recorded, processed, summarized and reported within the time periods specified in applicable securities legislation and that all material information relating to NAL is made known to them by others, particularly during the period in which NAL's annual and interim filings are being prepared.

Under the supervision of the Chief Executive Officer and the Chief Financial Officer, NAL conducted an evaluation of the effectiveness of its DC&P as at December 31, 2011. Based on this evaluation, the officers concluded that as of December 31, 2011, NAL's DC&P provide reasonable assurance that information required to be disclosed by NAL in its annual filings, interim filings or other reports that it files or submits under applicable securities legislation is recorded, processed, summarized and reported within the time periods specified in such legislation and that these controls and procedures also provide reasonable assurance that material information relating to NAL is made known to the Chief Executive Officer and Chief Financial Officer by others.

Internal Control Over Financial Reporting ("ICFR")

The Chief Executive Officer and the Chief Financial Officer are responsible for establishing and maintaining internal control over financial reporting ("ICFR"), as such term is defined in NI 52-109, for NAL. They have, as at the financial year ended December 31, 2011, designed ICFR, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The control framework the officers used to design NAL's ICFR is the Internal Control - Integrated Framework (COSO Framework) published by The Committee of Sponsoring Organizations of the Treadway Commission (COSO).

NAL's ICFR includes policies and procedures that:

- Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions, acquisitions and dispositions of assets of the Corporation;
- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles; and
- Provide reasonable assurance regarding prevention, or timely detection, of unauthorized acquisition, use or disposition of the Corporation's assets that could have a material effect on the financial statements.

Under the supervision of the Chief Executive Officer and the Chief Financial Officer (collectively, the "Officers"), NAL conducted an evaluation of the effectiveness of its ICFR as at December 31, 2011 based on the COSO Framework. Based on this evaluation, the Officers concluded that as of December 31, 2011, NAL's ICFR is effective.

It should be noted that while the Officers believe that NAL's are effective, they do not expect that the disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, but not absolute, assurance that the objectives of the control system are met.

There were no changes in the Corporation's ICFR during the year ended December 31, 2011 that materially affected the Corporation's ICFR.

Accounting Policies

The Corporation has prepared its December 31, 2011 Consolidated Financial Statements in accordance with IFRS issued by the IASB. Previously, the Corporation prepared its financial statements in accordance with Canadian GAAP, or previous CGAAP. The adoption of IFRS has not had a material impact on the Corporation's operations and strategic decisions.

The Corporation's IFRS accounting policies are provided in Note 2 to the Consolidated Financial Statements. In addition, Note 18 to the Consolidated Financial Statements presents reconciliations between the Corporation's 2010 previous CGAAP results and the 2010 IFRS results. The reconciliations include the Consolidated Balance Sheets as at January 1, 2010 and December 31, 2010, the Consolidated Statements of Earnings, Comprehensive Income, and Changes in Shareholders Equity for the three months and year ended December 31, 2010 and the Consolidated Cash Flows for the year ended December 31, 2010.

The following discussion explains the significant differences between NAL's previous CGAAP accounting policies and those applied by the Corporation under IFRS. IFRS policies have been retrospectively and consistently applied except where specific IFRS1 optional and mandatory exemptions permitted an alternative treatment upon transition to IFRS for first-time adopters.

The most significant changes to the Corporation's accounting policies relate to the accounting for property, plant and equipment. Under previous CGAAP, NAL followed the Canadian Institute of Chartered Accountants ("CICA") guideline on full cost accounting in which all costs directly associated with the acquisition of, the exploration for, and the development of, natural gas and crude oil reserves were capitalized in one cost centre. Costs accumulated within the cost centre were depleted using the unit-of-production method based on proved reserves determined using estimated future prices and costs. Upon transition to IFRS, the Corporation was required to adopt new accounting policies, including exploration and evaluation costs ("E&E") and development and production costs ("D&P").

Under IFRS, E&E costs are those expenditures for an area where technical feasibility and commercial viability has not yet been determined. D&P costs include those expenditures for areas where technical feasibility and commercial viability have been determined.

A) Property, plant & equipment (PP&E) & exploration & evaluation assets (E&E)

The Corporation elected to apply the IFRS1 exemption available to entities which followed full cost accounting under previous CGAAP. This exemption permits the total carrying value of PP&E and E&E under IFRS on transition to equal the carrying value under previous CGAAP, subject to an impairment test. In addition, conversion to IFRS required the allocation of the carrying amount of the full cost pool under previous CGAAP to E&E, and to components and cash generating units ("CGUs") for PP&E assets. Firstly, E&E assets were recorded at the carrying amount under previous CGAAP. The remaining previous CGAAP carrying amount was then allocated, pro-rata to components (Areas) for D&P assets ("PP&E"), based on proved plus probable reserve values, using the present values at a 10 percent discount rate.

Impairment tests were completed on transition, resulting in no impairment charge to PP&E or E&E at January 1, 2010.

E&E assets are required to be segregated from D&P assets. These assets comprise possible reserves assigned as a result of business acquisitions and undeveloped land associated with exploratory areas. As at January 1, 2010 and December 31, 2010, NAL's E&E assets were $88.1 million and $63.1 million, respectively.

Under previous CGAAP these assets were included in the full cost pool as PP&E, in accordance with the CICA's full cost accounting guideline. Under IFRS, these costs are initially recorded as E&E, and on determination of technical feasibility and commercial viability of the assets, the capitalized costs are moved to PP&E.

B) Capitalized costs - PP&E

Under IFRS, employee costs included in general and administrative charges and share-based compensation charges are capitalized to the extent they are directly attributable to PP&E and E&E. The Corporation has adjusted its capitalization policy to comply with IFRS. For the three and twelve months ended December 31, 2010, $2.5 million and $9.3 million, respectively, of such costs have been expensed which were originally capitalized under previous CGAAP.

Additionally, for the three and twelve months ended December 31, 2010, lease rentals of $1.9 million and $7.7 million, respectively, were expensed under previous CGAAP, while under IFRS the Corporation has elected to capitalize these amounts.

C) Depreciation & depletion

Under previous CGAAP, depletion was based on NAL's single cost centre, on a unit of production basis using total proved reserves. Costs subject to depletion excluded possible reserve locations and undeveloped land.

Under IFRS, depletion is provided for at a component level, defined as an Area by NAL, on a unit of production basis using total proved plus probable reserves. Costs subject to depletion are D&P assets excluding land under development.

For the three and twelve months ended December 31, 2010, depletion decreased by $11.6 million and $50.6 million, respectively, from previous CGAAP, primarily a result of the change in depletion base to proved plus probable reserves.

D) Impairment

Under previous CGAAP, impairment was recognized if the carrying amount exceeded the undiscounted cash flows from proved reserves for NAL's single cost centre. The amount of impairment was then measured as the amount by which the carrying value of the cost centre exceeded the sum of proved plus probable reserves discounted at a risk free rate plus the cost of unproved interests and land, net of impairment. Impairments recognized under previous CGAAP were not reversed.

Under IFRS, an impairment is recognized if the carrying value exceeds the recoverable amount for a CGU. If the carrying value exceeds the recoverable amount of the CGU, the CGU is written down with an impairment recognized in net income. Impairments under IFRS are reversed when there has been a subsequent increase in recoverable amounts. Impairment reversals are recognized in net income and the carrying amount of the CGU is increased.

For the three and 12 months ended December 31, 2010, $26.2 million and $32.8 million, respectively, of impairment was recognized under IFRS.

E) Gains on dispositions

Under previous CGAAP, gains on dispositions were typically not recognized. Proceeds from dispositions were deducted from the full cost pool unless the deduction resulted in a change to the depletion rate of 20 percent or more, in which case a gain or loss was recorded.

Under IFRS, gains or losses are recorded on dispositions of properties and are calculated as the difference between the proceeds and the net book value of the assets disposed of at the point of disposition. For the three and twelve months ended December 31, 2010, gains of $6.4 million and $17.6 million, respectively, were recognized under IFRS, compared to no gain recognized under previous CGAAP.

F) Asset Retirement Obligations & Accretion

Under previous CGAAP, asset retirement obligations were measured at the estimated fair value of the expenditures expected to be incurred. Liabilities were not remeasured to reflect period end discount rates.

Under IFRS, the asset retirement obligation is measured as the best estimate of the expenditure to be incurred and requires the liability to be remeasured using the period end discount rate. As at January 1, 2010, the carrying value of the asset retirement obligation was $134.4 million, an increase of $6.5 million from the carrying value under previous CGAAP of $127.9 million. As at December 31, 2010, the carrying value of the asset retirement obligation was $149.0 million as compared to $144.7 million under previous CGAAP, an increase of $4.3 million. These adjustments reflect the remeasurement of the obligation using an eight percent discount rate.

In addition, accretion of the liability is impacted by the change in the recognized amount. For the three and twelve months ended December 31, 2010, accretion decreased by $1.3 million and $1.1 million, respectively, as compared to previous CGAAP.

G) Other Liabilities & Accounts Payable

The adjustment to the liability for share-based compensation reflects a forfeiture rate which was not included under previous CGAAP. On transition to IFRS, the payable was reduced by $0.7 million to reflect the inclusion of a forfeiture rate. For the three and twelve months ended December 31, 2010, share-based compensation expense increased by $0.9 million and $1.5 million, respectively, due to the expensing of amounts capitalized under previous CGAAP, partially offset by the inclusion of a forfeiture rate.

H) Convertible Debentures

As a trust, NAL designated its convertible debentures as a financial liability at fair value through profit or loss on transition. As at January 1, 2010, the fair value of the Corporation's convertible debentures was $203.7 million, based on quoted market prices. Under previous CGAAP, the convertible debentures were bifurcated between debt and equity in the amounts of $178.0 million and $12.6 million, respectively, at December 31, 2009. The difference between the fair value and CGAAP carrying value was charged to retained earnings on transition.

At each quarter end, the convertible debentures were fair valued based on the then-prevailing market price with the adjustment taken to income. As at December 31, 2010, the fair value adjustment to the convertible debentures was $17.8 million of which $0.8 million was recognized in income for 2010. Any accretion expense previously recognized through income under previous CGAAP was eliminated. For the three and twelve months ended December 31, 2011, accretion on convertible debentures recognized under previous CGAAP of $1.0 million and $4.0 million, respectively, was eliminated on conversion to IFRS.

On conversion to a corporation on December 31, 2010, the carrying value of the convertible debentures, which represented the fair value of the convertible debentures on December 31, 2010, was bifurcated between their debt and equity components as required under IFRS.

On December 31, 2010, the fair value of the convertible debentures was $204.5 million which following the Reorganization, was allocated $5.0 million to equity and $199.5 million to debt.

In addition, any issue costs associated with the convertible debentures were expensed during the period the convertible debentures were held at fair value through profit and loss, with $0.3 million being expensed in December 31, 2010. Under previous CGAAP, these issue costs were netted against the debt component of the convertible debentures.

I) Minority Interest

The mandatory exception under IFRS1 allows for the prospective application in the accounting for a minority interest.

Therefore, the minority interest has only been adjusted under IFRS to reflect the changes to the income statement and net assets of the jointly-owned Partnership with MFC (see Note 5 to the Consolidated Financial Statements) as compared to previous CGAAP.

Under IFRS, minority interests are presented as part of equity rather than a liability as under previous CGAAP.

J) Deferred Taxes

Under IFRS, NAL is required to record deferred taxes at the trust level at 39 percent, being the tax rate applicable to the undistributed profit of the Trust. Therefore, while a trust, the tax rate was significantly higher under IFRS compared to previous CGAAP. Under previous CGAAP, the rate used represented the anticipated rate at time of the temporary difference reversal. On conversion to a corporation, corporate tax rates apply, which has resulted in a decrease to previously recorded deferred tax amounts under IFRS at the trust level. Deferred taxes have also been adjusted to reflect the tax effect arising from the difference between IFRS and previous CGAAP as noted above. In addition, the deferred tax impact to share issue costs has been reflected.

Under IFRS, all deferred tax is presented as a long-term asset or liability. Under previous CGAAP, future income tax presentation was based on the presentation of the underlying asset or liability.

K) Other Exemptions - Business Combinations

NAL elected the exemption not to restate business combinations, prior to January 1, 2010, in accordance with IFRS. As a result, there were no adjustments required for business combinations prior to January 1, 2010.

Recent Prononouncements Issued

All accounting standards effective for periods beginning on or after January 1, 2011 have been adopted as part of the transition to IFRS. The following new IFRS pronouncements have been issued but are not effective and may have an impact on the Corporation:

Financial Instruments

As of January 1, 2013, NAL will be required to adopt IFRS 9, Financial Instruments, which is the result of the first phase of the IASB's project to replace IAS 39, Financial Instruments: Recognition and Measurement. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. NAL is currently assessing the impact of this standard on its consolidated financial statements.

Consolidated Financial Statements

As of January 1, 2013, NAL will be required to adopt IFRS 10, Consolidated Financial Statements. This standard introduces a new approach to determining which investments should be consolidated and identifies the concept of control as the determining factor. NAL is currently assessing the impact of this standard on its consolidated financial statements.

Joint Arrangements

As of January 1, 2013, NAL will be required to adopt IFRS 11, Joint Arrangements. The new standard focuses on the rights and obligations of joint arrangements, rather than the legal form (as is currently the case). It distinguishes joint arrangements between joint operations and joint ventures which replace the current definitions of jointly controlled operations, jointly controlled assets and jointly controlled entities. For jointly controlled entities that will be reclassified as joint ventures the new standard requires the equity method. Proportionate consolidation is no longer an option. Joint operations will continue to be proportionally accounted for. NAL is currently assessing the impact of this standard on its consolidated financial statements.

Disclosure of Interests in Other Entities

As of January 1, 2013, NAL will be required to adopt IFRS 12, Disclosure of Interests in Other Entities. This standard contains disclosure requirements for entities that have interests in subsidiaries, joint arrangements, associates and unconsolidated structured entities. The information is to enable users to evaluate the nature of, and risks associated with, an entity's interests in other entities, and the effects of those interests on the entity's financial position, financial performance and cash flows.

Fair Value Measurement

As at January 1, 2013, NAL will be required to adopt IFRS 13, Fair Value Measurement. This standard provides a single source of guidance on defining fair value, establishing a framework for measuring fair value and setting out disclosure requirements for fair value measurements. NAL is currently assessing the impact of this standard on its consolidated financial statements.

Critical Accounting Estimates

Management is required to make judgments, assumptions and estimates in applying its accounting policies and practices, which have a significant impact on the financial results of the Corporation. The preceding discussion outlines the Corporation's significant accounting policies and practices adopted under IFRS. The following discussion outlines the accounting policies and practices involving the use of estimates that are critical to determining NAL's financial results.

