FOR IMMEDIATE RELEASE

Suite 1000, 550 – 6th Avenue SW
Calgary, Alberta T2P 0S2
Tel: 403.294.3600 Fax: 403.294.3601
Web Site: www.nal.ca Email: Investor.Relations@nal.ca
TSX: NAE.UN

NAL OIL & GAS TRUST REPORTS FIRST QUARTER 2009 RESULTS - INCREASES CAPITAL PROGRAM AND PRODUCTION GUIDANCE

Media Release No. 16-09 **May 5, 2009**

CALGARY, ALBERTA – NAL Oil & Gas Trust ("NAL" or the "Trust") today announced its financial and operational results for the first quarter of 2009. All amounts are in Canadian dollars unless otherwise stated.

On NAL's first quarter, Mr. Andrew Wiswell stated "Our positive first quarter and actions taken to add opportunities through the Trust's development program, partnerships and acquisitions have all contributed to increased capital and production guidance for 2009. NAL's financial flexibility remains strong with an attractive balance sheet, available credit lines, a shelf prospectus and a long term financial partner in Manulife."

2009 YEAR TO DATE ACTIVITY HIGHLIGHTS

- The Trust has made significant progress during the first quarter toward achieving key objectives for full year 2009. To date, the Trust has:
  - Captured opportunities with the proposed acquisition of Alberta Clipper Energy Inc. ("Alberta Clipper") in partnership with Manulife Financial Corp. ("Manulife") (expected to close June 1, 2009).
  - Finalized a multi-year joint venture partnership agreement with a major industry player in the Cardium oil play in central Alberta.
  - Experienced ongoing success in our natural gas exploration program with Talisman in Sukunka, B.C.
  - Remained committed to operate within cash flow during 2009, including distributions and capital.
  - Renewed the Trust's fully secured revolving credit facility at the current level of $450 million with its largely Canadian banking syndicate, $145 million of which is currently available.
  - Filed a base shelf prospectus to broaden financial flexibility and expedite access to capital to fund future opportunities.

SUMMARY OF FIRST QUARTER RESULTS

- Production volumes exceeded expectations in the first quarter, averaging 23,836 boe per day compared to 23,601 boe per day a year earlier and remains weighted 52 percent toward oil and liquids and 48 percent toward natural gas. This increase was largely due to strong performance from the Trust's fourth quarter 2008 and first quarter 2009 capital program.
- Funds from operations ("FFO"), equaled $62.0 million or $0.64 per unit ($0.62 fully diluted), 19 percent lower compared to $76.2 million or $0.83 per unit ($0.79 fully diluted) a year earlier. These results were driven by significantly lower commodity prices on a Canadian dollar basis, partially offset by higher production volumes and strong realized gains from the Trust's commodity hedging program.
- NAL's first quarter 2009 operating netback averaged $19.26 per boe before hedging, increasing by $12.95 per boe to $32.21 per boe after hedging. In comparison, the first quarter 2008 operating netback was 29 percent higher at $41.71 per boe after hedging. Higher operating costs per boe in first quarter 2009 were more than offset by lower royalty rates.
- Net capital expenditures by the Trust (excluding property acquisitions) totaled $36.9 million in the quarter, up 26 percent from $29.3 million a year ago. These higher expenditures were concentrated on horizontal oil drilling in Saskatchewan and Alberta, and drilling and completion activities in northeast B.C.
- Overall, net bank debt increased $6 million to $325 million at quarter end from $319 million at year end 2008, resulting in a net debt (including convertible debentures) to trailing 12 month cash flow ratio of 1.36 times.

2009 UPDATED GUIDANCE

Based upon positive first quarter performance and the opportunities added to our portfolio, the Trust has increased its production and capital guidance for 2009, while maintaining its objective of operating within cash flow. The capital program is flexible and will be adjusted based on commodity prices.

	February 2009 Guidance	March 2009 Inc. Alberta Clipper	May 2009 Increased Guidance Inc. Alberta Clipper
Production (boe/d)	22,000 – 23,000	22,700 – 23,700	23,000 – 24,000
Net capital expenditures ($MM)	95	95	115
Operating costs ($/boe)	11.60- 11.90	11.60 – 11.90	11.60 – 11.90

The Trust's expanded capital program is expected to be lower during break-up in the second quarter and ramp up in the third and fourth quarters, focusing on the Cardium resource play utilizing horizontal drilling with multi-stage fracs. The increased capital is expected to add eight to ten wells (65 percent working interest), which will be tied in over the last half of 2009 to take advantage of the new Alberta royalty incentive program. Overall, full year average production is expected to increase by 300 – 500 boe. This incremental program will be primarily funded by higher production volume, drilling and royalty credit under the Alberta Government three point incentive program and industry cost structures that are trending lower.

NAL outlines the following 2009 full year financial forecast based on certain key assumptions:

2009 Forecast Assumptions	**Key Assumptions**	
	Case 1	Case 2
WTI oil price (US$/bbl)(1)	45.00	55.00
AECO natural gas price (C$/GJ)(1)	3.50	4.00
Exchange rate (CAD/USD)(1)	1.23	1.20
Capital expenditures ($MM)	105	115
Production (boe/d) (2)	23,200	23,500
Monthly distribution ($/unit)	0.09	0.09

2009 Financial Forecasts	**Sensitivities**	
	Case 1	Case 2
Funds from operations ($MM)(3)	211	229
Full year weighted average number of units outstanding (MM)	100	100
Funds from operations ($/unit – basic)	$2.11	$2.29
Funds from operations ($/unit – fully diluted)	$2.00	$2.17
Payout ratio (%)	53	49
Payout with capital (%)	103	99
Payout with DRIP (%)	98	94
Debt / cash flow (x)	1.6 / 2.0(4)	1.5 / 1.8(4)

(1) Commodity and exchange rate forecasts use actual prices for the first quarter 2009 and utilize the key assumptions for the nine month period April – December 2009.
(2) Includes Alberta Clipper volumes net to the Trust effective June 1, 2009.
(3) Includes impact of hedging and estimated $7.5 million royalty rebate and drilling credit associated with the Alberta Government three point incentive program.
(4) Includes convertible debentures.

