



Suite 1000, 550 – 6<sup>th</sup> Avenue SW  
Calgary, Alberta T2P 0S2  
Tel: 403.294.3600 Fax: 403.294.3601  
Web Site: [www.nal.ca](http://www.nal.ca) Email: [Investor.Relations@nal.ca](mailto:Investor.Relations@nal.ca)  
TSX: NAE.UN

**FOR IMMEDIATE RELEASE**

## **NAL OIL & GAS TRUST SECOND QUARTER 2010 RESULTS – INCREASED CAPITAL SPENDING POSITIONS PRODUCTION GROWTH IN SECOND HALF OF THE YEAR**

**Media Release No. 20-10**

**August 10, 2010**

CALGARY, ALBERTA – NAL Oil & Gas Trust (“NAL” or the “Trust”) today announced its financial and operational results for the second quarter of 2010. All amounts are in Canadian dollars unless otherwise stated.

“NAL’s performance is on track to deliver on its full year guidance” stated Mr. Andrew Wiswell, President and CEO, on NAL’s second quarter. “Operationally, we are positioned for a strong 2010 production exit rate that is expected to be in excess of 31,000 boe per day. In the second half of the year, the Trust will continue to prove up opportunities through the drill bit on acreage that has been added in our core areas in the Cardium light oil resource play in Alberta and the Mississippian light oil opportunity in southeast Saskatchewan. In addition, operating costs and netbacks are showing strong year-over-year improvement. Financially, the Trust is well capitalized with equity and available bank lines to execute on its business plan, and we continue to actively manage the hedging portfolio to reduce commodity price, interest rate and foreign exchange risks”.

### **2010 MID-YEAR HIGHLIGHTS**

- For the first half of 2010, NAL’s production averaged 29,863 boe per day, on track with full year guidance and an increase of 27 percent over the same period in 2009.
- Second quarter 2010 funds from operations of \$63 million represents a 21 percent increase over the same period a year ago. Key drivers include a 28 percent increase in production plus higher commodity prices partially offset by a higher Canadian dollar and significantly lower realized hedging gains (\$5 million versus \$22 million in Q2 2009).
- Operating costs were lower by seven percent quarter-over-quarter from \$11.80 to \$10.98 per boe.
- Operating netbacks before hedging improved by 25 percent to \$25.31 per boe compared to \$20.30 per boe in the second quarter of 2009. Year-to-date, operating netbacks before hedging improved by 43 percent to \$28.32 per boe compared to \$19.77 a year earlier.
- Spent \$40 million in capital, drilling 20 gross (11.5 net) wells in the second quarter.
- 87 percent of capital focused on drilling, completion and tie-in activities with a 100 percent success rate in oil focused programs. Year-to-date capital totals \$118 million with 77 percent spent on drilling, completion and tie-in activities and \$19 million (16 percent) spent on new land acquisitions:
  - Participated in eight (five net) Cardium wells in the Garrington and Cochrane areas delivering results consistent with forecast type curves;
  - Drilled eight (3.7 net) wells in Saskatchewan, primarily targeting Mississippian oil at Alida, Steelman and Hoffer with first month average production rates between 100 – 200 boe/d (Trust 50 percent working interest); and
  - Drilled one Fireweed, B.C. well with a first month average production rate of approximately 800 boe per day.
- Followed up on the new pool discovery at Hoffer in SE Saskatchewan by adding 244 gross sections of undeveloped land (50 percent working interest) at an average cost of \$525 per acre which compares favorably with recent Crown sales at over \$1,000 per acre.
- Successfully completed a \$100 million equity financing with proceeds directed primarily to toward 2010 capital program of \$35 million (\$175 million increased to \$210 million), additional Hoffer/Edson land (\$50 million) and other tuck-in acquisitions (\$10 million).

## OUTLOOK

For the remainder of 2010, NAL expects to continue to be active in drilling our oil resource opportunities in the Cardium and Mississippian plays. The Trust is planning to provide an operational update in September, 2010.

## 2010 GUIDANCE

The Trust's guidance remains unchanged from its update in May, 2010. As previously outlined, NAL is forecasting a 2010 full year average in the range of 29,500 – 30,500 boe per day with a projected production volume exit rate in excess of 31,000 boe per day.

	Current 2010 Guidance
Production (boe/d)	29,500 – 30,500
Capital expenditures (\$MM)*	210
Operating costs (\$/boe)	10.75 – 11.25

\*Before Alberta Drilling Credits

## CORPORATE CONVERSION

NAL plans to convert to a dividend paying corporation towards the end of 2010. By itself, the change in structure of the underlying entity from a trust to a corporation, does not affect our business plan or our disciplined operational and financial focus.

NAL's Board will continue to assess the Trust's dividend and payout policy based upon commodity prices, NAL's asset base, opportunities and market conditions. Upon conversion, the Trust's total return will be driven by a combination of yield and growth, with yield expected to remain a meaningful component of the overall return. Specific payout and dividend levels will be established closer to the time of conversion.

## FORWARD-LOOKING INFORMATION

Please refer to the disclaimer on forward-looking information set forth under the Management's Discussion and Analysis in this document. The disclaimer is applicable to all forward-looking information in this document, including the guidance for full year 2010 set forth above.

## NON-GAAP MEASURES

Please refer to the discussion of non-GAAP measures set forth under the Management's Discussion and Analysis regarding the use of the following terms: "funds from operations", "payout ratio" and "operating netback".

## CONFERENCE CALL DETAILS

At 3:30 p.m. MDT (5:30 p.m. EDT) on August 10, 2010, NAL will hold a conference call to discuss the second quarter 2010 results. Mr. Andrew Wiswell, President and CEO, will host the conference call with other members of the management team. The call is open to analysts, investors and all interested parties. If you wish to participate, call 1-800-769-8320 toll free across North America. The conference call will also be accessible through the internet at <http://events.digitalmedia.telus.com/nal/081010/index.php>

A recorded playback of the call will be available until August 17, 2010 by calling 1-800-408-3053, reservation 1823803.

- Notes: (1) All amounts are in Canadian dollars unless otherwise stated.  
 (2) When converting natural gas to barrels of oil equivalent (boe) within this press release, NAL uses the widely recognized standard of six thousand cubic feet (Mcf) to one barrel of oil. However, boes may be misleading, particularly if used in isolation. A conversion ratio of 6 Mcf:1 boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

**FINANCIAL AND OPERATING HIGHLIGHTS**(thousands of dollars, except per unit and boe data)  
(unaudited)

	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
<b>FINANCIAL</b>				
Revenue <sup>(1)</sup>	\$121,511	\$82,650	\$258,394	\$163,312
Cash flow from operating activities	43,326	63,690	106,974	130,236
Cash flow per unit - basic	0.30	0.63	0.76	1.31
Cash flow per unit - diluted	0.30	0.60	0.74	1.27
Funds from operations	62,684	51,998	135,926	114,022
Funds from operations per unit - basic	0.43	0.51	0.96	1.15
Funds from operations per unit - diluted	0.42	0.50	0.92	1.11
Net income (loss)	8,046	(9,407)	37,395	(4,683)
Distributions declared	39,361	27,422	76,546	57,238
Distributions per unit	0.27	0.27	0.54	0.58
Basic payout ratio:				
based on cash flow from operating activities	91%	43%	72%	44%
based on funds from operations	63%	53%	56%	50%
Basic payout ratio including capital expenditures <sup>(2)</sup> :				
based on cash flow from operating activities	183%	70%	182%	85%
based on funds from operations	127%	85%	143%	97%
Units outstanding (000's)				
Period end	145,968	111,865	145,968	111,865
Weighted average	144,617	101,868	141,157	99,040
Capital expenditures <sup>(2)</sup>	40,034	16,952	118,353	53,888
Property acquisitions (dispositions), net	43,080	1,221	30,378	2,535
Corporate acquisitions, net <sup>(3)</sup>	-	37,350	309	37,350
Net debt, excluding convertible debentures <sup>(4)</sup>	269,451	266,894	269,451	266,894
Convertible debentures (at face value)	194,744	79,744	194,744	79,744
<b>OPERATING</b>				
Daily production <sup>(5)</sup>				
Crude oil (bbl/d)	11,643	9,725	11,715	9,857
Natural gas (Mcf/d)	90,928	67,654	92,121	68,306
Natural gas liquids (bbl/d)	2,812	2,048	2,795	2,199
Oil equivalent (boe/d)	29,609	23,049	29,863	23,440
<b>OPERATING NETBACK (\$/boe)</b>				
Revenue before hedging gains	45.10	39.40	47.80	38.49
Royalties	(8.85)	(7.44)	(8.69)	(7.01)
Operating costs	(10.98)	(11.80)	(10.89)	(11.88)
Other income <sup>(6)</sup>	0.04	0.14	0.10	0.17
Operating netback before hedging	25.31	20.30	28.32	19.77
Hedging gains	2.18	10.65	1.40	11.82
Operating netback	27.49	30.95	29.72	31.59

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

(2) Excludes property and corporate acquisitions, and is net of drilling incentive credits of \$3.9 million for the quarter ended June 30, 2010 and \$6.3 million for the six months ended June 30, 2010.

(3) Represents total consideration for corporate acquisitions including fees.

(4) Bank debt plus working capital and other liabilities, excluding derivative contracts, notes payable/receivable and future income tax balances.

(5) Includes royalty interest volumes.

(6) Excludes minimal Trust interest paid on notes with Manulife Financial Corporation.

## 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, 2010 and the audited consolidated financial statements and MD&A for the year ended December 31, 2009 of NAL Oil & Gas Trust ("NAL" or the "Trust"). It contains information and opinions on the Trust'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 equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. Use of boe in isolation may be misleading.

## NON-GAAP FINANCIAL MEASURES

Throughout this discussion and analysis, Management uses the terms funds from operations, funds from operations per unit, payout ratio, cash flow from operations per unit, 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 Trust's principal business activities. Management uses the terms to facilitate the understanding of the results of operations. However, these terms do not have any standardized meaning as prescribed by Canadian Generally Accepted Accounting Principles ("GAAP"). Investors should be cautioned that these measures should not be construed as an alternative to net income determined in accordance with GAAP 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 GAAP. 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 distributions. Funds from operations per unit and cash flow from operations per unit are calculated using the weighted average units outstanding for the period.

Payout ratio is calculated as distributions 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, notes payable/receivable and future income tax balances.

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

\$(000s)	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
Cash flow from operating activities	43,326	63,690	106,974	130,236
Add back change in non-cash working capital	19,358	(11,692)	28,952	(16,214)
Funds from operations	62,684	51,998	135,926	114,022

## FORWARD-LOOKING INFORMATION

This discussion and analysis contains forward-looking information as to the Trust'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 distributions to unitholders; reserves and reserves values; 2010 production; the future tax treatment of the Trust; the future corporate conversion of the Trust and its subsidiaries; the Trust'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; future results from operations; payout ratios; cost estimates and royalty rates; drilling plans; tie-in of wells; future development, exploration and acquisition 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 distributions 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 development activities; our ability to market our oil and natural gas successfully to current and new customers; and 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 volatility in 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 Trust including the Trust'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 the MD&A is made as of the date of this MD&A. The forward-looking information contained in the MD&A is expressly qualified by this cautionary statement.

## EXPLORATION & DEVELOPMENT ACTIVITIES

The Trust spent \$34.7 million on drilling, completion and tie-in operations during the second quarter of 2010, compared to \$7.6 million during the second quarter of 2009, and drilled 20 (11.5 net) wells in the second quarter, compared to five (2.7 net) wells during the same period in 2009. Drilling was accelerated on six Cardium wells in Garrington utilizing two pads to work from through break up. Access conditions were also favorable in Irricana, Fireweed and Edson allowing additional operations to proceed. NAL had up to eight rigs running through the quarter with up to four rigs working in Saskatchewan, one in British Columbia and three in Alberta. A significant portion of the production from the second quarter drilling will be on stream during the third quarter.

The Trust has drilled 68 (32.6 net) wells year-to-date and is planning to drill an additional 61 (33 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	17	9.7	2	1.7	0	0	0	0	19	11.4
Non-operated wells	0	0	1	0.1	0	0	0	0	1	0.1
Total wells drilled	17	9.7	3	1.8	0	0	0	0	20	11.5

### **Southeast Saskatchewan (Alida, Nottingham, Steelman, Hoffer)**

In Saskatchewan, there were eight (3.7 net) horizontal oil wells drilled during the second quarter. Activity was focused on the Mississippian in Alida, Steelman and Hoffer. The Trust expects to have 11 wells on stream at Hoffer by the end of July producing approximately 1,300 boe/d (650 boe/d net). Production from this program is expected to positively impact third quarter volumes as wet conditions accounted for 23 lost drilling days and shut in volumes at single well battery operations during the quarter. The Trust intends to drill 40 (20 net) additional horizontal Mississippian oil wells in the third and fourth quarters across its expanded land base, largely focused in the greater Hoffer area. Facility planning is under way with expectations for full scale battery construction during the first quarter of 2011.