Property, Plant & Equipment & Exploration & Evaluation Assets

Reserves estimates can have a significant impact on earnings, as they are a key input to the Corporation's depletion calculations and impairment tests. Costs accumulated within each area are depleted using the unit-of-production method based on proved plus probable reserves using estimated future commodity prices and costs. Costs subject to depletion include estimated future costs to be incurred in developing proved and probable reserves. A downward revision in reserves estimates or an increase in estimated future development costs could result in the recognition of a higher depletion charge to net income.

D&P costs, are aggregated into CGUs based on their ability to generate largely independent cash flows. If the carrying value of the CGU exceeds the recoverable amount, the cash-generating unit is written down with an impairment recognized in net income. E&E assets are assessed for impairment, together with D&P assets in total, when they are reclassified to property, plant and equipment, and/or if facts and circumstances suggest that the carrying amount exceeds the recoverable amount. If an E&E impairment is indicated when combined with the D&P assets, it is recognized through the statement of income. The recoverable amount of an asset or CGU is the greater of its fair value less costs to sell and its value in use. Fair value less costs to sell may be determined using discounted future net cash flows of proved and probable reserves using forecast prices and costs. A downward revision in reserves estimates could result in the recognition of impairments charged to net income.

Reversals of impairments are recognized when there has been a subsequent increase in the recoverable amount. In this event, the carrying amount of the asset or CGU is increased to its revised recoverable amount with an impairment reversal recognized in net income, net of what depletion would have been had the asset not been impaired.

All of NAL's oil and gas reserves and resources are evaluated and reported on by independent qualified reserves evaluators. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. Reserves estimates can be revised upward or downward based on the results of future drilling, testing, production levels and the economics of recovery based on cash flow forecasts. Contingent resources are not classified as reserves due to the absence of a commercial development plan that includes a firm intention to develop the resources within a reasonable time frame.

Asset Retirement Obligations

Asset retirement obligations include present obligations where the Corporation will be required to retire tangible long-lived assets such as producing well sites, and natural gas processing plants. The asset retirement obligation is measured as the present value of the expenditure to be incurred. The associated asset retirement cost is capitalized as part of the cost of the related asset. Changes in the estimated obligation resulting from revisions to estimated timing, amount of cash flows or changes in discount rate are recognized as a change in the asset retirement obligation and the related asset retirement cost.

Increases in the estimated asset retirement obligation and costs increase the corresponding charges of accretion and depletion to net income. A decrease in discount rates increases the asset retirement obligation, which increases future accretion charged to net earnings. Actual expenditures incurred are charged against the accumulated asset retirement obligation.

Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed for impairment annually at December 31 of each year. Goodwill is currently attributed to the area to which it relates.

To assess impairment, the goodwill carrying amount is compared to the recoverable amount of the aggregated CGUs to which the goodwill is allocated. If the carrying amount for the CGU exceeds the recoverable amount, the associated goodwill is written down with an impairment recognized in net income. Goodwill impairments are not reversed.

The recoverable amount is the greater of the CGU's fair value less costs to sell and its value in use. Fair value less costs to sell may be determined using discounted future net cash flow of proved and probable reserves using forecast prices and costs. A downward revision in reserves estimates could result in the recognition of a goodwill impairment charge to net income.

Income Taxes

NAL follows the balance sheet method of accounting for income taxes. Under this method, deferred income taxes are recorded for the effect of any temporary difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates. Current income taxes for the current and prior periods are measured at the amount expected to be recoverable from or payable to the taxation authorities based on the income tax rates enacted or substantively enacted at the end of the reporting period. The deferred income tax assets and liabilities are adjusted to reflect changes in enacted or substantively enacted income tax rates that are expected to apply, with the corresponding adjustment recognized in net income or in shareholders' equity depending on the item to which the adjustment relates.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Corporation and its subsidiaries operate are subject to change. As such, income taxes are subject to measurement uncertainty and the interpretations can impact net income through the income tax expense arising from the changes in deferred income tax assets or liabilities.

Derivative Financial Instruments

As described in the Risk Management section of this MD&A, derivative financial instruments are used by NAL to manage its exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates.

Derivative financial instruments are recorded at fair value. Instruments are recorded in the balance sheet as either an asset or liability with changes in fair value recognized in net income. Realized gains or losses are presented as the contracts are settled. Unrealized gains and losses are presented at the end of each respective reporting period based on the change in fair value and are recognized in net income. The estimate of fair value of all derivative instruments is based on an approximation of the amounts that would be received or paid to settle these instruments at the end of the period, with reference to forward commodity prices, foreign exchange rates and interest rates. The estimated fair value of financial assets and liabilities is subject to measurement uncertainty.

Share-based Compensation

Share-based compensation is recognized over the vesting period, based on the market price of a notional common share at each period end and an expected performance multiplier and forfeiture rate, in the statement of income with a corresponding increase or decrease in liabilities.

Provisions & Contingencies

A provision is recognized if, as a result of a past event, there is a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects the current market assessments of the time value of money and the risks specific to the liability.

Dated: March 7, 2012

Registered Office:
1000 550 6th Avenue SW
Calgary
AB, T2P 0S2

consolidated financial statements

Management's Report

NAL Resources Management Limited, as manager of NAL Energy Corporation is responsible for the preparation of the accompanying consolidated financial statements of the Corporation. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards, and where applicable, amounts based on management's best estimates and judgment.

Management has established procedures and systems of internal control designed to provide reasonable assurance that assets are safeguarded and that accurate financial information is produced in a timely manner.

The Board of Directors is responsible for reviewing and approving the consolidated financial statements, and through its Audit Committee, ensuring that management fulfills its responsibilities for financial reporting. The Audit Committee, which is comprised of four independent directors, meets regularly with management, the internal auditor and the external auditors to satisfy itself that each party is properly discharging its responsibilities. The Audit Committee reviews the consolidated financial statements and recommends their approval to the Board of Directors.

KPMG LLP, an independent firm of Chartered Accountants, appointed by the shareholders of NAL Energy Corporation, have audited the consolidated financial statements in accordance with Canadian generally accepted auditing standards. KPMG LLP have full and free access to the Audit Committee.

Andrew B. Wiswell
President and CEO

Keith A. Steeves
Vice President, Finance and CFO

March 7, 2012

auditors' report

To the Shareholders of NAL Energy Corporation

We have audited the accompanying consolidated financial statements of NAL Energy Corporation ("NAL" or the "Corporation"), which comprise the consolidated balance sheets as at December 31, 2011, December 31, 2010 and January 1, 2010, the consolidated statements of income, comprehensive income, changes in equity and cash flows the years ended December 31, 2011 and December 31, 2010, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of NAL Energy Corporation as at December 31, 2011, December 31, 2010 and January 1, 2010, and its consolidated financial performance and its consolidated cash flows for the years then ended December 31, 2011 and December 31, 2010 in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Accountants
Calgary, Canada

March 7, 2012

consolidated balance sheets

(Thousands of Canadian dollars)

	December 31, 2011	December 31, 2010 (Note 18)	January 1, 2010 (note 18)
Assets			
Current assets			
Cash (Note 14)	$1,722	$821	$1,604
Accounts receivable	50,708	57,839	61,631
Prepaids and other receivables	15,104	14,532	15,663
Derivative contracts (Note 15)	655	422	6,285
	68,189	73,614	85,183
Derivative contracts (Note 15)	54	-	2,461
Deferred tax asset (Note 13)	17,051	13,978	-
Goodwill	14,722	14,722	14,722
Property, plant and equipment (Note 6)	1,416,769	1,472,660	1,415,830
Exploration and evaluation assets (Note 6)	44,419	63,127	88,122
	$1,561,204	$1,638,101	$1,606,318
Liabilities and Shareholders' Equity			
Current liabilities			
Accounts payable and accrued liabilities	$91,640	$100,265	$110,715
Note payable	-	-	8,907
Dividends payable to shareholders	10,577	13,252	12,372
Convertible debentures (Note 8)	81,037	-	-
Derivative contracts (Note 15)	5,377	7,819	11,231
	188,631	121,336	143,225
Bank debt (Note 7)	327,170	266,965	230,713
Convertible debentures (Note 8)	116,127	199,520	203,730
Other liabilities (Note 9)	1,527	3,012	7,173
Derivative contracts (Note 15)	950	2,503	-
Asset retirement obligations (Note 11)	130,074	149,015	134,358
Deferred tax liability (Note 13)	-	-	16,572
	764,479	742,351	735,771
Shareholders' equity			
Share capital (Note 12)	927,804	890,777	-
Unitholders' capital (Note 12)	-	-	1,485,421
Equity component of convertible debentures (Note 8)	4,973	4,973	-
Minority interest (Note 5)	-	-	3,370
Deficit	(136,052)	-	(618,244)
	796,725	895,750	870,547
	$1,561,204	$1,638,101	$1,606,318
Commitments (Note 16)			
Subsequent events (Note 17)			
Common shares outstanding (000's)	151,107	147,248	137,471

See accompanying notes to the consolidated financial statements.

Irvine J. Koop
Director and Chairman of the Board

Gordon S. Lackenbauer
Director and Chairman of the Audit Committee

consolidated statements of income (loss) & comprehensive income (loss)

Years ended December 31
(Thousands of Canadian dollars, except per share amounts)

	2011	2010
(Note 18)		
Revenue		
Oil, natural gas and liquid sales	$531,947	$497,538
Crown royalties	(64,446)	(62,900)
Freehold and other royalties	(25,461)	(23,585)
	442,040	411,053
Gain (loss) on derivative contracts (Note 15):		
Realized gain (loss)	(4,204)	24,446
Unrealized gain (loss)	4,282	(7,415)
	78	17,031
Other income	811	1,403
	442,929	429,487
Expenses		
Operating	124,209	111,911
Transportation	5,681	6,501
General and administrative	25,873	25,697
Share-based incentive compensation	(1,077)	4,632
Interest on bank debt	12,616	11,794
Interest and amortization on convertible debentures	10,214	12,521
Fair value adjustment on convertible debentures	-	763
Convertible debenture issue costs	-	345
Gains on disposition of property, plant and equipment	(26,046)	(17,596)
Impairment of oil and gas assets (Note 6)	101,996	32,804
Depletion and depreciation	193,376	200,787
Accretion on asset retirement obligations	10,123	11,006
	456,965	401,165
Income (loss) before taxes	(14,036)	28,322
Current tax recovery	6	782
Deferred tax reduction	2,996	29,921
Total tax reduction (Note 13)	3,002	30,703
Net income (loss) and comprehensive income (loss)	$(11,034)	$59,025
Net income (loss) per share (Note 12)		
Basic and diluted	$(0.07)	$0.41
Weighted average shares outstanding (000s)	148,709	143,913

See accompanying notes to the consolidated financial statements.

consolidated statements of cash flows

Years ended December 31
(Thousands of Canadian dollars)

	2011	2010 (Note 18)
Operating Activities		
Net income (loss)	$(11,034)	$59,025
Items not involving cash:		
Depletion and depreciation	193,376	200,787
Accretion on asset retirement obligations	10,123	11,006
Unrealized (gain) loss on derivative contracts	(4,282)	7,415
Gain on disposition of property, plant and equipment	(26,046)	(17,596)
Fair value adjustment on convertible debentures	-	763
Deferred tax reduction	(2,996)	(29,921)
Lease amortization	(1,757)	(1,655)
Impairment of oil and gas assets	101,996	32,804
Interest expense and amortization on convertible debentures	22,830	24,315
Convertible debenture issue costs	-	345
Abandonment and reclamation	(6,871)	(6,617)
Change in non-cash working capital (Note 14)	(16,538)	(6,065)
	258,801	274,606
Financing Activities		
Dividends paid to shareholders	(100,444)	(129,559)
Increase in bank debt	60,205	36,252
Issue of shares, net of issue costs	9,701	94,466
Convertible debenture issue costs	-	(345)
Interest paid	(25,087)	(24,989)
Change in non-cash working capital (Note 14)	62	153
	(55,563)	(24,022)
Investing Activities		
Property, plant and equipment expenditures	(243,952)	(221,560)
Exploration and evaluation expenditures	(3,107)	(25,985)
Acquisitions	-	(22,587)
Proceeds from dispositions	30,139	22,178
Acquisition of Breaker	-	(901)
Disposition of Spearpoint	-	(309)
Change in non-cash working capital (Note 14)	14,583	(2,111)
	(202,337)	(251,275)
Increase (decrease) in cash	901	(691)
Cash, beginning of year	821	1,604
Dissolution of the Partnership	-	(92)
Cash, end of year	$1,722	$821

See accompanying notes to the consolidated financial statements.

consolidated statements of changes in equity

(In thousands of Canadian dollars, except share amounts)

	Number of Shares	Share Capital	Equity component of convertible debentures	Deficit	Minority interest	Total Shareholders' Equity
Balance at January 1, 2010	137,471	$1,485,421	$-	$(618,244)	$3,370	$870,547
Net income	-	-	-	59,025	-	59,025
Equity offering	7,550	100,038	-	-	-	100,038
Less issue costs (net of tax of $548)	-	(5,024)	-	-	-	(5,024)
Issued from Distribution Reinvestment Plan	2,227	25,338	-	-	-	25,338
Dividends declared	-	-	-	(155,777)	-	(155,777)
Dissolution of partnership	-	-	-	-	(3,370)	(3,370)
Reclassification of deficit to share capital (Note 1)	-	(714,996)	-	714,996	-	-
Equity component of convertible debentures on conversion to corporation	-	-	4,973	-	-	4,973
Balance at December 31, 2010	147,248	$890,777	$4,973	$-	$-	$895,750
Net loss	-	-	-	(11,034)	-	(11,034)
Equity offering	1,159	10,001	-	-	-	10,001
Less issue costs (net of tax of $77)	-	(223)	-	-	-	(223)
Issued from Distribution Reinvestment Plan	2,700	27,249	-	-	-	27,249
Dividends declared	-	-	-	(125,018)	-	(125,018)
Balance at December 31, 2011	151,107	$927,804	$4,973	$(136,052)	$-	$796,725

See accompanying notes to the consolidated financial statements.

notes to the consolidated financial statements

Years ended December 31, 2011 and 2010
(Tabular amounts in thousands of Canadian dollars, except per share amounts)

1) Nature of Operations & Structure of The Corporation

NAL Energy Corporation ("NAL" or the "Corporation") is engaged in the exploration for, and the development and production of natural gas, natural gas liquids and crude oil in Western Canada. The Corporation resulted from a reorganization by plan of arrangement effective December 31, 2010 involving, among others, NAL Oil & Gas Trust (the "Trust"), the Corporation and the security holders of the Trust ("Reorganization").

Pursuant to the Reorganization, the Trust was restructured from an open-ended unincorporated trust to NAL Energy Corporation, a publicly traded exploration and development corporation. Unitholders of the Trust received one common share of the Corporation for each trust unit held. The Corporation and its subsidiaries now carry on the business formerly carried on by the Trust and its subsidiaries. The outstanding convertible debentures of the Trust were assumed by NAL and are now convertible into common shares of the Corporation, rather than trust units of the Trust, with the same terms and conditions as those previously agreed to by the Trust.

