MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion and analysis ("MD&A") should be read in conjunction with the interim unaudited consolidated financial statements for the three and six month periods ended June 30, 2011 and the audited consolidated financial statements and MD&A for the year ended December 31, 2010 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 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 effective December 31, 2010 as part of a plan of arrangement 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 three and six months ended June 30, 2011, including required comparative information, have been prepared in accordance with International Financial Reporting Standards 1, First-time Adoption of International Financial Reporting Standards, and with International Accounting Standard ("IAS") 34, Interim Financial Reporting, 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 its 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 income funds and companies and, accordingly, they may not be comparable to measures used by other income funds and companies.

Funds from operations is calculated as cash flow from operating activities before changes in non-cash working capital. 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, note payable and deferred income tax balances.

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

	Three months ended June 30		Six months ended June 30	
$(000s)	**2011**	2010	**2011**	2010
Cash flow from operating activities	**60,897**	50,066	**121,880**	117,619
Add back change in non-cash working capital	**5,556**	17,781	**7,570**	29,709
Funds from operations	**66,453**	67,847	**129,450**	147,328

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; 2011 production; future tax treatment of the Corporation; the Corporation's tax pools; future oil and gas prices; operating, drilling and completion costs; the amount of future asset retirement obligations; future liquidity and future financial capacity; the initiation of an "at-the-market" financing program; future results from operations; payout ratios; cost estimates and royalty rates; drilling plans; tie-in of wells; future development, exploration, and acquisition and development activities and related 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, we have made assumptions 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 we intend to pay; the cost of expanding our property holdings; our ability to obtain equipment in a timely manner to carry out exploration and development activities; our ability to market our oil and natural gas successfully to current and new customers; the impact of increasing competition; our ability to obtain financing on acceptable terms; and our ability to add production and reserves through our 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 are based will occur. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated and which may cause NAL's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance. These risks and uncertainties include, without limitation: changes in commodity prices; unanticipated operating results or production declines; the impact of weather conditions on seasonal demand and 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 Trust unitholders 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 and 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. Comparatives information contained in the three and six months ended June 30, 2010 is accounted for on a consolidated basis, while the three and six months ended June 30, 2011 is accounted for on a proportionate basis.

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

EXPLORATION & DEVELOPMENT ACTIVITIES

The Corporation spent $28.6 million on drilling, completion and tie-in operations during the second quarter of 2011, compared to $34.6 million during the second quarter of 2010, and drilled 16 (5.1 net) wells in the second quarter, compared to 20 (11.5 net) wells during the same period in 2010. Approximately half of the capital was spent on drilling activities, with the remainder being directed toward completion, equipping and tie-in operations to bring wells on production late in the second quarter and into the third quarter. In addition, nine non-operated wells were drilled in the quarter, predominantly on the Corporation's non-core Cardium acreage in Alberta.

The Corporation has drilled 68 (34.4 net) wells year-to-date and is planning to drill an additional 71 (38 net) horizontal wells during the remainder of the year.

Second Quarter Drilling Activity

	Crude Oil		Natural Gas		Service Wells		Dry & Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Operated wells	7	4.2	0	0	0	0	0	0	7	4.2
Non-operated wells	8	0.8	1	0.1	0	0	0	0	9	0.9
Total wells drilled	15	5.0	1	0.1	0	0	0	0	16	5.1

Southeast Saskatchewan (Alida, Nottingham, Hoffer, Beaubier, Oungre, Neptune)

In Saskatchewan, there was one (0.5 net) horizontal oil well drilled at Hoffer versus a plan of ten (5.0 net) during the second quarter. While weather in Saskatchewan has improved somewhat in July, certain regions, particularly in the eastern part of the province, remain affected by extremely wet ground conditions. Road bans remained in effect for more than three months versus one month in a typical year. The protracted wet conditions affected drilling, tie-in, maintenance and trucking operations. At the end of July, the Corporation estimates that 800 – 1,000 boe/d (net) remains off-line or delayed in Saskatchewan.

NAL currently has four rigs operating in Saskatchewan and intends to drill 42 (21.0 net) additional horizontal Mississippian oil wells in the third and fourth quarters, largely focused in the greater Hoffer and Nottingham areas. In addition, ground preparation work has now begun for the previously announced central gathering facility at Hoffer. Current plans call for the battery to be commissioned around year end 2011. Once in place, the battery will tie-in all production currently producing to single well oil batteries in the area, reducing operating costs and improving reliability in bringing volumes to market from this emerging area.

Alberta (Cochrane, Garrington)

In Alberta, NAL participated in drilling 15 (4.6 net) locations with 14 (4.6 net) oil wells drilled in the Cardium at Garrington/Cochrane, including third party farm-outs. Four operated Cardium wells remain to be tied-in from the first half of 2011 drilling program. NAL now uses water based fracs in its Cardium programs and has evolved the completion technique to incorporate longer lateral sections, higher frac density with smaller per-frac tonnage. Drilling results based on these advancements continue to meet or exceed management expectations. NAL commenced a six well Cardium oil program in the Lochend area in early June, with one rig expected to operate continuously for the duration of the program. These Lochend wells are expected to be tied-in toward the end of the third quarter.

The Corporation's first Viking oil well, 14-36-35-07W5M, averaged approximately 300 boe/d (net) over the first 30 days on production, in-line with internal expectations. The second Viking oil well is currently recovering load fluid and waiting on tie-in activities to be completed. It is expected that initial results on this well will be available in September. NAL intends to evaluate the performance of this Viking opportunity and determine the future potential for more activity in 2012.

For the remainder of 2011, the Corporation intends to drill 16 (9 net) Cardium oil wells, ten of which will be in the greater Garrington area and six wells at Lochend/Cochrane.

Northeast British Columbia (Fireweed, Sukunka)
There were no operated or non-operated working interest wells drilled in British Columbia in the quarter. The second of two Fireweed wells (b-96-I/94-A-12), drilled in the first quarter, was brought on-stream in July and current production at Fireweed is approximately 2,500 boe/d. Production at Fireweed remains rate limited by facility capacity and NAL's development plans for the area are intended to hold volumes flat in the 2,500 boe/d range. At Sukunka, natural gas production net to the Corporation is currently in the range of 1,800 boe/d.

CAPITAL EXPENDITURES
Capital expenditures, before property acquisitions and dispositions, for the quarter ended June 30, 2011 of $36.1 million is in-line with internal forecasts and compares with $39.5 million in the same period a year ago. Second quarter capital expenditures are generally lower than other quarters due to the impact of spring break-up conditions in Western Canada. This year however, the Corporation and industry were affected by severe flooding conditions in southeast Saskatchewan and wet ground conditions in central Alberta. These conditions prevented NAL from accessing, drilling and completing wells in certain areas resulting in production delays. Second quarter land and seismic expenditures of $2.5 million represent a combination of Crown and private land purchases in and around established core areas and proprietary 3D seismic to help delineate play concepts on significant land blocks acquired in 2010.

On a year-to-date basis, capital expenditures, before property acquisitions, totaled $118.7 million compared to $117.8 million in the comparable period of 2010. NAL expects to spend an additional $105 -$110 million of exploration and development capital in the second half of 2011, focused primarily on Cardium and Mississippian oil opportunities. Spending for the remainder of the year will be weighted toward the third quarter, with some capital shifted into the fourth quarter to ensure continuity of ongoing operations for the full year.

The 2011 year-to-date net property acquisitions and dispositions of $29 million relate primarily to the non-core property dispositions in the first quarter of 2011.

Capital Expenditures ($000s)

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
Drilling, completion and production equipment	**28,643**	34,648	**97,436**	90,641
Plant and facilities	**4,414**	1,355	**6,535**	1,782
Seismic	**831**	151	**5,367**	1,812
Land[(1)]	**1,716**	2,528	**8,435**	22,458
Total exploration and development	**35,604**	38,682	**117,773**	116,693
Office equipment	**495**	846	**913**	1,134
Total capitalized expenditures before acquisitions	**36,099**	39,528	**118,686**	117,827
Property acquisitions	**(299)**	43,183	**684**	45,157
Proceeds on disposition	**(2,583)**	(103)	**(29,673)**	(14,779)
Total property acquisitions (dispositions) net	**(2,882)**	43,080	**(28,989)**	30,378
Total capitalized expenditures	**33,217**	82,608	**89,697**	148,205

(1) Land expenditures include lease rental charges

PRODUCTION

Second quarter 2011 production of 26,758 boe/d was nine percent lower than production of 29,334 in the same period of 2010. The majority of the decrease in production was due to severe weather conditions in several of our core operating areas which extended road bans, limited lease access due to high water levels, and outages at third party facilities (Sem Cams Kaybob 3 in Pine Creek, TCPL turnaround at Kakwa, Altagas maintenance at East Prairie and BP Steelman outage in Saskatchewan).

On a year-to-date basis average production of 27,387 boe/d was in line with NAL's 2011 forecast versus 29,575 boe/d for the comparable period of 2010, a decrease of seven percent. Similar trends account for the year-to-date to decrease in volumes.

Average Daily Production Volumes

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
Oil (bbl/d)	**9,747**	11,643	**10,077**	11,715
Natural gas (Mcf/d)	**86,852**	90,928	**88,209**	92,121
NGLs (bbl/d)	**2,535**	2,812	**2,609**	2,795
Oil equivalent (boe/d)	**26,758**	29,609	**27,387**	29,863
Less 50% of oil equivalent production relating to the non-controlling interest (boe/d)[(1)]	**-**	(275)	**-**	(288)
Oil equivalent (boe/d)	**26,758**	29,334	**27,387**	29,575

(1) See "Structure of the Business" in this MD&A for further information

Oil and natural gas liquids totaled 46 percent of production with natural gas at 54 percent during the first half of 2011. The Corporation's oil and liquids weighting is two percentage points lower than for the comparative period in 2010 and attributable to the weather related interruptions in Saskatchewan which curtailed oil volumes. NAL projects a 48 percent oil and liquids production weighting for full year 2011.

Production Weighting

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
Oil	**36%**	39%	**37%**	39%
Natural gas	**54%**	51%	**54%**	52%
NGLs	**10%**	10%	**9%**	9%

REVENUE

Gross revenue from oil, natural gas and natural gas liquids sales, after transportation costs and prior to hedging, totaled $129.3 million for the three months ended June 30, 2011, six percent higher than the second quarter of 2010. The increase was due to an 18 percent increase in the average realized price per boe, offset by a 10 percent decrease in production volumes. The 18 percent increase in realized price was driven by a 32 percent increase in the realized crude oil price, partially offset by a three percent decrease in the realized natural gas price. The increase in realized prices reflects higher West Texas Intermediate ("WTI") prices, partially offset by a stronger Canadian dollar. AECO spot prices were comparable in the second quarter of 2011 and 2010.

For the six month period ended June 30, 2011, revenue after transportation costs totaled $251.1 million, a decrease of three percent from the comparable period in 2010. The decrease was attributable to an eight percent decrease in production, partially offset by a six percent increase in the average realized price per boe. The increase in realized prices reflects higher West Texas Intermediate ("WTI") prices, partially offset by a stronger Canadian dollar and lower AECO prices in the first six months of 2011.

Revenue

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
Revenue(1) ($000s)				
Oil	**83,534**	75,774	**160,541**	156,859
Gas	**29,741**	32,000	**59,433**	74,064
NGL's	**15,570**	13,761	**30,449**	27,513
Sulphur	**497**	(24)	**671**	(42)
Total revenue	**129,342**	121,511	**251,094**	258,394
$/boe	**53.12**	45.10	**50.65**	47.80

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

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 situation of particular crude oil quality streams during the year.

NAL's second quarter average realized Canadian crude oil price per barrel, net of transportation costs and excluding hedging, was $94.17, compared to $71.52 for the comparable quarter of 2010. The increase in realized price quarter-over-quarter of 32 percent, or $22.65/bbl, was primarily driven by a 31 percent increase in the WTI price (US$/bbl) and an increase in crude oil differentials over the comparable period, partially offset by a six percent increase in the value of the Canadian dollar.

For the second quarter of 2011, NAL's crude oil price differential was 95 percent, an increase of six percentage points from the comparable period in 2010. The differential is calculated as realized price as a percentage of the WTI price stated in Canadian dollars.