### **Alberta (Cochrane, Garrington, Irricana, Edson)**

In Alberta, NAL participated in drilling 11 (6.9 net) locations with nine (6 net) oil wells drilled in the Cardium at Garrington/Cochrane and the Wabamun at Irricana. The majority of production from this program is expected to be brought on stream in the third quarter. Test results are in line with type curves supporting first month production rates of 180 - 200 boe/d. A Wilrich gas well (70 percent working interest) was also drilled and tested in the Edson area with final test rates of 10 mmcf/d at a flowing well head pressure of 1200 psi. For the remainder of 2010, the Trust intends to drill 21 (12.8 net) wells in Alberta with 17 (11 net) Cardium, Leduc and Wabamun oil wells and four (2 net) liquid rich gas wells in the Edson and Kakwa areas.

### **British Columbia (Fireweed, Sukunka)**

NAL drilled a 100 percent working interest liquid rich Doig gas well in the second quarter at Fireweed with a first month average production rate of approximately 800 boe/d. Sukunka gas production was down for 21 days in June and July for a planned turn around at the Spectra Pine River gas plant. Production resumed at full capability (2,600 boe/d net) in the second week of July as expected.

## **CAPITAL EXPENDITURES**

Capital expenditures, before property acquisitions, for the quarter ended June 30, 2010 totaled \$40.0 million compared with \$17.0 million for the quarter ended June 30, 2009. The year-over-year increase is directly related to the corresponding increase in wells drilled as well as a continued shift towards horizontal drilling and multi-stage frac completions which significantly increases per well costs.

On a year-to-date basis, capital expenditures, before property acquisitions, totaled \$118.4 million compared to \$53.9 million in the comparable period of 2009 due to increased drilling and significant land acquisitions. NAL expects to spend an additional \$92 million of exploration and development capital in the second half of 2010, focused primarily on Cardium and Mississippian oil opportunities. The \$30 million in year-to-date property acquisitions and dispositions relates primarily to oil focused transactions at Hoffer and Alida/Nottingham, partially offset by the sale of a minor Bakken position earlier in the year.

### **Capital Expenditures (\$000s)**

	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
Drilling, completion and production equipment	34,648	7,622	90,641	38,086
Plant and facilities	1,355	5,531	1,782	8,390
Seismic	151	158	1,812	247
Land	693	486	18,842	2,461
Total exploration and development	36,847	13,797	113,077	49,184
Office equipment	844	142	1,134	380
Capitalized G&A	2,772	1,835	4,296	2,994
Capitalized unit-based compensation	(429)	1,178	(154)	1,330
Total other capital	3,187	3,155	5,276	4,704
Total capitalized expenditures before acquisitions	40,034	16,952	118,353	53,888
Property acquisitions, net	43,080	1,221	30,378	2,535
Total capitalized expenditures	83,114	18,173	148,731	56,423

## PRODUCTION

Second quarter 2010 production volume was 29,609 boe/d, compared to production of 23,049 boe/d in the same period of 2009. Higher year-over-year production in the second quarter is related to the impact of acquisitions completed in 2009 and an aggressive drilling program during the first half of 2010. As in previous years, second quarter production tends to be the lowest of the year due to turnaround activities and limited access for well operations due to spring break up. The Trust actively manages and anticipates these activities and the impacts on production during the quarter were in line with expectations. Turnaround activity and plant outages in Sukunka (-300 boe/d for the second and third quarters), Fireweed (-300 boe/d) and minor volume outages in central Alberta and Saskatchewan (-200 boe/d) contributed to an average reduction of 800 boe/d of production for the quarter which were included in the Trust's forecasts. On a year-to-date basis, production of 29,863 boe/d, compared to 23,440 boe/d for the comparable period of 2009. The Trust remains well positioned to deliver volumes at the midpoint of guidance (29,500 – 30,500 boe/d) for full year 2010 and an exit rate in excess of 31,000 boe/d.

### Average Daily Production Volumes

	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
Oil (bbl/d)	<b>11,643</b>	9,725	<b>11,715</b>	9,857
Natural gas (Mcf/d)	<b>90,928</b>	67,654	<b>92,121</b>	68,306
NGLs (bbl/d)	<b>2,812</b>	2,048	<b>2,795</b>	2,199
Oil equivalent (boe/d)	<b>29,609</b>	23,049	<b>29,863</b>	23,440

Oil equivalent volumes of 29,609 boe/d for the second quarter of 2010 and 29,863 boe/d year-to-date include 275 boe/d (2009 – 423 boe/d) and 288 boe/d (2009 – 432 boe/d), respectively, attributable to the non-controlling interest in the Tiberius and Spear properties (see “Related Party Transactions”). The Trust's net production, after deducting the non-controlling interest, is 29,334 boe/d for the second quarter of 2010 (2009 - 22,626 boe/d) and 29,575 boe/d (2009 - 23,008 boe/d) year-to-date.

Oil and natural gas liquids totaled 48 percent of production with natural gas at 52 percent during the first half of 2010. The Trust's oil and liquids weighting is three percent lower than for the comparative period in 2009 due to volumes delivered from the gas weighted acquisitions completed late in 2009.

### Production Weighting

	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
Oil	<b>39%</b>	42%	<b>39%</b>	42%
Natural gas	<b>51%</b>	49%	<b>52%</b>	49%
NGLs	<b>10%</b>	9%	<b>9%</b>	9%

## REVENUE

Gross revenue from oil, natural gas and natural gas liquids sales, after transportation costs and prior to hedging, totaled \$121.5 million for the three months ended June 30, 2010, 47 percent higher than the second quarter of 2009. The increase is due to a 28 percent increase in production and a 14 percent increase in the average realized price per boe, driven by a 16 percent increase in the realized crude oil price and a 11 percent increase 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, and higher AECO prices in the second quarter of 2010.

For the six month period ended June 30, 2010, revenue after transportation costs totaled \$258.4 million, an increase of 58 percent from the comparable period in 2009. The increase is attributable to a 24 percent increase in the average realized price per boe and a 27 percent increase in production. The increase in realized prices reflects higher West Texas Intermediate (“WTI”) prices, partially offset by a stronger Canadian dollar, and higher AECO prices in the first six months of 2010.

## Revenue

	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
Revenue <sup>(1)</sup> (\$000s)				
Oil	<b>75,774</b>	54,798	<b>156,859</b>	95,481
Gas	<b>32,000</b>	21,540	<b>74,064</b>	54,116
NGL's	<b>13,761</b>	6,152	<b>27,513</b>	13,130
Sulphur	<b>(24)</b>	160	<b>(42)</b>	585
Total revenue	<b>121,511</b>	82,650	<b>258,394</b>	163,312
\$/boe	<b>45.10</b>	39.40	<b>47.80</b>	38.49

(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 \$71.52, compared to \$61.92 for the comparable quarter of 2009. The increase in realized price quarter-over-quarter of 16 percent, or \$9.60/bbl, was primarily driven by a 31 percent increase in the WTI price (US\$/bbl) over the comparable period, partially offset by a 12 percent increase in the value of the Canadian dollar.

For the second quarter of 2010, NAL's crude oil price differential was 89 percent, the same percentage experienced during the comparable period in 2009. 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, 2010, NAL's average oil price was \$73.98 per barrel compared to \$53.52 for the comparable period in 2009. The increase in realized price was driven by a 53 percent increase in the WTI price (US\$/bbl) and an increase in crude oil differentials to 91 percent from 86 percent in 2009, partially offset by a 14 percent increase in the value of the Canadian dollar.

Natural gas liquids averaged \$53.78/bbl in the second quarter of 2010, a 63 percent increase from the \$33.01/bbl realized in 2009. For the six months ended June 30, 2010, natural gas liquids averaged \$54.39/bbl, an increase of 65 percent from the comparable period in 2009.

### NATURAL GAS MARKETING

Approximately 69 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 31 percent tied to NYMEX or other indexed reference prices.

For the three months ended June 30, 2010, the Trust's natural gas sales averaged \$3.87/Mcf compared to \$3.50/Mcf in the comparable period of 2009, an increase of 11 percent. The quarter-over-quarter increase in gas prices was attributable to a 13 percent increase in the benchmark AECO daily spot prices.

Prices for Lake Erie natural gas decreased to \$4.91/Mcf in the second quarter of 2010, compared to \$5.16/Mcf in 2009, a decrease of five percent. Lake Erie production of 3.3 mmcf/d accounted for four percent of the Trust's natural gas production in the second quarter of 2010, as compared to five percent in the comparable period of 2009. 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, 2010, NAL averaged \$4.44/Mcf, a one percent increase from the \$4.38/Mcf realized in the comparable period of 2009. The increase in natural gas prices was attributable to a six percent increase in the benchmark AECO daily spot prices.

**Average Pricing  
(net of transportation charges)**

	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
Liquids				
WTI (US\$/bbl)	<b>78.10</b>	59.62	<b>78.40</b>	51.35
NAL average oil (Cdn\$/bbl)	<b>71.52</b>	61.92	<b>73.98</b>	53.52
NAL natural gas liquids (Cdn\$/bbl)	<b>53.78</b>	33.01	<b>54.39</b>	32.99
Natural Gas (Cdn\$/mcf)				
AECO – daily spot	<b>3.89</b>	3.44	<b>4.43</b>	4.18
AECO – monthly	<b>3.86</b>	3.66	<b>4.61</b>	4.65
NAL Western Canada natural gas	<b>3.83</b>	3.42	<b>4.41</b>	4.31
NAL Lake Erie natural gas	<b>4.91</b>	5.16	<b>5.30</b>	5.75
NAL average natural gas	<b>3.87</b>	3.50	<b>4.44</b>	4.38
NAL Oil Equivalent before hedging (Cdn\$/boe – 6:1)	<b>45.10</b>	39.40	<b>47.80</b>	38.49
Average Foreign Exchange Rate (Cdn\$/US\$)	<b>1.028</b>	1.167	<b>1.034</b>	1.206

**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 forecasted total production, net of royalties. Management's practice is to hedge more near-term volumes on a six to 12 month forward basis with more limited volumes hedged in future periods. The execution of NAL's commodity hedging program is layered in using a combination of swaps and collars. As at June 30, 2010, NAL had several financial WTI oil contracts and AECO natural gas contracts in place.

NAL hedges floating rate debt for periods of up to five years. As at June 30, 2010, NAL had several interest rate swaps outstanding with a total notional value of \$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, 2010, NAL had several exchange rate contracts outstanding with a total notional value of US\$84 million.

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

All derivative contracts are recorded on the balance sheet at fair value based upon forward curves at June 30, 2010. 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, 2010. 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, 2010 was a net asset of \$17.2 million, comprised of an \$0.8 million asset on interest rate swaps, an \$11.1 million asset on gas contracts, a \$0.7 million asset on foreign exchange contracts and a \$4.6 million asset on oil contracts.

Second quarter income for 2010 includes a \$1.2 million unrealized gain on derivatives resulting from the change in the fair value of the derivative contracts during the quarter from an unrealized gain of \$16.0 million at March 31, 2010 to an unrealized gain of \$17.2 million at June 30, 2010. The \$1.2 million unrealized gain was comprised of a \$15.9 million unrealized gain on crude oil contracts, offset by a \$1.9 million unrealized loss on interest rate swaps, a \$5.0 million unrealized loss on foreign exchange swaps and a \$7.8 million unrealized loss on natural gas contracts.

For the six months ended June 30, 2010, income includes an unrealized gain of \$19.7 million, resulting from the change in the fair value of the derivative contracts during the period from an unrealized loss of \$2.5 million at

December 31, 2009 to an unrealized gain of \$17.2 million at June 30, 2010. The unrealized gain was comprised of a \$17.5 million unrealized gain on crude oil contracts and a \$7.2 million unrealized gain on natural gas contracts, partially offset by a \$1.7 million unrealized loss on interest rate swaps and a \$3.3 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	
	2010	2009	2010	2009
Unrealized gain (loss):				
Crude oil contracts	15,939	(34,769)	17,485	(55,967)
Natural gas contracts	(7,848)	(10)	7,173	2,691
Interest rate swaps	(1,887)	3,828	(1,696)	3,150
Exchange rate swaps	(5,033)	1,467	(3,282)	2,138
Unrealized gain (loss)	1,171	(29,484)	19,680	(47,988)
Realized gain (loss):				
Crude oil contracts	(2,712)	15,901	(4,794)	36,653
Natural gas contracts	6,900	4,507	9,397	11,463
Interest rate swaps	(385)	(178)	(642)	(207)
Exchange rate swaps	1,682	1,929	2,972	2,012
Realized gain	5,485	22,159	6,933	49,921
Gain (loss) on derivative contracts	6,656	(7,325)	26,613	1,933

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	
	2010	2009	2010	2009
Commodity contracts:				
Average crude volumes hedged (bbl/d)	6,500	4,737	6,433	4,173
Crude oil realized gain (loss) (\$000s)	(2,712)	15,901	(4,794)	36,653
Gain (loss) per bbl hedged (\$)	(4.58)	36.88	(4.12)	48.52
Average natural gas volumes hedged (GJ/d)	39,000	10,484	38,486	19,691
Natural gas realized gain (\$000s)	6,900	4,507	9,397	11,463
Gain per GJ hedged (\$)	1.94	4.72	1.35	3.22
Average BOE hedged (boe/d)	12,661	6,394	12,513	7,284
Total realized commodity contracts gain (\$000s)	4,188	20,408	4,603	48,116
Gain per boe hedged (\$)	3.63	35.07	2.03	36.50
Gain per boe (\$)	1.56	9.73	0.85	11.35
Interest rate swaps realized loss (\$000s)	(385)	(178)	(642)	(207)
Loss per boe (\$)	(0.14)	(0.08)	(0.12)	(0.05)
Exchange rate swaps realized gain (\$000s)	1,682	1,929	2,972	2,012
Gain per boe (\$)	0.62	0.92	0.55	0.47
Total realized gain (\$000s)	5,485	22,159	6,933	49,921
Gain per boe (\$)	2.04	10.57	1.28	11.77

Average hedged boe for the second quarter of 2010 were 12,661 compared to 12,363 for the first quarter of 2010.