Pursuant to the Reorganization, share capital was reduced by the amount of the deficit of the Trust on December 31, 2010.

The Reorganization to a corporation has been accounted for on a continuity of interest basis and accordingly, the consolidated financial statements for 2010 and 2011 reflect the financial position, results of operations and cash flows as if the Corporation had carried on the business formerly carried on by the Trust.

References to NAL or the Corporation in these financial statements for periods prior to December 31, 2010 are references to the Trust and for periods after December 30, 2010 are references to NAL Energy Corporation. Additionally, NAL or the Corporation refers to shares, shareholders and dividends which are comparable to units, unitholders and distributions previously under the Trust.

2) Summary of Accounting Policies

(a) Statement of Compliance and Conversion to International Financial Reporting Standards ("IFRS")

These consolidated financial statements as at December 31, 2011, including 2010 comparatives, comprise the Corporation's first annual audited financial statements prepared and issued in accordance with International Financial Reporting Standards ("IFRS"). The consolidated financial statements were authorized for issue by the Board of Directors on March 7, 2012.

An explanation of how the transition to IFRS has affected the reported financial position, financial performance and cash flows of the Corporation is provided in Note 18. That note includes reconciliations as at January 1, 2010 and December 31, 2010 and for the year ended December 31, 2010.

(b) Basis of Presentation

The Corporation's consolidated financial statements include the accounts of the Corporation and its subsidiary entities, which include NAL Petroleum (Holdings) Ltd., Addison Limited Partnership, NAL Energy (General Partner) Inc., NAL Canada West Inc., NAL Properties Inc. and Startech Energy Corp. ("Startech"). These subsidiary entities are all incorporated or established and domiciled in Canada, except for Startech, a shell company, that was incorporated and is domiciled in the United States. All subsidiaries are 100 percent controlled by the Corporation. The consolidated financial statements are stated in Canadian dollars, which is the Corporation's and its subsidiaries' functional currency, excluding Startech, for which the US dollar is the functional currency. All inter-entity transactions and balances have been eliminated. The accounting policies set out below have been applied consistently to all periods presented in these consolidated financial statements. They have also been applied in preparing the opening IFRS statement of financial position as at January 1, 2010 for the purposes of the transition to IFRS, as required by IFRS1.

Operating expenses in the consolidated statement of income are presented as a combination of function and nature in conformity with industry practice. Depletion and depreciation are presented as separate lines by their nature, while general and administrative expenses are presented on a functional basis. Significant expenses such as salaries are presented by their nature in the notes to the consolidated financial statements.

(c) Basis of Measurement

The consolidated financial statements have been prepared on the historical cost basis except for the following:

- Convertible Debentures were classified as financial liabilities at fair value through profit and loss until conversion to a corporation. Subsequent to the Reorganization, the convertible debentures were bifurcated between debt and equity, with the bond premium amortized over the period to maturity. The equity portion is carried at the historic carrying amount determined at the time of Reorganization, subject to any debenture conversions.
- Derivative contracts are classified at fair value through profit and loss.

The methods used to measure fair values are discussed within the notes to which they relate.

(d) Use of Estimates & Judgments

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected.

Significant areas of estimation, uncertainty and critical judgments in applying accounting policies that impact the amounts recognized in the consolidated financial statements include:

- Reserve estimates including production profiles, future development costs, future commodity prices, future costs and discount rates are a critical part of many of the estimated amounts and calculations contained in the financial statements. These estimates are verified by third party professional engineers, who work with information provided by the Corporation to establish reserve determinations. These determinations are updated at least on an annual basis, and more frequently as significant business combinations take place.
- Impairment testing – estimates of reserves, future commodity prices, future costs, discount rates, and the market value of land.
- Composition of Cash Generating Units ("CGU") – assessment of assets constituting a CGU.
- Depletion and depreciation – estimates of reserves and future development costs used in the calculation of depletion.
- Asset Retirement Obligations ("ARO") – estimates relating to amounts, likelihood, timing, inflation and discount rates.
- Share-based compensation – forfeiture rates and performance factors.
- Derivatives – expected future oil and natural gas prices, expected future interest rates, expected future foreign exchange rates and expected volatility in these variables.
- Deferred Tax – estimates of reversal of temporary differences, tax rates substantively enacted, and likelihood of assets being realized.
- Provisions and Contingencies – estimates and likelihood of occurrence relating to onerous contracts and contingent items, including discount rates associated with long term contracts.

(e) Basis of Consolidation

Subsidiaries are entities controlled by the Corporation. Control exists when the Corporation has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, potential voting rights that are currently exercisable are taken into account. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases.

The purchase method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured at the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The excess of the cost of acquisition over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of acquisition is less than the fair value of the net assets of the subsidiary acquired, the difference is recognized immediately in the statement of income.

(f) Joint Operations

Many of the Corporation's oil and natural gas activities involve jointly controlled assets. The consolidated financial statements include the Corporation's share of these jointly controlled assets and a proportionate share of the relevant revenue and related costs.

(g) Financial Instruments

A financial instrument is any contract that gives rise to a financial asset of one entity and to a financial liability or equity instrument of another entity. Upon initial recognition, all financial instruments, including derivatives, are recognized on the balance sheet at fair value. Subsequent measurement is then dependent on the financial instruments being classified into one of five categories: Financial liabilities or financial assets at fair value through profit or loss, held to maturity investments, loans and receivables, available for sale financial assets or other financial liabilities.

The Corporation will assess at each reporting period whether a financial asset is impaired. An impairment loss, if any, is included in net income.

Transaction costs are frequently attributable to the issue of a financial asset or liability. For financial assets or liabilities measured at fair value through profit and loss, these costs are expensed. For all other financial assets and liabilities, these costs are netted in the initial carrying amount recorded.

(i) Non-derivative Financial Instruments

Non-derivative financial instruments comprise cash and cash equivalents, accounts and other receivables, accounts payable and accrued liabilities, dividends payable to shareholders, notes payable, convertible debentures and bank debt. Non-derivative financial instruments are recognized initially at fair value plus, for instruments not at fair value through profit and loss, any directly attributable transaction costs. Subsequent to initial recognition, non-derivative financial instruments are measured as described below.

Cash and cash equivalents comprises cash on hand, term deposits held with banks and other short-term highly liquid investments with original maturities of three months or less. The Corporation has classified cash and cash equivalents and accounts and other receivables as loans and receivables, which are measured at amortized cost less any impairment losses. Accounts payable and accrued liabilities, dividends payable to shareholders, notes payable and bank debt are classified as other financial liabilities which are measured at amortized cost, which is determined using the effective interest method.

As a Trust, the convertible debentures were considered to contain an embedded derivative related to the conversion feature. On transition to IFRS, an election was made to designate the convertible debentures in their entirety as a financial liability at fair value through profit and loss, based on the debentures' quoted market value as at the reporting date, with gains or losses recorded in net income. On Reorganization, the embedded equity feature ceased to be a derivative and the Company ceased to fair value the convertible debentures as a whole, and the equity feature had to be bifurcated. Therefore, the fair value of the convertible debentures was determined at that time, with the debt and equity then recorded separately. Subsequent to the Reorganization, the equity portion is recorded at its assigned cost and the debt portion is recorded at amortized cost.

(ii) Derivative Financial Instruments

The Corporation has entered into certain financial derivative contracts in order to manage exposure to market risks from fluctuations in commodity prices, foreign exchange and interest rates. These instruments are not used for trading or speculative purposes. The Corporation has not designated its financial derivative contracts as effective accounting hedges, and thus has not applied hedge accounting, even though the Corporation considers all derivative contracts to be effective economic hedges. As a result, all financial derivative contracts are classified as fair value through profit or loss and are recorded on the balance sheet at fair value. Proceeds and costs realized from holding the derivative contracts are recognized in net income at the time each transaction under a contract is settled. The fair value of derivative contracts is based on an approximation of the amounts that would be received or paid to settle these instruments at the end of the period, with reference to forward commodity prices, foreign exchange rates and interest rates using remaining contracted volumes discounted at a credit-adjusted rate.

The Corporation applies trade date accounting for the recognition of a purchase or sale of short term investments and derivative contracts.

(iii) Unitholder's Equity/Share Capital

The Trust's units and common shares of the Corporation are classified as equity. Incremental costs directly attributable to the issue of trust units and common shares are recognized as a deduction from equity, net of any tax effects.

(iv) Impairment of Financial Assets

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired, namely if one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

All impairment losses are recognized in profit or loss.

An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost, the reversal is recognized in profit or loss.

(h) Property, Plant and Equipment and Exploration and Evaluation Assets

(i) Recognition & Measurement

Exploration and Evaluation ("E&E") expenditures:

Pre-license costs ("Pre-E&E"), or costs incurred before acquiring legal rights to explore are recognized in the statement of income as incurred. Once a legal right to explore has been established, but before technical feasibility and commercial viability has been determined, costs are capitalized as E&E. E&E expenditures can include the costs of acquiring licenses on exploratory lands or assigned values on business acquisitions for possible reserves.

The technical feasibility and commercial viability of extracting oil and natural gas resources is generally considered to be determinable when proved and/or probable reserves exist. Upon determination of technical feasibility and commercial viability, intangible E&E assets are first tested for impairment, and then moved to Development and Production assets.

In addition, exploration and evaluation assets are assessed for impairment when facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

Development and Production ("D&P") costs:

Items of property, plant and equipment ("PP&E"), which include oil and natural gas development and production assets, are measured at cost, including asset retirement costs, less accumulated depletion and depreciation and accumulated net impairment losses.

D&P costs are accumulated on an Area basis and are grouped into cash generating units ("CGUs") for impairment testing. CGUs are the smallest group of assets that generate independent cash in-flows. NAL has defined nine CGUs.

Gains and losses on disposition of property, plant and equipment, property swaps and farm-outs are recorded. Gains and losses are determined by comparing the proceeds from disposal or fair value of the asset received with the disposed amount of carrying amount of PP&E and ARO and are recognized in the statement of income.

(ii) Subsequent Costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as oil and natural gas interests only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in profit or loss as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in profit or loss as incurred.

(iii) Depletion & Depreciation

The net carrying value of D&P assets is depleted on a unit of production basis on proved and probable reserves, using estimated future prices and costs, and taking into account estimated future development costs. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by independent reserve engineers at least annually. Natural gas reserves are converted to barrels of oil equivalent based on relative energy content (6:1).

Depletion is calculated at a "component" level, which is defined as those parts of assets with similar characteristics that are significant in relation to the total cost of the asset. For the Corporation, components relating to D&P assets are consistent with the areas determined by management.

Depreciation methods, useful lives, and residual values are reviewed at each reporting date.

(iv) Impairment

The carrying amounts of the Corporation's D&P assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. Goodwill is allocated to CGUs on acquisition and for these CGUs, impairment is tested each year end, or more frequently if indications of impairment exist.

E&E assets are assessed for impairment, together with D&P assets in total, when they are reclassified to property, plant and equipment, and/or if facts and circumstances suggest that the carrying amount exceeds the recoverable amount. If an E&E impairment is indicated when combined with the D&P assets, it is recognized through the statement of income.

For the purpose of impairment testing, D&P assets are grouped together into CGUs. The recoverable amount of a CGU is the greater of its value in use and its fair value less costs to sell. CGUs are reviewed annually for reasonableness and continued applicability, or on a more frequent basis should conditions change that would materially impact classification.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves.

Fair value less costs to sell is generally determined as the current market bid price, when an active market exists. The intent is that this represents what a market participant would pay to acquire control of the CGU.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in the statement of income. Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the units and then to reduce the carrying amounts of the other assets in the unit on a pro rata basis.

An impairment loss in respect of goodwill is not reversed. In respect of other assets, impairment losses recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation or amortization, if no impairment loss had been recognized.

(i) Goodwill

Goodwill arising through a business combination is assigned at the time acquired, to a cash generating unit or units that are expected to benefit from the synergies of the combination. It is measured at cost less accumulated impairment losses. No amortization is recorded for goodwill.

Acquisitions prior to January 1, 2010:

As part of its transition to IFRS, the Corporation elected to restate only those business combinations that occurred on or after January 1, 2010. In respect of acquisitions prior to January 1, 2010, goodwill represents the amount recognized under the Corporation's previous accounting framework, previous Canadian generally accepted accounting principles ("CGAAP").

Acquisitions on or after January 1, 2010:

For acquisitions on or after January 1, 2010, goodwill represents the excess of the cost of the acquisition over the net fair value of the identifiable assets, liabilities and contingent liabilities of the acquiree. When the excess is negative, it is recognized immediately in profit for loss.

(j) Share-Based Incentive Compensation

The Corporation is managed by NAL Resources Management Limited (the "Manager"). The Manager has established a share-based incentive compensation plan (the "Plan") for all employees. Under the Plan, employees receive cash compensation based upon the value and overall return of a specified number of awarded notional common shares on a fixed vesting date. The notional common shares are in the form of Restricted Share Units ("RSUs") and Performance Share Units ("PSUs"). Dividends paid on the Corporation's outstanding common shares during the vesting period are assumed to be reinvested in the awarded notional common shares on the date of dividend. Compensation expense incorporates the common share price and the number of RSUs and PSUs outstanding at each period end. In addition, for the PSUs there is a performance multiplier which is based on the Corporation's performance relative to its peers and may range from zero to two times the value of the notional common shares held at vesting.

Compensation expense is recognized over the vesting period and is determined based on the market price of the notional common shares at each period end and an expected performance multiplier with a corresponding increase or decrease in liabilities. Classification between current liabilities and long-term liabilities is dependent on the expected payout date.

The Corporation charges its share of the accrued compensation amounts relating to head office employees of the Manager to general and administrative expenses.

The Corporation has incorporated an estimated forfeiture rate for common shares that will not vest, that is adjusted to reflect the actual number of awards that vest.

(k) Provisions

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

(i) Asset Retirement Obligations

The Corporation's activities give rise to dismantling, decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Asset retirement obligations are measured at the present value of management's best estimate of expenditure required to settle the present obligation at the balance sheet date. The discount rate applied is the credit adjusted risk free rate. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time, changes in the estimated future cash flows underlying the obligation, and the discount rate applied is adjusted to the current applicable rate as at each reporting period. The increase in the provision due to the passage of time is recognized as accretion of asset retirement obligations whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the retirement obligations are charged against the provision to the extent the provision was established.

(ii) Onerous Contracts

A provision for onerous contracts is recognized by the Corporation when the expected benefits to be derived from a contract are lower than the unavoidable cost of meeting its obligations under the contract. The provision is measured at the present value of the lower of the expected cost of terminating the contract and the expected net costs of continuing with the contract. Before a provision is established, the Corporation recognizes any impairment loss on associated assets, if applicable.