For the six months ended June 30, 2011, NAL's average oil price was $88.02 per barrel compared to $73.98 for the comparable period in 2010. The 19 percent increase in realized price was driven by a 25 percent increase in the WTI price (US$/bbl), partially offset by a five percent increase in the value of the Canadian dollar. The crude oil differential was comparable year-over-year at 92 percent.

Natural gas liquids averaged $67.50/bbl in the second quarter of 2011, a 26 percent increase from the $53.78/bbl realized in 2010. For the six months ended June 30, 2011, natural gas liquids averaged $64.49/bbl, an increase of 19 percent from the comparable period in 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.

For the three months ended June 30, 2011, the Corporation's natural gas sales averaged $3.76/Mcf compared to $3.87/Mcf in the comparable period of 2010, a decrease of three percent. The quarter-over-quarter decrease in gas prices was attributable to a three percent decrease in the benchmark AECO monthly spot prices. The AECO daily spot price was consistent quarter-over-quarter.

Prices for Lake Erie natural gas decreased to $4.54/Mcf in the second quarter of 2011, compared to $4.91/Mcf in 2010, a decrease of eight percent. Lake Erie production of 3.1 mmcf/d accounted for three percent of the Corporation's natural gas production in the second quarter of 2011, as compared to four percent 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.

For the six months ended June 30, 2011, NAL averaged $3.72/Mcf, a 16 percent decrease from the $4.44/Mcf realized in the comparable period of 2010. The decrease in natural gas prices was attributable to a 14 percent and 18 percent decrease in the benchmark AECO daily and monthly spot prices, respectively.

Average Pricing
(net of transportation charges)

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
Liquids				
WTI (US$/bbl)	**102.56**	78.10	**98.33**	78.40
NAL average oil (Cdn$/bbl)	**94.17**	71.52	**88.02**	73.98
NAL natural gas liquids (Cdn$/bbl)	**67.50**	53.78	**64.49**	54.39
Natural Gas (Cdn$/mcf)				
AECO – daily spot	**3.88**	3.89	**3.83**	4.43
AECO – monthly	**3.74**	3.86	**3.76**	4.61
NAL Western Canada natural gas	**3.73**	3.83	**3.69**	4.41
NAL Lake Erie natural gas	**4.54**	4.91	**4.63**	5.30
NAL average natural gas	**3.76**	3.87	**3.72**	4.44
NAL Oil Equivalent before hedging (Cdn$/boe – 6:1)	**53.12**	45.10	**50.65**	47.80
Average Foreign Exchange Rate (Cdn$/US$)	**0.9676**	1.028	**0.9769**	1.034

RISK MANAGEMENT

NAL employs risk management practices to assist in managing cash flows and to support capital programs and distributions. 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 forecast total production, net of royalties. Management's practice is to layer in hedges up to 18 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 June 30, 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 June 30, 2011, NAL had several interest rate swaps outstanding with a total notional value of US$139 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 June 30, 2011, NAL had several exchange rate contracts outstanding with a total notional value of US$135 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 June 30, 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 June 30, 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 June 30, 2011 was a net liability of $4.4 million, comprised of a $9.0 million liability on oil contracts, partially offset by a $0.1 million asset on interest rate swaps, a $2.0 million asset on gas contracts and a $2.5 million asset on foreign exchange contracts.

Second quarter income for 2011 includes a $25.8 million unrealized gain on derivatives resulting from the change in the fair value of the derivative contracts during the quarter from an unrealized loss of $30.2 million at March 31, 2011 to an unrealized loss of $4.4 million at June 30, 2011. The $25.8 million unrealized gain was comprised of a $27.6 million unrealized gain on crude oil contracts, a $0.3 million unrealized gain on natural gas contracts, offset by a $0.9 million unrealized loss on interest rate swaps and a $1.2 million unrealized loss on foreign exchange swaps.

For the six months ended June 30, 2011, income includes an unrealized gain of $5.5 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 $4.4 million at June 30, 2011. The unrealized gain was comprised of a $6.4 million unrealized gain on crude oil contracts and a $0.3 million unrealized gain on natural gas contracts, partially offset by a $0.6 million unrealized loss on interest rate swaps and a $0.6 million unrealized loss on foreign exchange swaps.

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

Gain / (Loss) on Derivative Contracts ($000s)

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
Unrealized gain (loss):				
Crude oil contracts	**27,648**	15,939	**6,330**	17,485
Natural gas contracts	**271**	(7,848)	**327**	7,173
Interest rate swaps	**(864)**	(1,887)	**(558)**	(1,696)
Exchange rate swaps	**(1,239)**	(5,033)	**(561)**	(3,282)
Unrealized gain	**25,816**	1,171	**5,538**	19,680
Realized gain (loss):				
Crude oil contracts	**(7,243)**	(2,712)	**(10,370)**	(4,794)
Natural gas contracts	**1,403**	6,900	**2,319**	9,397
Interest rate swaps	**(131)**	(385)	**(260)**	(642)
Exchange rate swaps	**1,891**	1,682	**3,233**	2,972
Realized gain (loss)	**(4,080)**	5,485	**(5,078)**	6,933
Gain on derivative contracts	**21,736**	6,656	**460**	26,613

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

Realized Gain / (Loss) on Derivative Contracts

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
Commodity contracts:				
Average crude volumes hedged (bbl/d)	**5,900**	6,500	**5,801**	6,433
Crude oil realized gain (loss) ($000s)	**(7,243)**	(2,712)	**(10,370)**	(4,794)
Gain (loss) per bbl hedged ($)	**(13.49)**	(4.58)	**(9.88)**	(4.12)
Average natural gas volumes hedged (GJ/d)	**20,000**	39,000	**12,543**	38,486
Natural gas realized gain ($000s)	**1,403**	6,900	**2,319**	9,397
Gain per GJ hedged ($)	**0.77**	1.94	**1.02**	1.35
Average BOE hedged (boe/d)	**9,060**	12,661	**7,782**	12,513
Total realized commodity contracts gain (loss) ($000s)	**(5,840)**	4,188	**(8,051)**	4,603
Gain (loss) per boe hedged ($)	**(7.08)**	3.63	**(5.72)**	2.03
Gain (loss) per boe ($)	**(2.40)**	1.56	**(1.62)**	0.85
Interest rate swaps realized loss ($000s)	**(131)**	(385)	**(260)**	(642)
Loss per boe ($)	**(0.05)**	(0.14)	**(0.05)**	(0.12)
Exchange rate swaps realized gain ($000s)	**1,891**	1,682	**3,233**	2,972
Gain per boe ($)	**0.77**	0.62	**0.65**	0.55
Total realized gain (loss) ($000s)	**(4,080)**	5,485	**(5,078)**	6,933
Gain (loss) per boe ($)	**(1.68)**	2.04	**(1.02)**	1.28

Average hedged boe for the second quarter of 2011 was 9,060 compared to 6,490 for the first quarter of 2011.

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	July 2011 – Dec 2011	$39.0	1.5864%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	July 2011 – Jan 2013	$22.0	1.3850%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	July 2011 – Jan 2014	$22.0	1.5100%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	July 2011 – Mar 2013	$14.0	1.8750%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	July 2011 – Mar 2014	$14.0	1.9850%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	July 2011 – Mar 2013	$14.0	1.8500%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	July 2011 – Mar 2014	$14.0	1.9300%	CAD-BA-CDOR (3 months)

(1) Notional debt amount

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

Fixed Rate (CAD/USD)	Notional (US) per month	Term	Counterparty Floating Rate
1.05	$2.0 MM	July 1, 2011 to Dec 31, 2011	BofC Monthly Average Noon Rate
1.0608	$0.5 MM	July 1, 2011 to Dec 31, 2011	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 (CAD/USD)	Notional (US) per month	Term	Counterparty Floating Rate	Monthly Premium Received (CAD)
$0.93 - $1.01	$3.0 MM	July 1, 2011 to Dec 31, 2011	BofC Monthly Average Noon Rate	$60K
$0.93 - $1.01	$2.0 MM	Jan 1, 2012 to Jun 30, 2012	BofC Monthly Average Noon Rate	$40K

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

Option Fixing Rate (CAD/USD)	Notional (US) per month	Term	Counterparty Floating Rate
$0.94 - $1.06	$0.5 MM	July 1, 2011 to Dec 31, 2011	BofC Monthly Average Noon Rate
$0.95 - $1.07	$0.5 MM	July 1, 2011 to Dec 31, 2011	BofC Monthly Average Noon Rate
$0.94 - $1.08	$0.5 MM	July 1, 2011 to Dec 31, 2011	BofC Monthly Average Noon Rate
$0.95 - $1.04	$0.5 MM	July 1, 2011 to Dec 31, 2011	BofC Monthly Average Noon Rate
$0.95 - $1.0125	$0.5 MM	July 1, 2011 to Jun 30, 2012	BofC Monthly Average Noon Rate
$0.95 - $1.0138	$1.0 MM	July 1, 2011 to Jun 30, 2012	BofC Monthly Average Noon Rate

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

Option Fixing Range (CAD/USD)	Notional (US) per month	Term	Counterparty Floating Rate
$1.05 - $1.15	$1.0 MM	July 1, 2011 to Dec 31, 2011	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 USD 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 USD 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 USD.

Fade-in Level	Strike Price	Participation Level	Notional	Term	Counterparty Floating Rate
$0.92	$0.985	1.03	$2.0 mm	Jul 1, 2012-Dec 31, 2012	BofC Monthly Average Noon Rate
$0.91	$1.0075	1.05	$1.5 mm	Jan 1, 2012-Dec 31, 2012	BofC Monthly Average Noon Rate

NAL is fixed to sell USD 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 USD.

NAL has the following commodity risk management contracts outstanding:

CRUDE OIL	Q3-11	Q4-11	Q1-12	Q2-12	Q3-12	Q4-12
US$ Collar Contracts						
$US WTI Collar Volume (bbl/d)	200	200	900	900	700	700
Bought Puts – Average Strike Price ($US/bbl)	90.00	90.00	101.11	101.11	101.43	101.43
Sold Calls – Average Strike Price ($US/bbl)	100.50	100.50	117.07	117.07	117.66	117.66
US$ Swap Contracts						
$US WTI Swap Volume (bbl/d)	5,700	5,700	700	700	700	700
Average WTI Swap Price ($US/bbl)	88.10	88.10	107.76	107.76	107.76	107.76
Total Oil Volume (bbl/d)	5,900	5,900	1,600	1,600	1,400	1,400

Two 500 bbl/d, calendar 2011, swap contracts with an average price of $95.00 contain extendable call options. The extendible call option provides the counterparty with the option to extend the contract into calendar 2012 under the same price and volumetric terms. The counterparty can exercise this option any time before December 31, 2011.

NATURAL GAS	Q3-11	Q4-11	Q1-12	Q2-12	Q3-12	Q4-12
Swap Contracts						
AECO Swap Volume (GJ/d)	27,000	27,000	24,000	5,000	5,000	3,674
AECO Average Price ($Cdn/GJ)	3.99	3.99	3.98	4.16	4.16	4.17
Total Natural Gas Volume (GJ/d)	27,000	27,000	24,000	5,000	5,000	3,674

For the remainder of 2011, the Corporation has outstanding contracts representing approximately 40 percent of its net crude oil and natural gas production after royalties. In 2012, the Corporation has outstanding contracts representing approximately 12 percent of its forecast net crude oil and natural gas production after royalties.

ROYALTY EXPENSES

Crown, freehold and overriding royalties totaled $21.9 million for the three months ended June 30, 2011. Expressed as a percentage of gross sales net of transportation costs, before gain/loss on derivative contracts, the net royalty rate was 16.9 percent for the quarter ended June 30, 2011, a decrease from the 19.3 percent experienced in the same period of the previous year. The decrease in royalty rates is attributable to royalty adjustments relating to prior periods. Excluding the impact of these amendments, the royalty rate would be 17.5 percent in both the second quarter of 2011 and 2010.

Royalties increased to $8.97 per boe for the second quarter of 2011, an increase of three percent compared to the second quarter of 2010. The increase is attributable to higher crude oil commodity prices on a quarter-over-quarter basis.

On a year-to-date basis, royalties were $41.7 million, down from $46.0 million in the comparable period of 2010. 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, a decrease from the 17.8 percent experienced in the comparable period of 2010. Excluding the impact of prior period amendments, the royalty rate in 2011 would be 17.7 percent compared to 17.5 percent in 2010.