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 2009 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 May 5, 2009, NAL will hold a conference call to discuss the first quarter 2009 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 1-866-300-4047 toll free across North America. The conference call will also be accessible through the internet at http://events.onlinebroadcasting.com/nal/050509/index.php

A recorded playback of the call will be available until May 12, 2009 by calling 1-800-408-3053, reservation 4755352.

Notes: (1) All amounts are in Canadian dollars unless otherwise stated.
(2) When converting natural gas to barrels of oil equivalent (boe) within this report, NAL uses the widely recognized standard of six thousand cubic feet (Mcf) to one barrel of oil. However, boe's 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

Three months ended
(thousands of dollars, except per unit and boe data)
(unaudited)

	March 31, 2009	March 31, 2008	December 31, 2008
FINANCIAL			
Revenue[1]	**$80,662**	$145,209	$107,041
Cash flow from operating activities	**66,546**	70,561	77,326
Cash flow per unit - basic	**0.69**	0.77	0.80
Cash flow per unit - diluted	**0.67**	0.73	0.77
Funds from operations	**62,024**	76,220	67,040
Funds from operations per unit - basic	**0.64**	0.83	0.70
Funds from operations per unit - diluted	**0.62**	0.79	0.67
Net income	**4,724**	13,733	55,374
Distributions declared	**29,816**	44,025	46,167
Distributions per unit	**0.31**	0.48	0.48
Basic payout ratio:			
based on cash flow from operating activities	**45%**	62%	60%
based on funds from operations	**48%**	58%	69%
Basic payout ratio including capital expenditures[2]:			
based on cash flow from operating activities	**99%**	104%	110%
based on funds from operations	**107%**	96%	126%
Units outstanding (000's)			
Period end	**96,181**	93,519	96,181
Weighted average	**96,181**	91,717	96,145
Capital expenditures[3]	**36,936**	29,323	41,212
Property acquisitions (dispositions), net	**1,314**	6,870	(127)
Corporate acquisitions	**-**	58,107	315
Net debt[4]	**324,614**	309,347	319,044
Convertible debentures (at face value)	**79,744**	100,000	79,744
OPERATING			
Daily production			
Crude oil (bbl/d)	**9,990**	10,254	10,223
Natural gas (Mcf/d)	**68,966**	67,210	69,049
Natural gas liquids (bbl/d)	**2,352**	2,145	2,254
Oil equivalent (boe/d)	**23,836**	23,601	23,984
OPERATING NETBACK (boe)			
Revenue before hedging gains (losses)	**37.60**	67.61	48.51
Royalties	**(6.59)**	(13.65)	(9.59)
Operating costs	**(11.95)**	(9.91)	(11.67)
Other income[5]	**0.20**	0.22	0.18
Operating netback before hedging	**19.26**	44.27	27.43
Hedging gains (losses)	**12.95**	(2.56)	7.49
Operating netback	**32.21**	41.71	34.92

(1) Oil, natural gas and liquid sales less transportation costs and prior to royalties.
(2) Capital expenditures included are net of non-controlling interest amount of $0.6 million (2008 - $nil) attributable to the Tiberius and Spear properties
(3) Excludes property and corporate acquisitions.
(4) Bank debt plus working capital, excluding derivative contracts, notes payable/receivable and future income tax balances.
(5) Excludes interest 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 months ended March 31, 2009 and the audited consolidated financial statements and MD&A for the year ended December 31, 2008 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, excluding derivative contracts, notes payable/receivable and future income tax balances.

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

	Three months ended March 31	
$(000s)	2009	2008
Cash flow from operating activities	66,546	70,561
Add back change in non-cash working capital	(4,522)	5,659
Funds from operations	62,024	76,220

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; 2009 production; future tax treatment of the Trust; future structure of the Trust and its subsidiaries; the Trust's tax pools; future oil and gas prices; operating costs; the amount of future asset retirement obligations; future liquidity and future financial capacity; future results from operations; payout ratios; cost estimates and royalty rates; drilling plans;

tie-in of wells; future development, exploration, and acquisition and development activities and related expenditures; and the successful acquisition of Alberta Clipper Energy Inc. "Alberta Clipper")..

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 development activities; our ability to market our oil and natural gas successfully to current and new customers; the impact of increasing competition; our ability to obtain financing on acceptable terms; and our ability to add production and reserves through our development and exploitation activities.

Although NAL believes that the expectations reflected in the forward-looking information contained in the MD&A and the press release through which it was disseminated, and the assumptions on which such forward-looking information are made, are reasonable, readers are cautioned not to place undue reliance on such forward looking statements as there can be no assurance that the plans, intentions or expectations upon which the forward-looking information are based will occur. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated and which may cause NAL's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance. These risks and uncertainties include, without limitation: changes in commodity prices; unanticipated operating results or production declines; the impact of weather conditions on seasonal demand and ability to execute the 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 ability to obtain industry partner and other third party consents and approvals, when required; failure to receive the shareholders, court or regulatory approvals required to complete the acquisition of Alberta Clipper; 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; including the impact of legislation relating to the taxation of "specified investment flow-through" entities; stock market volatility and market valuations; OPEC's ability to control production and balance global supply and demand for crude oil at desired price levels; political uncertainty, including the risk of hostilities in the petroleum producing regions of the world; and other risk factors discussed in other public filings of the 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.

RECENT DEVELOPMENTS:

Base Shelf Prospectus

Earlier today, NAL filed a Preliminary Short Form Base Shelf Prospectus with the securities regulatory authorities in Canada. The base shelf prospectus is intended to increase flexibility and expedite access to capital to fund future opportunities. Once the prospectus is cleared and the shelf registration statement becomes effective, these filings will allow NAL to offer and issue Trust Units, Debt Securities, Subscription Receipts, and Warrants (collectively the "Securities") by way of one or more Prospectus Supplements at any time during the 25-month period that the prospectus remains in place. The Securities will be issued from time to time at the discretion of NAL, with an aggregate offering amount not to exceed Cdn $600 million. Unless otherwise indicated in a Prospectus Supplement relating to a particular offering of Securities, NAL intends to use the net proceeds from the sale of any Securities for the direct or indirect financing of future growth opportunities, including acquisitions and capital expenditures, repayment of indebtedness related to any such opportunities and/or general trust purposes. The terms of such future offerings, if any, would be established at the time of such offering. This news release shall not constitute an offer to sell or the solicitation of an offer to buy the Securities, nor shall there be any sale of the Securities in any jurisdiction in which such offer, solicitation or sale would be unlawful prior to registration or qualification under the securities laws of such jurisdiction.