NAL has the following interest rate risk management contracts outstanding:

INTEREST RATE CONTRACT	Remaining Term	Amount (millions) <sup>(1)</sup>	Trust Fixed Rate	Counterparty Floating Rate
Swaps-floating to fixed	July 2010 – Dec 2011	\$39.0	1.5864%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	July 2010 – Jan 2013	\$22.0	1.3850%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	July 2010 – Jan 2014	\$22.0	1.5100%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	July 2010 – Mar 2013	\$14.0	1.8500%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	July 2010 – Mar 2013	\$14.0	1.8750%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	July 2010 – Mar 2014	\$14.0	1.9300%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	July 2010 – Mar 2014	\$14.0	1.9850%	CAD-BA-CDOR (3 months)

(1) Notional debt amount

NAL has the following exchange rate risk management contracts outstanding:

EXCHANGE RATE CONTRACT	Remaining Term	Amount <sup>(1)</sup> (US\$ MM)	Trust Fixed Rate	Counterparty Floating Rate
Swaps-floating to fixed	July 2010 – Dec 2010	54.0	1.0904	BofC Average Noon Rate
Swaps-floating to fixed	Jan 2011 – Dec 2011	30.0	1.0522	BofC Average Noon Rate

(1) Notional US\$ denominated commodity sales

In addition, NAL has the following exchange rate contract commitments:

1. From July to December 2010, NAL has a commitment to sell US\$6 million (\$1 million/month) at 1.045 if the monthly Bank of Canada average noon rate exceeds 1.045. NAL is paid a premium of approximately \$10,000 a month when the average noon rate falls between 0.95 and 1.045.
2. For calendar 2011, NAL has a commitment to sell US\$6 million (\$500,000/month) at 1.12 if the monthly Bank of Canada average noon rate exceeds 1.12. NAL is paid a premium of approximately \$25,000 a month when the average noon rate falls between 0.95 and 1.12.

NAL has the following commodity risk management contracts outstanding:

CRUDE OIL	Q3-10	Q4-10	Q1-11	Q2-11
<u>US\$ Collar Contracts</u>				
\$US WTI Collar Volume (bbl/d)	2,100	1,900	800	800
Bought Puts – Average Strike Price (\$US/bbl)	67.50	68.03	81.25	81.25
Sold Calls – Average Strike Price (\$US/bbl)	79.70	80.62	94.47	94.47
<u>US\$ Swap Contracts</u>				
\$US WTI Swap Volume (bbl/d)	3,665	3,900	700	700
Average WTI Swap Price (\$US/bbl)	83.60	83.45	83.08	83.08
<b>Total Oil Volume (bbl/d)</b>	<b>5,765</b>	<b>5,800</b>	<b>1,500</b>	<b>1,500</b>
<u>NATURAL GAS</u>				
<u>Swap Contracts</u>				
AECO Swap Volume (GJ/d)	42,000	31,337	5,000	4,000
AECO Average Price (\$Cdn/GJ)	5.55	5.52	5.61	5.78
<b>Total Natural gas Volume (GJ/d)</b>	<b>42,000</b>	<b>31,337</b>	<b>5,000</b>	<b>4,000</b>

For the remainder of 2010, the Trust has outstanding contracts representing approximately 47 percent of its net liquids and natural gas production after royalties.

## ROYALTY EXPENSES

Crown, freehold and overriding royalties totaled \$23.9 million for the three months ended June 30, 2010. Expressed as a percentage of gross sales net of transportation costs, before gain/loss on derivative contracts, the net royalty rate was 19.6 percent for the quarter ended June 30, 2010, an increase from the 18.9 percent experienced in the same period of the previous year.

Royalties increased to \$8.85 per boe for the second quarter of 2010, an increase of 19 percent compared to the second quarter of 2009. The increase is attributable to higher commodity prices on a quarter-over-quarter basis.

On a year-to-date basis, royalties were \$47.0 million, up from \$29.7 million in the comparable period of 2009. Expressed as a percentage of gross sales net of transportation costs, before gain/loss on derivative contracts, the net royalty rate was 18.2 percent, the same percentage experienced during the comparable period of 2009.

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, 2010, 45 percent of crude oil production (946,638 bbl) and 66 percent of natural gas production (10,968,256 mcf) is from Alberta.

#### Royalty Expenses

	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
Royalties (\$000s)	23,851	15,608	46,997	29,742
As % of revenue	19.6	18.9	18.2	18.2
\$/boe	8.85	7.44	8.69	7.01

#### OPERATING COSTS

Operating costs averaged \$10.98 per boe for the quarter ended June 30, 2010, down seven percent from \$11.80 per boe for the quarter ended June 30, 2009. Operating costs continue to trend down driven by lower natural gas prices impacting the cost of power and continued gains from an aggressive optimization program in field operations.

On a year-to-date basis, operating costs are \$10.89 per boe compared to \$11.88 per boe in 2009. Operating costs for the full year are expected to be at the mid range of guidance (\$10.75 - \$11.25 per boe) as industry activity increases from 2009 levels and the Trust continues its program to reduce costs in all areas of its business.

#### Operating Costs

	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
Operating costs (\$000s)	29,582	24,759	58,886	50,399
As a % of revenue	24.3	30.0	22.8	30.9
\$/boe	10.98	11.80	10.89	11.88

#### OTHER INCOME

Other income was nil per boe for the second quarter of 2010 compared to \$0.08 per boe in the comparable quarter of 2009. Other income includes gas processing fees, other miscellaneous income and fees and interest income and interest expense on notes due from and to MFC (see "Related Party Transactions"). On a year-to-date basis, interest expense totaled \$0.2 million compared to net interest income of \$0.4 million for the comparable period of 2009, the decrease being attributable to the repayment of a note receivable from Manulife Financial Corporation ("MFC") in the first quarter of 2009.

### Other Income

	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
Interest on notes with MFC (\$000s)	(108)	(129)	(220)	414
Other (\$000s)	112	308	555	729
Total other income (\$000s)	4	179	335	1,143
As a % of revenue	-	0.2	0.1	0.7
Interest on notes with MFC (\$/boe)	(0.04)	(0.06)	(0.04)	0.10
Other (\$/boe)	0.04	0.14	0.10	0.17
Total other income (\$/boe)	-	0.08	0.06	0.27

### OPERATING NETBACK

For the quarter ended June 30, 2010, NAL's operating netback before hedging gains was \$25.31 per boe, a increase of 25 percent from \$20.30 per boe for the quarter ended June 30, 2009. The increase was due to higher revenues, a result of higher commodity prices, and decreased operating costs, partially offset by increased royalty expense. Hedging gains, related to commodity and exchange rate derivative contracts, were \$2.18 per boe in the second quarter of 2010, as compared to \$10.65 per boe in 2009, the decrease in 2010 attributable mainly to higher realized crude oil prices.

On a year-to-date basis, similar trends resulted in an operating netback, before hedging, of \$28.32 per boe compared to \$19.77 per boe in 2009. Hedging gains, related to commodity and exchange rate derivative contracts, were \$1.40 for the six months ended June 30, 2010, as compared to \$11.82 per boe in 2009, the decrease in 2010 attributable to lower oil hedging gains due to increasing crude oil prices.

## Operating Netback

	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
<b>AVERAGE DAILY PRODUCTION</b>				
Oil (bbl/d)	<b>11,643</b>	9,725	<b>11,715</b>	9,857
Gas (Mcf/d)	<b>90,928</b>	67,654	<b>92,121</b>	68,306
NGLs (bbl/d)	<b>2,812</b>	2,048	<b>2,795</b>	2,199
Total (boe/d)	<b>29,609</b>	23,049	<b>29,863</b>	23,440
<b>REVENUE</b>				
Oil (\$/bbl)	<b>71.52</b>	61.92	<b>73.98</b>	53.52
Gas (\$/Mcf)	<b>3.87</b>	3.50	<b>4.44</b>	4.38
NGLs (\$/bbl)	<b>53.78</b>	33.01	<b>54.39</b>	32.99
Total (\$/boe)	<b>45.10</b>	39.40	<b>47.80</b>	38.49
<b>ROYALTIES</b>				
Oil (\$/bbl)	<b>15.00</b>	14.03	<b>15.14</b>	11.34
Gas (\$/Mcf)	<b>0.52</b>	0.24	<b>0.49</b>	0.50
NGLs (\$/bbl)	<b>14.38</b>	9.23	<b>13.43</b>	8.40
Total (\$/boe)	<b>8.85</b>	7.44	<b>8.69</b>	7.01
<b>OPERATING EXPENSES</b>				
Oil (\$/bbl)	<b>10.98</b>	12.08	<b>10.89</b>	12.44
Gas (\$/Mcf)	<b>1.83</b>	1.97	<b>1.82</b>	1.95
NGLs (\$/bbl)	<b>10.98</b>	10.53	<b>10.89</b>	10.17
Total (\$/boe)	<b>10.98</b>	11.80	<b>10.89</b>	11.88
<b>OTHER INCOME<sup>(1)</sup></b>				
Oil (\$/bbl)	<b>0.07</b>	0.22	<b>0.17</b>	0.24
Gas (\$/Mcf)	<b>-</b>	0.01	<b>0.01</b>	0.02
NGLs (\$/bbl)	<b>0.06</b>	0.12	<b>0.12</b>	0.15
Total (\$/boe)	<b>0.04</b>	0.14	<b>0.10</b>	0.17
<b>OPERATING NETBACK, BEFORE HEDGING</b>				
Oil (\$/bbl)	<b>45.61</b>	36.03	<b>48.12</b>	29.98
Gas (\$/Mcf)	<b>1.52</b>	1.30	<b>2.14</b>	1.95
NGLs (\$/bbl)	<b>28.48</b>	13.37	<b>30.19</b>	14.57
Total (\$/boe)	<b>25.31</b>	20.30	<b>28.32</b>	19.77
<b>HEDGING GAINS/(LOSSES)<sup>(2)</sup></b>				
Oil (\$/bbl)	<b>(0.97)</b>	20.15	<b>(0.86)</b>	21.67
Gas (\$/Mcf)	<b>0.83</b>	0.73	<b>0.56</b>	0.93
NGLs (\$/bbl)	<b>-</b>	-	<b>-</b>	-
Total (\$/boe)	<b>2.18</b>	10.65	<b>1.40</b>	11.82
<b>OPERATING NETBACK, AFTER HEDGING</b>				
Oil (\$/bbl)	<b>44.64</b>	56.18	<b>47.26</b>	51.65
Gas (\$/Mcf)	<b>2.35</b>	2.03	<b>2.70</b>	2.88
NGLs (\$/bbl)	<b>28.48</b>	13.37	<b>30.19</b>	14.57
Total (\$/boe)	<b>27.49</b>	30.95	<b>29.72</b>	31.59

(1) Excludes interest on notes with MFC.

(2) 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 Trust plus the reimbursement of the G&A expenses incurred by NAL Resources Management Limited (the “Manager”) on the Trust’s behalf.

For the three months ended June 30, 2010, G&A expenses were \$4.0 million consistent with the comparable quarter of 2009. In addition, \$2.8 million of G&A costs relating to exploitation and development activities were capitalized in the second quarter of 2010, compared with \$1.8 million in the second quarter of 2009. G&A expense per boe was \$1.50 in the quarter, as compared to \$1.92 for the same period in 2009.

For the six months ended June 30, 2010, G&A expenses increased 26 percent to \$8.4 million from \$6.7 million in the comparable period in 2009. In addition, on a year-to-date basis, \$4.3 million of G&A costs relating to exploitation and development activities were capitalized, compared with \$3.0 million in the comparable period of 2009. G&A expense per boe was \$1.55 in 2010, compared to \$1.57 in 2009.

The year-to-date increase in total year-to-date G&A of \$3.0 million is attributable to unusually low costs in 2009 resulting from an adjustment to the short term incentive payout, plus higher 2010 compensation costs due to acquisitions.

#### General and Administrative Expenses

	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
G&A expenses (\$000s)				
Expensed	<b>4,039</b>	4,031	<b>8,398</b>	6,658
Capitalized	<b>2,772</b>	1,835	<b>4,296</b>	2,994
Total G&A (\$000s)	<b>6,811</b>	5,866	<b>12,694</b>	9,652
Expensed G&A costs:				
\$/boe	<b>1.50</b>	1.92	<b>1.55</b>	1.57
As % of revenue	<b>3.3</b>	4.9	<b>3.3</b>	4.1
Per trust unit (\$)	<b>0.03</b>	0.04	<b>0.06</b>	0.07

#### UNIT-BASED INCENTIVE COMPENSATION PLAN

The employees of the Manager are all members of a unit-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 trust units of the Trust. The Plan consists of Restricted Trust Units (“RTUs”) and Performance Trust Units (“PTUs”). RTUs vest as to one third of the amount of the grant on November 30 in each of three years after the date of grant. PTUs vest on November 30, three years from the date of grant. Distributions paid on the Trust’s outstanding trust units during the vesting period are assumed to be paid on the awarded notional trust units and reinvested in additional notional trust units on the date of distribution. Upon vesting, the employee is entitled to a cash payout based on the trust unit price at the date of vesting of the units held. In addition, the PTUs have a performance multiplier which is based on the Trust’s performance relative to its peers and may range from zero to two times the market value of the notional trust units held at vesting.