On March 11, 2010, the Government of Alberta announced measures to advance Alberta's competitiveness in the upstream oil and gas sector. The royalty framework for natural gas and conventional oil was modified for all production effective January 1, 2011 and the new royalty curves were announced on May 31, 2010. The current incentive program rate of five percent on new natural gas and conventional oil wells is a permanent feature of the royalty system. The maximum royalty rate for conventional oil is reduced at higher price levels from 50 percent to 40 percent. The maximum royalty rate for natural gas is reduced at higher price levels from 50 percent to 36 percent.

For the six months ended June 30, 2011, 45 percent of crude oil production and 70 percent of natural gas production is from Alberta.

Royalty Expenses

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
Royalties ($000s)	**21,868**	23,444	**41,657**	46,043
As a % of revenue	**16.9**	19.3	**16.6**	17.8
$/boe	**8.97**	8.70	**8.40**	8.52

OPERATING COSTS

Operating costs averaged $11.96 per boe for the quarter ended June 30, 2011, up 14 percent from $10.45 per boe for the quarter ended June 30, 2010. This increase is primarily attributable to lower volumes. Operating costs of $29 million in the quarter remain consistent with costs in the same period of 2010. Second quarter operating costs are typically the highest in the year for NAL due to high levels of facility turnaround activity in the quarter and seasonally lower volumes during the spring break-up timeframe.

On a year-to-date basis, operating costs were $11.37 per boe compared to $10.40 per boe in 2010. Operating costs of $56 million are consistent with costs in the same period a year ago. For full year 2011, operating costs on a boe basis are expected to be at the higher end of guidance in the $10.90 per boe range as a result of lower volumes related to delays and deferral caused by wet weather conditions.

Operating Costs

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
Operating costs ($000s)	**29,118**	28,156	**56,375**	56,223
As a % of revenue	**22.5**	23.2	**22.5**	21.8
$/boe	**11.96**	10.45	**11.37**	10.40

OTHER INCOME

Other income was $0.20 per boe for the second quarter of 2011 and $0.16 for the six months ended June 30, 2011 compared to $0.04 per boe and $0.10 per boe, respectively, for the comparable periods in 2010. The increase in other income is attributable to increased marketing fee income and other non-recurring miscellaneous items.

In 2010, other income also included interest paid on notes with MFC of $0.1 million ($0.04 per boe) and $0.2 million ($0.04 per boe) for the three and six months ended June 30, 2010, respectively.

Other Income

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
Other income	**498**	112	**779**	555
Interest on notes with MFC	**-**	(108)	**-**	(220)
Total other income	**498**	4	**779**	335
Other income, excluding interest on notes with MFC:				
As a % of revenue	**0.4**	-	**0.3**	0.1
$/boe	**0.20**	0.04	**0.16**	0.10

OPERATING NETBACK

For the quarter ended June 30, 2011, NAL's operating netback before hedging gains was $32.39 per boe, an increase of 25 percent from $25.99 per boe for the quarter ended June 30, 2010. The increase was due to higher revenues, a result of higher crude oil prices, partially offset by increased royalty expense and operating costs per boe. Realized hedging losses, related to commodity and exchange rate derivative contracts, were $(1.63) per boe in the second quarter of 2011, as compared to a gain of $2.18 per boe in 2010, the loss in 2011 attributable mainly to higher realized crude oil prices.

On a year-to-date basis, similar trends resulted in an operating netback, before hedging, of $31.04 per boe compared to $28.98 per boe in 2010. Realized hedging losses, related to commodity and exchange rate derivative contracts, were $0.97 for the six months ended June 30, 2011, as compared to a gain of $1.40 per boe in 2010. The loss in 2011 was attributable to lower oil hedging gains due to increasing crude oil prices.

Operating Netback

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
AVERAGE DAILY PRODUCTION				
Oil (bbl/d)	**9,747**	11,643	**10,077**	11,715
Gas (Mcf/d)	**86,852**	90,928	**88,209**	92,121
NGLs (bbl/d)	**2,535**	2,812	**2,609**	2,795
Total (boe/d)	**26,758**	29,609	**27,387**	29,863
REVENUE(1)				
Oil ($/bbl)	**94.17**	71.52	**88.02**	73.98
Gas ($/Mcf)	**3.76**	3.87	**3.72**	4.44
NGLs ($/bbl)	**67.50**	53.78	**64.49**	54.39
Total ($/boe)	**53.12**	45.10	**50.65**	47.80
ROYALTIES				
Oil ($/bbl)	**19.71**	14.83	**17.77**	14.96
Gas ($/Mcf)	**0.06**	0.49	**0.10**	0.46
NGLs ($/bbl)	**17.04**	14.20	**16.07**	13.20
Total ($/boe)	**8.97**	8.70	**8.40**	8.52
OPERATING EXPENSES				
Oil ($/bbl)	**13.63**	11.82	**13.38**	10.77
Gas ($/Mcf)	**1.90**	1.64	**1.75**	1.78
NGLs ($/bbl)	**8.57**	8.09	**8.37**	7.40
Total ($/boe)	**11.96**	10.45	**11.37**	10.40
OTHER INCOME(2)				
Oil ($/bbl)	**0.36**	0.07	**0.27**	0.15
Gas ($/Mcf)	**0.01**	-	**0.01**	0.01
NGLs ($/bbl)	**0.26**	0.06	**0.20**	0.11
Total ($/boe)	**0.20**	0.04	**0.16**	0.10
OPERATING NETBACK, BEFORE HEDGING				
Oil ($/bbl)	**61.19**	44.94	**57.14**	48.40
Gas ($/Mcf)	**1.81**	1.74	**1.88**	2.21
NGLs ($/bbl)	**42.15**	31.55	**40.25**	33.90
Total ($/boe)	**32.39**	25.99	**31.04**	28.98
HEDGING GAINS/(LOSSES)(3)				
Oil ($/bbl)	**(6.03)**	(0.97)	**(3.91)**	(0.86)
Gas ($/Mcf)	**0.18**	0.83	**0.15**	0.56
NGLs ($/bbl)	**-**	-	**-**	-
Total ($/boe)	**(1.63)**	2.18	**(0.97)**	1.40
OPERATING NETBACK, AFTER HEDGING				
Oil ($/bbl)	**55.16**	43.97	**53.23**	47.54
Gas ($/Mcf)	**1.99**	2.57	**2.03**	2.77
NGLs ($/bbl)	**42.15**	31.55	**40.25**	33.90
Total ($/boe)	**30.76**	28.17	**30.07**	30.38

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

GENERAL AND ADMINISTRATIVE EXPENSES

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 three months ended June 30, 2011, G&A expenses were $7.2 million, compared to $6.9 million in the same quarter of 2010. G&A expense per boe was $2.96 in the quarter, as compared to $2.57 for the same period in 2010.

For the six months ended June 30, 2011, G&A expenses increased 14 percent to $14.6 million from $12.8 million in the comparable period in 2010, a four percent difference. G&A expense per boe was $2.95 in 2011, compared to $2.37 in 2010. The year-to-date increase in total year-to-date G&A of $1.8 million is attributable to higher consulting and software costs.

General and Administrative Expenses

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
G&A expenses ($000s)	**7,203**	6,929	**14,634**	12,811
$/boe	**2.96**	2.57	**2.95**	2.37
As a % of revenue	**5.6**	5.7	**5.8**	5.0
Per share ($)	**0.05**	0.05	**0.10**	0.09

SHARE-BASED INCENTIVE COMPENSATION PLAN

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"). RSUs vest as to one third of the amount of the grant on November 30 in each of 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, the 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 the second quarter of 2011, the Corporation recorded a $1.1 million reduction for share-based incentive compensation that reflects a decrease in the share price and PSU performance multipliers, partially offset by the impact of vesting. The share price of the Corporation decreased by 17 percent, from $13.23 at March 31, 2011 to $11.04 at June 30, 2011. A decrease in share price results in previously accrued amounts being reversed.

The share-based incentive compensation recovery in the second quarter of 2011 of $1.1 million is comparable to the recovery in the second quarter of 2010. Both periods had decreases in share price, 17 percent in 2011 and 18 percent in 2010, in addition to lower relative performance factors used to determine the compensation.

On a year-to-date basis, the Corporation has recorded a recovery of $0.5 million compared to a $0.4 million recovery in the comparable period of 2010.

At June 30, 2011, the share price used to determine share-based incentive compensation was $11.04. The closing share price of the Corporation on the Toronto Stock Exchange on August 8, 2011 was $8.80.

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 in each quarter and over-time.

At June 30, 2011, the Corporation has recorded a total accumulated liability for share-based incentive compensation in the amount of $5.3 million, of which $3.7 million is recorded as a current liability, as it is payable in December 2011, and $1.6 million is long-term, as it is payable in December 2012 and December 2013.

Share-Based Compensation

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
Share-based compensation ($000s):	**(1,112)**	(1,064)	**(476)**	(378)
As a % of revenue	**(0.9)**	(0.9)	**(0.2)**	(0.2)
$/boe	**(0.46)**	(0.39)	**(0.10)**	(0.07)
Per share ($)	**(0.01)**	(0.01)	**0.00**	0.00

RELATED PARTY TRANSACTIONS

The Corporation continues to be 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 $6.5 million (2010 - $6.3 million) for the reimbursement of G&A expenses during the second quarter and $12.8 million (2010 - $11.5 million) year-to-date. 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 in the first quarter of 2011, representing shares that vested on November 30, 2010 (2010 - $6.9 million).

At June 30, 2011 the Corporation owed the Manager $1.8 million for the reimbursement of G&A and had a receivable from NAL Resources of $10.5 million, relating to operating revenue less capital expenditures.

In conjunction with the Reorganization, a partnership that was indirectly owned jointly by the Corporation and MFC was dissolved on December 31, 2010. The Partnership held the assets acquired from the acquisitions of Tiberius and Spear in February 2008. See “Structure of the Business” in this MD&A for more information.

As part of the original structuring of the Partnership in 2008, both the Trust and MFC entered into net profit interest royalty agreements (“NPI”) with the Partnership. These agreements entitle each royalty holder to a 49.5 percent interest in the cash flow from the Partnership’s reserves.

In addition, 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.

INTEREST

Interest on bank debt includes the interest rate charges on borrowings, plus a standby fee, a stamping fee and the fee for renewal. Interest on bank debt for the second quarter of 2011 was $2.9 million, an increase of $0.2 million from $2.7 million for the comparable period in 2010 due to higher average debt levels. Average outstanding bank debt for the second quarter of 2011 was $271.9 million, $66.2 million higher than the $205.7 million outstanding for the second quarter of 2010, driven primarily by lower average bank debt in 2010 due to $94.7 million raised in equity in the second quarter of 2010, net of issuance costs. NAL's effective interest rate averaged 4.32 percent during the second quarter of 2011, compared to 5.22 percent during the comparable period in 2010. The decrease in the rate from the second quarter of 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.

For the six months ended June 30, 2011, interest on bank debt increased $0.4 million to $6.2 million, compared to $5.8 million in 2010. Average outstanding debt for the six months ended June 30, 2011 increased to $265.6 million, compared to $219.0 million for the corresponding period of 2010, and the effective interest rate averaged 4.68 percent in 2011, compared to 5.30 percent in 2010.

Interest on convertible debentures represents interest charges of $2.6 million for the three months ended June 30, 2011 ($5.1 million for the six months ended June 30, 2011) compared to $3.1 million in the second quarter of 2010 ($6.2 million for the six months ended June 30, 2010).

The interest includes the interest on the 2007 debentures at 6.75 percent and the interest on the debentures issued in December 2009 at 6.25 percent. Amortization of the debt premium was $0.6 million for the three months ended June 30, 2011 (2010 - nil), and $1.2 million for the six months ended June 30, 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.