(l) Revenue Recognition

Revenues from the sale of petroleum and natural gas are recorded when title passes to the purchaser and if collection is reasonably assured.

(m) Income Tax

The Corporation is a taxable entity under the Income Tax Act (Canada).

As a Trust, the organization was a taxable entity under the Income Tax Act (Canada) and, until 2011, was taxable only on income that was not distributed or distributable to unitholders, provided that the Trust continued to adhere to the transition rules provided for under the Federal legislation. The Trust met the criteria qualifying for income tax treatment permitting a tax deduction for distributions paid to the unitholders in addition to other deductions available in the Trust until its conversion to a Corporation on December 31, 2010.

Current and deferred tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different taxable entities, with the intent to settle current tax liabilities and assets on a net basis or the tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(n) Basic & Diluted per Share Calculation

Basic per share amounts are calculated by dividing net income by the weighted average number of common shares outstanding. Diluted net income per share is calculated using the "if converted method" to determine the dilutive effects of the convertible debentures. Dilutive shares are arrived at by taking the weighted average shares and the shares issuable on conversion of the convertible debentures, giving effect to the potential dilution that would occur had conversion occurred at the beginning of the period or on issuance of the convertible instrument, whichever is later. Interest and accretion on convertible debentures is added back to net income, net of tax in calculating diluted net income per share/unit.

3) New IFRS Standards

The International Accounting Standards Board ("IASB") has issued certain new accounting standards and interpretations. The following new IFRS pronouncements have been issued but are not yet effective and may have an impact on the Corporation:

Financial Instruments

As of January 1, 2013, NAL will be required to adopt IFRS 9, Financial Instruments, which is the result of the first phase of the IASB's project to replace IAS 39, Financial Instruments: Recognition and Measurement. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. NAL is currently assessing the impact of this standard on its consolidated financial statements.

Consolidated Financial Statements

As of January 1, 2013, NAL will be required to adopt IFRS 10, Consolidated Financial Statements. This standard introduces a new approach to determining which investees should be consolidated and identifies the concept of control as the determining factor. NAL is currently assessing the impact of this standard on its consolidated financial statements.

Joint Arrangements

As of January 1, 2013, NAL will be required to adopt IFRS 11, Joint Arrangements. The new standard focuses on the rights and obligations of joint arrangements, rather than the legal form (as is currently the case). It distinguishes joint arrangements between joint operations and joint ventures which replace the current definitions of jointly controlled operations, jointly controlled assets and jointly controlled entities. For jointly controlled entities that will be reclassified as joint ventures the new standard requires the equity method. Proportionate consolidation is no longer an option. Joint operations will continue to be proportionally accounted for. NAL is currently assessing the impact of this standard on its consolidated financial statements.

Disclosure of Interests in Other Entities

As of January 1, 2013, NAL will be required to adopt IFRS 12, Disclosure of Interests in Other Entities. This standard contains disclosure requirements for entities that have interests in subsidiaries, joint arrangements, associates and unconsolidated structured entities. The information is to enable users to evaluate the nature of, and risks associated with, an entity's interests in other entities, and the effects of those interests on the entity's financial position, financial performance and cash flows.

Fair Value Measurement

As at January 1, 2013, NAL will be required to adopt IFRS 13, Fair Value Measurement. This standard provides a single source of guidance on defining fair value, establishing a framework for measuring fair value and setting out disclosure requirements for fair value measurements. NAL is currently assessing the impact of this standard on its consolidated financial statements.

4) Acquisition

On December 3, 2010, the Corporation acquired working interests in certain petroleum and natural gas producing properties in central Alberta, the purpose of which was to increase the working interests already held by the Corporation in certain properties and to acquire new properties in the same areas. This purchase was accounted for using the acquisition method of accounting as follows:

Net assets acquired:	
Property, plant and equipment	$29,384
Asset retirement obligation	(6,797)
	$22,587
Consideration paid:	
Cash	$22,587

The operating results from this acquisition have been included in the accounts of the Corporation from December 3, 2010. Revenue of $0.6 million, and net income of $0.5 million have been included in the consolidated statement of income for the year ended December 31, 2010, related to these assets. Acquisition costs of $0.1 million have been included in the statement of income and are reported as general and administrative expenses.

The following table shows select pro-forma financial information as if the acquisition had occurred on January 1, 2010 instead of the actual closing of December 3, 2010:

	2010
Oil and natural gas revenue	$12,247
Net income for the year	$7,486

5) Related Party Transactions

The Manager is a wholly-owned subsidiary of Manulife Financial Corporation ("MFC") and manages, on their behalf, NAL Resources Limited ("NAL Resources"), another wholly-owned subsidiary of MFC. NAL Resources and the Corporation maintain ownership interests in many of the same oil and natural gas properties. NAL Resources operates these properties on behalf of the Corporation and MFC. As a result, a significant portion of the net operating revenues and capital expenditures represent joint operations amounts from NAL Resources. These transactions are in the normal course of joint operations and are based on the original exchange amounts established through transactions with third parties.

The Manager provides certain services to the Corporation pursuant to an Administrative Services and Cost Sharing Agreement. This agreement requires the Corporation to reimburse the Manager, at cost, for general and administrative ("G&A") expenses incurred by the Manager on behalf of the Corporation. The Corporation paid $22.2 million (2010 - $21.7 million) for the reimbursement of G&A expenses during 2011. The Corporation also pays the Manager its portion of share-based compensation expense when cash compensation is paid to employees under the terms of the Manager's incentive compensation plans, of which $6.9 million was paid in 2011, representing notional shares that vested on November 30, 2010 (2010 - $6.8 million).

The following amounts are due to and from related parties as at December 31, 2011 and December 31, 2010 and have been included in accounts receivable, prepaids and other receivables and accounts payable and accrued liabilities on the balance sheet:

	2011	2010
Due from NAL Resources Limited	$9,387	$8,149
Due to NAL Resources Management Limited	(3,670)	(8,705)
Due to Manulife Financial Corporation	-	(265)
	$5,717	$(821)

In conjunction with the Reorganization, a partnership (the "Partnership") that was jointly owned by the Corporation and MFC was dissolved on December 31, 2010. This Partnership held the assets acquired from the acquisitions of Tiberius and Spear in February 2008.

Prior to December 31, 2010 the Corporation, by virtue of being the owner of the general partner of the Partnership, was required to consolidate the results of the Partnership into its financial statements on the basis that the Corporation had control over the Partnership. The Corporation had recorded a minority interest in respect of the 50 percent ownership held by MFC. The Corporation adjusted its financial statements on December 30, 2010 based on the dissolution of the Partnership to reflect its proportionate share of the Partnership's assets, liabilities, revenues and expenses. Accordingly at December 31, 2011 and 2010, no minority interest was reflected on the balance sheet.

In the Partnership there was a note payable to MFC, which was settled on dissolution of the Partnership. At January 1, 2010, the note payable of $8.9 million was included on consolidation of the Partnership, but was effectively eliminated through the non-controlling interest. The note was due on demand, unsecured and bore interest at prime plus three percent.

Key Management Personnel

Key management personnel comprise the Board of Directors of the Corporation and the Executive Officers of the Manager, which include the Chief Executive Officer, the Chief Financial Officer, the Chief Operating Officer and the Vice President of Business Development.

For the years ended December 31, 2011 and 2010, key management personnel compensation is as follows:

	2011[1]	2010[1]
Salaries	$743	$858
Short-term incentives and benefits	1,248	1,375
Share-based payments (2)	(556)	932
	$1,435	$3,165

(1) Represents the proportion of compensation that the Corporation reimburses the Manager for. The Manager allocates G&A based on relative production levels. For 2011, the relative proportion of personnel expenses charged to the Corporation was 61% (2010: 63%)
(2) Represents the share-based compensation expense associated with notional shares granted to executive officers and directors (deferred share unit plan), as recorded in the consolidated financial statements.

6) Property, Plant And Equipment & Exploration & Evaluation Assets

(i) Property, Plant and Equipment ("PP&E")

	2011	2010
Gross cost		
Opening balance, beginning of year	$1,706,163	$1,415,830
Additions[1]	254,832	210,789
Acquisitions	-	29,384
Asset retirement cost additions and revisions	763	4,892
Disposals	(42,145)	(5,712)
Transfers from evaluation and exploration assets	21,815	50,980
Closing balance, end of year	$1,941,428	$1,706,163
Accumulated depletion and impairment losses		
Opening balance, beginning of year	$233,503	$-
Disposals	(4,216)	(88)
Depletion for the year	193,376	200,787
Impairment losses	101,996	32,804
Closing balance, end of year	$524,659	$233,503
Net book value		
Opening balance, beginning of year	$1,472,660	$1,415,830
Additions	255,595	245,065
Depletion for the year	(193,376)	(200,787)
Disposals	(37,929)	(5,624)
Transfers from evaluation and exploration assets	21,815	50,980
Impairment losses	(101,996)	(32,804)
Closing balance, end of year	$1,416,769	$1,472,660

(1) Includes non-cash earned values on farm-outs of $8.2 million (2010 - $nil).

The calculation of depletion included future development costs for proved plus probable reserves of $509.1 million (2010 - $420.3 million). Undeveloped land amounting to $50.1 million (2010 - $46.5 million) is included in PP&E assets and has not been included in the depletable base while development activity is completed on this development acreage. Depletion and depreciation and impairment of property plant and equipment, and any eventual reversal thereof, are recognized in the income statement.

At December 31, 2011 and 2010 all of the Corporation's properties were pledged as security for the bank debt.

(ii) Exploration & Evaluation Assets

	2011	2010
Net book value		
Opening balance, beginning of year	$63,127	$88,122
Additions	3,107	25,985
Transfers to PP&E	(21,815)	(50,980)
Closing balance, end of year	$44,419	$63,127

(iii) Assessment of PP&E

	2011	2010
Impairment	$101,996	$32,804

During the year ended December 31, 2011, impairment losses of $102.0 million (2010 - $32.8 million) were recorded and reported as impairment of oil and gas assets in the statement of income. The impairment related to PP&E assets and was calculated using the fair value less costs to sell approach, which was based on the McDaniel reserves report, using future prices as at December 31, 2011 and future costs, discounted at a rate of 10 percent (2010 – 10 percent) commensurate with market transactions. There has been no reversal of previously booked impairment amounts.

These impairment losses were recognized in four natural gas CGUs and one crude oil CGU, which have no goodwill assigned. The impairment results from a reduction in forward natural gas prices and reserve revisions and adjustments to future costs since December 31, 2010, as estimated by the Corporation's independent engineering consultants.

(iv) Impairment of Goodwill

For the purposes of impairment testing, goodwill is allocated to the CGUs to which it relates. All of the goodwill of $14.7 million is allocated to the Saskatchewan CGU. An impairment test for this CGU as at December 31, 2011 and 2010 was performed and no impairment was recorded. The impairment test was calculated using the fair value less costs to sell approach, which was determined using discounted future cash flows generated from the related independently evaluated reserves. These cash flows are projected over the next 50 years, are discounted at 10 percent and incorporate the following pricing and production profiles.

Year	WTI oil (US$/bbl)	US$/Cdn$ Exchange rate	WTI oil (Cdn$/bbl)	Production (Boe/d)
2012	97.50	0.975	100.00	6,615
2013	97.50	0.975	100.00	6,666
2014	100.00	0.975	102.56	5,748
2015	100.80	0.975	103.38	4,675
2016	101.70	0.975	104.31	3,970
Remainder	+2%/year	0.975	+2%/year	

To result in a potential impairment charge to this CGU, the above estimates would have to significantly change. In order for the estimate of the recoverable amount to decrease to the carrying amount of the CGU, future planned revenues would have to decrease by approximately 36 percent or the discount rate would have to be approximately 23 percent.

7) Bank Debt

	2011	2010
Production loan facility	$325,903	$266,965
Working capital facility	1,267	-
	$327,170	$266,965

The Corporation maintains a fully secured, extendible, revolving term credit facility with a syndicate of Canadian chartered banks and one U.S. based lender. The facility consists of a $535 million production facility and a $15 million working capital facility. The total amount of the facility is determined by reference to a borrowing base. The borrowing base is calculated by the bank syndicate and is based on the net present value of the Corporation's oil and gas reserves and other assets. Given that the borrowing base is dependent on the Corporation's reserves and future commodity prices, lending limits are subject to change on renewal.

The credit facility is fully secured by first priority security interests on all existing and future acquired properties and assets of the Corporation and its subsidiary and affiliated entities. The facility has a three year fixed term, maturing April 30, 2014, at which time the debt is due and payable. The Corporation can apply at any time for an extension of the latest maturity date to a business day, not later than three years from April 30th of the year in which the request for the extension is made.

Amounts are advanced under the credit facility in Canadian dollars by way of prime interest rate based loans and by issues of bankers' acceptances and in U.S. dollars by way of U.S. based interest rate and Libor based loans. The interest charged on advances is at the prevailing interest rate for bankers' acceptances, Libor loans, lenders' prime or U.S. base rates plus an applicable margin or stamping fee. The applicable margin or stamping fee, if any, varies based on the consolidated debt-to-cash flow ratio of the Corporation. As at December 31, 2011 and 2010 all amounts outstanding were in Canadian dollars.

On December 31, 2011 the effective interest rate on amounts outstanding under the credit facility was 4.44 percent (2010 – 5.16 percent). The Corporation's interest charge includes this fixed interest rate component, plus a standby fee, a stamping fee and the fee for renewal.

8) Convertible Debentures

On August 28, 2007, the Corporation issued $100 million principal amount of 6.75 percent convertible extendible unsecured subordinated debentures, at a price of $1,000 per debenture. Interest on these debentures is paid semi-annually in arrears, on February 28 and August 31, and the debentures are convertible at the option of the holder at any time into common shares at a conversion price of $14.00 per share. The debentures mature on August 31, 2012 at which time they are due and payable. The debentures are redeemable by the Corporation at a price of $1,025 per debenture before August 31, 2012. On redemption or maturity the Corporation may opt to satisfy its obligation to repay the principal by issuing common shares. These debentures are reported as a current liability as they are due and payable in August 2012.

On December 3, 2009, the Corporation issued $115 million principal amount of 6.25 percent convertible unsecured subordinated debentures, at a price of $1,000 per debenture. Interest on these debentures is paid semi-annually in arrears, on June 30 and December 31, and the debentures are convertible at the option of the holder at any time into common shares at a conversion price of $16.50 per share. The debentures mature on December 31, 2014 at which time they are due and payable. The debentures are redeemable by the Corporation at a price of $1,050 per debenture on or after January 1, 2013 and on or before December 31, 2013, and at a price of $1,025 per debenture on or after January 1, 2014 and on or before December 31, 2014. On redemption or maturity, the Corporation may opt to satisfy its obligation to repay the principal by issuing common shares.