Joint Venture Partnership Agreement

Effective April 20, 2009, the Trust and Manulife Financial Corporation ("MFC") entered into a joint venture partnership agreement with a senior industry player. The arrangement consists of a three year commitment to spend $50 million 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 Trusts 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 earn an interest in over 150 sections (97.5 net) of freehold and crown acreage. If the capital spending commitments are not met, interests in the freehold and crown acreage will not be earned and the Trust will not be required to pay unspent commitment amounts to the senior industry player. This transaction doubles NAL's Cardium oil acreage position by adding land south of NAL's Garrington area.

Renewal of Credit Facility

On April 6, 2009, the Trust announced the renewal of its credit facility at the previously approved amount of $450 million, with the same lending syndicate

Plan of Arrangement – Alberta Clipper Energy Inc.

On March 23, 2009 NAL and Alberta Clipper entered into an arrangement agreement pursuant to which NAL will indirectly acquire all of the issued and outstanding common shares of Alberta Clipper by way of a Plan of Arrangement. Under the arrangement, Alberta Clipper shareholders will receive 0.078875 trust units of NAL for each share of Alberta Clipper resulting in the expected issuance of approximately 5.7 million trust units. The transaction is subject to the approval of the Alberta Clipper shareholders, the Court of Queen's Bench of the Province of Alberta, and the regulatory authorities and is expected to close on or about June 1, 2009.

Concurrent with the execution of the arrangement agreement, the Trust has entered into a letter of agreement with MFC, pursuant to which MFC has agreed, subject to the satisfaction of certain conditions, including the preparation of definitive documentation, to purchase a 50 percent working interest in all the oil and gas assets of Alberta Clipper, for a cash purchase price of approximately $57.5 million adjusted to approximately $52.5 million to reflect the value of certain corporate assets not transferred to MFC. The letter of agreement between the Trust and MFC contains provisions whereby MFC will indemnify the Trust for a 50 percent share of certain corporate liabilities of Alberta Clipper. All of the cash proceeds received from MFC will be used to pay down the debt assumed by the Trust in the transaction. It is expected that the closing of the sale of assets to MFC will occur immediately following completion of the acquisition of Alberta Clipper by the Trust. MFC is a related party to the Trust, see "Related Party Transactions".

This acquisition is anticipated to add approximately 1,550 boe/d of net production to the Trust and 4.3 million boe of proved plus probable reserves, in addition to 110,000 acres of undeveloped land and $216 million of tax pools.

EXPLORATION & DEVELOPMENT ACTIVITIES

The Trust spent $30.5 million on drilling, completion and tie-in operations during the first quarter of 2009, compared to $22.5 million during the first quarter of 2008 and drilled 26 (9.8 net) wells in the first quarter, compared to 43 (18.4 net) wells during the same period in 2008.

The Trust participated in 14 (5.8 net) horizontal wells across Saskatchewan and Alberta during the quarter and it is expected that the remaining operated drilling program for 2009 will be focused on horizontal oil prospects.

First Quarter Drilling Activity

	Crude Oil		Natural Gas		Service Wells		Dry & Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Operated wells	11	6.1	4	2.8	0	0	0	0	15	8.9
Non-operated wells	5	0.4	6	0.5	0	0	0	0	11	0.9
Total wells drilled	16	6.5	10	3.3	0	0	0	0	26	9.8

Southeast Saskatchewan (Alida, Nottingham, Rosebank, Midale, Elswick)

In Saskatchewan, there were eight (3.1 net) horizontal oil wells drilled during the first quarter. Activity was focused on the Mississippian in Alida, Nottingham and Torquay with results meeting expectations. Construction on the expansion of the Nottingham gas plant is proceeding with start up expected by the third quarter.

Alberta (Garrington, Westward Ho, Drumheller, Pine Creek, Lacombe, Medicine River, Sylvan Lake)
In Alberta, NAL participated in drilling 18 (6.7 net) locations including 10 (0.9 net) non-operated minor interest wells. Operated drilling was successful in the Pine Creek and Garrington areas with five horizontal wells being brought on stream during the month of April at a combined flush production rate of 1,500 boe/d, net to the Trust. It is expected that these initial production rates will decline by 50 percent in the first two to three months of production.

N**ortheast British Columbia (Sukunka)**
NAL is a partner with Talisman, which has successfully completed the d-27-F well that tested at a rate of approximately 40 mmcf/d (Trust working interest 10 percent). Production is expected to be on stream by the third quarter of 2009. Processing capacity at the Pine River gas plant is limited so initial production rates will be restricted by system hydraulics and the available interruptible capacity at the plant. The Trust is also participating in one additional well at a-100-C (Trust working interest 20 percent) with drilling expected to be complete by mid year 2009.

CAPITAL EXPENDITURES

Capital expenditures, before property acquisitions, for the quarter ended March 31, 2009 totaled $36.9 million compared with $29.3 million for the quarter ended March 31, 2008. The year-over-year increase is attributed to a shift towards horizontal drilling and multi stage frac completions significantly increasing per well costs.

Capital Expenditures ($000s)

	Three months ended March 31	
	2009	2008
Drilling, completion and production equipment	30,464	22,530
Plant and facilities	2,859	3,231
Seismic	89	756
Land	1,975	994
Total exploitation and development	35,387	27,511
Office equipment	238	315
Capitalized G&A	1,159	942
Capitalized unit-based compensation	152	555
Total other capital	1,549	1,812
Total capitalized expenditures before acquisitions	36,936	29,323
Property acquisitions (dispositions), net	1,314	6,870
Total capitalized expenditures	38,250	36,193

PRODUCTION

First quarter 2009 production of 23,836 boe/d, which exceeded expectations, was above production of 23,601 boe/d in the comparable period of 2008. The increase is due to the ongoing execution of the Trust's capital program. New production from five horizontal wells in Alberta were positioned for April start up in order to capture new royalty incentives and are expected to provide a strong start to second quarter volumes.