Interest and Debt

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
Interest on bank debt ($000s)[1]	**2,929**	2,670	**6,158**	5,756
Interest and amortization on convertible debentures ($000s)	**2,552**	3,094	**5,101**	6,236
Total interest before interest rate hedges($000)	**5,481**	5,764	**11,259**	11,992
Loss on interest rate swaps ($000s)	**131**	385	**260**	642
Total interest after interest rate hedges ($000s)	**5,612**	6,149	**11,519**	12,634
Bank debt outstanding at period end ($000s)	**291,912**	216,321	**291,912**	216,321
Convertible debentures at period end ($000s)[2]	**198,336**	201,105	**198,336**	201,105
$/boe:				
Interest on bank debt	**1.20**	0.99	**1.24**	1.06
Interest on convertible debentures	**1.29**	1.15	**1.27**	1.15
Amortization on convertible debentures	**(0.24)**	-	**(0.24)**	-
Loss on interest rate swaps	**0.05**	0.14	**0.05**	0.12
Total interest after interest rate hedges	**2.30**	2.28	**2.32**	2.33

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

CASH FLOW NETBACK

For the quarter ended June 30, 2011, NAL's cash flow netback was $25.72 per boe, a nine percent increase from $23.67 per boe for the comparable period in 2010. The increase was due to a higher operating netback after hedging, offset by higher G&A expenses, including unit-based incentive compensation and higher interest charges.

For the six months ended June 30, 2011, NAL's cash flow netback was $24.66 per boe, a four percent decrease from $25.71 per boe in 2010. The decrease was due to a lower operating netback after hedging, higher interest charges on bank debt and convertible debentures and higher G&A expenses, including share-based incentive compensation.

Cash Flow Netback ($/boe)

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
Operating netback, after hedging	**30.76**	28.17	**30.07**	30.38
G&A expenses, including share-based incentive compensation	**(2.50)**	(2.18)	**(2.85)**	(2.30)
Interest on bank debt and convertible debentures(1)	**(2.49)**	(2.14)	**(2.51)**	(2.21)
Interest on notes with MFC(2)	**-**	(0.04)	**-**	(0.04)
Realized loss on interest rate derivative contracts	**(0.05)**	(0.14)	**(0.05)**	(0.12)
Cash flow netback	**25.72**	23.67	**24.66**	25.71

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

GAIN ON DISPOSITION OF OIL AND GAS PROPERTIES

During the second quarter of 2011, NAL disposed of certain non-core properties resulting in a gain of $2.8 million (2010 - nil). The gain on dispositions for the six months ended June 30, 2011 was $15.4 million (2010 - $11.2 million). The gain is computed as the difference between sales proceeds and the net book value.

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
Gain on sale of oil and gas properties ($000s)	**2,844**	-	**15,378**	11,193
As a % of revenue	**2.2**	-	**6.1**	4.3
$/boe	**1.17**	-	**3.10**	2.07

DEPLETION, ACCRETION OF ASSET RETIREMENT OBLIGATIONS AND IMPAIRMENT

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 quarter ended June 30, 2011, depletion on property, plant and equipment was $18.32 per boe, two percent lower than the $18.77 per boe for the same period in 2010. For the six months ended June 30, 2011, depletion on property, plant and equipment was $18.36 per boe consistent with $18.29 per boe in the comparable period of 2010.

Accretion on asset retirement obligation was $2.5 million for the second quarter in 2011, a nine percent decrease from $2.8 million at the comparable period of 2010 due to disposition of properties. Similar trends are noted for the six months ended June 30, 2011.

No impairment has been recorded in the second quarter of 2011, or the comparable period in 2010. For the three months ended March 31, 2011, impairment of $5.2 million has been recorded. No impairment was charged in the corresponding period in 2010. Impairment is recognized if the carrying amount of PP&E is greater than their 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 has occurred in natural gas CGUs due to lower gas prices 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.

Depletion, Accretion and Impairment

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
Depletion ($000s)	**44,619**	50,584	**91,031**	98,849
Depletion rate per boe ($)	**18.32**	18.77	**18.36**	18.29
Accretion of asset retirement obligation ($000s)	**2,525**	2,764	**5,069**	5,467
Impairment ($000s)	**-**	-	**5,200**	-

TAXES

In the second quarter of 2011, NAL had a deferred tax expense of $11.4 million compared to a $8.5 million recovery in the corresponding period of the prior year. For the six month period ended June 30, 2011, NAL had a deferred tax expense of $11.1 million compared to $5.8 million recovery in 2010.

As at June 30, 2011, the Corporation’s (including all subsidiaries) estimated tax pools (unaudited) available for deduction from future taxable income approximated $1.5 billion, of which approximately 28 percent represented COGPE, 18 percent represented UCC, with the remaining balance represented by CEE, CDE, share issue costs and non-capital loss carry forwards.

Estimated Tax Pools ($ millions)

	June 30, 2011	December 31, 2010
Canadian exploration expense	91	57
Canadian development expense	394	376
Canadian oil and gas property expense	416	456
Undepreciated capital costs	262	251
Other (including loss carry forwards)	308	279
Total estimated tax pools	1,471	1,419

Based on current strip prices at June 30, 2011, the Corporation is not expected to be taxable in 2011.

MINORITY INTEREST

The Corporation had recorded a minority interest in respect of the 50 percent ownership interest indirectly held by MFC in the Partnership holding the Tiberius and Spear assets (see “Structure of the Business” in this MD&A for more information) for the period ended June 30, 2010. As the Partnership was dissolved December 31, 2010, no minority interest was recorded for the period ended June 30, 2011.

The minority interest presented in the statement of income has two components: the royalty paid to MFC under the NPI, being a cash payment to the royalty holder, and 50 percent of net income remaining in the Partnership, after NPI expense, attributable to MFC. This share of net income attributable to MFC is a non-cash item.

The minority interest in the consolidated statement of income is comprised of:

Minority Interest ($000s)

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
Net profits interest expense	-	216	-	834
Share of net income attributable to MFC	-	309	-	623
	-	525	-	1,457

NET INCOME

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 disposals of property, plant and equipment, deferred income taxes and impairment losses/reversals, should these occur.

Net income for the second quarter of 2011 was $33.3 million compared to $23.4 million for the comparable period in 2010. The improvement of $9.9 million was mainly due to increased revenues net of royalties ($9.2 million), an increased gain on derivative contracts ($15.1 million), decreased depletion ($6.0 million) and a gain on disposition in 2011 ($2.8 million). This was offset by a tax expense compared to a recovery in 2010 ($20.0 million) and a positive fair value adjustment on convertible debentures in 2010 ($3.3 million).

Net income for the six months ended June 30, 2011 of $31.8 million was $41.8 million less than the comparable period of 2010. The decrease in net income in 2011 is attributable to decreased revenues net of royalties ($3.3 million), a decreased gain on derivative contracts ($26.2 million) and a tax expense compared to a recovery in 2010 ($17.0 million), offset by decreased depletion expense ($7.8 million) and a higher gain on disposition ($4.2 million).

Net Income ($000s)

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
Net income	**33,275**	23,443	**31,765**	73,612

CAPITAL RESOURCES AND LIQUIDITY

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

As at June 30, 2011, NAL had 148,406,660 common shares outstanding, compared with 147,248,494 common shares as at December 31, 2010. The increase from December 31, 2010 is attributable to 1,158,166 shares issued under the dividend reinvestment program ("DRIP").

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 distribution payable on April 15, 2009, following suspension of the program in October 2008. Participation in the DRIP has averaged 22 percent during the year.

As at June 30, 2011, the Corporation had net debt of $524.9 million (net of working capital and other liabilities, excluding derivative contracts and deferred taxes) including convertible debentures at face value of $194.7 million. Excluding the convertible debentures, net debt was $330.1 million, compared with $310.3 million at December 31, 2010. The increase in net debt, excluding convertible debentures, of $19.8 million during 2011 is attributable to increased bank debt of $24.9 million, offset by a change in working capital of $5.1 million.

Bank debt outstanding was $291.9 million at June 30, 2011 compared with $267.0 million as at December 31, 2010. Of the $291.9 million outstanding at June 30, 2011 $1.2 million is outstanding under the production facility and $290.7 million is outstanding under the working capital facility.

At the end of the second quarter, the Corporation had a net debt (excluding convertible debentures) to 12 months trailing cash flow ratio of 1.26 times and a total net debt (including convertible debentures) to 12 months trailing cash flow ratio of 2.00 times.

During the second quarter, the Corporation renewed its credit facility at the previously approved amount of $550 million. The credit facility is a fully secured, extendible, revolving facility and will revolve until April 30, 2012 at which time it is extendible for a further 364-day revolving period upon agreement between the Corporation and the bank syndicate. 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. Principal repayments to the bank are not required at this time. Should principal repayments become mandatory, and in the absence of refinancing arrangements, the Corporation would be required to repay the facility in five equal quarterly installments commencing May 1, 2013.

The Corporation has two series of convertible debentures currently outstanding.

On December 3, 2009, the Corporation issued $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.

In addition, 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 $1,050 per debenture on or after September 1, 2010 and on or before August 31, 2011, and at a price of $1,025 per debenture on or after September 1, 2011 and on or 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.

Subsequent to December 30, 2010, the convertible debentures are 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 with no equity portion. 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 $0.6 million (2010 - nil) of amortization of the debt premium in the second quarter of 2011 and $1.2 million (2010 - nil) year-to-date.

As at August 8, 2011, the Corporation has 148,643,233 common shares and $194.7 million in convertible debentures outstanding.

Capitalization

	June 30, 2011	December 31, 2010	June 30, 2010
Shareholders' equity ($000s)	**879,506**	895,750	974,836
Bank debt ($000s)	**291,912**	266,965	216,321
Working capital deficit (surplus)[(1)] ($000s)	**38,221**	43,337	52,543
Net debt excluding convertible debentures	**330,133**	310,302	268,864
Convertible debentures ($000s)[(2)]	**194,744**	194,744	194,744
Net debt	**524,877**	505,046	463,608
Net debt excluding convertible debentures to trailing 12-month cash flow[(3)]	**1.26**	1.11	1.02
Total net debt to trailing 12-month cash flow[(3)]	**2.00**	1.80	1.76
Common shares outstanding (000s)	**148,407**	147,248	145,968

(1) Working capital and other liabilities, excluding derivative contracts, deferred taxes 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.

As stated in the non-IRFS 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 three months ended June 30, 2011, funds from operations amounted to $66.5 million compared with $67.8 million for the comparable period in 2010. The two percent decrease is primarily due to a decrease in the realized gains/losses or derivative contracts ($9.6 million), from a gain of $5.5 million in 2010 to a loss of $4.1 million in 2011, and increased operating costs ($1.0 million), partially offset by increased revenues net of royalties ($9.2 million).

For the six months ended June 30, 2011, funds from operations decreased by $17.8 million to $129.5 million from $147.3 million in 2010. The 12 percent decrease is attributable to a decrease in realized gains/losses on derivative contracts ($12.0 million), from a gain of $6.9 million in 2010 to a loss of $5.1 million in 2011, decreased revenues, net of royalties ($3.3 million), increased G&A ($1.8 million) and increased abandonment costs ($2.2 million), partially offset by higher other income ($0.4 million), lower transportation costs ($0.4 million) and non-controlling interest NPI expense ($0.8 million).

Funds from Operations

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
Cash flow from operating activities ($000s)	**60,897**	50,066	**121,880**	117,619
Cash flow from operating activities per share	**0.41**	0.35	**0.82**	0.83
Payout ratio based on cash flow from operating activities	**51%**	79%	**51%**	65%
Funds from operations ($000s)	**66,453**	67,847	**129,450**	147,328
Funds from operations per share	**0.45**	0.47	**0.88**	1.04
Payout ratio based on funds from operations	**47%**	58%	**48%**	52%

Assuming the Corporation's commodity price and guidance assumptions are attained, dividend levels represent a payout ratio in the range of 40 – 50 percent of funds from operations.

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 $291.9 million is drawn at June 30, 2011, leaving available capacity of $258.1 million.

For 2011, the Corporation expects to continue to benefit from an active hedging program to help protect forecast funds from operations. Currently, the Corporation has in place oil hedges for approximately 51 percent of net forecast (after royalty) production for 2011. Crude volumes are hedged at an average price of US$88.10 per bbl on fixed price contracts. On collared contracts, crude volumes are hedged at an average ceiling price of US$100.50 per bbl and at an average floor price of US$90 per bbl. For natural gas, remaining 2011 hedges total approximately 31 percent of net budgeted production volumes hedged at an average floor price of approximately $4.00 per GJ ($4.21 per Mcf).