Prior to the Reorganization, the convertible debentures were recorded at fair value and classified as debt. On conversion to a Corporation on December 31, 2010, the fair value of the convertible debentures at that date based on quoted trading values was bifurcated between debt and equity. As a result, $5.0 million of debt was re-classified as equity, with the remaining debt premium to be amortized into income over the term to maturity. The amortization of the debt premium and the interest paid to debenture holders is expensed each period as part of the caption "interest and accretion on convertible debentures" in the consolidated statement of income.

The following table reconciles the principal amount, debt component and equity component of the convertible debentures:

	Year ended December 31, 2011			Year ended December 31, 2010		
	6.25%	6.75%	Total	6.25%	6.75%	Total
Principal, beginning and end of year	$115,000	$79,744	$194,744	$115,000	$79,744	$194,744
Debt component, beginning of year	$116,506	$83,014	$199,520	$119,600	$84,130	$203,730
Premium amortization	(379)	(1,977)	(2,356)	-	-	-
Fair value adjustment to Dec 30, 2010	-	-	-	1,161	(398)	763
Reclassification to equity	-	-	-	(4,255)	(718)	(4,973)
Debt component, end of year	$116,127	$81,037	$197,164	$116,506	$83,014	$199,520
Equity component, beginning of year	$4,255	$718	$4,973	$-	$-	$-
Reclassification from debt	-	-	-	4,255	718	4,973
Equity component, end of year	$4,255	$718	$4,973	$4,255	$718	$4,973

9) Other Liabilities

	2011	2010
Share-based incentive compensation (Note 10)	$1,289	$1,009
Excess office lease obligation (1)	238	2,003
	$1,527	$3,012

(1) Represents the present value of the long-term portion of the office lease obligation, in excess of a sub-lease, assumed on the acquisition of Alberta Clipper Energy Inc. and Breaker Energy Ltd. MFC reimburses the Corporation for 50 percent of the Alberta Clipper obligation of $0.5 million under a base price adjustment clause.

10) Share-Based Incentive Compensation Plan

The Manager has a long-term incentive plan (the "Plan") under which employees receive cash compensation based upon the value and overall return of a specified number of awarded notional shares on a fixed vesting date. The notional share grants are in the form of Restricted Share Units ("RSUs") and Performance Share Units ("PSUs"). One third of each RSU grant vests on November 30 in each of the three years after the date of grant. PSUs vest on November 30, three years after the date of grant.

Pursuant to the Reorganization, all previously issued Restricted Trust Units and Performance Trust Units were amended to represent one notional common share instead of a notional trust unit. The awards are otherwise on the same terms and continue to be governed by the same terms under the Plan.

The Corporation recorded a share-based compensation recovery was $1.1 million in 2011 (2010 – $4.6 million expense). The compensation expense was based on the December 31, 2011 share price of $7.88 (December 31, 2010 - $12.95), accrued dividends, performance factors and the estimated number of shares vesting on maturity.

A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of shares that vested. Forfeiture rates incorporated in the calculations are 10 percent for a one year vesting, 15 percent for a two year vesting and 20 percent for a three year vesting.

The Corporation has a deferred share unit plan ("DSU") under which directors of the Corporation receive cash compensation based upon the value and the overall return of a specified number of notional shares. The notional shares vest on retirement of the director.

The following table reconciles the change in total accrued share-based incentive compensation relating to the Plan:

	2011	2010
Balance, beginning of year	$13,209	$15,759
Increase (decrease) in liability	(1,077)	4,632
Partnership wind up (Note 5)	-	(87)
Cash payout, relating to shares vested[1]	(7,447)	(7,095)
Balance, end of year	$4,685	$13,209
Current portion of liability[2]	$3,396	$12,200
Long-term liability[3]	$1,289	$1,009

(1) Includes cash payout under Directors' DSU plan of $0.5 million (December 31, 2010 - $0.3 million).
(2) Included in accounts payable and accrued liabilities.
(3) Included in other liabilities.

The following table sets forth a reconciliation of the Corporation's Plan activity for the year ended December 31, 2011 and 2010.

	2011		
	Number of Restricted Shares	Number of Performance Shares	Total
Balance, beginning of year	122,468	543,011	665,479
Allocation rate change[1]	(4,857)	(21,534)	(26,391)
Issued	341,032	194,947	535,979
Exercised	(141,948)	(246,248)	(388,196)
Forfeited	(49,136)	(114,355)	(163,491)
Balance, end of year	267,559	355,821	623,380
Exercisable, end of year	-	-	-

(1) Allocation rate change reflects change in proportion of expenses charged to the Corporation from the Manager based on relative production of the Corporation and MFC.

	2010		
	Number of Restricted Shares	Number of Performance Shares	Total
Balance, beginning of year	189,465	670,030	859,495
Allocation rate change[1]	25,308	55,347	80,655
Issued	37,896	51,540	89,436
Exercised	(114,131)	(185,507)	(299,638)
Forfeited	(16,070)	(48,399)	(64,469)
Balance, end of year	122,468	543,011	665,479
Exercisable, end of year	-	-	-

(1) Allocation rate change reflects change in proportion of expenses charged to the Corporation from the Manager based on relative production of the Corporation and MFC.

11) Asset Retirement Obligations

The total future asset retirement obligation was estimated 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 Corporation has estimated the net present value of its asset retirement obligations to be $130.1 million as at December 31, 2011 (2010 - $149.0 million) based on a total undiscounted and inflated amount of cash flows required to settle its asset retirement obligations of $409.0 million (2010 - $445.3 million). These costs are expected to be made over the next 43 years with the majority of the costs incurred between 2012 and 2034. The Corporation's estimated credit-adjusted risk-free rate of eight percent (2010 – eight percent) and an inflation rate of two percent (2010 – two percent) were used to calculate the present value of the asset retirement obligations. The Corporation anticipates spending approximately $8.0 million on abandonment activities in 2012.

The following table reconciles the Corporation's asset retirement obligations.

	2011	2010
Balance, beginning of year	$149,015	$134,358
Accretion expense	10,123	11,006
Revisions to estimates	(910)	-
Partnership wind up (Note 5)	-	(377)
Liabilities incurred	1,673	4,892
Liabilities acquired (Note 4)	-	6,797
Liabilities disposed	(22,956)	(1,044)
Liabilities settled	(6,871)	(6,617)
Balance, end of year	$130,074	$149,015

12) Shareholders' Equity

The Corporation is authorized to issue an unlimited number of common shares and a number of preferred shares, issuable in series, 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.

Common Shares of NAL Energy Corporation:

	2011		2010	
	Shares	Amount	Shares	Amount
Balance, beginning of year	147,248	$890,777	-	$-
Issued pursuant to Reorganization (Note1)	-	-	147,248	890,777
Equity offering	1,159	10,001	-	-
Less issue expenses (net of tax of $77)		(223)		
Issued from Dividend Reinvestment Plan	2,700	27,249	-	-
Balance, end of year	151,107	$927,804	147,248	$890,777

Trust Units of NAL Oil & Gas Trust:

	2011		2010	
	Units	Amount	Units	Amount
Balance, beginning of the year	-	$-	137,471	$1,485,421
Equity offering	-	-	7,550	100,038
Less issue expenses (net of tax of $548)		-		(5,024)
Issued from Distribution Reinvestment Plan	-	-	2,227	25,338
Balance, prior to Reorganization	-	-	147,248	1,605,773
Exchanged for NAL common shares pursuant to Reorganization (Note 1)	-	-	(147,248)	(890,777)
Reduction in capital for reclassification of deficit (Note 1)	-	-	-	(714,996)
Balance, end of year	-	$-	-	$-

Dividend Reinvestment Plan

The Corporation has in place a Dividend Reinvestment Plan ("DRIP") and a Premium Dividend Reinvestment Plan ("Premium DRIP"). The regular DRIP entitles shareholders to reinvest cash dividends or make optional cash payments to acquire common shares from treasury under the DRIP at 95 percent of the average market price with no additional fees or commissions. The average market price is the arithmetic average of the daily volume weighted average trading price of the common shares during a defined period before the distribution payment date.

The Premium DRIP component of the plan allows shareholders to exchange common shares, acquired by reinvesting their cash dividends, for a cash payment from the plan broker equal to 102 percent of the monthly dividend on the applicable dividend payment date. The common shares issued under the Premium DRIP component of the plan at a five percent discount to the average market price will be delivered to the plan broker in exchange for 102 percent of the cash dividend payable on the participant's existing common shares.

At certain times and at the discretion of management, the DRIP and Premium DRIP may be suspended. Currently, the Premium DRIP is suspended.

Cash Distributions

Prior to December 31, 2010, the Corporation was required to distribute all of its cash available for distribution each calendar month, in accordance with the terms of the Trust Indenture. The cash available for distribution was defined as all cash amounts received less all costs, expenses, liabilities or obligations of the Corporation, plus net proceeds from the issuance of units, less any amounts the Trustee, upon recommendation of the Manager, considered it necessary to retain. The amount considered necessary to be retained included: any costs, expenses, liabilities or obligations which were reasonably expected to be incurred such as for property, plant and equipment; amounts required to be retained for repayment in order to comply with loan agreements; an allowance for contingencies, working capital, investments or acquisitions; or any amount appropriate to be retained as a reserve to stabilize distributions. This requirement was eliminated with the conversion to a corporation.

Dividends

During the year ended December 31, 2011, dividends of $125.0 million, or $0.84 per share were declared (2010 - $155.8 million or $1.08 per share). Dividends declared subsequent to year end, prior to March 7, 2012, totaled $15.2 million, or $0.10 per share.

Net Income per Share

Basic net income per share is calculated using the weighted average number of shares outstanding. The calculation of diluted net income per share includes the weighted average number of shares potentially issuable on the conversion of the convertible debentures.

The following table summarizes the weighted average number of shares outstanding:

	2011	2010
Weighted average shares outstanding – basic and diluted	148,709	143,913

The following table summarizes net income (loss):

	2011	2010
Net income (loss) attributable to equity holders – basic and diluted	$(11,034)	$59,025

The calculation of diluted net income per share includes the weighted average shares potentially issuable on the conversion of the convertible debentures. For the year ended December 31, 2011 and 2010, the shares potentially issuable on the conversion of the convertible debentures are anti-dilutive and are therefore excluded from the diluted net income per share calculation. Total weighted average shares issuable on conversion of the convertible debentures and excluded from the diluted net income per share calculation was 12,665,697, as they were anti-dilutive.

As at December 31, 2011, the total convertible debentures outstanding were immediately convertible to 12,665,697 shares (December 31, 2010 – 12,665,697).

13) Income Taxes

Reconciliation of Effective Tax Rate

The provision for income taxes in the consolidated financial statements differs from the result that would have been obtained by applying the combined federal and provincial tax rate to the net income before taxes as follows:

	2011	2010
Net income (loss) before tax	$(14,036)	$28,322
Expected tax rate[1]	26.5%	28.0%
Expected income tax	(3,720)	7,930
Increase (decrease) resulting from:		
Rate change	137	850
Rate variance	111	2,763
Net income of the Trust	-	(43,617)
Convertible debentures on Reorganization	-	2,317
Other	470	(946)
Total income tax reduction	$(3,002)	S(30,703)

(1) The statutory rate consists of the combined statutory tax rate for the Company and its subsidiaries for the year-ended December 31,

2011 and 2010. The general combined Federal/Provincial tax rate lowered to 26.5 percent from 2011 from 28 percent in 2010 due to the Federal rate dropping from 18 percent (2010) to 16.5 percent in 2011.

Unrecognized Deferred Tax Assets

Deferred tax assets have not been recognized in respect of the following items:

	2011	2010
Deductible temporary differences	$9,861	$9,970
Tax losses	324	328
	$10,185	$10,298

The Corporation has non-capital loss carry forwards of $255.0 million of which $5.5 million will expire between 2012 and 2016, $46.0 million will expire between 2017 and 2026, and $203.5 million will expire after 2026.

The deductible temporary differences do not expire under current tax legislation. Deferred tax assets have not been recognized in respect of these items because it is not probable that future taxable profit will be available against which the Corporation can utilize the benefits.

Recognized Deferred Tax Assets & Liabilities

Deferred tax assets and liabilities are attributable to the following:

	2011	2010
Deferred tax liabilities:		
Property, plant and equipment and exploration and evaluation assets	$(53,145)	$(101,543)
Resulting from different year ends	(33,027)	(3,514)
Less deferred tax assets:		
Non-capital tax loss carry forwards	65,096	71,091
Derivative contracts	1,434	2,553
Share issue costs	2,442	4,444
Asset retirement costs	33,208	38,431
Other	1,043	2,516
Net deferred tax asset	$17,051	$13,978

The Corporation has recognized a deferred tax asset based on the independently evaluated reserve report, as future cash flows are expected to be sufficient to fully realize the deferred tax asset.

The change in the deferred tax asset during the year is as follows:

	Balance January 1, 2011	Recognized in net income	Recognized in share capital	December 31, 2011
Property, plant and equipment and E&E	$(101,543)	$48,398	$-	$(53,145)
Results from different year ends	(3,514)	(29,513)	-	(33,027)
Non-capital tax loss carry forwards	71,091	(5,995)	-	65,096
Derivative contracts	2,553	(1,119)	-	1,434
Share issue costs	4,444	(2,079)	77	2,442
Asset retirement obligations	38,431	(5,223)	-	33,208
Other	2,516	(1,473)	-	1,043
Net deferred tax asset (liability)	$13,978	$2,996	$77	$17,051

	Balance January 1, 2010	Recognized in net income	Recognized in share capital	Recognized in PP&E	December 31, 2010
Property, plant and equipment and E&E	$(103,034)	$1,410	$-	$81	$(101,543)
Results from different year ends	(8,254)	4,740	-	-	(3,514)
Non-capital tax loss carry forwards	37,540	33,551	-	-	71,091
Derivative contracts	316	2,237	-	-	2,553
Share issue costs	7,015	(3,119)	548	-	4,444
Asset retirement obligations	41,766	(3,335)	-	-	38,431
Other	8,079	(5,563)	-	-	2,516
Net deferred tax asset (liability)	$(16,572)	$29,921	$548	$81	$13,978

14) Supplemental Disclosures

Income Statement Presentation

(i) Employee Compensation:

The aggregate payroll costs of employees and executive management included in general and administrative costs and share-based compensation are as follows:

	2011[1]	2010[1]
Salaries and wages	$13,826	$13,614
Benefits and other personnel costs	5,554	5,973
Share-based payments[2]	(1,159)	4,314
Total employee remuneration	$18,221	$23,901

1) Represents the proportion of compensation that the Corporation reimburses the Manager for. The Manager allocates G&A based on relative production levels. For 2011, the relative proportion of personnel expenses charged to the Corporation was 61% (2010: 63%).
2) Excludes Board of Directors DSU plan expense reported as share-based compensation in the statement of income.