Average Daily Production Volumes

	Three months ended March 31	
	2009	2008
Oil (bbl/d)	9,990	10,254
Natural gas (Mcf/d)	68,966	67,210
NGLs (bbl/d)	2,352	2,145
Oil equivalent (boe/d)	23,836	23,601

The oil equivalent volumes of 23,836 boe/d for the first quarter of 2009 include 442 boe/d (2008 – 212 boe/d), 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 23,394 boe/d for the first quarter of 2009, as compared to 23,389 boe/d for the first quarter of 2008.

For the quarter ended March 31, 2009, oil and natural gas liquids totaled 52 percent of production with natural gas at 48 percent.

Production Weighting

	Three months ended March 31	
	2009	2008
Oil	42%	43%
Natural gas	48%	48%
NGLs	10%	9%

REVENUE

Gross revenue from oil, natural gas and natural gas liquids sales, after transportation costs, totaled $80.7 million for the three months ended March 31, 2009, 44 percent lower than the first quarter of 2008. The decrease is due to a 44 percent decrease in the average realized price per boe, driven by a 50 percent decrease in the realized crude oil price and a 34 percent decrease in the realized natural gas price. The decrease in realized prices reflects lower West Texas Intermediate ("WTI"), partially offset by a weaker Canadian dollar, and lower AECO prices in the first quarter of 2009.

Revenue

	Three months ended March 31	
	2009	2008
Revenue[(1)] ($000s)		
Oil	40,684	83,888
Gas	32,576	48,796
NGL's	6,977	12,409
Sulphur	425	116
Total revenue	80,662	145,209
$/boe	37.60	67.61

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

OIL MARKETING

NAL sells 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 first quarter average realized Canadian crude oil price per barrel, net of transportation costs excluding hedging, was $45.25, as compared to $89.90 for the comparable quarter of 2008. The decrease in realized price quarter-over-quarter of 50 percent, or $44.65/bbl, was primarily driven by a 56 percent decrease in WTI (U.S.$/bbl) over the comparable period, partially offset by a 24 percent decrease in the value of the Canadian dollar.

For the first quarter of 2009, NAL's crude oil price differential was 84 percent, a decrease of eight percent from the comparable period in 2008. The differential is calculated as realized price as a percentage of WTI stated in Canadian dollars. The decrease in 2009 resulted from a wider differential between WTI and Edmonton/Cromer posted prices, due to lower demand for light crude in western Canada during the first quarter.

Natural gas liquids averaged $32.96/bbl in the first quarter of 2009, a 48 percent decrease from the $63.57/bbl realized in 2008.

NATURAL GAS MARKETING

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

For the three months ended March 31, 2009, the Trust's natural gas sales averaged $5.25/Mcf compared to $7.98/Mcf in the comparable period of 2008, a decrease of 34 percent. The quarter-over-quarter decrease in gas prices was attributable to a 38 percent decrease in the benchmark AECO daily spot prices.

Prices for Lake Erie natural gas decreased to $6.32/Mcf in the first quarter of 2009, compared to $9.23/Mcf in 2008, a decrease of 32 percent. Lake Erie production of 3.3 mmcf/d accounted for 5 percent of the Trust's natural gas production in the first quarter of 2009, the same percentage experienced during the comparable period of 2008. Natural gas sales from the Lake Erie property generally receive a higher price due to the close proximity of the Ontario and Northeastern U.S. markets.

Average Pricing
(net of transportation charges)

	Three months ended March 31	
	2009	2008
Liquids		
WTI (US$/bbl)	43.08	97.90
NAL average oil (Cdn$/bbl)	45.25	89.90
NAL natural gas liquids (Cdn$/bbl)	32.96	63.57
Natural Gas (Cdn$/mcf)		
AECO – daily spot	4.92	7.97
AECO – monthly	5.63	7.06
NAL Western Canada natural gas	5.19	7.93
NAL Lake Erie natural gas	6.32	9.23
NAL average natural gas	5.25	7.98
NAL Oil Equivalent before hedging (Cdn$/boe – 6:1)	37.60	67.61
Average Foreign Exchange Rate (Cdn$/US$)	1.245	1.004

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 management has authorization to hedge up to 50 percent of forecasted total production, net of royalties. Management's practice is to hedge more near-term volumes on a six 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 March 31, 2009, NAL had several financial WTI oil contracts and AECO natural gas contracts in place.

NAL's management has authorization to fix the interest rate on up to 50 percent of outstanding debt for periods of up to five years. As at March 31, 2009, NAL had several interest rate swaps outstanding with a total notional value of $139.0 million.

NAL's management has authorization to fix the foreign exchange rate on up to 50 percent of the Trust's U.S. dollar exposure for periods of up to 24 months. As at March 31, 2009, NAL had three exchange rate swaps outstanding with a total notional value of U.S.$48 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 March 31, 2009. 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 March 31, 2009. 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 March 31, 2009 was a net asset of $46.9 million, comprised of a $34.5 million asset on oil contracts, a $12.7 million asset on gas contracts and a $0.7 million asset on foreign exchange contracts, partially offset by a $1.0 million liability on interest rate swaps.

First quarter income for 2009 includes an $18.5 million unrealized loss on derivatives resulting from the change in the fair value of the derivative contracts during the quarter from an unrealized gain of $65.4 million at December 31, 2008 to an unrealized gain of $46.9 million at March 31, 2009. The $18.5 million unrealized loss was comprised of a $21.2 million unrealized loss on crude oil contracts and a $0.7 million unrealized loss on interest rate swaps, partially offset by a $2.7 million unrealized gain on natural gas contracts and a $0.7 million unrealized gain on foreign exchange swaps.