During the second quarter of 2010, the Trust recorded a \$1.2 million reduction for unit-based incentive compensation that reflects a decrease in the unit price and PTU performance multipliers, partially offset by the impact of vesting. The trust unit price of the Trust decreased by 18 percent, from \$12.95 at March 31, 2010 to \$10.60 at June 30, 2010. A decrease in unit price results in previously accrued amounts being reversed.

Unit-based incentive compensation decreased by 129 percent compared to the second quarter of 2009, from a \$3.9 million charge in 2009 to a reduction of \$1.2 million in 2010. The period-over-period decrease is a reflection of a 18 percent decrease in the trust unit price for the quarter compared to a 38 percent increase in the trust unit price for the comparable quarter last year, and lower relative performance factors used to determine the compensation.

On a year-to-date basis, the Trust has recorded a recovery of \$0.4 million compared to a \$4.4 million charge in the comparable period of 2009.

At June 30, 2010, the trust unit price used to determine unit-based incentive compensation was \$10.60. The closing trust unit price of the Trust on the Toronto Stock Exchange on August 9, 2010 was \$10.94.

The calculation of unit-based compensation expense is made at the end of each quarter based on the quarter end trust unit price and estimated performance factors. The compensation charges relating to the units granted are recognized over the vesting period based on the trust unit price, number of RTUs and PTUs 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, 2010, the Trust has recorded a total accumulated liability for unit-based incentive compensation in the amount of \$9.0 million, of which \$4.8 million is recorded as a current liability, as it is payable in December 2010, and \$4.2 million is long-term, as it is payable in December 2011 and December 2012.

### Unit-Based Compensation

	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
Unit-based compensation (\$000s):				
Expensed	(729)	2,767	(290)	3,060
Capitalized	(429)	1,178	(154)	1,330
Total unit-based compensation	(1,158)	3,945	(444)	4,390
Expensed unit-based compensation:				
As % of revenue	(0.6)	3.3	(0.1)	1.9
\$/boe	(0.27)	1.32	(0.05)	0.72
Per trust unit (\$)	(0.01)	0.03	0.00	0.03

### RELATED PARTY TRANSACTIONS

The Trust is managed by the Manager. The Manager is a wholly-owned subsidiary of MFC and also manages NAL Resources Limited (“NAL Resources”), another wholly-owned subsidiary of MFC. NAL Resources and the Trust 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 Trust and its subsidiary entities pursuant to an Administrative Services and Cost Sharing Agreement. This agreement requires the Trust to reimburse the Manager at cost for G&A and unit-based compensation expenses incurred by the Manager on behalf of the Trust 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 Trust paid \$3.6 million (2009 - \$3.4 million) for the reimbursement of G&A expenses during the second quarter and \$7.2 million (2009 - \$5.3 million) year-to-date. The Trust also pays the Manager its share of unit-based incentive compensation expense when cash compensation is paid to employees under the terms of the Plan, of which \$7.0 million was paid in the first quarter of 2010, representing units that vested on November 30, 2009 (2009 - \$2.3 million).

At June 30, 2010 the Trust owed the Manager \$1.4 million for the reimbursement of G&A and had a receivable from NAL Resources of \$13.3 million relating to net operating revenues less capital expenditures.

The Trust and a wholly owned subsidiary of MFC jointly own a limited partnership (the “Partnership”). This Partnership holds the assets acquired from the acquisitions of Tiberius Exploration Inc. (“Tiberius”) and Spear Exploration Inc. (“Spear”) in February 2008. In addition, 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.

The Trust, by virtue of being the owner of the general partner of the Partnership under the partnership agreement, is required to consolidate the results of the Partnership into its financial statements on the basis that the Trust has control over the Partnership. Accordingly, the Trust reports all revenues, expenses, assets and liabilities of the Partnership, together with its wholly owned subsidiaries and partnerships, in its consolidated financial statements. The 50 percent share of net income and net assets of the Partnership attributable to MFC is then deducted from net income and net assets as a one-line entry, in the income statement and balance sheet, ensuring that the bottom line net income and net assets reported represent only the Trust’s interest.

During the first quarter of 2009, MFC repaid the note receivable to the Partnership of \$49.6 million. The Partnership then paid an equal distribution of \$49.6 million to MFC. This resulted in a \$49.6 million reduction to the non-controlling interest on the balance sheet.

As at June 30, 2010, there is a note payable of \$7.6 million with MFC. The note payable is included on consolidation of the Partnership, but is effectively eliminated through the non-controlling interest. The note is due on demand, unsecured and bears interest at prime plus three percent. The amount of the note payable to MFC is adjusted to reflect MFC’s share of the capital expenditures of the Partnership which MFC has funded, less any loan repayments made.

Net interest expense on these notes of \$0.1 million was payable by the Trust for the second quarter of 2010 (2009 - \$0.1 million net interest expense), and net interest expense of \$0.2 million (2009 - \$0.4 million net interest income) was payable by the Trust year-to-date.

## 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 2010 was \$2.7 million, a decrease of \$0.3 million from \$3.0 million for the comparable period in 2009 due to lower average debt levels. Average outstanding bank debt for the second quarter of 2010 was \$205.7 million, \$87.7 million lower than the \$293.4 million outstanding for the second quarter of 2009, driven primarily by the \$94.7 million in equity raised in the second quarter, net of issue costs. NAL's effective interest rate averaged 5.22 percent during the second quarter of 2010, compared to 4.05 percent during the comparable period in 2009. The increase in the rate from the second quarter of 2009 is attributable to higher 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, 2010, interest on bank debt increased \$0.9 million to \$5.8 million, compared to \$4.9 million in 2009. Average outstanding debt for the six months ended June 30, 2010 decreased to \$219.0 million, compared to \$294.9 million for the corresponding period of 2009, and the effective interest rate averaged 5.30 percent in 2010, compared to 3.37 percent in 2009.

Interest on convertible debentures represents interest charges of \$3.1 million for the three months ended June 30, 2010 (\$6.2 million for the six months ended June 30, 2010) compared to \$1.3 million in the second quarter of 2009 (\$2.7 million for the six months ended June 30, 2009).

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. Accretion of the debt discount was \$1.0 million for the three months ended June 30, 2010 (\$2.0 million for the six months ended June 30, 2010) as compared to \$0.4 million for the three months ended June 30, 2009 (\$0.8 million for the six months ended June 30, 2009). The increase in interest and accretion is due to the December 2009 issuance of convertible debentures.

### Interest and Debt

	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
Interest on bank debt (\$000s) <sup>(1)</sup>	<b>2,670</b>	2,962	<b>5,756</b>	4,925
Interest and accretion on convertible debentures (\$000s)	<b>4,105</b>	1,725	<b>8,238</b>	3,449
Total interest before interest rate hedges(\$000)	<b>6,775</b>	4,687	<b>13,994</b>	8,374
Loss on interest rate swaps (\$000s)	<b>385</b>	178	<b>642</b>	207
Total interest after interest rate hedges (\$000s)	<b>7,160</b>	4,865	<b>14,636</b>	8,581
Bank debt outstanding at period end (\$000s)	<b>216,321</b>	244,323	<b>216,321</b>	244,323
Convertible debentures at period end (\$000s) <sup>(2)</sup>	<b>179,634</b>	74,762	<b>179,634</b>	74,762
\$/boe:				
Interest on bank debt	<b>0.99</b>	1.41	<b>1.06</b>	1.16
Interest on convertible debentures	<b>1.15</b>	0.64	<b>1.15</b>	0.63
Accretion on convertible debentures	<b>0.37</b>	0.18	<b>0.37</b>	0.18
Loss on interest rate swaps	<b>0.14</b>	0.08	<b>0.12</b>	0.05
Total interest after interest rate hedges	<b>2.65</b>	2.31	<b>2.70</b>	2.02

(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, 2010, NAL's cash flow netback was \$23.90 per boe, a six percent decrease from \$25.52 per boe for the comparable period in 2009. The decrease was due to a lower operating netback after hedging and higher interest charge on bank debt and convertible debentures, offset by lower G&A expenses, including unit-based incentive compensation.

For the six months ended June 30, 2010, NAL's cash flow netback was \$25.83 per boe, a six percent decrease from \$27.56 per boe in 2009. The decrease was due to a lower operating netback after hedging and higher interest charge

on bank debt and convertible debentures, offset by a lower G&A expenses, including unit-based incentive compensation.

#### Cash Flow Netback (\$/boe)

	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
Operating netback, after hedging	27.49	30.95	29.72	31.59
G&A expenses, including unit-based incentive compensation	(1.23)	(3.24)	(1.50)	(2.29)
Corporate conversion cost	(0.04)	-	(0.02)	-
Interest on bank debt and convertible debentures <sup>(1)</sup>	(2.14)	(2.05)	(2.21)	(1.79)
Interest on notes with MFC <sup>(2)</sup>	(0.04)	(0.06)	(0.04)	0.10
Realized loss on interest rate derivative contracts	(0.14)	(0.08)	(0.12)	(0.05)
Cash flow netback	<b>23.90</b>	25.52	<b>25.83</b>	27.56

(1) Excludes non-cash accretion on convertible debentures.

(2) Reported as other income.

#### DEPLETION, DEPRECIATION AND ACCRETION OF ASSET RETIREMENT OBLIGATIONS (“DDA”)

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 reserves volumes.

For the quarter ended June 30, 2010, depletion on property, plant and equipment and accretion on the asset retirement obligations was \$24.72 per boe, 16 percent higher than the \$21.29 per boe for the same period in 2009. The increase in depletion rate per boe in 2010 reflects a higher depletion rate associated with the oil and gas properties of Breaker Energy Ltd. (“Breaker”) which was acquired in December 2009. Similar trends are noted for the six months ended June 30, 2010.

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

#### Depletion, Depreciation and Accretion Expenses

	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
Depletion and depreciation (\$000s)	63,903	42,779	125,939	85,987
Accretion of asset retirement obligation (\$000s)	2,695	1,886	5,326	3,714
Total DDA (\$000s)	<b>66,598</b>	44,665	<b>131,265</b>	89,701
DDA rate per boe (\$)	<b>24.72</b>	21.29	<b>24.28</b>	21.14

#### TAXES

In the second quarter of 2010, NAL had a future income tax recovery of \$10.4 million compared to a \$12.2 million recovery in the corresponding period of the prior year. For the six month period ended June 30, 2010, NAL had a future income tax recovery of \$12.6 million compared to \$18.4 million in 2009.

The Trust is a taxable entity and files a trust income tax return annually. The Trust’s taxable income consists of royalty income, distributions from a subsidiary trust and interest and dividends from other subsidiaries, less deductions for the Trust’s G&A expenses, Canadian Oil and Gas Property Expense (“COGPE”) and issue costs. In addition, Canadian Exploration Expense (“CEE”), Canadian Development Expense (“CDE”) and Undepreciated Capital Cost (“UCC”) are incurred and deducted by the Trust’s subsidiaries. The Trust is taxable only on remaining income, if any, that is not distributed to unitholders.

As at June 30, 2010, the Trust’s (including all subsidiaries) estimated tax pools (unaudited) available for deduction from future taxable income approximated \$1.4 billion, of which approximately 34 percent represented COGPE, 21 percent represented UCC, with the remaining balance represented by CEE, CDE, trust unit issue costs and non-capital loss carry forwards.

### Estimated Tax Pools (\$ millions)

	June 30, 2010	December 31, 2009
Canadian exploration expense	61	50
Canadian development expense	419	379
Canadian oil and gas property expense	466	436
Undepreciated capital costs	282	274
Other (including loss carry forwards)	140	128
<b>Total estimated tax pools</b>	<b>1,368</b>	<b>1,267</b>

Based on current strip prices at June 30, 2010, the Trust is not expected to be taxable in 2010.

Under the specified investment flow-through (“SIFT”) legislation, effective January 1, 2011, distributions to unitholders will not be deductible against income by publicly traded income trusts and, as a result, the Trust will be taxed on its income similar to corporations. These measures are considered enacted for purposes of GAAP. Accordingly, the Trust has measured future income tax assets and liabilities under the SIFT tax rules. The scheduling of the reversal of temporary differences is based on management’s best estimates and current assumptions, which may change. Bill C-10, containing the legislation for the provincial SIFT rate, received Royal Assent on March 12, 2009. The Alberta provincial tax rate for 2011 is expected to be 10 percent. This will result in an effective combined SIFT rate of 26.5 percent in 2011 and 25.0 percent in 2012, a three percent decrease from the original legislation. The Trust has tax effected all temporary differences.

### NON-CONTROLLING INTEREST

The Trust has recorded a non-controlling interest in respect of the 50 percent ownership interest held by MFC in the Partnership holding the Tiberius and Spear assets (see “Related Party Transactions”).