The aggregate payroll costs included in operating expense are as follows:

	2011	2010
Total employee remuneration	$10,595	$8,372

Personnel expenses directly attributable to capital activities of $3.4 million (2010 - $2.7 million) have been capitalized and included in property, plant and equipment and exploration and evaluation assets.

(ii) Interest Expense:

The total interest expense for financial liabilities that are not recorded at fair value though profit and loss is as follows:

	2011	2010
Interest on bank debt	$12,616	$11,794
Interest and amortization on convertible debentures(1)	10,214	-
Total interest expense	$22,830	$11,794

1) The convertible debentures were held at fair value through profit and loss in 2010.

Cash Flow Statement Presentation

Changes in non-cash working capital is comprised of:

	2011	2010
Accounts receivable	$7,131	$3,792
Prepaids and other receivables	(572)	1,131
Accounts payable and accrued liabilities	(8,625)	(10,450)
Note payable	-	(8,907)
Other liabilities	(1,485)	(4,161)
Total	(3,551)	(18,595)
Reconciling items:		
Lease obligation - non-cash item	1,757	1,655
Interest paid less interest expense	(99)	674
Partnership wind up (Note 5)	-	8,994
Acquisition adjustments – non-cash item	-	(751)
Total	$(1,893)	$(8,023)
Related to Operating Activities	$(16,538)	$(6,065)
Related to Financing Activities	62	153
Related to Investing Activities	14,583	(2,111)
Total	$(1,893)	$(8,023)

Cash

The cash balance of $1.7 million (2010 - $0.8 million) was all cash in bank.

15) Financial Risk Management

Overview

The Corporation has exposure to the following risks from its use of financial instruments: credit risk, liquidity risk and market risk.

This note presents information about the Corporation's exposure to each of the above risks, the Corporation's objectives, policies and processes for measuring and managing risk, and the Corporation's management of capital. Certain other quantitative disclosures are included throughout these financial statements.

The Board of Directors has the responsibility to understand the principal risks of the business and to achieve a proper balance between the risks incurred and the potential return to shareholders. The Board of Directors has oversight for ensuring systems are in place to effectively monitor and manage those risks with a view to the long term viability of the Corporation.

Credit Risk

Credit risk is the risk of financial loss to the Corporation if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Corporation's receivables. The Corporation is managed by the Manager. The Manager is a wholly-owned subsidiary of MFC and manages on its behalf, NAL Resources, another wholly-owned subsidiary of MFC. NAL Resources and the Corporation maintain ownership interests in many of the same oil and natural gas properties in which NAL Resources is the operator. As a result, a significant portion of the Corporation's net operating revenues represent joint operations from NAL Resources. Accordingly, accounts receivable and other receivables include amounts due from NAL Resources for oil, natural gas and natural gas liquids sales. Oil and gas marketing is conducted by the Manager on behalf of the Corporation and NAL Resources, generally with large creditworthy purchasers, for which the Corporation views the credit risk as low. The Manager has a policy to perform regular reviews on the creditworthiness of its major purchasers and to obtain collateral when considered appropriate.

The accounts and other receivables are comprised of the following:

Accounts and Other Receivables	2011	2010
Trade receivables	$(39)	$3,470
Accrued receivables[1]	50,693	54,333
Due from related parties	54	36
Accounts receivables	$50,708	$57,839

1) Includes amounts accrued from related parties.

	2011	2010
Prepaids	$5,771	$6,344
Due from related parties	9,333	8,188
Other receivables	$15,104	$14,532

Cash and cash equivalents, when outstanding, consist of cash bank balances and short-term deposits maturing in less than 90 days. Derivative contracts consist of commodity contracts and foreign exchange rate contracts denominated in U.S. dollars for periods of up to two years and interest rate contracts for periods of up to five years. The Corporation manages the credit exposure related to short-term investments and derivative contracts by dealing with established counter-parties with high credit ratings by monitoring all investments and by avoiding complex investment vehicles with higher risks such as asset-backed commercial paper. All derivative contract counterparties are Canadian chartered banks in NAL's lending syndicate.

NAL management has reviewed its existing credit policy and has implemented regular reviews of purchasers to ensure credit-worthiness given current market conditions.

The carrying amounts of cash, accounts receivable and other receivables and derivatives represent the maximum credit exposure.

The Corporation considers all amounts greater than 90 days to be past due. Generally, the Corporation does not have amounts past due, due to receiving a significant portion of net operating revenues from NAL Resources. No receivables were past due as at December 31, 2011 and 2010.

Liquidity Risk

Liquidity risk is the risk that the Corporation will not be able to meet its financial obligations as they are due. The Corporation manages liquidity by ensuring, as far as possible, that it will have sufficient liquidity under both normal and stressed conditions.

The Corporation requires significant cash to fund capital programs necessary to maintain or increase production and develop reserves, to acquire strategic oil and gas assets, to repay maturing debt and to pay dividends.

The Corporation's capital programs are funded principally by internally generated cash flows and undrawn committed borrowing facilities. The Corporation also hedges a portion of its production to protect cash flow in the event of commodity price declines. To support the capital spending program, the Corporation maintains a fully secured, extendible, revolving term credit facility, as outlined in Note 7.

The Corporation prepares annual capital expenditure budgets, which are regularly monitored and updated as necessary. As well, the Manager utilizes authorizations for expenditures on both operated and non-operated projects. Furthermore, the Manager operates a high percentage of the Corporation's properties, which allows for significant control over future expenditures.

The Corporation's non-derivative financial liabilities include its accounts payable and accrued liabilities, dividends payable to shareholders, bank debt and convertible debentures. The Corporation's derivative financial liabilities include its commodity price, foreign exchange and interest rate contracts. The following table outlines cash flows associated with the contractual maturities of the Corporation's financial liabilities as at December 31, 2011.

Non-Derivative Financial Liability	< 1 Year	1 – 2 Years	2 – 5 Years
Accounts payable and accrued liabilities[1]	$91,640	$-	$-
Dividends payable to shareholders	10,577	-	-
Bank debt, principal	-	-	327,170
Convertible debentures, principal	79,744	-	115,000
Total	$181,961	$-	$442,170

(1) Includes interest payable of $1.8 million (2010 - $1.8 million).

Derivative Financial Liability	< 1 Year	1 – 2 Years	2 – 5 Years
Derivative contracts	$5,377	$950	$-

Market Risk

Market risk is the risk that changes in market prices, such as foreign exchange rates, commodity prices, and interest rates will affect the Corporation's net income or the value of financial instruments.

Foreign Currency Exchange Rate Risk

Foreign currency exchange rate risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in foreign exchange rates. Although substantially all of the Corporation's oil and natural gas sales are denominated in Canadian dollars, the underlying market prices in Canada for oil and natural gas are impacted by changes in the exchange rate between the Canadian and U.S. dollar.

NAL's management has authorization from the Board of Directors to fix the exchange rate on up to 50 percent of the Corporation's U.S. dollar exposure for periods of up to 24 months.

NAL has the following Canadian dollar / U.S. dollar foreign exchange option contracts outstanding.

Fixed Rate (USD/CAD)	Notional (US) per month	Term	Counterparty Floating Rate
0.9954	$2.0 MM	Jan 1, 2012 to Dec 31, 2012	BofC Monthly Average Noon Rate
1.0565	$1.5 MM	Jan 1, 2012 to Dec 31, 2012	BofC Monthly Average Noon Rate

NAL has a monthly commitment to settle the above fixed rates against the Bank of Canada monthly average noon rate.

Option Payout Range (USD/CAD)	Notional (US) per month	Term	Counterparty Floating Rate	Monthly Premium Received (CAD)
$0.93 - $1.03	$2.0 MM	Jan 1, 2012 to Dec 31, 2012	BofC Monthly Average Noon Rate	$40K
$0.90 - $1.15	$1.0 MM	Jan 1, 2013 to Sep 30, 2013	BofC Monthly Average Noon Rate	$40K

When the monthly average noon spot foreign exchange rate is outside the payout range, the monthly premium received is forfeited. NAL is committed to selling the above listed U.S. dollars at the upper payout range value for that month when the average noon spot foreign exchange rate exceeds the payout range.

Option Fixing Range (USD/CAD)	Notional (US) per month	Term	Counterparty Floating Rate
$0.97 - $1.04	$1.0 MM	Jan 1, 2012 to Dec 31, 2012	BofC Monthly Average Noon Rate

When the monthly average noon spot foreign exchange rate exceeds the option fixing range, NAL is committed to selling the above listed U.S. dollars at the lower option fixing range rate for that month. To the extent the monthly average spot foreign exchange rate is below the option fixing range, NAL is committed to selling the above listed U.S. dollars at the lower option fixing range rate. When the monthly average noon spot foreign exchange rate falls within the option fixing range, NAL has no commitment to sell U.S. dollars.

Fade-in Level (USD/ CAD)	Strike Price (USD/ CAD)	Participation Level (USD/CAD)	Notional (US) per month	Term	Counterparty Floating Rate
$0.92	$0.985	$1.03	$2.0 MM	Jan 1, 2012 to Dec 31, 2012	BofC Monthly Average Noon Rate
$0.91	$1.0075	$1.05	$1.5 MM	Jan 1, 2012 to Dec 31, 2012	BofC Monthly Average Noon Rate
$0.935	$1.00	$1.05	$0.5 MM	Jan 1, 2012 to Dec 31, 2012	BofC Monthly Average Noon Rate
$0.92	$1.012	$1.0625	$0.5 MM	Jan 1, 2012 to Dec 31, 2012	BofC Monthly Average Noon Rate
$0.92	$0.995	$1.035	$1.0 MM	Jan 1, 2012 to Dec 31, 2012	BofC Monthly Average Noon Rate
$0.93	$1.04	$1.075	$0.5 MM	Jan 1, 2012 to Dec 31, 2012	BofC Monthly Average Noon Rate
$0.90	$1.065	$1.15	$1.0 MM	Jan 1, 2013 to Sept 30, 2013	BofC Monthly Average Noon Rate

NAL is committed to selling U.S. dollars on a monthly basis at the strike price. If the Bank of Canada monthly average noon rate is below the fade-in level or between the strike and participating level, NAL has no commitment to sell U.S. dollars.

The fair value of foreign exchange derivative contracts has been included on the balance sheet with changes in the fair value reported separately on the statement of income as unrealized gain (loss). As at December 31, 2011, if exchange rates had strengthened by $0.01, with all other variables held constant, net income for the year would have been $0.6 million higher, due to changes in the fair value of the derivative contracts. An equal and opposite effect would have occurred to net income had exchange rates been $0.01 weaker.

Commodity Price Risk

Commodity price risk is the risk that future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by not only the relationship between the Canadian and U.S. dollar, but also macroeconomic events that dictate the levels of supply and demand. The Corporation has attempted to mitigate commodity price risk by entering into financial derivative contracts. The Corporation's policy is to enter into commodity contracts to a maximum of 60 percent of forecasted total revenue for a period of up to two years.

NAL has the following commodity risk management contracts outstanding:

Crude Oil	**Q1-12**	**Q2-12**	**Q3-12**	**Q4-12**	**Q1-13**	**Q2-13**	**Q3-13**	**Q4-13**
US$ Collar Contracts								
$US WTI Collar Volume (bbl/d)	900	900	700	700	-	-	-	-
Bought Puts – Average Strike Price ($US/bbl)	101.11	101.11	101.43	101.43	-	-	-	-
Sold Calls – Average Strike Price ($US/bbl)	117.07	117.07	117.66	117.66				
US$ Swap Contracts								
$US WTI Swap Volume (bbl/d)	7,115	7,200	7,000	7,000	500	500	500	500
Average WTI Swap Price ($US/bbl)	97.30	97.44	97.36	97.36	$100.95	$100.95	$100.95	$100.95
Total Oil Volume (bbl/d)	8,015	8,100	7,700	7,700	500	500	500	500
US$ Option Contracts								
Sold Call Options – Volume (bbl/d)	-	-	-	-	2,000	2,000	2,000	2,000
Average WTI Strike Price ($US/bbl)	-	-	-	-	110	110	110	110
Premium Received ($/bbl/d)	-	-	-	-	10.33	10.33	10.33	10.33

Certain calendar 2012 swap contracts for a total of 1,500 bbl/day and with an average price of $102.30, contain extendible call options into calendar 2013. The extendible call option provides the counterparty with the option to extend the contract into calendar 2013 under the same price and volumetric terms. The counterparty can exercise this option at any time before December 31, 2012.

Natural Gas	**Q1-12**	**Q2-12**	**Q3-12**	**Q4-12**	**Q1-13**	**Q2-13**	**Q3-13**	**Q4-13**
Collar Contracts								
AECO Collar Volume (GJ/d)	-	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Bought Puts & Average Strike Price ($Cdn/GJ)	-	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50
Sold Calls & Average Strike Price ($Cdn/GJ)	-	$3.05	$3.05	$3.05	$3.05	$3.05	$3.05	$3.05
Swap Contracts								
AECO Swap Volume (GJ/d)	24,000	7,000	7,000	5,674	2,000	2,000	2,000	2,000
AECO Average Price ($Cdn/GJ)	3.98	3.77	3.77	3.69	2.81	2.81	2.81	2.81
Total Natural Gas Volume (GJ/d)	24,000	9,000	9,000	7,674	4,000	4,000	4,000	4,000

The fair value of commodity derivative contracts has been included on the balance sheet with changes in the fair value reported separately on the statement of income as an unrealized gain (loss). As at December 31, 2011, if oil and natural gas liquids prices had been $1.00 per barrel lower and natural gas prices $0.10 per Mcf lower, with all other variables held constant, net income for the year would have been $3.0 million higher, due to changes in the fair value of the derivative contracts. An equal but opposite effect would have impacted net income had oil and natural gas liquids prices been $1.00 per barrel higher and natural gas $0.01 per Mcf higher.

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Corporation is exposed to interest rate fluctuations on its bank debt, which bears a floating rate of interest. The Corporation has attempted to mitigate interest rate risk by entering into derivative contracts.

The contracts have a combined notional debt amount of $100 million and require NAL to make fixed quarterly payments. In exchange, the counterparties are required to pay the Corporation a floating rate of interest based on the average rate for Canadian dollar bankers' acceptances. The Corporation's interest charge includes this fixed interest rate component plus a standby fee, a stamping fee and the fee for renewal. The Corporation's policy is to enter into interest rate swap contracts to fix the interest rate on up to 50 percent of outstanding bank debt for periods of up to five years.