NAL's capital program is designed to be scalable and flexible in response to commodity prices and market conditions. For 2011, the Corporation plans for a $200 – 230 million capital program. 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 forecast capital expenditures and/or dividend levels.

ASSET RETIREMENT OBLIGATION

At June 30, 2011, the Corporation reported an asset retirement obligation ("ARO") balance of $126.7 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 $5.1 million from accretion expense, and was reduced by $22.9 million for property dispositions, $0.3 million for liabilities incurred and revisions to estimates and $4.2 million for actual abandonment and reclamation expenditures incurred during the six months ended June 30, 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 June 30, 2011, the Corporation had spent $14.9 million under this agreement.

Farm-in Agreement:

Effective August 10, 2009, the Corporation and MFC entered into a farm-in agreement with a senior industry partner. The arrangement consists of a two year initial commitment, with a minimum capital commitment of $40 million in the first year and $57 million in the second year, with an option for a third year, at NAL's election, for an additional $50 million commitment. 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 1,400 gross sections of undeveloped oil and gas rights 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. As at June 30, 2011, the Corporation had spent $42.0 million under this 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)	**2011**	2012	2013	2014	2015
Office lease[1]	**1,073**	2,146	2,132	2,092	2,092
Office lease – Clipper and Breaker[2]	**1,105**	2,211	364	-	-
Transportation agreement	**1,962**	2,367	2,265	1,082	150
Processing agreement[3]	**302**	197	184	-	-
Convertible debentures[4]	**-**	79,744	-	115,000	-
Bank debt	**-**	-	175,147	116,765	-
Total	**4,442**	86,665	180,092	234,939	2,242

(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 will reimburse the Corporation for 50 percent of the Clipper obligation under the base price adjustment clause.
(3) Represents gas processing agreements with take or pay components.
(4) Principal amount.

QUARTERLY INFORMATION

	2011		2010				2009	
($000s, except per share and production amounts)	Q2	Q1	Q4	Q3	Q2	Q1	Q4[4]	Q3[4]
Revenue, net of royalties[1]	131,104	82,391	85,685	101,258	106,332	136,209	88,165	85,988
Per share	0.88	0.56	0.58	0.69	0.74	0.99	0.75	0.77
Cash flow	60,897	60,983	69,411	87,586	50,066	67,553	53,060	52,999
Per share	0.41	0.41	0.47	0.60	0.35	0.49	0.45	0.47
Funds from operations[2]	66,453	62,997	67,646	65,697	67,847	79,481	62,953	53,766
Per share	0.45	0.43	0.46	0.45	0.47	0.58	0.53	0.48
Net income (loss)	33,275	(1,510)	(19,936)	6,806	22,918	49,237	5,634	8,249
Per share								
basic	0.22	(0.01)	(0.14)	0.05	0.16	0.36	0.05	0.07
diluted	0.22	(0.01)	(0.14)	0.05	0.15	0.34	0.05	0.07
Average oil equivalent production (boe/d – 6:1)	26,758	28,024	28,596	29,473	29,609	30,120	25,748[3]	23,418

(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
(3) Includes Breaker volumes effective December 11, 2009.
(4) As computed under previous CGAAP.

DISCLOSURE CONTROLS AND PROCEDURES (“DC&P”)
The Chief Executive Officer and the Chief Financial Officer (“certifying officers”) have designed DC&P, or caused them to be designed under their supervision, to provide reasonable assurance that all material information required to be disclosed by NAL in its interim filings is processed, summarized and reported within the time periods specified in applicable securities legislation.

INTERNAL CONTROL OVER FINANCIAL REPORTING (“ICFR”)
NAL’s certifying officers are responsible for establishing and maintaining ICFR, as such term is defined in National Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*. The control framework NAL's officers used to design NAL's ICFR is the *Internal Control - Integrated Framework* (the “COSO Framework”) published by The Committee of Sponsoring Organizations of the Treadway Commission (“COSO”).

The certifying officers 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.

There has not been any change in NAL’s ICFR during the interim period ended June 30, 2011 that has materially affected, or is reasonably likely to materially affect, NAL's ICFR.

ACCOUNTING POLICIES
The Corporation has prepared its June 30, 2011 Interim Consolidated Financial Statements in accordance with IFRS1, *First-time Adoption of International Financial Reporting Standards*, and with IAS 34, *Interim Financial Reporting*, as 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 Interim Consolidated Financial Statements. In addition, Note 14 to the Interim Consolidated Financial Statements presents reconciliations between the Corporation's 2010 previous CGAAP results and the 2010 IFRS results. The reconciliations include the Consolidated Balance Sheet as at June 30, 2010, the Consolidated Statement of Earnings, Comprehensive Income, and Changes in Shareholders Equity for the three and six months ended June 30, 2010 and the Consolidated Cash Flows for the six months ended June 30, 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 has been determined.

A) **Property, plant and equipment (PP&E) and Exploration and 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 requires 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 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. At January 1, 2010 these assets were $88.1 million, representing their carrying value under previous CGAAP. These assets comprise possible reserves assigned as a result of business acquisitions and undeveloped land associated with exploratory areas. As at June 30, 2010 and December 31, 2010, NAL's E&E assets were $112.7 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, 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 are expensed under IFRS that were originally capitalized under previous CGAAP. For the three and six months ended June 30, 2010, $2.4 million, and $4.2 million were expensed, respectively.

Additionally for the year ended December 31, 2010, lease rentals of $7.7 million were expensed under previous CGAAP, while under IFRS the Corporation has elected to capitalize these amounts. For the three and six months ended June 30, 2010, $1.8 million and $3.6 million were capitalized.

C) **Depreciation and 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. For the three and six months ended June 30, 2010 depletion decreased by $13.3 million and $27.1 million, respectively. There was no impact to January 1, 2010 due to the IFRS1 election discussed above.

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 cash-generating unit ("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, NAL recognized a $32.8 million impairment loss relating to gas focused CGUs in Alberta, northeast British Columbia and Ontario. The impairment recognized was based on the difference between the December 31, 2010 net book value of the CGUs and the recoverable amount. The recoverable amount was determined using fair value less costs to sell based on discounted future cash flows of proved plus probable reserves. Under previous CGAAP, these assets were included in the one cost centre, which was not impaired at December 31, 2010. There was no impairment for the six months ended June 30, 2010.

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, NAL recognized $17.6 million as gains on disposition, compared to no gain recognized under previous CGAAP. Similarly, a gain of $11.2 million was recognized for the three months ended March 31, 2010 under IFRS with no gain recorded under previous CGAAP. No gain or loss was recognized for the three months ended June 30, 2010.

F) **Asset Retirement Obligations and 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, ARO 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 NAL elected the oil and gas assets IFRS1 exemption, the ARO exemption available to full cost entities was also elected. This exemption allows for the remeasurement of ARO on IFRS transition with the offset to retained earnings. The carrying value under previous CGAAP at December 31, 2009 of $127.9 million was revalued under IFRS, resulting in an opening IFRS balance at January 1, 2010 of $134.4 million. On transition to IFRS, NAL recorded the difference of $6.5 million as an increase to the liability with an offset to retained earnings. At December 31, 2010, the liability was increased by $4.3 million. The adjustments primarily reflect the remeasurement of the obligation using an eight percent discount rate at both dates.

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 and Accounts Payable**

The Corporation elected to apply the exemption to restate the liability for share-based compensation on transition with the offset to retained earnings. This is applicable to awards that have not vested prior to January 1, 2010, which applies to all of the outstanding grants at NAL.

The adjustment to the liability for share-based compensation is to reflect 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 full year 2010, the expense for share-based compensation increased by $1.5 million due to the expensing of amounts capitalized under previous CGAAP, offset slightly 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. Any accretion expense previously recognized through income under previous CGAAP was eliminated. On conversion to a corporation on December 31, 2010, the convertible debentures carrying value, which represented the fair value 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, for the period the convertible debentures were held at fair value through profit and loss any issue costs associated with the convertible debentures were expensed, of which $0.3 million was 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 (Note 4) 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 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 to 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.

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 sets 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 and equipment and Exploration and 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 cash-generating units ("CGU") 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 cash-generating unit 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 cash-generating unit 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 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 intent to develop 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 at 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 cash-generating units to which the goodwill is allocated. If the carrying amount for the cash-generating unit 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 cash-generating unit'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 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 approximation of the amounts that would be received or paid to settle these instruments at the end of the period, with reference to forward 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 the 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.

Dated: August 9, 2011

Consolidated Balance Sheets
(In thousands of Canadian dollars)
(unaudited)

	June 30, 2011	December 31, 2010
Assets		
Current assets		
Cash	$-	$821
Accounts receivable	47,090	57,839
Prepaids and other receivables	16,789	14,532
Derivative contracts (Note 12)	560	422
	64,439	73,614
Derivative contracts (Note 12)	314	-
Deferred tax asset	36,520	49,380
Goodwill	14,722	14,722
Property, plant and equipment (Note 5)	1,455,693	1,472,660
Exploration and evaluation assets (Note 5)	65,826	63,127
	$1,637,514	$1,673,503
Liabilities and Shareholders' Equity		
Current liabilities		
Bank indebtedness	$408	$-
Accounts payable and accrued liabilities	88,614	100,265
Dividends payable to shareholders	10,388	13,252
Derivative contracts (Note 12)	5,119	7,819
	104,529	121,336
Bank debt (Note 6)	291,912	266,965
Convertible debentures (Note 7)	198,336	199,520
Other liabilities (Note 8)	2,690	3,012
Derivative contracts (Note 12)	117	2,503
Asset retirement obligations (Note 10)	126,741	149,015
Deferred tax liability	33,683	35,402
	758,008	777,753
Shareholders' equity		
Share capital	904,889	890,777
Equity component of convertible debentures (Note 7)	4,973	4,973
Deficit	(30,356)	-
	879,506	895,750
	$1,637,514	$1,673,503
Commitments (Note 13)		
Common shares outstanding (000's)	148,407	147,248

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Income and Comprehensive Income
(In thousands of Canadian dollars, except per share amounts)
(unaudited)

	Three months ended June 30, 2011	Three months ended June 30, 2010 (Note 14)	Six months ended June 30, 2011	Six months ended June 30, 2010 (Note 14)
Revenue				
Oil, natural gas and liquid sales	$130,738	$123,116	$253,913	$261,636
Crown royalties	(15,691)	(17,378)	(29,992)	(33,936)
Freehold and other royalties	(6,177)	(6,066)	(11,665)	(12,107)
	108,870	99,672	212,256	215,593
Gain (loss) on derivative contracts (Note 12):				
Realized gain (loss)	(4,080)	5,485	(5,078)	6,933
Unrealized gain	25,816	1,171	5,538	19,680
	21,736	6,656	460	26,613
Other income	498	4	779	335
	131,104	106,332	213,495	242,541
Expenses				
Operating	29,118	28,156	56,375	56,223
Transportation	1,396	1,605	2,819	3,242
General and administrative	7,203	6,929	14,634	12,811
Share-based incentive compensation	(1,112)	(1,064)	(476)	(378)
Interest on bank debt	2,929	2,670	6,158	5,756
Interest and amortization on convertible debentures	2,552	3,094	5,101	6,236
Fair value adjustment on convertible debentures	-	(3,257)	-	(2,625)
Convertible debenture issue costs	-	-	-	345
Gain on disposition of property, plant and equipment	(2,844)	-	(15,378)	(11,193)
Impairment of oil and gas assets (Note 5)	-	-	5,200	-
Depletion and depreciation	44,619	50,584	91,031	98,849
Accretion on asset retirement obligations	2,525	2,764	5,069	5,467
	86,386	91,481	170,533	174,733
Income before taxes	44,718	14,851	42,962	67,808
Current tax expense	-	61	(56)	2
Deferred tax reduction (expense)	(11,443)	8,531	(11,141)	5,802
Total tax reduction (expense)	(11,443)	8,592	(11,197)	5,804
Net income and comprehensive income	$33,275	$23,443	$31,765	$73,612
Attributable to:				
Equity holders of the Corporation	$33,275	$22,918	$31,765	$72,155
Minority interest	-	525	-	1,457
Net income and comprehensive income	$33,275	$23,443	$31,765	$73,612
Net income per share (Note 11)				
Basic	$0.22	$0.16	$0.21	$0.51
Diluted	$0.22	$0.15	$0.21	$0.48
Weighted average shares outstanding (000s)	148,093	144,617	147,815	141,157