The non-controlling 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 non-controlling interest in the consolidated statement of income is comprised of:

#### Non-Controlling Interest (\$000s)

	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
Net profits interest expense	216	544	834	787
Share of net income attributable to MFC	151	92	325	708
	<b>367</b>	636	<b>1,159</b>	1,495

### NET INCOME

Net income is a measure impacted by both cash and non-cash items. The largest non-cash items impacting the Trust’s net income are DDA, unrealized gains or losses on derivative contracts and future income taxes.

Net income for the second quarter of 2010 was \$8.0 million compared to a net loss of \$9.4 million for the comparable period in 2009. The improvement of \$17.4 million was mainly due to increased revenues net of royalties (\$31.2 million), an increased gain on derivative contracts (\$14.0 million) and decreased unit-based compensation expense (\$3.5 million), offset by increased DD&A expense (\$21.1 million), increased operating costs (\$4.8 million) and a lower tax reduction (\$1.8 million).

Net income for the six months ended June 30, 2010 of \$37.4 million was \$42.1 million greater than the comparable period of 2009. The increase in net income in 2010 is attributable to increased revenues net of royalties (\$79.0 million), an increased gain on derivative contracts (\$24.7 million) and decreased unit-based compensation expense (\$3.4 million), offset by increased operating costs (\$8.5 million), increased DD&A expense (\$40.0 million), increased interest charges (\$5.6 million) and a lower tax reduction (\$5.8 million).

### Net Income (loss) (\$000s)

	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2008
Net income (loss)	8,046	(9,407)	37,395	(4,683)

### CAPITAL RESOURCES AND LIQUIDITY

The capital structure of the Trust is comprised of trust units, bank debt and convertible debentures.

As at June 30, 2010, NAL had 145,968,199 trust units outstanding, compared with 137,471,209 trust units as at December 31, 2009. The increase from December 31, 2009 is attributable to 946,990 units issued under the distribution reinvestment program (“DRIP”) and a new issuance pursuant to a bought deal offering of 7,550,000 trust units in April 2010.

Under the DRIP, unitholders may elect to reinvest distributions or make optional cash payments to acquire trust units 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 14.97 percent during the year.

The premium distribution reinvestment plan (“Premium DRIP”) allows unitholders to exchange trust units for a cash payment, from the plan broker, equal to 102 percent of the monthly distribution. The Premium DRIP program has been suspended since March 10, 2006.

As at June 30, 2010, the Trust had net debt of \$464.2 million (net of working capital and other liabilities, excluding derivative contracts, note payable with MFC and future income taxes) including convertible debentures at face value of \$194.7 million. Excluding the convertible debentures, net debt was \$269.5 million, compared with \$282.7 million at December 31, 2009. The decrease in net debt, excluding convertible debentures, of \$13.3 million during 2010 is attributable to decreased bank debt of \$14.4 million, offset by a change in working capital of \$1.1 million.

Bank debt outstanding was \$216.3 million at June 30, 2010 compared with \$230.7 million as at December 31, 2009. Of the \$216.3 million outstanding at June 30, 2010 \$214.9 million is outstanding under the production facility and \$1.4 million is outstanding under the working capital facility.

At the end of the second quarter, the Trust had a net debt (excluding convertible debentures) to 12 months trailing cash flow ratio of 1.07 times and a total net debt (including convertible debentures) to 12 months trailing cash flow ratio of 1.84 times.

During the second quarter, the Trust 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, 2011 at which time it is extendible for a further 364-day revolving period upon agreement between the Trust 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 Trust 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 Trust would be required to repay the facility in five equal quarterly installments commencing May 1, 2012.

The Trust has two series of convertible debentures currently outstanding.

On December 3, 2009, the Trust 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 anytime, into fully paid trust units at a conversion price of \$16.50 per trust unit. The debentures mature on December 31, 2014 at which time they are due and payable. The debentures are redeemable by the Trust 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 Trust may opt to satisfy its obligation to repay the principal by issuing trust units. If all of the outstanding debentures were converted at the conversion price, an additional 7.0 million trust units would be required to be issued.

In addition, the Trust has outstanding \$79.7 million principal amount of 6.75% 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 trust units at a conversion price of \$14.00 per trust unit. The debentures mature on August 31, 2012 at which time they are due and payable. The debentures are redeemable by the Trust 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 Trust may opt to satisfy its obligation to repay the principal by issuing trust units. If all of the outstanding debentures were converted at the conversion price, an additional 5.7 million trust units would be required to be issued.

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. As the debentures are converted to trust units, a portion of the debt and equity amounts are transferred to Unitholders' Capital. The debt component of the convertible debentures is carried net of issue costs. The debt balance, net of issue costs, accretes over time to the principal amount owing on maturity. The accretion of the debt discount and the interest paid to debenture holders are expensed each period as part of the line item "interest and accretion on convertible debentures" in the consolidated statement of income.

The Trust recognized \$1.0 million (2009 - \$0.4 million) of accretion of the debt discount in the second quarter of 2010 and \$2.0 million (2009 - \$0.8 million) year-to-date.

As at August 9, 2010, the Trust has 146,184,108 trust units and \$194.7 million in convertible debentures outstanding.

#### Capitalization

	June 30, 2010	December 31, 2009	June 30, 2009
Trust unit equity (\$000s)	962,333	894,192	618,335
Bank debt (\$000s)	216,321	230,713	244,323
Working capital deficit (surplus) <sup>(1)</sup> (\$000s)	53,130	52,014	22,571
Net debt excluding convertible debentures	269,451	282,727	266,894
Convertible debentures (\$000s) <sup>(2)</sup>	194,744	194,744	79,744
Net debt	464,195	477,471	346,638
Net debt excluding convertible debentures to trailing 12-month cash flow <sup>(3)</sup>	1.07	1.23	1.03
Total net debt to trailing 12-month cash flow <sup>(3)</sup>	1.84	2.07	1.33
Trust units outstanding (000s)	145,968	137,471	111,865

(1) Working capital and other liabilities, excluding derivative contracts, future income taxes and notes with MFC.

(2) Convertible debentures included at face value.

(3) Calculated as net debt divided by funds from operations for the previous 12 months.

The Trust actively manages its payout ratio (including capital) to ensure that its capital program can be executed and that distribution levels are maintained. The targeted payout ratios may change over time in response to market conditions and opportunities available to the Trust. In addition to cash generated from operations, the Trust may use a combination of equity and debt to take advantage of opportunities, both internally generated and acquisitions. Funds from operations is a non-GAAP measure used by management as an indicator of the Trust's ability to generate cash from operations. Currently, the Trust has a bank line of \$550 million of which \$216 million is drawn down at June 30, 2010, leaving available capacity of \$334 million.

For 2010, the Trust expects to continue to execute its active hedging program. Currently, the Trust has in place oil hedges for approximately 49 percent of net forecasted (after royalty) production for 2010. Crude volumes are hedged at an average price of US\$83.52 per bbl on fixed price contracts. On collared contracts, crude volumes are hedged at an average ceiling price of US\$80.14 per bbl and at an average floor price of US\$67.75 per bbl. For natural gas, remaining 2010 hedges total approximately 46 percent of net budgeted production volumes hedged at an average floor price in excess of \$5.54 per GJ (\$5.84 per Mcf).

NAL's capital program is designed to be scalable and flexible in response to commodity prices and market conditions. For 2010, the Trust plans for a \$210 million capital program, prior to deduction of Alberta drilling

credits. The Trust, through the Manager, operates approximately 85 percent of the assets to which the capital program is directed, allowing for significant flexibility over the timing and scale of the program.

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

Under the tax legislation regarding the change in the taxation of income trusts, the Trust has a grandfathering period to 2011, when the rules come into effect. The grandfathering period restricts “undue expansion” of the Trust by placing growth limits for issuances of equity and convertible debt, based on the market capitalization of the Trust on October 31, 2006, the date of the announcement of the changes in the tax legislation. For the remainder of 2010, the Trust has approximately \$423 million of safe harbour available, after taking into consideration the equity offering that closed during the second quarter of 2010.

### **ASSET RETIREMENT OBLIGATION**

At June 30, 2010, the Trust reported an asset retirement obligation (“ARO”) balance of \$134.1 million (\$127.9 million as at December 31, 2009) for future abandonment and reclamation of the Trust’s oil and gas properties and facilities. The ARO balance was increased by \$6.2 million to reflect \$2.9 million liabilities incurred and revisions to estimates and \$5.3 million from accretion expense, and was reduced by \$2.0 million for actual abandonment and environmental expenditures incurred during the first six months.

### **DISTRIBUTIONS TO UNITHOLDERS**

For the three and six months ended June 30, 2010, the Trust distributed 91 percent and 72 percent of its cash flow from operating activities, respectively, as compared to 43 percent and 44 percent for the same periods in 2009. The payout associated with cash flow from operating activities will fluctuate significantly period over period as cash flow from operating activities includes changes in non-cash working capital associated with operating activities. The Trust has distributed cash in excess of its net income in each period, due to the non-cash charges included in net income. Cash flow from operations usually exceeds net income, as net income includes non-cash charges such as DDA, future income tax expense and unrealized gains and losses on derivative contracts.

The Board of Directors of NAL Energy Inc. sets distribution levels taking into consideration commodity prices, the forecasted cash flow of the Trust, financial market conditions, availability of financing, internal capital investment opportunities and taxability.

Given that distributions have exceeded net income during 2010, the excess could be considered to be an economic return of capital to the unitholders. The Trust’s business model is such that it distributes a certain proportion of its cash flow while retaining cash to execute planned capital programs. As a result of the depleting nature of oil and gas assets, some capital expenditure is required in order to minimize production declines as well as to invest in facilities and infrastructure. NAL’s 2010 capital program may not fully replace production. When the Trust sets distribution levels, depletion expense is not considered to be indicative of the amount required to maintain productive capacity, and therefore, net income is not considered a driver of distribution levels. The Trust grows its productive capacity and sustains its cash flow through development activities and acquisitions. NAL’s productive capacity and future cash flow will be dependent on its ability to acquire assets and continue to find economic reserves. Acquisitions are financed through equity, debt or a combination of the two.

Generally, the capital expenditures of the Trust and the distributions in any given period exceed the cash flow from operating activities. The shortfall is financed from a combination of debt and equity. Fluctuations in commodity prices, other market factors, or growth opportunities may make it necessary to adjust forecasted capital expenditures or distribution levels.

NAL intends to continue to make cash distributions to unitholders. However, these cash distributions cannot be guaranteed. The primary drivers of the level of distributions are the factors that contribute to cash flow, namely production, operating costs and commodity prices as well as the opportunities for capital expenditures. The future sustainability of this distribution policy will be dependent upon maintaining productive capacity through both capital expenditures and acquisitions. A significant further decrease in commodity prices may impact cash from operating activities, access to credit facilities and the Trust’s ability to fund operations and maintain distributions.

### Distributions

(\$000s except for percentages)	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
Cash flow from operating activities	43,326	63,690	106,974	130,236
Net income (loss)	8,046	(9,407)	37,395	(4,683)
Actual cash distributions paid or payable	39,361	27,422	76,546	57,238
Excess of cash flow from operating activities over cash distribution paid	3,965	36,268	30,428	72,998
Percentage of cash flow from operations distributed	91%	43%	72%	44%
Excess (shortfall) of net income over cash distributions paid	(31,315)	(36,829)	(39,151)	(61,921)

As stated in the non-GAAP measures section of the MD&A, NAL uses funds from operations as a key performance indicator to measure the ability of the Trust to generate cash from operations and to pay monthly distributions.

For the three months ended June 30, 2010, funds from operations amounted to \$62.7 million, compared with \$52.0 million for the three months ended June 30, 2009. The 21 percent increase is due to higher revenues resulting from higher commodity prices, offset by lower realized hedging gains of \$16.7 million. On a per trust unit basis, funds from operations decreased 16 percent from \$0.51 in 2009 to \$0.43 in 2010.

For the six months ended June 30, 2010, funds from operations increased 19 percent to \$135.9 million from \$114.0 million for the comparable period of 2009. The increase is primarily due to higher revenues driven by higher commodity prices, offset by lower realized hedging gains of \$43.0 million.

### Funds from Operations

	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
Funds from operations (\$000s)	62,684	51,998	135,926	114,022
Funds from operations per trust unit	0.43	0.51	0.96	1.15
Payout ratio based on funds from operations	63%	53%	56%	50%

### VARIABLE INTEREST ENTITIES

NAL has no variable interest entities.

### CONTRACTUAL OBLIGATIONS

#### Joint Venture Partnership Agreement:

Effective April 20, 2009, the Trust 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 to earn an interest in freehold and crown acreage. The Trust has a 65 percent interest in this agreement and MFC a 35 percent interest and therefore the Trust'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 Trust) 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 undrilled freehold and crown acreage will not be earned and the Trust will be subject to a payment of 65 percent of a \$5 million performance bond which reduces with every expenditure. As at June 30, 2010, the Trust had spent \$5.3 million and at the end of the current drilling program, the Trust and MFC will have spent approximately \$15 million, which is on track to meet the commitments under this agreement

#### Farm-in Agreement:

Effective August 10, 2009, the Trust and MFC entered into a Farm-in Agreement with BP Canada. The arrangement consists of a two year initial commitment, with a minimum capital commitment of \$30 million (\$18 million net) in the first year and \$50 million (\$30 million net) in the second year, with an option for a third year, at NAL's election, for an additional \$50 million (\$30 million net) commitment. The Trust 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 Trust will not be required to pay any unspent amounts under the Agreement. As at June 30, 2010, the Trust had spent \$21.8 million (net) and satisfied its first year commitment under the agreement.