The gain/loss on derivative contracts is as follows:

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

	Three months ended March 31	
	2009	2008
Unrealized gain (loss):		
Crude oil contracts	(21,198)	(3,763)
Natural gas contracts	2,701	(18,772)
Interest rate swaps	(678)	-
Exchange rate swaps	671	-
Unrealized loss	(18,504)	(22,535)
Realized gain (loss):		
Crude oil contracts	20,752	(7,031)
Natural gas contracts	6,956	1,540
Interest rate swaps	(29)	-
Exchange rate swaps	83	-
Realized gain (loss)	27,762	(5,491)
Gain (loss) on derivative contracts	9,258	(28,026)

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

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

	Three months ended March 31	
	2009	2008
Commodity contracts:		
Average crude volumes hedged (bbl/d)	3,603	4,200
Crude oil realized gain (loss) ($000s)	20,752	(7,031)
Gain (loss) per bbl hedged ($)	63.99	(18.40)
Average natural gas volumes hedged (GJ/d)	29,000	20,841
Natural gas realized gain ($000s)	6,956	1,540
Gain per GJ hedged ($)	2.67	0.81
Average BOE hedged (boe/d)	8,185	7,492
Total realized commodity contracts gain ($000s)	27,708	(5,491)
Gain (loss) per boe hedged ($)	37.61	(8.05)
Gain (loss) per boe ($)	12.91	(2.56)
Exchange rate swaps realized gain ($000s)	83	-
Gain per boe ($)	0.04	-
Interest rate swaps realized loss ($000s)	(29)	-
Loss per boe ($)	(0.01)	-
Total realized gain (loss) ($000s)	27,762	(5,491)
Gain (loss) per boe ($)	12.94	(2.56)

Average hedged boes for the first quarter of 2009 were 8,185 as compared to 9,893 for the fourth quarter of 2008.

NAL has the following interest rate risk management contracts outstanding:

INTEREST RATE	Remaining Term	Amount (millions)[1]	Trust Fixed Rate	Counterparty Floating Rate
Swaps-floating to fixed	Apr 2009 – Dec 2011	$39.0	1.5864%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Apr 2009 – Jan 2013	$22.0	1.3850%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Apr 2009 – Jan 2014	$22.0	1.5100%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Mar 2010 – Mar 2013	$14.0	1.8500%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Mar 2010 – Mar 2013	$14.0	1.8750%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Mar 2010 – Mar 2014	$14.0	1.9300%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Mar 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	Remaining Term	Amount[1] (US$ MM)	Trust Fixed Rate	Counterparty Floating Rate
Swaps-floating to fixed	Apr 2009 – Nov 2009	$16.0	1.2730	BofC Average Noon Rate
Swaps-floating to fixed	Apr 2009 – Nov 2009	$16.0	1.2875	BofC Average Noon Rate
Swaps-floating to fixed*	Apr 2009 – Nov 2009	$16.0	1.2625	BofC Average Noon Rate

**Entered into subsequent to quarter-end*

(1) Notional US$ denominated commodity sales

NAL has the following commodity risk management contracts outstanding:

CRUDE OIL	Q2-09	Q3-09	Q4-09	Q1-10	Q2-10	Q3-10	Q4-10
US$ Collar Contracts							
$US WTI Collar Volume (bbl/d)	200	100	-	1,300	1,100	400	400
Bought Puts – Average Strike Price ($US/bbl)	$110.00	$110.00	-	$57.88	$58.41	$60.00	$60.00
Sold Calls – Average Strike Price ($US/bbl)	$154.95	$157.50	-	$69.29	$69.61	$70.61	$70.61
US$ Swap Contracts							
$US WTI Swap Volume (bbl/d)	-	900	900	-	-	-	-
Average WTI Swap Price ($US/bbl)	-	$59.22	$59.22	-	-	-	-
Cdn$ Collar Contracts							
$Cdn WTI Collar Volume (bbl/d)	1,567	1,100	1,500	300	-	-	-
Bought Puts – Average Strike Price ($Cdn/bbl)	$127.27	$121.56	$102.07	$66.00	-	-	-
Sold Calls – Average Strike Price ($Cdn/bbl)	$168.57	$170.81	$137.63	$80.17	-	-	-
Cdn$ Swap Contracts							
$Cdn WTI Swap Volume (bbl/d)	2,970	1,600	1,300	-	-	-	-
Average WTI Swap Price ($Cdn/bbl)	$92.49	$97.94	$92.55	-	-	-	-
Total Oil Volume (bbl/d)	4,737	3,700	3,700	1,600	1,100	400	400

NATURAL GAS	Q2-09	Q3-09	Q4-09	Q1-10	Q2-10	Q3-10
Collar Contracts						
AECO Collar Volume (GJ/d)	5,000	5,000	1,685	-	-	-
Bought Puts – AECO Average Strike Price ($Cdn/GJ)	$8.90	$8.90	$8.90	-	-	-
Sold Calls – AECO Average Strike Price ($Cdn/GJ)	$11.44	$11.44	$11.44	-	-	-
Swap Contracts						
AECO Swap Volume (GJ/d)	5,319	17,630	27,000	22,000	15,000	15,000
AECO Average Price ($Cdn/GJ)	$7.54	$6.01	$5.95	$5.95	$5.60	$5.60
Total Natural gas Volume (GJ/d)	10,319	22,630	28,685	22,000	15,000	15,000

For the remainder of 2009, the Trust has outstanding contracts representing approximately 40 percent of its net liquids and natural gas production after royalties, assuming a royalty rate of 20 percent.

ROYALTY EXPENSES

Crown, freehold and overriding royalties were $14.1 million for the three months ended March 31, 2009. Expressed as a percentage of gross sales net of transportation costs, before gain/loss on derivative contracts, the net royalty rate was 17.5 percent for the quarter ended March 31, 2009, a decrease from the 20.2 percent experienced in the same period of the previous year. Included in the first quarter of 2009 are a number of prior period benefits recognized in the current period.

Royalties decreased to $6.59 per boe for the first quarter of 2009, a decrease of 52 percent compared to the first quarter of 2008. The decrease is attributable to lower commodity prices on a quarter-over-quarter basis.

On January 1, 2009, the new royalty framework for Alberta became effective. This new framework, first announced on October 25, 2007, provides for conventional oil and gas royalties calculated on a sliding scale that is determined by commodity price and production volumes. Natural gas royalty rates have increased from 35 percent to 50 percent, with rates capped at $16.59/GJ. Crude oil royalty rates have increased from 35 percent to 50 percent, with rates capped at $120/bbl.