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flows
(In thousands of Canadian dollars)
(unaudited)

	Six months ended June 30 2011	2010 (Note 14)
Operating Activities		
Net income	$31,765	$72,155
Items not involving cash:		
Depletion and depreciation	91,031	98,849
Accretion on asset retirement obligations	5,069	5,467
Unrealized gain on derivative contracts	(5,538)	(19,680)
Gain on disposition of property, plant and equipment	(15,378)	(11,193)
Fair value adjustment on convertible debentures	-	(2,625)
Deferred tax expense (reduction)	11,141	(5,802)
Minority interest	-	623
Lease amortization	(868)	(799)
Impairment of oil and gas assets	5,200	-
Interest expense and amortization on convertible debentures	11,259	11,992
Debenture issue costs	-	345
Abandonment and reclamation	(4,231)	(2,004)
Change in non-cash working capital	(7,570)	(29,709)
	121,880	117,619
Financing Activities		
Dividends paid to shareholders	(50,873)	(64,430)
Increase (decrease) in bank debt	24,947	(14,392)
Issue of shares, net of issue costs	-	94,576
Convertible debenture issue costs	-	(345)
Interest expense	(12,811)	(15,429)
Change in non-cash working capital	241	2,216
	(38,496)	2,196
Investing Activities		
Property, plant and equipment expenditures	(116,572)	(138,373)
Exploration and evaluation expenditures	(2,798)	(24,610)
Proceeds from dispositions	29,673	14,779
Disposition of Spearpoint	-	(309)
Change in non-cash working capital	5,084	27,845
	(84,613)	(120,668)
Decrease in cash	(1,229)	(853)
Cash, beginning of period	821	1,604
Cash (bank indebtedness), end of period	$(408)	$751

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Changes in Equity
(In thousands of Canadian dollars)
(unaudited)

	Number of Shares	Share Capital	Equity component of convertible debentures	Deficit	Minority interest	Total Share-holders' Equity
Balance at January 1, 2010	137,471	$1,485,421	$-	$(618,244)	$3,370	$870,547
Net income before minority interest	-	-	-	73,612	-	73,612
Net income attributable to minority interest	-	-	-	(1,457)	623	(834)
Equity offering	7,550	100,038	-	-	-	100,038
Less issue costs (net of tax of $1,158)	-	(3,331)	-	-	-	(3,331)
Issued from Distribution Reinvestment Plan	947	11,350	-	-	-	11,350
Dividends declared		-	-	(76,546)	-	(76,546)
Balance at June 30, 2010	145,968	$1,593,478	-	$(622,635)	$3,993	$974,836
Net loss before minority interest	-	-	-	(13,130)	-	(13,130)
Issue costs (net of tax of $588)	-	(1,693)	-	-	-	(1,693)
Issued from Distribution Reinvestment Plan	1,280	13,988	-	-	-	13,988
Dividends declared	-	-	-	(79,231)	-	(79,231)
Dissolution of partnership	-	-	-	-	(3,993)	(3,993)
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 income	-	-	-	31,765	-	31,765
Issued from Distribution Reinvestment Plan	1,159	14,112	-	-	-	14,112
Dividends declared	-	-	-	(62,121)	-	(62,121)
Balance at June 30, 2011	148,407	$904,889	$4,973	$(30,356)	$-	$879,506

See accompanying notes to the consolidated financial statements.

1) NATURE OF OPERATIONS AND 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 effective December 31, 2010 as part of a Plan of Arrangement 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.

The Corporation, as with the Trust, continues to be managed by NAL Resources Management Limited (the "Manager"). 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 interim consolidated financial statements were authorized for issue by the Board of Directors on August 9, 2011.

2) SUMMARY OF ACCOUNTING POLICIES

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

These IFRS consolidated interim financial statements as at June 30, 2011, including 2010 comparative periods, comprise a period of the Corporation's first annual audited financial statements to be issued under IFRS at December 31, 2011. As a result, these interim consolidated financial statements have been prepared in accordance with IFRS1 "*First-time Adoption of*

International Financial Reporting Standards" ("IFRS1") and IAS34 *"Interim Financial Reporting"*. The consolidated interim financial statements do not include all of the information required for full annual financial statements.

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 14. That note includes reconciliations as at and for the three and six months ended June 30, 2010 as required under IFRS. Included in Note 14 to the consolidated interim financial statements as at and for the three months ended June 30, 2011, are reconciliations as at January 1, 2010 and as at and for the year ended December 31, 2010.

(b) For a summary of significant accounting policies under IFRS refer to Note 2 of the consolidated interim financial statements for the three months ended March 31, 2011.

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 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.

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 sets out disclosure requirements for fair value measurements. NAL is currently assessing the impact of this standard on its consolidated financial statements.

4) RELATED PARTY TRANSACTIONS

NAL has several subsidiaries within its corporate structure. Two active entities hold the working interests in the oil and gas properties being NAL Petroleum Ltd. ("ACE") and Addison Energy Limited Partnership ("Addison"). The partners of Addison are ACE and NAL.

In addition, there are several inactive subsidiaries, namely, NAL Canada West Inc., NAL Properties Inc., Startech Energy and NAL Energy Inc.

The Corporation is managed by the Manager. The Manager is a wholly-owned subsidiary of MFC and also manages on their behalf NAL Resources, another wholly-owned subsidiary of MFC.

The Manager continues to provide 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 $6.5 million (2010 - $6.3 million) for the reimbursement of G&A expenses during the second quarter and $12.8 million year-to-date (2010 - $11.5 million). 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 the first six months of 2011, representing notional shares that vested on November 30, 2010 (2010 - $6.9 million).

In conjunction with the Reorganization, 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. As a result of the Partnership dissolution on December 31, 2010, the Corporation only reflects its proportionate share of the Partnership's assets, liabilities, revenues and expenses in the June 30, 2011 financial statements. Accordingly at June 30, 2011 and December 31, 2010, no minority interest was reflected on the balance sheet. For the six months ended June 30, 2010, the minority interest in the statement of income is comprised of:

	Six months ended June 30	
	2011	2010
Net profits interest expense	$-	$834
Share of net income attributable to MFC	-	623
	$-	$1,457

As a part of the original structuring of the Partnership in 2008, both the Corporation and MFC entered into net profit interest royalty agreements with the Partnership. These agreements entitled each royalty holder to a 49.5 percent interest in the cash flow from the Partnership's reserves.

The following amounts are due to and from related parties as at June 30, 2011 and December 31, 2010 and have been included in prepaids and other receivables and accounts payable and accrued liabilities on the balance sheet:

	June 30, 2011	December 31, 2010
Due from (to) NAL Resources Limited	**$10,457**	$8,149
Due to NAL Resources Management Limited	**(1,833)**	(8,705)
Due (to) from Manulife Financial Corporation	**-**	(265)
	$8,624	$(821)

5) PROPERTY, PLANT AND EQUIPMENT AND EXPLORATION AND EVALUATION ASSETS

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

	Six months ended June 30	
	2011	2010
Gross cost		
Opening balance, beginning of period	**$1,673,359**	$1,415,830
Additions	**116,572**	140,437
Asset retirement cost additions and revisions	**(223)**	4,033
Disposals	**(41,400)**	(3,789)
Transfers from evaluation and exploration assets	**99**	62
	1,748,407	1,556,573
Accumulated depletion and impairment losses		
Opening balance, beginning of period	**$200,699**	$-
Disposals	**(4,216)**	-
Depletion for the period	**91,031**	98,849
Impairment losses	**5,200**	-
	292,714	98,849
Net book value		
Opening balance, beginning of period	**$1,472,660**	$1,415,830
Additions	**116,349**	144,470
Depletion for the period	**(91,031)**	(98,849)
Disposals	**(37,184)**	(3,789)
Transfers from evaluation and exploration assets	**99**	62
Impairment losses	**(5,200)**	-
	$1,455,693	$1,457,724

The calculation of year-to-date depletion included future development costs for proved plus probable reserves of $419.0 million (2010 - $405.6 million). Undeveloped land amounting to $47.0 million (2010 - $51.9 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.

(ii) Exploration and evaluation assets

	Six months ended June 30	
	2011	2010
Net book value		
Opening balance, beginning of period	**$63,127**	$88,122
Additions	**2,798**	24,610
Transfers to PP&E	**(99)**	(62)
	$65,826	$112,670

(iii) Impairment of oil and gas assets

During the three months ended March 31, 2011, impairment losses of $5.2 million (2010 - $nil) were recorded and reported as impairment of oil and gas assets in the statement of income. The impairment related to Development and Production ("D&P") assets was calculated using the fair value less costs to sell approach, which was based on the engineering report, using future prices as at March 31, 2011 and future costs, discounted at a rate commensurate with market transactions.

These impairment losses were recognized in three natural gas CGUs, which have no goodwill assigned, and were the result of a further reduction in forward natural gas prices, from December 31, 2010, as estimated by the Corporation's independent engineers. There was no further impairment recognized during the three months ended June 30, 2011.

6) BANK DEBT

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 in all existing and future acquired properties and assets of the Corporation and its subsidiary and affiliated entities. The facility will revolve until April 30, 2012 at which time it may be extended for a further 364-day revolving period upon agreement between the Corporation and the bank syndicate. If the credit facility is not extended in April 2012, the amounts outstanding at that time will be converted to a two-year term loan. The term loan will be payable in five equal quarterly installments commencing May 1, 2013.

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 June 30, 2011 and December 31, 2010 all amounts outstanding were in Canadian dollars.

On June 30, 2011 the effective interest rate on amounts outstanding under the credit facility was 4.7 percent (2010 – 5.3 percent). The Corporation's interest charge includes this fixed interest rate component, plus a standby fee, a stamping fee and the fee for renewal.

7) CONVERTIBLE DEBENTURES

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

	Six months ended June 30, 2011			Year ended December 31, 2010		
	6.25%	6.75%	Total	6.25%	6.75%	Total
Principal, beginning of period	115,000	79,744	194,744	115,000	79,744	194,744
Issued during period	-	-	-	-	-	-
Principal, end of period	115,000	79,744	194,744	115,000	79,744	194,744
Debt component, beginning of period	116,506	83,014	199,520	119,600	84,130	203,730
Premium amortization	(189)	(995)	(1,184)	-	-	-
Fair value adjustment to Dec 30, 2010	-	-	-	1,161	(398)	763
Reclassification to equity	-	-	-	(4,255)	(718)	(4,973)
Debt component, end of period	116,317	82,019	198,336	116,506	83,014	199,520
Equity component, beginning of period	4,255	718	4,973	-	-	-
Reclassification from debt	-	-	-	4,255	718	4,973
Equity component, end of period	4,255	718	4,973	4,255	718	4,973

8) OTHER LIABILITIES

	June 30, 2011	December 31, 2010
Share-based incentive compensation (Note 9)	**$1,563**	$1,009
Excess office lease obligation (1)	**$1,127**	$2,003
	$2,690	$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 will reimburse the Corporation for 50 percent of the Alberta Clipper obligation of $0.7 million under a base price adjustment clause.

9) SHARE-BASED INCENTIVE COMPENSATION PLAN

The Manager has a long-term incentive 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 such that instead of them representing one notional trust unit they represent one notional common share on the same terms and continue to be governed by the same terms under the Plan.

The Corporation recorded a share-based compensation recovery of $1.1 million in the three months ended June 30, 2011 (2010 - $1.1 million recovery). On a year to date basis, the total share-based compensation recovery was $0.5 million (2010 – $0.4 million recovery). The compensation expense was based on the June 30, 2011 share price of $11.04 (June 30, 2010 - $10.60), 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 vest, 15 percent for a two year vest and 20 percent for a three year vest.

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:

	Six months ended June 30, 2011	Year ended December 31, 2010
Balance, beginning of period	**$13,209**	$15,759
Increase (decrease) in liability	**(476)**	4,545
Cash payout, relating to shares vested[(1)]	**(7,417)**	(7,095)
Balance, end of period	**$5,316**	$13,209
Current portion of liability[(2)]	**$3,753**	$12,200
Long-term liability[(3)]	**$1,563**	$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 incentive plan activity for the six months ended June 30, 2011 and 2010.