**Other:**

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

(\$000s)	2010	2011	2012	2013	2014
Office lease <sup>(1)</sup>	2,078	3,505	3,505	3,482	3,414
Office lease – Alberta Clipper and Breaker <sup>(2)</sup>	1,089	2,184	2,192	358	-
Transportation agreement	6,351	-	-	-	-
Processing agreement <sup>(3)</sup>	1,198	2,242	401	384	-
Convertible debentures <sup>(4)</sup>	-	-	79,744	-	115,000
Bank debt	-	-	129,793	86,528	-
<b>Total</b>	<b>10,716</b>	<b>7,931</b>	<b>215,635</b>	<b>90,752</b>	<b>118,414</b>

(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 Trust is allocated a pro rata share (currently approximately 64 percent) of the expense on a monthly basis.

(2) Represents the full amount of the office lease assumed with the acquisition of Alberta Clipper Inc. (“Alberta Clipper”) and Breaker. MFC will reimburse the Trust for 50 percent of the Alberta Clipper obligation under the base price adjustment clause.

(3) Represents a gas processing agreement with a take or pay component.

(4) Principal amount.

**QUARTERLY INFORMATION**

(\$000s, except per unit and production amounts)	2010			2009			2008		
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	
Revenue, net of royalties <sup>(1)</sup>	105,925	135,662	88,165	85,988	60,922	77,791	161,156	234,993	
Per unit	0.73	0.99	0.75	0.77	0.60	0.81	1.68	2.46	
Cash flow from operations	43,326	63,648	53,060	52,999	63,690	66,546	77,326	98,860	
Per unit	0.30	0.46	0.45	0.47	0.63	0.69	0.80	1.03	
Funds from operations <sup>(2)</sup>	62,684	73,242	62,953	53,766	51,998	62,024	67,040	79,233	
Per unit	0.43	0.53	0.53	0.48	0.51	0.64	0.70	0.83	
Net income (loss)	8,046	29,349	5,634	8,249	(9,407)	4,724	55,374	111,045	
Per unit									
basic	0.06	0.21	0.05	0.07	(0.09)	0.05	0.58	1.16	
diluted	0.06	0.21	0.05	0.07	(0.09)	0.05	0.56	1.11	
Average oil equivalent production (boe/d – 6:1)	29,609	30,120	25,748 <sup>(3)</sup>	23,418	23,049	23,836	23,984	23,808	

(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

**DISCLOSURE CONTROLS AND PROCEDURES (“DC&P”)**

NAL’s 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 Issuer’s Annual and Interim Filings. The control framework NAL’s officers used to design NAL’s ICFR is the *Internal Control – Integrated Framework* published by the Committee of Sponsoring Organizations of the Treadway Commission (the “COSO Framework”).

Under the supervision of the Chief Executive Officer and the Chief Financial Officer, NAL conducted an evaluation of the effectiveness of its ICFR as at December 31, 2009 based on the COSO Framework. Based on this evaluation, the officers concluded that as of December 31, 2009, NAL’s ICFR provides reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP.

There has not been any change in NAL’s internal control over financial reporting during the first six months of 2010 that has materially affected, or is reasonably likely to materially affect, NAL’s internal control over financial reporting.

## **CRITICAL ACCOUNTING ESTIMATES**

The significant accounting policies used by NAL are disclosed in the notes to NAL's December 31, 2009 audited consolidated financial statements. Certain accounting policies require that management make appropriate decisions when formulating estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The Manager reviews the estimates regularly. The emergence of new information and changed circumstances may result in actual results or changes in estimated amounts that differ materially from current estimates. NAL might realize different results from the application of new accounting standards published, from time to time, by various regulatory bodies. An assessment of NAL's significant accounting estimates is discussed in the MD&A filed with NAL's audited consolidated financial statements for the year ended December 31, 2009.

## **FUTURE ACCOUNTING CHANGES**

### **International Financial Reporting Standards ("IFRS")**

In February 2008, the Accounting Standards Board confirmed that the transition date to IFRS from Canadian GAAP will be January 1, 2011 for publicly accountable enterprises. Therefore, the Trust will be required to report its results in accordance with IFRS starting in 2011, with comparative disclosure for 2010.

The Trust has an IFRS conversion plan and has established timelines for the completion and execution of the conversion project. The conversion plan includes the following phases:

1. An IFRS diagnostic phase which involves a high level assessment of the differences between Canadian GAAP and IFRS, identifying major impact areas.
2. An in-depth review of GAAP differences and determination of transition policy choices as well as ongoing IFRS accounting policies.
3. The implementation phase where solutions are developed and assessed. This involves an evaluation of information systems, business processes, procedures, internal controls and training to support the new accounting requirements.
4. A post implementation phase which involves the parallel running of 2010 financial results, the preparation of IFRS financial statements and disclosures and a review of processes and controls to make any required changes.

The first two phases are complete. Phase three progress to date has included evaluation and implementation changes to information systems and business processes as well as IFRS training to relevant personnel.

The Trust considers the significant IFRS differences and majority of the implementation work to be in relation to property, plant and equipment ("PP&E"). IFRS policies for PP&E have been developed, however it is premature to provide meaningful numerical analysis on the impact of the changes.

The Trust has also identified a number of other areas where potentially significant differences between Canadian GAAP and IFRS exist for the Trust. Provisions, including asset retirement obligations ("ARO") and unit based compensation have been reviewed, accounting policies recommended and implementation steps are being developed. The review of presentation and disclosure standards has been performed and changes to financial statements are summarized.

In July 2009, the International Accounting Standards Board ("IASB") issued certain amendments and exemptions to IFRS 1 in order to make it more practical for Canadian entities adopting IFRS for the first time. The amendment allows the Trust to elect to measure its oil and gas assets at the date of transition to IFRS using the net book value based on the entity's previous GAAP at December 31, 2009, allowing for IFRS to be adopted prospectively to its full cost pool, rather than performing retrospective assessment of the oil and gas assets and related expenditures. The Trust intends to use this election on adoption of IFRS.

The most significant change identified will be to PP&E. The Trust, like many other Canadian oil and gas reporting issuers, applies the "full cost" accounting methodology to its oil and gas assets. Under full cost, capital expenditures are maintained in a single cost centre for each country, and the cost centre is subject to a single depletion calculation and impairment test. IFRS will require a much more detailed assessment of oil and gas assets as follows:

- Capital expenditures have to be segregated between exploration and evaluation ("E&E") and development and production ("D&P") assets. In addition, assets have to be aggregated at a component level. Transitional amounts have been calculated and recorded, which requires establishing the book value of

the undeveloped land and unproved properties and then allocating the remaining carrying value to the D&P assets, based on reserve allocations for each component.

- For depletion and depreciation purposes, the Trust must determine an appropriate depletion or depreciation method, and must deplete by component. There is the choice whether to deplete E&E assets or not. In addition, there is the option to deplete using a reserve base of proved reserves or both proved plus probable reserves. NAL has determined not to deplete E&E assets and to deplete its oil and gas properties using both proved plus probable reserves.
- Impairment tests are to be calculated at a cash generating unit level (“CGU”), which is defined as the lowest level of assets that produce independent cash inflows. The Trust identified its CGU’s for this purpose. An impairment test is performed individually for all CGU’s on transition and there is no impairment noted. On a go forward, an impairment test must be performed when indicators suggest there may be impairment. In addition, the recognition of impairment in a prior year must be reversed should impairment conditions reverse.

Provisions and contingent liabilities and assets, including ARO are identified and calculated somewhat differently under IFRS. ARO calculations are expected to be impacted due to differences in the discount rates to be used to present value the liability. In addition, under IFRS, ARO is required to be revalued each reporting period at the then prevailing interest rate. This may increase or decrease the ARO recorded on the balance sheet depending on the direction of change in interest rates. In addition, onerous contracts will require identification and, to the extent they exist, must be recorded as a liability on the balance sheet.

IFRS will allow the Trust to use IFRS rules for business combinations on a prospective basis rather than restating all business combinations. The IFRS business combination rules converge with the new CICA Handbook Section 1582 that is also effective for NAL on January 1, 2011, however, early adoption is permitted. The Trust intends to elect this exemption on transition to IFRS.

Regular reporting on the status of IFRS is provided to the Board of Directors through the Audit Committee. In addition, the Trust has actively engaged its auditors in the conversion project and will continue to engage in ongoing discussions as the project progresses.

The development of the Trust’s opening balance sheet in accordance with IFRS, as at January 1, 2010, is in progress. Financial systems have been modified to accommodate the reporting of both Canadian GAAP financial results and IFRS financial results in 2010. In addition, modifications have been made to ensure data is captured with the added level of granularity required under IFRS. As accounting policies are finalized further modifications to the financial systems may be required. Other IT systems that capture data used in the financial system are under review as to whether any modifications are still required.

Internal staff has been assigned to lead the transition project, supplemented with consultants as required. Training of key internal finance and accounting personnel has begun both through external IFRS oil and gas training and internal training. As accounting policies are finalized, training will be expanded to other key personnel within the organization.

As accounting policies are finalized under IFRS, NAL will be assessing the impact on its various business activities, including banking arrangements, compensation arrangements and risk management agreements, during 2010.

Internal business processes and controls are being assessed and developed to enable the collection of information so that data can be attained in the manner necessary to report under IFRS both on an ongoing basis and on transition. For example, processes are currently being developed to enable the monitoring of E&E assets and when the transfer to D&P will occur. As processes are developed or amended, internal controls are being assessed to determine any required changes. This will be an ongoing process throughout 2010 to ensure all changes in accounting policies include appropriate controls and procedures.

In addition, NAL will also ensure that adequate information regarding the transition is provided to all stakeholders on a timely basis.

The International Accounting Standards Board is currently undertaking an extractive activities project to develop accounting standards specifically related to the oil and gas industry. However, it is not expected that the project will be completed prior to IFRS adoption in Canada.

The transition from Canadian GAAP to IFRS is a significant undertaking that may materially affect our reported financial position and results of operations. As we have not finalized our accounting policies, we are unable to quantify the impact of adopting IFRS on our financial statements. Notwithstanding this, the Trust is confident that it will meet the requirements for transition by the changeover deadline.

Dated: August 10, 2010

## CONSOLIDATED BALANCE SHEETS

(thousands of dollars) (unaudited)

	As at June 30, 2010	As at December 31, 2009
<b>Assets</b>		
Current assets		
Cash and cash equivalents	\$751	\$1,604
Accounts receivable	43,954	61,631
Prepays and other receivables	26,154	15,663
Derivative contracts (Note 11)	16,821	6,285
Future income tax asset	-	3,132
	<b>87,680</b>	88,315
Derivative contracts (Note 11)	765	2,461
Goodwill	14,722	14,722
Property, plant and equipment (Note 3)	1,531,704	1,503,952
	<b>1,634,871</b>	<b>\$1,609,450</b>
<b>Liabilities and Unitholders' Equity</b>		
Current liabilities		
Accounts payable and accrued liabilities	\$103,745	\$110,897
Note payable (Note 2)	7,600	8,907
Distributions payable to unitholders	13,137	12,372
Derivative contracts (Note 11)	391	11,231
Future income tax liability	2,584	-
	<b>127,457</b>	143,407
Bank debt (Note 4)	\$216,321	\$230,713
Convertible debentures (Note 5)	179,634	177,977
Other liabilities (Note 6)	7,107	7,643
Asset retirement obligations (Note 8)	134,093	127,872
Future income tax liability	4,733	24,778
Non-controlling interest (Note 9)	3,193	2,868
	<b>672,538</b>	715,258
Unitholders' equity		
Unitholders' capital (Note 10)	1,589,321	1,482,029
Equity component of convertible debentures (Note 5)	12,628	12,628
Deficit (Note 10)	(639,616)	(600,465)
	<b>962,333</b>	894,192
	<b>\$1,634,871</b>	<b>\$1,609,450</b>
Commitments (Note 12)		
Trust units outstanding (000s)	145,968	137,471

See accompanying notes.