In response to the economic downturn, on November 19, 2008 the Government of Alberta announced special transitional rates for some conventional oil and gas wells. The lower transitional rates apply to newly drilled oil and gas wells at depths between 1,000 and 3,500 metres.

On March 3, 2009, the Government of Alberta announced a new three point incentive program for the energy sector. Firstly, there is a drilling royalty credit for new conventional oil and natural gas wells. The credit is on a sliding scale, based on prior year production levels, to a maximum of $200 per metre drilled or 50 percent of the royalties owed. Secondly, there is a new well incentive program that provides for a maximum five per cent royalty rate for the first 12 months of production up to a maximum of 50,000 barrels of oil or 500 million cubic feet of natural gas. The 12 month period starts on the date of production provided it occurs between April 1, 2009 and March 31, 2010.

Thirdly, the province will invest $30 million in a fund committed to abandoning and reclaiming old well sites, to encourage the clean up of inactive oil and gas wells.

For the quarter ended March 31, 2009, 25 percent of crude oil and 71 percent of natural gas production is from Alberta.

Royalty Expenses

	Three months ended March 31	
	2009	2008
Royalties ($000s)	14,134	29,311
As % of revenue	17.5	20.2
$/boe	6.59	13.65

OPERATING COSTS

Operating costs averaged $11.95 per boe for the quarter ended March 31, 2009, up from $9.91 per boe for the quarter ended March 31, 2008. A one time prior period adjustment from a non operated property added $0.33 per boe to quarterly operating costs.

Operating costs for the full year are expected to be at the lower end of guidance ($11.60 - $11.90 per boe) as activity falls off from 2008 levels and the Trust continues its program to reduce costs in all areas of its business.

Operating Costs

	Three months ended March 31	
	2009	2008
Operating costs ($000s)	25,640	21,273
As a % of revenue	31.8	14.6
$/boe	11.95	9.91

OTHER INCOME

Other income was $0.45 per boe for the first quarter of 2009 compared to $0.37 per boe in the comparable quarter of 2008. Other income includes gas processing, blending income, other miscellaneous income and fees and interest income and interest expense on notes due from and to MFC (see “Related Party Transactions”). In the first quarter of 2009, this interest totaled $0.5 million.

Other Income

	Three months ended March 31	
	2009	2008
Interest on notes with MFC ($000s)	544	323
Other ($000s)	420	482
Total other income ($000s)	964	805
As a % of revenue	1.20	0.55
Interest on notes with MFC ($/boe)	0.25	0.15
Other ($/boe)	0.20	0.22
Total other income ($/boe)	0.45	0.37

OPERATING NETBACK

For the quarter ended March 31, 2009, NAL’s operating netback before hedging gains was $19.26 per boe, a decrease of 56 percent from $44.27 per boe for the quarter ended March 31, 2008. The decrease was due to lower revenues, a result of lower commodity prices, and increased operating costs, partially offset by decreased royalty expense. Hedging gains, related to commodity and exchange rate derivative contracts, were $12.95 per boe in the first quarter of 2009, as compared to a loss of $2.56 per boe in 2008, attributable mainly to lower realized commodity prices in 2009.

Operating Netback ($/boe)

	Three months ended March 31	
	2009	2008
Revenue	37.60	67.61
Royalties	(6.59)	(13.65)
Operating expenses	(11.95)	(9.91)
Other income[(1)]	0.20	0.22
Operating netback, before hedging	19.26	44.27
Hedging gains (losses)[(2)]	12.95	(2.56)
Operating netback, after hedging	32.21	41.71

(1) Excludes interest on notes with MFC.
(2) 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 March 31, 2009, G&A expenses were $2.6 million, compared with $3.7 million in the comparable quarter of 2008. In addition, $1.2 million of G&A costs relating to exploitation and development activities were capitalized in the first quarter of 2009, compared with $0.9 million in the first quarter of 2008. G&A expense per boe was $1.22 in the quarter, as compared to $1.74 for the same period in 2008.

The year-over-year decrease in total G&A of $0.9 million is attributable to a lower payout under the 2008 short term incentive plan of the Manager than was provided for at December 31, 2008 ($0.6 million), plus other cost saving measures within G&A expenses.

General and Administrative Expenses

	Three months ended March 31	
	2009	2008
G&A expenses ($000s)		
G&A	2,627	3,641
Retention bonus	-	96
Expensed G&A ($000s)	2,627	3,737
Capitalized G&A ($000s)	1,159	942
Total G&A ($000s)	3,786	4,679
Expensed G&A costs:		
G&A, excluding retention bonus ($/boe)	1.22	1.70
Retention bonus ($/boe)	-	0.04
Total G&A expenses ($/boe)	1.22	1.74
As % of revenue	3.3	2.6
Per trust unit ($)	0.03	0.04

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 receiving cash compensation based upon the value and overall return of a specified number of notional trust units. 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 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 first quarter of 2009, the Trust recorded a $0.4 million charge for unit-based incentive compensation that reflects the impact of vesting, additional notional units and an increase in the PTU performance multiplier for the 2008 grants. These factors were partially offset by a decrease in the unit price of the Trust of 16 percent, from $8.05 at December 31, 2008 to $6.80 at March 31, 2009. A decrease in unit price results in previously accrued amounts being reversed.

Unit-based incentive compensation decreased by 73 percent compared to the first quarter of 2008, from $1.7 million in 2008 to $0.4 million in 2009. The decrease is a reflection of a 49 percent decrease in unit price used to determine the compensation, year-over-year. In addition, during the first quarter of 2008 the unit price increased from the December 31, 2007 unit price by 14 percent, resulting in an increase to previously accrued amounts.

At March 31, 2009, the unit price used to determine unit-based incentive compensation was $6.80. The closing unit price of the Trust on the Toronto Stock Exchange on May 4, 2009 was $9.38.

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 March 31, 2009, the Trust has recorded a liability for unit-based incentive compensation in the amount of $3.9 million, of which $2.5 million is recorded as current as it is payable in December 2009, and $1.4 million is long-term as it is payable in December 2010 and December 2011.