NAL has the following interest rate derivative contracts outstanding:

Interest Rate Contract	Remaining Term	Amount (Cdn$MM)[1]	Corporation Fixed Rate	Counterparty Floating Rate
Swaps-floating to fixed	Jan 2012 – Jan 2013	$22.0	1.3850%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Jan 2012 – Jan 2014	$22.0	1.5100%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Jan 2012 – Mar 2013	$14.0	1.8750%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Jan 2012 – Mar 2014	$14.0	1.9850%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Jan 2012 - Mar 2013	$14.0	1.8500%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Jan 2012 – Mar 2014	$14.0	1.9300%	CAD-BA-CDOR (3 months)

1) Notional debt amount.

The fair value of interest rate derivative contracts has been included on the balance sheet with changes in the fair value reported separately on the statement of income as an unrealized gain (loss). As at December 31, 2011, if interest rates had been one percent lower, with all other variables held constant, net income for the year would have been $1.1 million lower, due to changes in the fair value of the derivative contracts. An equal and opposite effect would have occurred to net income had interest rates been one percent higher.

Fair Value of Financial Instruments

The carrying amount of the Corporation's financial instruments, including accounts and other receivables, accounts payable and accrued liabilities, and dividends payable to shareholders, approximate their fair value due to their short term to maturity.

The Corporation's bank debt and cash bear interest at floating market rates and, accordingly, the fair market value approximates the carrying amount.

During 2010, when the Corporation's convertible debentures were measured at fair value, the fair value was based on quoted and observable market values, which were used to mark-to-market the convertible debentures within the financial statements. On conversion to a Corporation, the convertible debentures are no longer fair valued. The mark-to-market on the convertible debentures is included in the December 31, 2010 convertible debenture total of $199.5 million. The fair value of the convertible debentures at December 31, 2011 was $200.7 million.

Derivative commodity contracts are recorded at fair value on the balance sheet as current or long-term, assets or liabilities, based on their fair values on a contract-by-contract basis. The fair value of commodity contracts is determined as the difference between the contracted prices and published forward curves (ranging from US$98.11 per barrel to US$99.48 per barrel for oil and $2.63 per GJ to $3.33 per GJ for natural gas) as of the balance sheet date, using the remaining contracted oil and natural gas volumes with option contracts also including an element of volatility. The fair value of the interest rate swaps is determined by discounting the difference between the contracted interest rate and forward bankers' acceptances rates (ranging from 0.8 percent to 0.96 percent) as of the balance sheet date, using the notional debt amount and outstanding term of the swap. The fair value of the exchange rate derivatives is calculated as the discounted value of the difference between the contracted exchange rate and the market forward exchange rates (ranging from 1.017 to 1.026) as of the balance sheet date, using the notional U.S. dollar amount and outstanding term of the swap. The fair value of the derivative contracts at December 31, 2011 is as follows:

Fair Value of Derivative Contracts	Commodity contracts	Interest rate contracts	Exchange rate contracts	Total
Current asset	$611	$-	$44	$655
Current liability	(2,796)	-	(2,581)	(5,377)
Long term asset	-	-	54	54
Long term liability	-	(950)	-	(950)
Total	$(2,185)	$(950)	$(2,483)	$(5,618)

As at December 31, 2011, the total fair value of derivative contracts was a net liability of $5.6 million (December 31, 2010 - $9.9 million). The changes in the fair value for year ended December 31, 2011 of a $4.3 million gain, has been recognized in the statement of income (2010 - $7.4 million unrealized loss).

The financial instruments carried at fair value, being the derivative contracts, are required to be classified into a hierarchy that prioritizes the inputs used to measure the fair value. The three levels of the fair value hierarchy are:

Level 1: Unadjusted quoted prices in active markets for identical assets or liabilities;

Level 2: Inputs, other than quoted prices, that are observable for the asset or liability either directly or indirectly; and

Level 3: Inputs that are not based on observable market data.

Fair values are classified as Level 1 when the related derivative is actively traded and a quoted price is available. If different levels of inputs are used to measure a financial instrument's fair value, the classification within the hierarchy is based on the lowest level input that is significant to the fair value measurement. The following table illustrates the classification of the financial instruments within the fair value hierarchy as at December 31, 2011:

	Assets at fair value as at December 31, 2011			
	Level 1	Level 2	Level 3	Total
Foreign exchange rate contracts	$-	$98	$-	$98
Commodity contracts	-	611	-	611
	$-	$709	$-	$709

	Liabilities at fair value as at December 31, 2011			
	Level 1	Level 2	Level 3	Total
Foreign exchange rate contracts	$-	$2,581	$-	$2,581
Interest rate contracts	-	950	-	950
Commodity contracts	-	2,796	-	2,796
	$-	$6,327	$-	$6,327

Capital Management

The Corporation's policy is to maintain a strong and flexible capital base to ensure that dividend levels are sustainable, while at the same time providing the flexibility to take advantage of operational and acquisition opportunities.

The Corporation manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying oil and natural gas assets. The Corporation considers its capital structure to include common shares, bank debt, convertible debentures, other liabilities, and working capital (excluding derivative contracts) as shown below. In order to maintain or adjust its capital structure, the Corporation may adjust the amount of dividends paid to shareholders, issue new shares, adjust its capital spending to modify debt levels, or suspend/resume its DRIP programs.

The Corporation monitors its capital based on the ratio of its net debt to 12 months trailing funds from operations. This ratio, which is a non-IFRS measure, is calculated as net debt as a proportion of funds from operations for the previous 12 months. Funds from operations is defined as cash flow from operating activities prior to the change in non-cash working capital less interest expense on bank debt and convertible debentures, excluding amortization on convertible debentures, and is calculated as below.

Years ended Dec 31	2011	2010
Cash flow from operating activities	$258,801	$274,606
Adjust for change in non-cash working capital	16,538	6,065
Less interest expense	(25,186)	(24,315)
Funds from operations	$250,153	$256,356

Net debt is defined as bank debt, plus convertible debentures at face value, plus working capital (excluding derivative contracts and including other liabilities). Net debt is measured with and without convertible debentures. The Corporation's strategy is to maintain a net debt to 12 month trailing funds from operations that is competitive with our peer group of oil and gas companies, both before and after taking into account the convertible debentures. The Corporation will, for the appropriate opportunity, increase its debt to funds from operations ratio above the Corporation's average. In order to facilitate the management of this ratio, the Corporation prepares an annual budget which is approved by the Board of Directors. On a monthly basis an updated forecast for the year is prepared based on updated commodity prices, results of operational activity and other events. The monthly forecast is provided to the Board of Directors.

As at December 31, 2011, the Corporation had a total net debt to 12 months trailing funds from operations ratio of 2.23 (December 31, 2010 – 1.97), as calculated in the table below. The increase in the net debt to 12 months trailing funds from operations ratio in 2011 is attributable to higher debt levels and a decrease in funds from operations.

The Corporation has no restrictions on the issuance of common shares.

There has been no change in the approach to capital management during 2011.

Capitalization	December 31, 2011	December 31, 2010
Shareholders' equity	$796,725	$895,750
Bank debt	327,170	266,965
Working capital deficit (surplus)[1]	36,210	43,337
Net debt excluding convertible debentures	363,380	310,302
Convertible debentures[2]	194,744	194,744
Net debt	$558,124	$505,046
Net debt excluding convertible debentures to trailing 12-month cash flow(3)	1.45	1.21
Total net debt to trailing 12-month cash flow[3]	2.23	1.97
Common shares outstanding (000s)	151,107	147,248

(1) Working capital and other liabilities, excludes derivative contracts, current amount of convertible debentures and note with MFC.
(2) Convertible debentures included at face value.
(3) Calculated as net debt divided by funds from operations for the previous 12 months.

16) Commitments

(i) Joint Venture Agreement

Effective April 20, 2009, the Corporation and MFC entered into a joint venture agreement with a senior industry partner. The arrangement consists of a three year commitment to spend $50 million on or before August 31, 2012, that provides the Corporation and MFC an opportunity to earn an interest in freehold and Crown acreage. The Corporation has a 65 percent interest in this agreement and MFC a 35 percent interest. The three year commitment to the Corporation is $32.5 million. The agreement is exclusive and structured to be extendible for up to an additional six years for a total potential commitment of $150 million ($97.5 million net to the Corporation) to earn an interest in over 150 (97.5 net) sections of freehold and Crown acreage. If the capital spending commitments are not met, interests in the freehold and Crown acreage will not be earned and the Corporation will not be required to pay unspent commitment amounts under the arrangement. As at December 31, 2011, the Corporation had spent $26.1 million under this agreement.

(ii) Farm-in Agreement

Effective January 2012, the Corporation and MFC renegotiated a prior farm-in agreement with a senior industry partner, which resulted in the replacement of the original agreement with a new agreement. The renegotiated arrangement consists of a four year capital commitment to December 2015, for a total of $50 million, of which at least $10 million must be spent each year. The Corporation has a 60 percent interest in this agreement and MFC a 40 percent interest. The agreement provides the opportunity to earn an interest in approximately 280 gross (182 net) sections of undeveloped Cardium rights as well as other zones of interest in Alberta held by the partner. If the capital spending commitments are not met, interest in the acreage will not be earned and the Corporation will not be required to pay any unspent amounts under the agreement.

(iii) Other

NAL has entered into several contractual obligations as part of conducting day-to-day business. NAL has the following remaining commitments for the next five years:

	2012	2013	2014	2015	2016
Office lease[1]	$2,182	$2,168	$2,126	$2,126	$-
Office lease – Clipper and Breaker[2]	2,211	364	-	-	-
Transportation agreement	4,068	2,019	574	72	19
Processing agreements[3]	197	184	-	-	-
Convertible debentures[4]	79,744	-	115,000	-	-
Bank debt	-		327,170	-	-
Total	$88,402	$4,735	$444,870	$2,198	$19

(1) Represents the Corporation's share of office lease commitments, including both base rent and operating costs, in relation to the lease held by the Manager, of which the Corporation is allocated a pro rata share (currently approximately 60 percent) of the expense on a monthly basis.
(2) Represents the full amount of the office leases assumed with the acquisitions of Clipper and Breaker. MFC reimburses the Corporation for 50 percent of the Clipper obligation under a base price adjustment clause.
(3) Represents gas processing agreements with take or pay components.
(4) Principal amount.

17) Subsequent Events

Subsequent to year end, the Corporation issued $150 million principal amount of 6.25 percent convertible unsecured subordinated debentures, at a price of $1,000 per debenture. Interest on these debentures is paid semi-annually in arrears on March 31 and September 30, and the debentures are convertible at the option of the holder at any time into common shares at a conversion price of $9.90 per share. The debentures mature on March 31, 2017.

Subsequent to year-end, the Corporation issued 300,000 common shares at prevailing market prices pursuant to its equity distribution agreement outlined in the Prospectus Supplement dated June 20, 2011. Total gross proceeds were $2.3 million and commissions were $0.1 million, for net proceeds to the Corporation of $2.2 million.

18) Transition To International Financial Reporting Standards ("IFRS")

As stated in Note 2, these consolidated financial statements as at December 31, 2011, including 2010 comparative periods, comprise the Corporation's first annual audited financial statements issued under IFRS. As a result, these consolidated financial statements have been prepared in accordance with IFRS1, "First-time adoption of International Financial Reporting Standards" as issued by the IASB. Previously the Corporation prepared its consolidated financial statements in accordance with previous CGAAP.

IFRS1 requires the presentation of comparative information as at the January 1, 2010 transition date and subsequent comparative periods as well as the consistent and retroactive application of IFRS accounting policies. To assist with the transition, IFRS1 outlines certain mandatory exceptions and optional exemptions that NAL could elect to eliminate the need for retroactive application of standards in certain circumstances.

Reconciliations of previous CGAAP to IFRS are set out in the tables which follow. A summary of the significant policy changes and exemptions are discussed in the notes that follow the reconciliations.

Reconciliation of Equity at January 1, 2010

	January 1, 2010 as stated under CGAAP	Adjustments	Notes	January 1, 2010 as restated under IFRS
Assets				
Current assets				
Cash	$1,604	$-		$1,604
Accounts receivable	61,631	-		61,631
Prepaids and other receivables	15,663	-		15,663
Derivative contracts	6,285	-		6,285
Future income tax assets	3,132	(3,132)	J	-
	88,315	(3,132)		85,183
Derivative contracts	2,461	-		2,461
Goodwill	14,722	-		14,722
Property, plant and equipment	1,503,952	(88,122)	A	1,415,830
Exploration and evaluation assets	-	88,122	A	88,122
	$1,609,450	$(3,132)		$1,606,318
Liabilities and Shareholders' Equity				
Current liabilities				
Accounts payable and accrued liabilities	$110,897	$(182)	G	$110,715
Note payable	8,907	-		8,907
Dividends payable to shareholders	12,372	-		12,372
Derivative contracts	11,231	-		11,231
	143,407		(182)	143,225
Bank debt	230,713	-		230,713
Convertible debentures	177,977	25,753	H	203,730
Other liabilities	7,643	(470)	G	7,173
Asset retirement obligations	127,872	6,486	F	134,358
Deferred income tax liability	24,778	(8,206)	J	16,572
Minority interest	2,868	(2,868)	I	-
	715,258	20,513		735,771
Shareholders' equity				
Share capital	1,482,029	3,392	J	1,485,421
Equity component of convertible debentures	12,628	(12,628)	H	-
Minority interest	-	3,370	I	3,370
Deficit	(600,465)	(17,779)		(618,244)
	894,192	(23,645)		870,547
	$1,609,450	$(3,132)		$1,606,318

Reconciliation of Equity at December 31, 2010

	December 31, 2010 as stated under CGAAP	Adjustments	Notes	December 31, 2010 as restated under IFRS
Assets				
Current assets				
Cash	$821	$-		$821
Accounts receivable	57,839	-		57,839
Prepaids and other receivables	14,532	-		14,532
Derivative contracts	422	-		422
Future income tax assets	3,830	(3,830)	J	-
	77,444	(3,830)		73,614
Deferred tax asset	17,152	(3,174)	J	13,978
Goodwill	14,722	-		14,722
Property, plant and equipment	1,503,546	(30,886)	A - F	1,472,660
Exploration and evaluation assets	-	63,127	A	63,127
	$1,612,864	$25,237		$1,638,101
Liabilities and Shareholders' Equity				
Current liabilities				
Accounts payable and accrued liabilities	$100,837	$(572)	G	$100,265
Dividends payable to shareholders	13,252	-		13,252
Derivative contracts	7,819	-		7,819
	121,908	(572)		121,336
Bank debt	266,965	-		266,965
Convertible debentures	181,672	17,848	H	199,520
Other liabilities	3,057	(45)	G	3,012
Derivative contracts	2,503	-		2,503
Asset retirement obligations	144,738	4,277	F	149,015
	720,843	21,508		742,351
Shareholders' equity				
Share capital	879,393	11,384	J	890,777
Equity component of convertible debentures	12,628	(7,655)	H	4,973
Deficit	-	-		-
	892,021	3,729		895,750
	$1,612,864	$25,237		$1,638,101