	2011		
	Number of Restricted Shares	Number of Performance Shares	Total
Balance, beginning of period	122,482	543,011	665,493
Allocation rate change[1]	(6,412)	(28,425)	(34,837)
Issued	194,404	185,489	379,893
Forfeited	(11,092)	(27,367)	(38,459)
Balance, end of period	299,382	672,708	972,090
Exercisable, end of period	-	-	-

[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 period	189,465	670,030	859,495
Allocation rate change[1]	27,216	61,791	89,007
Issued	30,741	40,550	71,291
Forfeited	(5,966)	(25,902)	(31,868)
Balance, end of period	241,456	746,469	987,925
Exercisable, end of period	-	-	-

[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.

10) ASSET RETIREMENT OBLIGATIONS

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

	Six months ended June 30, 2011	Year ended December 31, 2010
Balance, beginning of period	**$149,015**	$134,358
Accretion expense	**5,069**	11,006
Revisions to estimates	**(910)**	-
Liabilities incurred	**687**	4,515
Liabilities acquired	**-**	6,797
Liabilities disposed	**(22,889)**	(1,044)
Liabilities settled	**(4,231)**	(6,617)
Balance, end of period	**$126,741**	$149,015

NAL'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.

11) 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 shares potentially issuable on the conversion of the convertible debentures.

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

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
Weighted average shares outstanding	**148,093**	144,617	**147,815**	141,157
On conversion of convertible debentures	**12,666**	12,666	**-**	12,666
Weighted average diluted shares outstanding	**160,759**	157,283	**147,815**	153,823

The following table summarizes net income:

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
Net income attributable to equity holders	**$33,275**	$22,918	**$31,765**	$72,155
Interest and amortization, net of tax	**1,719**	1,887	**-**	3,804
Fair value adjustment, net of tax	**-**	(1,987)	**-**	(1,601)
Debenture issue costs, net of tax	**-**	-	**-**	210
Diluted net income	**$34,994**	$22,818	**$31,765**	$74,568

For the six months ended June 30, 2011, 12,665,697 common shares and interest were excluded from the diluted earnings per share calculation, as they were anti-dilutive.

As at June 30, 2011, the total convertible debentures outstanding were immediately convertible to 12,665,697 shares (June 30, 2010 – 12,665,697).

12) 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 which 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 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. NAL Resources, and ultimately the Corporation, has not historically experienced any collection issues with their oil and gas marketers. The Manager does not obtain collateral from oil and natural gas marketers.

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 and monitors all investments, 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 more regular reviews of purchasers to ensure credit-worthiness given the 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 June 30, 2011 and June 30, 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 6.

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, foreign exchange and interest rate contracts. The following table outlines cash flows associated with the maturities of the Corporation's financial liabilities.

The following are the contractual maturities of financial liabilities as at June 30, 2011.

Non-Derivative Financial Liability	<1 Year	1 – 2 Years	2 – 5 Years
Bank indebtedness	$408	$-	$-
Accounts payable and accrued liabilities	88,614	-	-
Dividends payable to shareholders	10,388	-	-
Bank debt, principal	-	58,382	233,530
Convertible debentures, principal	-	79,744	115,000
Total	$99,410	$138,126	$348,530

Derivative Financial Liability	<1 Year	1 – 2 Years	2 – 5 Years
Derivative contracts	$5,119	$ 117	$ -

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 or 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 (CAD/USD)	Notional (US) per month	Term	Counterparty Floating Rate
1.05	$2.0 MM	Jul 1, 2011 to Dec 31, 2011	BofC Monthly Average Noon Rate
1.0608	$0.5 MM	Jul 1, 2011 to Dec 31, 2011	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 (CAD/USD)	Notional (US) per month	Term	Counterparty Floating Rate	Monthly Premium Received (CAD)
$0.93 - $1.01	$3.0 MM	Jul 1, 2011 to Dec 31, 2011	BofC Monthly Average Noon Rate	$60K
$0.93 - $1.01	$2.0 MM	Jan 1, 2012 to Jun 30, 2012	BofC Monthly Average Noon Rate	$40K

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

Option Fixing Range (CAD/USD)	Notional (US) per month	Term	Counterparty Floating Rate
$0.94 - $1.06	$0.5 MM	Jul 1, 2011 to Dec 31, 2011	BofC Monthly Average Noon Rate
$0.95 - $1.07	$0.5 MM	Jul 1, 2011 to Dec 31, 2011	BofC Monthly Average Noon Rate
$0.94 - $1.08	$0.5 MM	Jul 1, 2011 to Dec 31, 2011	BofC Monthly Average Noon Rate
$0.95 - $1.04	$0.5 MM	Jul 1, 2011 to Dec 31, 2011	BofC Monthly Average Noon Rate
$0.95 - $1.0125	$0.5 MM	Jul 1, 2011 to Jun 30, 2012	BofC Monthly Average Noon Rate
$0.95 - $1.0138	$1.0 MM	Jul 1, 2011 to Jun 30, 2012	BofC Monthly Average Noon Rate

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

Option Fixing Range (CAD/USD)	Notional (US) per month	Term	Counterparty Floating Rate
$1.05 - $1.15	$1.0 MM	Jul 1, 2011 to Dec 31, 2011	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 USD 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 USD 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 USD.

Fade-in Level	Strike Price	Participation Level	Notional	Term	Counterparty Floating Rate
$0.92	$0.985	1.03	$2.0 mm	Jul 1, 2012-Dec 31, 2012	BofC Monthly Average Noon Rate
$0.91	$1.0075	1.05	$1.5 mm	Jan 1, 2012-Dec 31, 2012	BofC Monthly Average Noon Rate

NAL is fixed to sell USD 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 USD.

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 June 30, 2011, if exchange rates had strengthened by $0.01, with all other variables held constant, net income for the period would have been $1.0 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 the fair value or 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 forecast, net of royalty, production volumes for a period of up to two years.

NAL has the following commodity risk management contracts outstanding:

CRUDE OIL	Q3-11	Q4-11	Q1-12	Q2-12	Q3-12	Q4-12
US$ Collar Contracts						
$US WTI Collar Volume (bbl/d)	200	200	900	900	700	700
Bought Puts – Average Strike Price ($US/bbl)	90.00	90.00	101.11	101.11	101.43	101.43
Sold Calls – Average Strike Price ($US/bbl)	100.50	100.50	117.07	117.07	117.66	117.66
US$ Swap Contracts						
$US WTI Swap Volume (bbl/d)	5,700	5,700	700	700	700	700
Average WTI Swap Price ($US/bbl)	88.10	88.10	107.76	107.76	107.76	107.76
Total Oil Volume (bbl/d)	5,900	5,900	1,600	1,600	1,400	1,400

Two 500 bbl/d, calendar 2011, swap contracts with an average price of $95.00 contain extendable call options. The extendible call option provides the counterparty with the option to extend the contract into calendar 2012 under the same price and volumetric terms. The counterparty can exercise this option any time before December 31, 2011.

NATURAL GAS	Q3-11	Q4-11	Q1-12	Q2-12	Q3-12	Q4-12
Swap Contracts						
AECO Swap Volume (GJ/d)	27,000	27,000	24,000	5,000	5,000	3,674
AECO Average Price ($Cdn/GJ)	3.99	3.99	3.98	4.16	4.16	4.17
Total Natural Gas Volume (GJ/d)	27,000	27,000	24,000	5,000	5,000	3,674

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 unrealized gain (loss). As at June 30, 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 period would have been $2.1 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 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 $139 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	Remaining Term	Amount (Cdn$MM)[1]	Corporation Fixed Rate	Counterparty Floating Rate
Swaps-floating to fixed	Jul 2011 – Dec 2011	$39.0	1.5864%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Jul 2011 – Jan 2013	$22.0	1.3850%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Jul 2011 – Jan 2014	$22.0	1.5100%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Jul 2011 – Mar 2013	$14.0	1.8750%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Jul 2011 – Mar 2014	$14.0	1.9850%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Jul 2011 - Mar 2013	$14.0	1.8500%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Jul 2011 – 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 unrealized gain (loss). As at June 30, 2011, if interest rates had been one percent lower, with all other variables held constant, net income for the year would have been $2.6 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 receivable, 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/bank indebtedness 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 $199,520. The fair value of the convertible debentures at June 30, 2011 was $201,537.

Other liabilities include share-based compensation liabilities as well as excess office lease obligations.

Share-based compensation liabilities are recorded at fair value and are based upon the outstanding shares, valued at the Corporation's share price at the reporting date, performance factors and the number of shares vesting on maturity and estimated forfeitures.

The excess office lease obligation represents the present value of the long-term portion of office lease obligations, in excess of sub-leases, assumed on previous business acquisitions.

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$95.42 per barrel to US$100.86 per barrel for oil and $3.58 per GJ to $4.32 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 0.90 percent to 1.804 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 0.9642 to 0.9779) 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 is as follows:

	June 30, 2011	December 31, 2010
Fair value of commodity contracts	**$(7,060)**	$(13,717)
Fair value of interest rate swaps	**148**	706
Fair value of foreign exchange rate swaps	**2,550**	3,111
	$(4,362)	$(9,900)

The gain/(loss) on derivative contracts is as follows:

Gain / (Loss) on Derivative Contracts

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
Unrealized gain (loss):				
Crude oil contracts	**27,648**	15,939	**6,330**	17,485
Natural gas contracts	**271**	(7,848)	**327**	7,173
Interest rate swaps	**(864)**	(1,887)	**(558)**	(1,696)
Exchange rate swaps	**(1,239)**	(5,033)	**(561)**	(3,282)
Unrealized gain	**25,816**	1,171	**5,538**	19,680
Realized gain (loss):				
Crude oil contracts	**(7,243)**	(2,712)	**(10,370)**	(4,794)
Natural gas contracts	**1,403**	6,900	**2,319**	9,397
Interest rate swaps	**(131)**	(385)	**(260)**	(642)
Exchange rate swaps	**1,891**	1,682	**3,233**	2,972
Realized gain (loss)	**(4,080)**	5,485	**(5,078)**	6,933
Gain on derivative contracts	**21,736**	6,656	**460**	26,613

These contracts are presented on the balance sheet as short term / long term, assets and liabilities as follows:

	June 30, 2011	December 31, 2010
Current unrealized loss on derivative contracts	**$(5,119)**	$(7,819)
Current unrealized gain on derivative contracts	**560**	422
Current unrealized loss on derivative contracts	**(4,559)**	(7,397)
Long term unrealized gain on derivative contracts	**314**	-
Long term unrealized loss on derivative contracts	**(117)**	(2,503)
Net fair value of derivative contracts	**$(4,362)**	$(9,900)

As at June 30, 2011, the total fair value of derivative contracts was a net liability of $4.4 million (December 31, 2010 - net liability of $9.9 million). The change in the fair value for the three and six months ended June 30, 2011 of $25.8 million and $5.5 million, respectively, have been recognized as unrealized gains in the statement of income (2010 - $1.2 million and $19.7 million unrealized gains, respectively).

The following table reconciles the movement in the fair value of the Corporation's derivative contracts:

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
Unrealized (loss) gain, beginning of period	**$(30,178)**	$16,024	**$(9,900)**	$(2,485)
Unrealized (loss) gain, end of period	**(4,362)**	17,195	**(4,362)**	17,195
Unrealized gain for the period	**25,816**	1,171	**5,538**	19,680
Realized gain (loss) in the period	**(4,080)**	5,485	**(5,078)**	6,933
Gain on derivative contracts	**$21,736**	$6,656	**$460**	$26,613

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 June 30, 2011:

	Assets at fair value as at June 30, 2011			
	Level 1	Level 2	Level 3	Total
Foreign exchange rate contracts	-	$2,550	-	$2,550
Interest rate contracts	-	148	-	148
	-	$2,698	-	$2,698

	Liabilities at fair value as at June 30, 2011			
	Level 1	Level 2	Level 3	Total
Commodity contracts	-	$7,060	-	$7,060

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 and future income tax) 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. Net debt is defined as bank debt, plus convertible debentures at face value, plus working capital (excluding derivative contracts and deferred tax balances and including other liabilities). Net debt is measured with and without convertible debentures. The Corporation's strategy is to maintain a conservative net debt to 12 month trailing funds from operations as compared to other 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 a reforecast 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 June 30, 2011, the Corporation had a total net debt to 12 months trailing funds from operations ratio of 2.00 (June 30, 2010 – 1.76), 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 the second quarter of 2011.