Unit-Based Compensation

	Three months ended March 31	
	2009	2008
Unit-based compensation ($000s):		
Expensed	293	1,108
Capitalized	152	555
Total unit-based compensation	445	1,663
Expensed unit-based compensation:		
As % of revenue	0.36	0.76
$/boe	0.14	0.52
Per trust unit ($)	0.01	0.01

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 (the "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 $1.9 million (2008 - $2.9 million) for the reimbursement of G&A expenses during the first quarter. 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 $2.4 million was paid in the first quarter of 2009, representing units that vested on November 30, 2008 (2008 - $1.8 million).

At March 31, 2009 the Trust owed the Manager $1.2 million for the reimbursement of G&A and had a payable to NAL Resources of $1.1 million, relating to capital expenditures less net operating revenues.

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 and 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. 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 over the Partnership as described below.

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 note receivable bore interest at prime plus three percent. 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 March 31, 2009, there is a note payable of $9.8 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 on these notes of $0.5 million for the first quarter of 2009 was received by the Trust and is reported as other income.

INTEREST

Interest on bank debt includes charges on borrowings, plus standby fees on the unused portion of the bank credit facility. Interest on bank debt for the first quarter of 2009 was $2.0 million, a decrease of $2.0 million from $4.0 million for the comparable period in 2008. The decrease was due to a decrease in the average effective interest rate, partially offset by an increase in average debt levels. Average outstanding bank debt for the first quarter of 2009 was $296.4 million, $0.9 million higher than the $295.5 million outstanding for the first quarter of 2008. NAL's effective interest rate averaged 2.58 percent during the first quarter of 2009, compared to 5.35 percent during the comparable period in 2008. The decrease in the rate from the first quarter of 2008 is attributable to lower rates in the market. NAL's interest is calculated based upon a floating rate.

Interest on convertible debentures represents interest charges of $1.3 million for the three months ended March 31, 2009 as compared to $1.7 million for the same period in 2008, based on interest at 6.75 percent, and accretion of the debt discount of $0.4 million (2008 - $0.5 million). The decrease in interest and accretion in 2009 is due to conversions of convertible debentures to trust units that occurred after March 31, 2008.

Interest and Debt

	Three months ended March 31	
	2009	2008
Interest on bank debt ($000s)	1,963	3,981
Interest and accretion on convertible debentures ($000s)	1,724	2,142
Total interest ($000)	3,687	6,123
Bank debt outstanding at period end ($000s)	304,918	313,370
Convertible debentures at period end ($000s)*	74,382	91,353
$/boe:		
Interest on bank debt	0.92	1.85
Interest on convertible debentures	0.63	0.78
Accretion on convertible debentures	0.17	0.22
Total interest	1.72	2.85

* *Debt component of the debentures, as reported on the balance sheet.*

CASH FLOW NETBACK

For the quarter ended March 31, 2009, NAL's cash flow netback was $29.54 per boe, a 20 percent decrease from $36.97 per boe for the comparable period in 2008. The decrease was due to lower operating netback after hedging,

offset by lower G&A expenses, including unit-based incentive compensation, lower interest charges and higher interest income on the notes with MFC.

Cash Flow Netback ($/boe)

	Three months ended March 31	
	2009	2008
Operating netback, after hedging	32.21	41.71
G&A expenses, including unit-based incentive compensation	(1.36)	(2.26)
Interest on bank debt and convertible debentures[(1)]	(1.55)	(2.63)
Interest on notes with MFC[(2)]	0.25	0.15
Realized loss on interest rate derivative contracts	(0.01)	-
Cash flow netback	29.54	36.97

(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 March 31, 2009, depletion on property, plant and equipment and accretion on the asset retirement obligations was $20.99 per boe, five percent lower than the $22.12 per boe for the same period in 2008. The decrease in depletion rate per boe in 2009 reflects an increase in proved reserves volumes and a decrease in the related cost base, year-over-year.

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 March 31	
	2009	2008
Depletion and depreciation ($000s)	43,208	45,712
Accretion of asset retirement obligation ($000s)	1,828	1,798
Total DDA ($000s)	45,036	47,510
DDA rate per boe ($)	20.99	22.12

TAXES

In the first quarter of 2009, NAL had a future income tax recovery of $6.1 million compared to a $6.5 million recovery in the corresponding period of the prior year. The recovery in the first quarter of 2009 is mainly attributable to the unrealized loss on derivative contracts, a result of a decrease in the fair value of derivative contracts since December 31, 2008.

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 March 31, 2009, the Trust's (including all subsidiaries) estimated tax pools (unaudited) available for deduction from future taxable income approximated $743.9 million, of which approximately 40 percent represented COGPE, 28 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)

	March 31, 2009	December 31, 2008
Canadian exploration expense	12	12
Canadian development expense	214	202
Canadian oil and gas property expense	295	301
Undepreciated capital costs	208	209
Other (including loss carry forwards)	15	14
Total estimated tax pools	744	738

Based on current strip prices at March 31, 2009, the Trust is not expected to be taxable in 2009.

Under the specified investment flow-through ("SIFT") legislation, which becomes 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. For 2009, the Trust has recognized $14.2 million of future income tax liability in the financial statements under the SIFT tax rules ($15.0 million in 2008), the decrease from 2008 reflecting a lower SIFT tax rate. It is expected that all remaining taxable temporary differences not recognized as a future tax liability will reverse prior to January 1, 2011, the date the taxation changes take effect. 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.

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 operations attributable to the Tiberius and Spear assets were as follows:

	Three months ended March 31			
$(000s)	2009[1]	Net Impact to Trust[2]	2008[3]	Net Impact to the Trust[2]
Total production volumes (boes)	79,527	39,764	38,680	19,340
Production volumes (boe/d)	884	442	425	213
Oil, natural gas and liquid sales	$3,630	$1,815	$3,910	$1,955
Royalties	(490)	(245)	(538)	(269)
Operating costs	(1,335)	(667)	(321)	(161)
General and administrative	(62)	(31)	(28)	(14)
Unit-based incentive compensation	(11)	(5)	(20)	(10)
Interest income, net	1,086	543	646	323
Depletion, depreciation and accretion	(1,101)	(551)	(199)	(99)
Net profit interest income (expense)	(486)	(243)	(2,957)	(1,478)
Net income	$1,231	$616	$493	$247

(1) Total results of the Partnership consolidated into the results of the Trust
(2) Net impact to the Trust, removing 50 percent of results attributable to MFC
(3) Represents results of operations commencing February 27, 2008, the closing date of the acquisition

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 March 31	
	2009	2008
Net profits interest expense	243	1,478
Share of net income attributable to MFC	616	247
	859	1,725

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 first quarter of 2009 was $4.7 million compared to $13.7 million for the comparable period in 2008. The decrease of $9.0 million was mainly due to decreased revenues net of royalties, ($49.2 million) and increased operating costs ($4.3 million), largely offset by increased gains on derivative contracts ($37.3 million) and decreased DD&A expense ($2.5 million).