## CONSOLIDATED STATEMENTS OF INCOME (LOSS), COMPREHENSIVE INCOME (LOSS) AND DEFICIT

*(thousands of dollars, except per unit amounts) (unaudited)*

	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
<b>Revenue</b>				
Oil, natural gas and liquid sales	\$123,116	\$83,676	\$261,636	\$165,379
Crown royalties	(17,785)	(10,743)	(34,890)	(21,354)
Freehold and other royalties	(6,066)	(4,865)	(12,107)	(8,388)
	<b>99,265</b>	68,068	<b>214,639</b>	135,637
Gain (loss) on derivative contracts (Note 11):				
Realized gain	5,485	22,159	6,933	49,921
Unrealized gain (loss)	1,171	(29,484)	19,680	(47,988)
	<b>6,656</b>	(7,325)	<b>26,613</b>	1,933
Other income	4	179	335	1,143
	<b>105,925</b>	60,922	<b>241,587</b>	138,713
<b>Expenses</b>				
Operating	29,582	24,759	58,886	50,399
Transportation	1,605	1,026	3,242	2,067
General and administrative	4,039	4,031	8,398	6,658
Unit-based incentive compensation (Note 7)	(729)	2,767	(290)	3,060
Corporate conversion costs	118	-	118	-
Interest on bank debt	2,670	2,962	5,756	4,925
Interest and accretion on convertible debentures	4,105	1,725	8,238	3,449
Depletion, depreciation and amortization	63,903	42,779	125,939	85,987
Accretion on asset retirement obligations	2,695	1,886	5,326	3,714
	<b>107,988</b>	81,935	<b>215,613</b>	160,259
Income (loss) before taxes and non-controlling interest	(2,063)	(21,013)	25,974	(21,546)
Income tax recovery (expense)	61	-	2	1
Future income tax reduction	10,415	12,242	12,578	18,357
Total income tax reduction	<b>10,476</b>	12,242	<b>12,580</b>	18,358
Income (loss) before non-controlling interest	<b>8,413</b>	(8,771)	<b>38,554</b>	(3,188)
Non-controlling interest (Note 9)	(367)	(636)	(1,159)	(1,495)
<b>Net income (loss) and comprehensive income (loss)</b>	<b>8,046</b>	(9,407)	<b>37,395</b>	(4,683)
Deficit, beginning of period	(608,301)	(514,604)	(600,465)	(489,512)
Net income (loss)	8,046	(9,407)	37,395	(4,683)
Distributions declared	(39,361)	(27,422)	(76,546)	(57,238)
Deficit, end of period	<b>\$(639,616)</b>	\$(551,433)	<b>\$(639,616)</b>	\$(551,433)
Net income (loss) per trust unit (Note 10)				
Basic	\$0.06	\$(0.09)	\$0.26	\$(0.05)
Diluted	\$0.06	\$(0.09)	\$0.26	\$(0.05)
Weighted average trust units outstanding (000s)	<b>144,617</b>	101,868	<b>141,157</b>	99,040

*See accompanying notes.*

## CONSOLIDATED STATEMENTS OF CASH FLOWS

(thousands of dollars) (unaudited)

	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
<b>Operating Activities</b>				
Net income (loss)	\$8,046	\$(9,407)	\$37,395	\$(4,683)
Items not involving cash:				
Depletion, depreciation and amortization	63,903	42,779	125,939	85,987
Accretion on asset retirement obligations	2,695	1,886	5,326	3,714
Unrealized loss (gain) on derivative contracts	(1,171)	29,484	(19,680)	47,988
Future income tax reduction	(10,415)	(12,242)	(12,578)	(18,357)
Non-cash accretion expense on convertible debentures	1,011	380	2,002	758
Non-controlling interest	151	92	325	708
Lease amortization	(423)	-	(799)	-
Abandonment and reclamation	(1,113)	(974)	(2,004)	(2,093)
Change in non-cash working capital	(19,358)	11,692	(28,952)	16,214
	<b>43,326</b>	<b>63,690</b>	<b>106,974</b>	<b>130,236</b>
<b>Financing Activities</b>				
Distributions paid to unitholders	(32,461)	(22,801)	(64,430)	(59,350)
Increase (decrease) in bank debt	(28,374)	(139,447)	(14,392)	(116,861)
Issue of trust units, net of issue costs	94,731	82,017	94,576	82,017
Note repayment from MFC (Note 2)	-	-	-	49,599
Partnership distribution paid to MFC	-	(3,500)	-	(53,302)
Issuance of convertible debentures	(1)	-	(345)	-
Change in non-cash working capital	-	48	-	81
	<b>33,895</b>	<b>(83,683)</b>	<b>15,409</b>	<b>(97,816)</b>
<b>Investing Activities</b>				
Additions to property, plant and equipment	(40,034)	(16,952)	(118,353)	(53,888)
Property acquisitions	(43,183)	(1,485)	(45,157)	(2,799)
Proceeds from dispositions	103	264	14,779	264
Acquisition of Clipper	-	(748)	-	(748)
Disposition of Clipper	-	52,657	-	52,657
Disposition of Spearpoint	-	-	(309)	-
Change in non-cash working capital	1,602	(16,377)	25,804	(23,509)
	<b>(81,512)</b>	<b>17,359</b>	<b>(123,236)</b>	<b>(28,023)</b>
Increase (decrease) in cash and cash equivalents	(4,291)	(2,634)	(853)	4,397
Cash and cash equivalents, beginning of period	5,042	12,615	1,604	5,584
Cash and cash equivalents, end of period	\$751	\$9,981	\$751	\$9,981
Supplementary disclosure of cash flow information:				
Cash paid (received) during the period for:				
Interest	\$8,633	\$4,600	\$15,429	\$9,278
Tax	\$443	-	\$502	\$(72)
Cash and cash equivalents is comprised of:				
Cash	\$751	\$3,982	\$751	\$3,982
Short term investments	-	5,999	-	5,999
	<b>\$751</b>	<b>\$9,981</b>	<b>\$751</b>	<b>\$9,981</b>

Refer to Notes 8 and 10 for significant non-cash amounts not included in the cash flow statement.

See accompanying notes.

## NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Six months ended June 30, 2010

*(Tabular amounts in thousands of dollars, except per unit amounts)*

*(unaudited)*

### 1. SUMMARY OF ACCOUNTING POLICIES

Management prepared the interim consolidated financial statements of NAL Oil & Gas Trust (“NAL” or the “Trust”) in accordance with accounting principles generally accepted in Canada and following the same accounting policies and methods of computation as the consolidated financial statements for the fiscal year ended December 31, 2009. The following disclosure is incremental to the disclosure included within the annual financial statements. Please read the interim consolidated financial statements in conjunction with the consolidated financial statements and notes thereto in NAL’s annual report for the year ended December 31, 2009.

### 2. RELATED PARTY TRANSACTIONS

The Trust is managed by NAL Resources Management Limited (the “Manager”). The Manager is a wholly-owned subsidiary of Manulife Financial Corporation (“MFC”) and also manages on its behalf NAL Resources Limited, another wholly-owned subsidiary of MFC.

The Manager provides certain services to the Trust pursuant to an administrative services and cost sharing agreement. This agreement requires the Trust to reimburse the Manager, at cost, for general and administrative (“G&A”) expenses incurred by the Manager on behalf of the Trust. The Trust paid \$3.6 million (2009 - \$3.4 million) for the reimbursement of G&A expenses during the second quarter and \$7.2 million (2009 - \$5.3 million) year-to-date. The Trust also pays the Manager its share of unit-based compensation expense when cash compensation is paid to employees under the terms of the Manager’s incentive compensation plans, of which, \$7.0 million has been paid year-to-date relating to notional units that vested on November 30, 2009 (2009 - \$2.3 million).

The Trust and a wholly owned subsidiary of MFC jointly own a limited partnership (the “Partnership”). This Partnership holds the assets acquired from the acquisition of Tiberius Exploration Inc. and Spear Exploration Inc. (“Tiberius and Spear”) in February 2008. Both the Trust and MFC have 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 exchange for this interest, the royalty holders each paid \$49.6 million to the Partnership by way of promissory notes in 2008. Although the MFC note resided in the Partnership, it was consolidated by virtue of the Trust having control of the Partnership as described below.

The Trust, by virtue of being the owner of the general partner under the partnership agreement, is required to consolidate the results of the Partnership into its financial statements on the basis that the Trust has control over the Partnership.

During the first quarter of 2009, MFC repaid the note receivable to the Partnership for \$49.6 million. The Partnership then paid an equal distribution of \$49.6 million to MFC. This resulted in a \$49.6 million reduction to the non-controlling interest (Note 9). In addition, during 2009 the Partnership paid distributions to its partners, MFC’s share being \$5.0 million (Note 9).

As at June 30, 2010, there is a note payable of \$7.6 million with MFC arising from the Tiberius and Spear acquisition. The note payable is included on consolidation of the Partnership, but is effectively eliminated through the non-controlling interest. The note is due on demand, unsecured and bears interest at prime plus three percent. The amount of the note payable to MFC is adjusted to reflect MFC’s share of the capital expenditures of the Partnership which MFC has funded, less any loan repayments made.

Net interest expense on this note of \$0.1 million was payable by the Trust for the second quarter of 2010 (2009 - \$0.1 million net interest expense), and net interest expense of \$0.2 million (2009 - \$0.4 million net interest income) was payable by the Trust for the first half of 2010. This amount is reported as other income.

The following amounts are due to and from related parties as at June 30, 2010 and December 31, 2009 and have been included in prepaids and other receivables, accounts payable and accrued liabilities and note payable on the balance sheet:

	<b>June 30, 2010</b>	December 31, 2009
Due from NAL Resources Limited	<b>\$13,000</b>	\$1,731
Due to NAL Resources Management Limited	<b>(1,410)</b>	(8,753)
Due to Manulife Financial Corporation <sup>(1)</sup>	<b>(8,008)</b>	(9,472)
	<b>\$3,582</b>	\$(16,494)

(1) Included on consolidation, eliminated through non-controlling interest. Represents note payable \$7.6 million (2009: \$8.9 million), plus amounts due from (to) MFC of (\$0.4) million (2009: (\$0.6) million), presented in accounts payable/ accounts receivable, relating to the net interest and NPI amounts due.

### 3. PROPERTY, PLANT AND EQUIPMENT

	<b>June 30, 2010</b>	December 31, 2009
Petroleum and natural gas properties, at cost	<b>\$2,732,959</b>	\$2,579,268
Less: Accumulated depletion and depreciation	<b>(1,201,255)</b>	(1,075,316)
	<b>\$1,531,704</b>	\$1,503,952

The calculation of second quarter depletion and depreciation included future development costs for proved reserves of \$209.2 million (2009 - \$41.8 million) and excluded costs associated with undeveloped land and unproved properties of \$165.2 million (2009 - \$45.1 million).

During the six months ended June 30, 2010, the Trust capitalized \$4.3 million (2009 - \$3.0 million) of G&A costs and had a recovery of \$0.2 million (2009 - a \$1.3 million charge) of unit-based incentive compensation that were directly related to exploitation and development programs.

### 4. BANK DEBT

	<b>June 30, 2010</b>	December 31, 2009
Production loan facility	<b>\$214,901</b>	\$230,713
Working capital facility	<b>1,420</b>	-
Total debt outstanding	<b>\$216,321</b>	\$230,713

The Trust 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 Trust's oil and gas reserves and other assets. Given that the borrowing base is dependent on the Trust'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 Trust and its subsidiary and affiliated entities. The facility will revolve until April 30, 2011 at which time it may be extended for a further 364-day revolving period upon agreement between the Trust and the bank syndicate. If the credit facility is not extended in April 2011, 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, 2012.

The Trust is restricted under the credit facility from making distributions to its unitholders in excess of its consolidated operating cash flow during the 18 month period preceding the distribution date. The Trust is in compliance with this covenant.

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 Trust. As at June 30, 2010 and December 31, 2009 all amounts outstanding were in Canadian dollars.

On June 30, 2010 the effective interest rate on amounts outstanding under the credit facility was 5.3 percent (2009 – 4.36 percent). The Trust’s interest charge includes this fixed interest rate component, plus a standby fee, a stamping fee and the fee for renewal.

## 5. CONVERTIBLE DEBENTURES

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

	Six months ended June 30, 2010			Year ended December 31, 2009		
	6.25%	6.75%	Total	6.25%	6.75%	Total
Principal, beginning of period	\$115,000	\$79,744	\$194,744	\$-	\$79,744	\$79,744
Issued during period	-	-	-	115,000	-	115,000
Principal, end of period	\$115,000	\$79,744	\$194,744	\$115,000	\$79,744	\$194,744
Debt component, beginning of period	\$102,450	\$75,527	\$177,977	\$-	\$74,004	\$74,004
Issued during period	-	-	-	106,965	-	106,965
Issue costs	(345)	-	(345)	(4,714)	-	(4,714)
Accretion	1,229	773	2,002	199	1,523	1,722
Debt component, end of period	\$103,334	\$76,300	\$179,634	\$102,450	\$75,527	\$177,977
Equity component, beginning of period	\$8,036	\$4,592	\$12,628	\$-	\$4,592	\$4,592
Issued during period	-	-	-	8,036	-	8,036
Equity component, end of period	\$8,036	\$4,592	\$12,628	\$8,036	\$4,592	\$12,628

## 6. OTHER LIABILITIES

	June 30, 2010	December 31, 2009
Unit-based incentive compensation (Note 7)	\$4,243	\$3,935
Excess office lease obligation <sup>(1)</sup>	2,864	3,708
	\$7,107	\$7,643

(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 Inc. and Breaker Energy Ltd. MFC will reimburse the Trust for 50 percent of the Alberta Clipper obligation of \$0.6 million under the base price adjustment clause.

## 7. UNIT-BASED INCENTIVE COMPENSATION PLAN

The Trust recorded a \$0.4 million recovery in the first six months of 2010, of which \$0.3 million was recorded as a recovery through earnings and \$0.1 million as a deduction to property, plant and equipment (\$8.8 million was expensed through earnings and \$3.7 million recorded as property, plant and equipment for the year ended December 31, 2009). The compensation expense was based on the June 30, 2010 trust unit price of \$10.60 (December 31, 2009 - \$13.74), accrued distributions, performance factors and the number of units vesting on maturity.