Capitalization

	June 30, 2011	December 31, 2010	June 30, 2010
Shareholders' equity ($000s)	879,506	895,750	974,836
Bank debt ($000s)	291,912	266,965	216,321
Working capital deficit[1] ($000s)	38,221	43,337	52,543
Net debt excluding convertible debentures	330,133	310,302	268,864
Convertible debentures ($000s)[2]	194,744	194,744	194,744
Net debt	524,877	505,046	463,608
Net debt excluding convertible debentures to trailing 12-month cash flow[3]	1.26	1.11	1.02
Total net debt to trailing 12-month cash flow[3]	2.00	1.80	1.76
Common shares outstanding (000s)	148,407	147,248	145,968

(1) Working capital and other liabilities, excludes derivative contracts, deferred tax 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.

13) 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 June 30, 2011, the Corporation has spent $14.9 million under this agreement.

(ii) Farm-in Agreement

Effective August 10, 2009, the Corporation and MFC entered into a farm-in agreement with a senior industry partner. The arrangement consists of a two year initial commitment, with a minimum capital commitment of $40 million in the first year and $57 million in the second year, with an option for a third year, at NAL's election, for an additional commitment of $50 million. 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 1,400 gross sections of undeveloped oil and gas rights 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. As at June 30, 2011, the Corporation has spent $42.0 million under this agreement and met its first year commitment.

(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:

($000s)	2011	2012	2013	2014	2015
Office lease[1]	$1,073	$2,146	$2,132	$2,092	$2,092
Office lease – Clipper and Breaker[2]	1,105	2,211	364	-	-
Transportation agreement	1,962	2,367	2,265	1,082	150
Processing agreements[3]	302	197	184	-	-
Convertible debentures[4]	-	79,744	-	115,000	-
Bank debt	-	-	175,147	116,765	-
Total	$4,442	$86,665	$180,092	$234,939	$2,242

(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 will reimburse the Corporation for 50 percent of the Clipper obligation under the base price adjustment clause.
(3) Represents gas processing agreements with take or pay components.
(4) Principal amount.

14) TRANSITION TO INTERNATIONAL FINANCIAL REPORTING STANDARDS ("IFRS")

As stated in Note 2, these interim consolidated financial statements as at June 30, 2011, including 2010 comparative periods, comprise a period of the Corporation's first annual audited financial statements to be issued under IFRS at December 31, 2011. As a result these interim consolidated financial statements have been prepared in accordance with IFRS1, "First-time adoption of International Financial Reporting Standards" and with IAS 34, "Interim Reporting" as issued by the IASB. Previously the Corporation prepared its consolidated financial statements in accordance with previous Canadian GAAP ("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 June 30, 2010

	June 30, 2010 as stated under CGAAP	Adjustments	Notes	June 30, 2010 as restated under IFRS
Assets				
Current assets				
Cash	$751	$-		$751
Accounts receivable	43,954	-		43,954
Prepaids and other receivables	26,154	-		26,154
Derivative contracts	16,821	-		16,821
	87,680			87,680
Derivative contracts	765	-		765
Goodwill	14,722	-		14,722
Deferred tax asset	-	45,303	J	45,303
Property, plant and equipment	1,531,704	(73,980)	A-F	1,457,724
Exploration and evaluation assets	-	112,670	A	112,670
	$1,634,871	$83,993		$1,718,864
Liabilities and Shareholders' Equity				
Current liabilities				
Accounts payable and accrued liabilities	$103,745	$(100)	G	$103,645
Note payable	7,600	-		7,600
Dividends payable to shareholders	13,137	-		13,137
Derivative contracts	391	-		391
Deferred tax liability	2,584	(2,584)	J	-
	127,457	(2,684)		124,773
Bank debt	216,321	-		216,321
Convertible debentures	179,634	21,471	H	201,105
Other liabilities	7,107	(487)	G	6,620
Asset retirement obligations	134,093	7,559	F	141,652
Deferred tax liability	4,733	48,824	J	53,557
Minority interest	3,193	(3,193)	I	-
	672,538	71,490		744,028
Shareholders' equity				
Share capital	1,589,321	4,157	J	1,593,478
Equity component of convertible debentures	12,628	(12,628)	H	-
Minority interest	-	3,993	I	3,993
Deficit	(639,616)	16,981		(622,635)
	962,333	12,503		974,836
	$1,634,871	$83,993		$1,718,864

Reconciliation of Net Income for the three months ended June 30, 2010

	Three months ended June 30, 2010 as stated under CGAAP	Adjustments	*Notes*	Three months ended June 30, 2010 as restated under IFRS
Revenue				
Oil, natural gas and liquid sales	$123,116	$-		$123,116
Crown royalties	(17,785)	407	*B*	(17,378)
Freehold and other royalties	(6,066)	-		(6,066)
	99,265	407		99,672
Gain on derivative contracts:				
Realized gain	5,485	-		5,485
Unrealized gain	1,171	-		1,171
	6,656	-		6,656
Other income	4	-		4
	105,925	407		106,332
Expenses				
Operating	29,582	(1,426)	*B*	28,156
Transportation	1,605	-		1,605
General and administrative	4,157	2,772	*B*	6,929
Share-based incentive compensation	(729)	(335)	*B*	(1,064)
Interest on bank debt	2,670	-		2,670
Interest and accretion on convertible debentures	4,105	(1,011)	*H*	3,094
Fair value adjustment on convertible debentures	-	(3,257)	*H*	(3,257)
Depletion and depreciation	63,903	(13,319)	*C*	50,584
Accretion on asset retirement obligations	2,695	69	*F*	2,764
	107,988	(16,507)		91,481
Income (loss) before taxes	(2,063)	16,914		14,851
Current tax expense	61	-		61
Deferred tax reduction (expense)	10,415	(1,884)	*J*	8,531
Total tax reduction (expense)	10,476	(1,884)		8,592
Net income and comprehensive income	$8,413	$15,030		$23,443
Attributable to:				
Equity holders of the Corporation	$8,046	$14,872		$22,918
Minority interest	367	158		525
Net income and comprehensive income	$8,413	$15,030		$23,443
Net income per share				
Basic	$0.06	$0.10		$0.16
Diluted	$0.06	$0.09		$0.15

Reconciliation of Net Income for the six months ended June 30, 2010

	Six months ended June 30, 2010 as stated under CGAAP	Adjustments	Notes	Six months ended June 30, 2010 as restated under IFRS
Revenue				
Oil, natural gas and liquid sales	$261,636	$-		$261,636
Crown royalties	(34,890)	954	B	(33,936)
Freehold and other royalties	(12,107)	-		(12,107)
	214,639	954		215,593
Gain on derivative contracts:				
Realized gain	6,933	-		6,933
Unrealized gain	19,680	-		19,680
	26,613	-		26,613
Other income	335	-		335
	241,587	954		242,541
Expenses				
Operating	58,886	(2,663)	B	56,223
Transportation	3,242	-		3,242
General and administrative	8,516	4,295	B	12,811
Share-based incentive compensation	(290)	(88)	B	(378)
Interest on bank debt	5,756	-		5,756
Interest and accretion on convertible debentures	8,238	(2,002)	H	6,236
Fair value adjustment on convertible debentures	-	(2,625)	H	(2,625)
Convertible debenture issue costs	-	345	H	345
Gain on disposition of property, plant and equipment	-	(11,193)	E	(11,193)
Depletion and depreciation	125,939	(27,090)	C	98,849
Accretion on asset retirement obligations	5,326	141	F	5,467
	215,613	(40,880)		174,733
Income before taxes	25,974	41,834		67,808
Current tax expense	2	-		2
Deferred tax reduction (expense)	12,578	(6,776)	J	5,802
Total tax reduction (expense)	12,580	(6,776)		5,804
Net income and comprehensive income	$38,554	$35,058		$73,612
Attributable to:				
Equity holders of the Corporation	$37,395	$34,760		$72,155
Minority interest	1,159	298		1,457
Net income and comprehensive income	$38,554	$35,058		$73,612
Net income per share				
Basic	$0.26	$0.25		$0.51
Diluted	$0.26	$0.22		$0.48

Reconciliation of Cash Flows for the six months ended June 30, 2010

	Six months ended June 30, 2010 as stated under CGAAP	Adjustments	Notes	Six months ended June 30, 2010 as restated under IFRS
Operating Activities				
Net income	$37,395	34,760		$72,155
Items not including cash:				
Depletion and depreciation	125,939	(27,090)	*C*	98,849
Accretion on asset retirement obligations	5,326	141	*F*	5,467
Unrealized gain on derivative contracts	(19,680)	-		(19,680)
Gain on disposition of property, plant and equipment	-	(11,193)	*E*	(11,193)
Fair value adjustment on convertible debentures	-	(2,625)	*H*	(2,625)
Deferred tax reduction	(12,578)	6,776	*J*	(5,802)
Non-controlling interest	325	298	*I*	623
Lease amortization	(799)	-		(799)
Interest expense	-	11,992		11,992
Convertible debenture issue costs	-	345		345
Non-cash accretion expense on convertible debentures	2,002	(2,002)	*H*	-
Abandonment and reclamation	(2,004)	-		(2,004)
Change in non-cash working capital	(28,952)	(757)		(29,709)
	106,974	10,645		117,619
Financing Activities				
Distributions paid to shareholders	(64,430)	-		(64,430)
Decrease in bank debt	(14,392)	-		(14,392)
Issue of shares, net of issue costs	94,576	-		94,576
Convertible debenture issue costs	(345)	-		(345)
Interest expense	-	(15,429)		(15,429)
Change in non-cash working capital	-	2,216		2,216
	15,409	(13,213)		2,196
Investing Activities				
Additions to property, plant and equipment	(118,353)	(20,020)		(138,373)
Additions to exploration and evaluation assets	-	(24,610)		(24,610)
Property acquisitions	(45,157)	45,157		-
Proceeds from dispositions	14,779	-		14,779
Disposition of Spearpoint	(309)	-		(309)
Change in non-cash working capital	25,804	2,041		27,845
	(123,236)	2,568		(120,668)
Decrease in cash	(853)	-		(853)
Cash, beginning of period	1,604	-		1,604
Cash, end of period	$751	$-		$751

A) **Property, plant and equipment (PP&E) and Exploration and 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 requires 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 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 June 30, 2010, NAL’s E&E assets were $112.7 million.

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, 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 six months ended June 30, 2010, $2.3 million and $4.1 million, respectively, of such costs are expensed that were originally capitalized under previous CGAAP.

Additionally for the three and six months ended June 30, 2010, lease rentals of $1.8 million and $3.6 million, respectively, were expensed under previous CGAAP, while under IFRS the Corporation has elected to capitalize these amounts.

C) **Depreciation and 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 six months ended June 30, 2010, depletion decreased by $13.3 million and $27.1 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 cash-generating unit ("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 six months ended June 30, 2010, no impairment was recognized under IFRS or previous CGAAP.

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. No gain or loss was recognized for the three months ended June 30, 2010, $11.2 million was recognized in the three months ended March 31, 2010, compared to no gain recognized under previous CGAAP.

F) **Asset Retirement Obligations and 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 June 30, 2010, the carrying value of the asset retirement obligation was $141.7 million as compared to $134.1 million under previous CGAAP, an adjustment of $7.6 million, primarily reflecting 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 six months ended June 30, 2010, accretion increased by $0.1 million as compared to previous CGAAP.

G) **Other Liabilities and Accounts Payable**

The adjustment to the liability for share-based compensation is to reflect 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 six months ended June 30, 2010, the recovery of share-based compensation increased by $0.3 million and $0.1 million, respectively, due to the expensing of amounts capitalized under previous CGAAP, offset slightly 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 June 30, 2010, the fair value adjustment to the convertible debentures was $21.5 million of which $3.3 million and $2.6

million were recognized in income for the three and six months ended June 30, 2010, respectively. Any accretion expense previously recognized through income under previous CGAAP was eliminated. On conversion to a corporation on December 31, 2010, the convertible debentures carrying value, which represented the fair value 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, for the period the convertible debentures were held at fair value through profit and loss any issue costs associated with the convertible debentures were expensed, of which $0.3 million was expensed in the six months ended June 30, 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 (Note 4) 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 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 to business combinations prior to January 1, 2010.