Reconciliation of Net Income for the year ended December 31, 2010

	Year ended December 31, 2010 as stated under CGAAP	Adjustments	Notes	Year ended December 31, 2010 as restated under IFRS
Revenue				
Oil, natural gas and liquid sales	$497,538	$-		$497,538
Crown royalties	(65,032)	2,132	B	(62,900)
Freehold and other royalties	(23,585)	-		(23,585)
	408,921	2,132		411,053
Gain (loss) on derivative contracts:				
Realized gain	24,446	-		24,446
Unrealized loss	(7,415)	-		(7,415)
	17,031	-		17,031
Other income	1,403	-		1,403
	427,355	2,132		429,487
Expenses				
Operating	117,523	(5,612)	B	111,911
Transportation	6,501	-		6,501
General and administrative	17,876	7,821	B	25,697
Share-based incentive compensation	3,170	1,462	G	4,632
Interest on bank debt	11,794	-		11,794
Interest and accretion on convertible debentures	16,562	(4,041)	H	12,521
Fair value adjustment on convertible debentures	-	763	H	763
Convertible debenture issue costs	-	345	H	345
Gain on disposition of property, plant and equipment	-	(17,596)	E	(17,596)
Depletion and depreciation	251,343	(50,556)	C	200,787
Impairment of oil and gas assets	-	32,804	D	32,804
Accretion on asset retirement obligations	12,112	(1,106)	F	11,006
	436,881	(35,716)		401,165
Income (loss) before taxes	(9,526)	37,848		28,322
Current tax recovery	782	-		782
Deferred tax reduction	41,154	(11,233)	J	29,921
Total tax recovery	41,936	(11,233)		30,703
Net income and comprehensive income	$32,410	$26,615		$59,025

Reconciliation of Cash Flows for the year ended December 31, 2010

	Year ended December 31, 2010 as stated under CGAAP	Adjustments	Notes	Year ended December 31, 2010 as restated under IFRS
Operating Activities				
Net income	32,410	$26,615		$59,025
Items not including cash:				
Depletion and depreciation	251,343	(50,556)	C	200,787
Accretion on asset retirement obligations	12,112	(1,106)	F	11,006
Unrealized loss on derivative contracts	7,415	-		7,415
Gain on disposition of property, plant and equipment	-	(17,596)	E	(17,596)
Fair value adjustment on convertible debentures	-	763	H	763
Impairment of oil and gas assets	-	32,804		32,804
Deferred tax reduction	(41,154)	11,233	J	(29,921)
Lease amortization	(1,655)	-		(1,655)
Interest expense and amortization on convertible debentures	-	24,315		24,315
Convertible debenture issue costs	-	345	H	345
Non-cash accretion expense on convertible debentures	4,040	(4,040)	H	-
Abandonment and reclamation	(6,617)	-		(6,617)
Change in non-cash working capital	(3,754)	(2,311)		(6,065)
	254,140	20,466		274,606
Financing Activities				
Distributions paid to shareholders	(129,559)	-		(129,559)
Increase in bank debt	36,252	-		36,252
Issue of shares, net of issue costs	94,466	-		94,466
Convertible debenture issue costs	(345)	-		(345)
Interest expense	-	(24,989)		(24,989)
Change in non-cash working capital	-	153		153
	814	(24,022)		(24,022)
Investing Activities				
Property, plant and equipment expenditures	(203,038)	(18,522)		(221,560)
Exploration and evaluation expenditures	-	(25,985)		(25,985)
Property acquisitions	(68,607)	68,607		-
Acquisitions	-	(22,587)		(22,587)
Proceeds from dispositions	22,178	-		22,178
Acquisition of Breaker	(901)	-		(901)
Disposition of Spearpoint	(309)			(309)
Change in non-cash working capital	(4,968)	2,857		(2,111)
	(255,645)	4,370		(251,275)
Decrease in cash	(691)	-		(691)
Cash, beginning of year	1,604	-		1,604
Dissolution of partnership	(92)	-		(92)
Cash, end of year	$821	$-		$821

A) Property, Plant & Equipment (PP&E) & Exploration & Evaluation Assets (E&E)

The Corporation elected to apply the IFRS1 exemption available to entities which followed full cost accounting under previous CGAAP. This exemption permits the total carrying value of PP&E and E&E under IFRS on transition to equal the carrying value under previous CGAAP, subject to an impairment test. In addition, conversion to IFRS required the allocation of the carrying amount of the full cost pool under previous CGAAP to E&E, and to components and CGUs for PP&E assets. Firstly, E&E were recorded at the carrying amount under previous CGAAP. The remaining previous CGAAP carrying amount was then allocated, pro-rata to components (Areas) for D&P assets ("PP&E"), based on proved plus probable reserve values, using the present values at a 10 percent discount rate.

Impairment tests were completed on transition, resulting in no impairment charge to PP&E or E&E at January 1, 2010.

E&E assets are required to be segregated from D&P assets. These assets comprise possible reserves assigned as a result of business acquisitions and undeveloped land associated with exploratory areas. As at January 1, 2010 and December 31, 2010, NAL's E&E assets were $88.1 million and $63.1 million, respectively.

Under previous CGAAP these assets were included in the full cost pool as PP&E, in accordance with the CICA's full cost accounting guideline. Under IFRS, these costs are initially recorded as E&E and, on determination of technical feasibility and commercial viability of the assets, the capitalized costs are moved to PP&E.

B) Capitalized Costs - PP&E

Under IFRS, employee costs included in general and administrative charges and share-based compensation charges are capitalized to the extent they are directly attributable to PP&E and E&E. The Corporation has adjusted its capitalization policy to comply with IFRS. For the year ended December 31, 2010, $9.3 million of such costs have been expensed which were originally capitalized under previous CGAAP.

Additionally, for the year ended December 31, 2010, lease rentals of $7.7 million were expensed under previous CGAAP in 2010, while under IFRS the Corporation has elected to capitalize these amounts.

C) Depreciation & Depletion

Under previous CGAAP, depletion was based on NAL's single cost centre, on a unit of production basis using total proved reserves. Costs subject to depletion excluded possible reserve locations and undeveloped land.

Under IFRS, depletion is provided for at a component level, defined as an Area by NAL, on a unit of production basis using total proved plus probable reserves. Costs subject to depletion are D&P assets excluding land under development.

For the year ended December 31, 2010, depletion decreased by $50.6 million from previous CGAAP, primarily a result of the change in depletion base to proved plus probable reserves.

D) Impairment

Under previous CGAAP, impairment was recognized if the carrying amount exceeded the undiscounted cash flows from proved reserves for NAL's single cost centre. The amount of impairment was then measured as the amount by which the carrying value of the cost centre exceeded the sum of proved plus probable reserves discounted at a risk free rate plus the cost of unproved interests and land, net of impairment. Impairments recognized under previous CGAAP were not reversed.

Under IFRS, an impairment is recognized if the carrying value exceeds the recoverable amount for a CGU. If the carrying value exceeds the recoverable amount of the CGU, the CGU is written down with an impairment recognized in net income. Impairments under IFRS are reversed when there has been a subsequent increase in recoverable amounts. Impairment reversals are recognized in net income and the carrying amount of the CGU is increased.

For the year ended December 31, 2010, $32.8 million of impairment was recognized under IFRS. See Note 6 (iii) for further detail.

E) Gains on dispositions

Under previous CGAAP, gains on dispositions were typically not recognized. Proceeds from dispositions were deducted from the full cost pool unless the deduction resulted in a change to the depletion rate of 20 percent or more, in which case a gain or loss was recorded.

Under IFRS, gains or losses are recorded on dispositions of properties and are calculated as the difference between the proceeds and the net book value of the assets disposed of at the point of disposition. For the year ended December 31, 2010, gains of $17.6 million were recognized under IFRS, compared to no gain recognized under previous CGAAP.

F) Asset Retirement Obligations & Accretion

Under previous CGAAP, the asset retirement obligations were measured at the estimated fair value of the expenditures expected to be incurred. Liabilities were not remeasured to reflect period end discount rates.

Under IFRS, the asset retirement obligation is measured as the best estimate of the expenditure to be incurred and requires the liability to be remeasured using the period end discount rate. As at January 1, 2010, the carrying value of the asset retirement obligation was $134.4 million, an increase of $6.5 million from the carrying value under previous CGAAP of $127.9 million. As at December 31, 2010, the carrying value of the asset retirement obligation was $149.0 million as compared to $144.7 million under previous CGAAP, an increase of $4.3 million. These adjustments reflect the remeasurement of the obligation using an eight percent discount rate.

In addition, accretion of the liability is impacted by the change in the recognized amount. For the year ended December 31, 2010, accretion decreased by $1.1 million as compared to previous CGAAP.

G) Other Liabilities & Accounts Payable

The adjustment to the liability for share-based compensation reflects a forfeiture rate which was not included under previous CGAAP. On transition to IFRS, the payable was reduced by $0.7 million to reflect the inclusion of a forfeiture rate. For the year ended December 31, 2010, share-based compensation expense increased by $1.5 million, due to the expensing of amounts capitalized under previous CGAAP, partially offset by the inclusion of a forfeiture rate.

H) Convertible Debentures

As a trust, NAL designated its convertible debentures as a financial liability at fair value through profit or loss on transition. As at January 1, 2010, the fair value of the Corporation's convertible debentures was $203.7 million, based on quoted market prices. Under previous CGAAP, the convertible debentures were bifurcated between debt and equity in the amounts of $178.0 million and $12.6 million, respectively, at December 31, 2009. The difference between the fair value and CGAAP carrying value was charged to retained earnings on transition.

At each quarter end, the convertible debentures were fair valued based on the then-prevailing market price with the adjustment taken to income. As at December 31, 2010, the fair value adjustment to the convertible debentures was $17.8 million, of which $0.8 million was recognized in income for 2010. Any accretion expense previously recognized through income under previous CGAAP was eliminated. For the year ended December 31, 2010, accretion on convertible debentures of $4.0 million as recognized under previous CGAAP, was eliminated on conversion to IFRS.

On conversion to a corporation on December 31, 2010, the carrying value of the convertible debentures which represented the fair of the convertible debentures on December 31, 2010, was bifurcated between debt and equity components as required under IFRS.

On December 31, 2010, the fair value of the convertible debentures was $204.5 million which following the Reorganization, was allocated $5.0 million to equity and $199.5 million to debt.

In addition, any issue costs associated with the convertible debentures were expensed during the period the convertible debentures were held at fair value through profit and loss, with $0.3 million expensed in 2010. Under previous CGAAP, these issue costs were netted against the debt component of the convertible debentures.

I) Minority Interest

The mandatory exception under IFRS1 allows for the prospective application in the accounting for a minority interest.

Therefore, the minority interest has only been adjusted under IFRS to reflect the changes to the income statement and net assets of the jointly-owned Partnership with MFC (see Note 5) as compared to previous CGAAP.

Under IFRS, minority interests are presented as part of equity rather than as a liability as they were under previous CGAAP.

J) Deferred Taxes

Under IFRS, NAL is required to record deferred taxes at the trust level at 39 percent, being the tax rate applicable to the undistributed profit of the Trust. Therefore, while a trust, the tax rate was significantly higher under IFRS compared to previous CGAAP. Under previous CGAAP, the rate used represented the anticipated rate at time of the temporary difference reversal. On conversion to a corporation, corporate tax rates apply, which has resulted in a decrease to previously recorded deferred tax amounts under IFRS at the trust level. Deferred taxes have also been adjusted to reflect the tax effect arising from the difference between IFRS and previous CGAAP as noted above. In addition, the deferred tax impact to share issue costs has been reflected.

Under IFRS, all deferred tax is presented as a long-term asset or liability. Under previous CGAAP, future income tax presentation was based on the presentation of the underlying asset or liability.

K) Other Exemptions - Business combinations

NAL elected the exemption not to restate business combinations, prior to January 1, 2010, in accordance with IFRS. There were no adjustments required for business combinations prior to January 1, 2010.

corporate information

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William J. Eeuwes
Donald R. Ingram
Kelvin B. Johnston
Andrew B. Wiswell

Legal Counsel
Bennett Jones LLP

Auditors
KPMG LLP

Independent Engineers
McDaniel and Associates Consultants Ltd.

Officers
Andrew B. Wiswell
President & Chief Executive Officer

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

John C. Koyanagi
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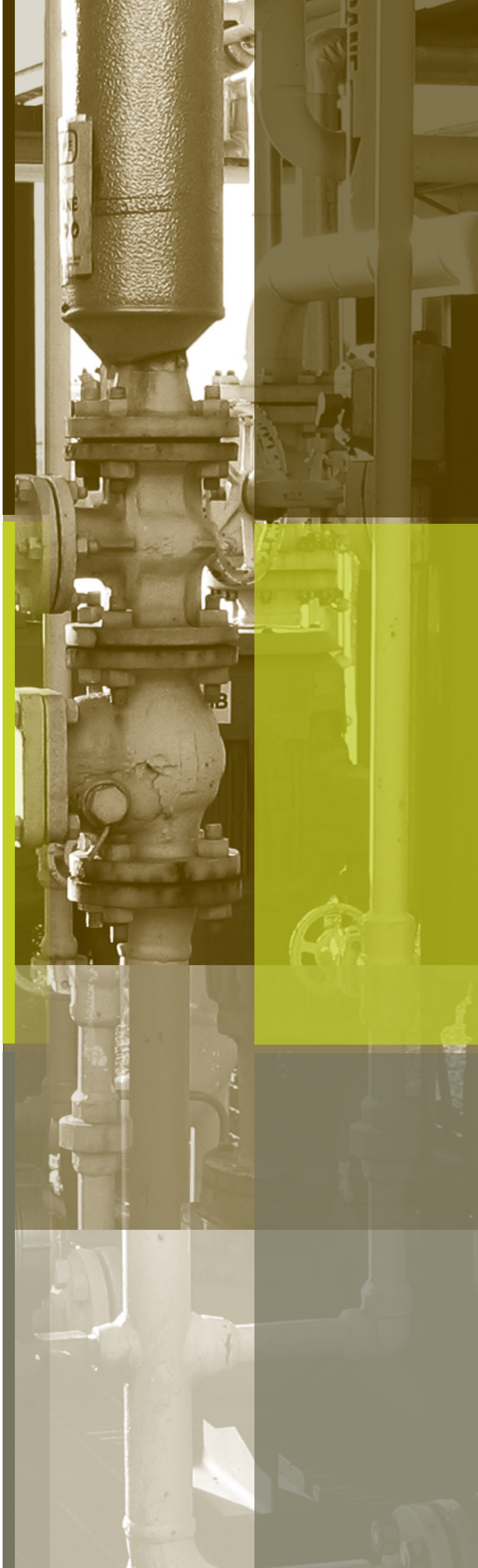

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