The following table reconciles the change in total accrued trust unit-based incentive compensation relating to the plan:

	Six months ended June 30, 2010	Year ended December 31, 2009
Balance, beginning of period	\$16,411	\$6,274
Increase (decrease) in liability	(444)	12,461
Cash payout, relating to units vested	(6,968)	(2,324)
Balance, end of period	\$8,999	\$16,411
Current portion of liability <sup>(1)</sup>	\$4,756	\$12,476
Long-term liability <sup>(2)</sup>	\$4,243	\$3,935

(1) Included in accounts payable and accrued liabilities.

(2) Included in other liabilities, (Note 6)

## 8. ASSET RETIREMENT OBLIGATIONS

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

	Six months ended June 30, 2010	Year ended December 31, 2009
Balance, beginning of period	\$127,872	\$90,844
Accretion expense	5,326	7,856
Revisions to estimates	(569)	558
Liabilities incurred	1,181	1,522
Liabilities acquired	2,462	32,311
Liabilities disposed	(175)	-
Liabilities settled	(2,004)	(5,219)
Balance, end of period	\$134,093	\$127,872

NAL's estimated credit-adjusted risk-free rate of eight to nine percent (2009 – eight to nine percent) and an inflation rate of two percent (2009 – two percent) were used to calculate the present value of the asset retirement obligations.

## 9. NON-CONTROLLING INTEREST

The Trust has recorded a non-controlling interest in respect of the 50 percent ownership interest held by MFC in the Partnership holding the Tiberius and Spear assets. The non-controlling interest on the balance sheet represents 50 percent of the net assets of the Partnership as follows:

	Six months ended June 30, 2010	Year ended December 31, 2009
Non-controlling interest, beginning of period	\$2,868	\$56,380
Net income attributable to non-controlling interest	325	1,040
Distributions to MFC <sup>(1)</sup>	-	(54,552)
Non-controlling interest, end of period	\$3,193	\$2,868

(1) Includes \$49.6 million distribution paid following settlement of note receivable (Note 2).

The non-controlling interest in the statement of income is comprised of:

	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
Net profits interest expense	\$216	\$544	\$834	\$787
Share of net income attributable to MFC	151	92	325	708
	\$367	\$636	\$1,159	\$1,495

## 10. UNITHOLDERS EQUITY

### Units Issued:

	Six months ended June 30, 2010		Year ended December 31, 2009	
	Units	Amount	Units	Amount
Balance, beginning of the period	137,471	\$1,482,029	96,181	\$1,042,183
Equity offering	7,550	100,038	9,603	86,422
Issued on corporate acquisition	-	-	30,453	345,075
Less issue expenses (net of tax)	-	(4,096)	-	(3,565)
Issued from Distribution Reinvestment Plan	947	11,350	1,234	11,914
Balance, end of the period	145,968	\$1,589,321	137,471	\$1,482,029

### Per Unit Information

Basic net income per trust unit is calculated using the weighted average number of trust units outstanding. The calculation of diluted net income per trust unit includes the weighted average trust units potentially issuable on the conversion of the convertible debentures. For the three and six months ended June 30, 2010 and 2009, the trust units potentially issuable on the conversion of the convertible debentures are anti-dilutive and are therefore excluded from the calculation. Total weighted average trust units issuable on conversion of the convertible debentures and excluded from the diluted net income per trust unit calculation for the three and six months

ended June 30, 2010 were 12,665,697 (2009 – 5,696,000) and 12,665,697 (2009 – 5,696,000), respectively. As at June 30, 2010, the total convertible debentures outstanding were immediately convertible to 12,665,697 trust units.

### Deficit

The deficit is comprised of the following:

	Six months ended June 30, 2010	Year ended December 31, 2009
Accumulated income	\$599,626	\$562,231
Accumulated cash distributions	(1,239,242)	(1,162,696)
	<b>\$(639,616)</b>	<b>\$(600,465)</b>

## 11. FINANCIAL RISK MANAGEMENT

### Foreign currency exchange rate risk

NAL has the following exchange rate derivative contracts outstanding:

EXCHANGE RATE CONTRACT	Remaining Term	Total Remaining Contracted Amount <sup>(1)</sup> (US\$ MM)	Trust Fixed Rate	Counterparty Floating Rate
Swaps-floating to fixed	July 2010 – Dec 2010	54.0	1.0904	BofC Average Noon Rate
Swaps-floating to fixed	Jan 2011 – Dec 2011	30.0	1.0522	BofC Average Noon Rate

(1) Notional US\$ denominated commodity sales.

In addition, NAL has the following exchange rate contract commitments:

- From July to December 2010, NAL has a commitment to sell US\$6 million (\$1 million/month) at 1.045 if the monthly Bank of Canada average noon rate exceeds 1.045. NAL is paid a premium of approximately \$10,000 a month when the average noon rate falls between 0.95 and 1.045.
- From January to December 2011, NAL has a commitment to sell US\$6 million (\$500,000/month) at 1.12 if the monthly Bank of Canada average noon rate exceeds 1.12. NAL is paid a premium of approximately \$25,000 a month when the average noon rate falls between 0.95 and 1.12.

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, 2010, if exchange rates had strengthened by \$0.01, with all other variables held constant, net income for the period would have been \$0.8 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

NAL has the following commodity risk management contracts outstanding:

CRUDE OIL	Q3-10	Q4-10	Q1-11	Q2-11
<u>US\$ Collar Contracts</u>				
\$US WTI Collar Volume (bbl/d)	2,100	1,900	800	800
Bought Puts – Average Strike Price (\$US/bbl)	67.50	68.03	81.25	81.25
Sold Calls – Average Strike Price (\$US/bbl)	79.70	80.62	94.47	94.47
<u>US\$ Swap Contracts</u>				
\$US WTI Swap Volume (bbl/d)	3,665	3,900	700	700
Average WTI Swap Price (\$US/bbl)	83.60	83.45	83.08	83.08
Total Oil Volume (bbl/d)	5,765	5,800	1,500	1,500

NATURAL GAS	Q3-10	Q4-10	Q1-11	Q2-11
<u>Swap Contracts</u>				
AECO Swap Volume (GJ/d)	42,000	31,337	5,000	4,000
AECO Average Price (\$Cdn/GJ)	5.55	5.52	5.61	5.78
Total Natural gas Volume (GJ/d)	42,000	31,337	5,000	4,000

The fair value of commodity derivative contracts has been included on the balance sheet with changes in the fair value reported separately on the statement of income as unrealized gain (loss). As at June 30, 2010, 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 \$1.7 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 \$0.10 per Mcf higher.

### Interest rate risk

NAL has the following interest rate derivative contracts outstanding:

INTEREST RATE CONTRACT	Remaining Term	Amount (millions) <sup>(1)</sup>	Trust Fixed Rate	Counterparty Floating Rate
Swaps-floating to fixed	July 2010 – Dec 2011	\$39.0	1.5864%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	July 2010 – Jan 2013	\$22.0	1.3850%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	July 2010 – Jan 2014	\$22.0	1.5100%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	July 2010 – Mar 2013	\$14.0	1.8500%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	July 2010 – Mar 2013	\$14.0	1.8750%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	July 2010 – Mar 2014	\$14.0	1.9300%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	July 2010 – Mar 2014	\$14.0	1.9850%	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, 2010, if interest rates had been one percent lower, with all other variables held constant, net income for the period would have been \$4.1 million lower, due to changes in the fair value of the derivative contracts. An equal and opposite effect would have occurred to net income had interest rates been one percent higher.

### Fair Value of Derivative Contracts

Derivative 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\$75.63 per barrel to US\$80.40 per barrel for oil and \$3.70 per GJ to \$5.30 per GJ for natural gas) as of the balance sheet date, using the remaining contracted oil and natural gas volumes. 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 0.883 percent to 2.316 percent) as of the balance sheet date, using the notional debt amount and outstanding term of the swap. The fair value of the exchange rate derivatives is calculated as the discounted value of the difference between the contracted exchange rate and the market forward exchange rates (ranging from 1.0631 to 1.0714) 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:

	Six months ended June 30, 2010	Year ended December 31, 2009
Fair value of commodity contracts	\$15,726	\$(8,932)
Fair value of interest rate swaps	765	2,461
Fair value of foreign exchange rate swaps	704	3,986
	<b>\$17,195</b>	<b>\$(2,485)</b>

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

	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
Unrealized gain (loss):				
Crude oil contracts	15,939	(34,769)	17,485	(55,967)
Natural gas contracts	(7,848)	(10)	7,173	2,691
Interest rate swaps	(1,887)	3,828	(1,696)	3,150
Exchange rate swaps	(5,033)	1,467	(3,282)	2,138
Unrealized gain (loss)	1,171	(29,484)	19,680	(47,988)
Realized gain (loss):				
Crude oil contracts	(2,712)	15,901	(4,794)	36,653
Natural gas contracts	6,900	4,507	9,397	11,463
Interest rate swaps	(385)	(178)	(642)	(207)
Exchange rate swaps	1,682	1,929	2,972	2,012
Realized gain	5,485	22,159	6,933	49,921
Gain (loss) on derivative contracts	6,656	(7,325)	26,613	1,933

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

	June 30, 2010	December 31, 2009
Current unrealized loss on derivative contracts	\$(391)	\$(11,231)
Current unrealized gain on derivative contracts	16,821	6,285
Current unrealized gain (loss) on derivative contracts	16,430	(4,946)
Long term unrealized gain on derivative contracts	765	2,461
Net fair value of derivative contracts	\$17,195	\$(2,485)

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

	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
Unrealized gain (loss), beginning of period	\$16,024	\$46,902	\$(2,485)	\$65,406
Unrealized gain acquired <sup>(1)</sup>	-	408	-	408
Unrealized gain, end of period	17,195	17,826	17,195	17,826
Unrealized gain (loss) for the period	1,171	(29,484)	19,680	(47,988)
Realized gain in the period	5,485	22,159	6,933	49,921
Gain (loss) on derivative contracts	\$6,656	\$(7,325)	\$26,613	\$1,933

(1) Assumed on acquisition of Alberta Clipper Energy Inc.

## 12. COMMITMENTS

### (i) Joint Venture Partnership Agreement:

Effective April 20, 2009, the Trust 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 to earn an interest in freehold and crown acreage. The Trust has a 65 percent interest in this agreement and MFC a 35 percent interest and therefore the Trust'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 Trust) 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 undrilled freehold and crown acreage will not be earned and the Trust will be subject to a payment of 65 percent of a \$5 million performance bond which reduces with every expenditure. As at June 30, 2010, the Trust had spent \$5.3 million and at the end of the current drilling program, the Trust and MFC will have spent approximately \$15 million, which is on track to meet the commitments under this agreement

### (ii) Farm-in Agreement:

Effective August 10, 2009, the Trust and MFC entered into a farm-in agreement with BP Canada. The arrangement consists of a two year initial commitment, with a minimum capital commitment of \$30 million in the first year and \$50 million in the second year, with an option for a third year, at NAL's election, for an additional \$50 million commitment. The Trust 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 Trust will not be required to pay any unspent amounts under the Agreement. As at June 30, 2010, the Trust had spent \$21.8 million (net) and satisfied its first year commitment under the agreement.

**(iii) Other:**

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

	2010	2011	2012	2013	2014
Office lease <sup>(1)</sup>	2,078	3,505	3,505	3,482	3,414
Office lease – Clipper and Breaker <sup>(2)</sup>	1,089	2,184	2,192	358	-
Transportation agreement	6,351	-	-	-	-
Processing agreement <sup>(3)</sup>	1,198	2,242	401	384	-
Convertible debentures <sup>(4)</sup>	-	-	79,744	-	115,000
Bank debt	-	-	129,793	86,528	-
<b>Total</b>	<b>10,716</b>	<b>7,931</b>	<b>215,635</b>	<b>90,752</b>	<b>118,414</b>

(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 Trust is allocated a pro rata share (currently approximately 64 percent) of the expense on a monthly basis.

(2) Represents the full amount of the office lease assumed with the acquisition of Alberta Clipper Energy Inc. and Breaker Energy Ltd. MFC will reimburse the Trust for 50 percent of the Clipper obligation under the base price adjustment clause.

(3) Represents a gas processing agreement with a take or pay component.

(4) Principal amount.

## TRADING PERFORMANCE

	For the Quarter Ended			
	30-Jun-10	31-Mar-10	30-Jun-09	31-Mar-09
<b>PRICE</b>				
High	\$13.57	\$14.95	\$10.53	\$8.99
Low	\$9.68	\$12.50	\$6.63	\$5.38
Close	\$10.60	\$12.95	\$9.37	\$6.80
Daily Average Volume	601,723	589,149	459,603	359,591

NAL Oil & Gas Trust provides investors with a yield-oriented opportunity to participate in the Canadian Upstream Conventional Oil and Gas Industry. The Trust generates monthly cash distributions for its Unitholders by pursuing a strategy of acquiring, developing, producing and selling crude oil, natural gas and natural gas liquids from pools in southeastern Saskatchewan, central Alberta, northeastern British Columbia and Lake Erie, Ontario. Trust units trade on the Toronto Stock Exchange under the symbol "NAE.UN".

**For further information:**

Investor Relations

Telephone: 403.294.3620

Toll Free: 888.223.8792

Fax: 403.294.3601

Email: [Investor.Relations@nal.ca](mailto:Investor.Relations@nal.ca)

Website: [www.nal.ca](http://www.nal.ca)