Net Income ($000s)

	Three months ended March 31	
	2009	2008
Net income	4,724	13,733

CAPITAL RESOURCES AND LIQUIDITY

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

As at March 31, 2009, NAL had 96,181,397 trust units outstanding, the same amount as at December 31, 2008.

Under NAL's distribution reinvestment plan (the "DRIP"), unitholders may elect to reinvest distributions or make optional cash payments to acquire trust units from treasury under the DRIP 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.

The premium distribution reinvestment plan ("Premium DRIP") allows unitholders to exchange such 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 March 31, 2009 the Trust had net debt of $404.4 million (net of working capital and excluding derivative contracts, note payable with MFC and future income taxes) including convertible debentures at face value of $79.7 million. Excluding the convertible debentures, net debt was $324.6 million, compared with $319.0 million at December 31, 2008. The increase in net debt, excluding convertible debentures, of $5.6 million during 2009 is attributable to increased bank debt of $22.6 million, offset by a positive change in working capital of $17.0 million.

Bank debt outstanding was $304.9 million at March 31, 2009 compared with $282.3 million as at December 31, 2008. Of the $304.9 million outstanding at March 31, 2009, $5.9 million is outstanding under the working capital facility and $299.0 million outstanding under the production facility.

At the end of the first quarter, the Trust had a net debt (excluding convertible debentures) to 12 months trailing cash flow ratio of 1.09 times and a total net debt (including convertible debentures) to 12 months trailing cash flow ratio of 1.36 times.

Subsequent to quarter end, the Trust renewed its credit facility at the previously approved amount of $450 million. The credit facility is a fully secured, extendible, revolving facility and will revolve until April 28, 2010 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 $440 million production facility and a $10 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 April 29, 2011.

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 of $4 million. 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 $0.4 million (2008 - $0.5 million) of accretion of the debt discount in the first quarter of 2009.

As at May 4, 2009, the Trust has 96,352,012 trust units and $79.7 million in convertible debentures outstanding.

Capitalization

	March 31, 2009	December 31, 2008	March 31, 2008
Trust unit equity ($000s)	532,171	557,263	511,072
Bank debt ($000s)	304,918	282,332	313,370
Working capital deficit (surplus)[(1)] ($000s)	19,696	36,712	(4,023)
Net debt excluding convertible debentures	324,614	319,044	309,347
Convertible debentures ($000s)[(2)]	79,744	79,744	100,000
Net debt	404,358	398,788	409,347
Net debt excluding convertible debentures to trailing 12-month cash flow[(3)]	1.09	1.03	1.29
Total net debt to trailing 12-month cash flow[(3)]	1.36	1.28	1.70
Trust units outstanding (000s)	96,181	96,181	93,519

(1) Working capital excludes derivative contracts and future income tax asset.
(2) Convertible debentures included at face value.
(3) Calculated as net debt divided by funds from operations for the previous 12 months.

The current economic slowdown, reduced availability of credit, and challenging equity markets have resulted in the Trust setting its objective for 2009 to operating within forecasted funds from operations and targeting a total payout ratio of approximately 100 percent (distribution plus capital). 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 $450 million of which $305 million is drawn down at March 31, 2009, leaving available capacity of $145 million.

On March 11, 2009 the Trust announced a reduction in distributions from $0.11 per unit to $0.09 per unit commencing with the distribution to be paid on April 15, 2009. This reduction was made in response to declining commodity prices, taking into account the need for an ongoing capital program and maintenance of a strong balance sheet.

For 2009, the Trust is benefiting from an active hedging program at prices above current market levels. Currently, the Trust has in place oil hedges for approximately 43 percent of net budgeted production (after royalty) for the remaining nine months of 2009. Volumes are hedged at an average floor price of $99.96 per boe. For natural gas, remaining 2009 hedges total approximately 36 percent of net budgeted production volumes hedged at an average floor price in excess of $6.66 per GJ (or $7.02 per Mcf).

NAL's capital program for 2009 has been designed to be scalable and flexible in response to uncertain commodity prices and market conditions. NAL initially planned a $110 million capital program with the expectation to drill approximately 82 (40 net) wells. Capital for the first half of 2009 was reduced in February by $15 million in response to weaker commodity prices. Capital has now been increased for the second half of 2009 to reflect a $115 million program for 2009, in response to the Alberta Clipper acquisition and the joint venture partnership agreement. The Trust, through the Manager, operates over 90 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, other market factors, or growth opportunities may make it necessary to adjust forecasted capital expenditures 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 2009 and 2010, the Trust has approximately $1.11 billion of available safe harbour prior to the acquisition of Alberta Clipper, all of which is currently available.

ASSET RETIREMENT OBLIGATION

At March 31, 2009, the Trust reported an asset retirement obligation ("ARO") balance of $92.3 million ($90.8 million as at December 31, 2008) for future abandonment and reclamation of the Trust's oil and gas properties and facilities. The ARO balance was increased by $0.8 million due to liabilities incurred and revisions to estimates and $1.8 million from accretion expense, and was reduced by $1.1 million for actual abandonment and environmental expenditures incurred during the first quarter.

DISTRIBUTIONS TO UNITHOLDERS

For the three months ended March 31, 2009, the Trust distributed 45 percent of its cash flow from operating activities, as compared to 62 percent for the same period in 2008. 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 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 exceeded net income during 2009, 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 2009 capital program may not fully replace production. When the Trust sets distribution levels, depletion expense is not considered to be indicative of a measure for maintaining 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 the credit facility. However, given the current economic slowdown, the Trust is targeting cash flow to equal distributions and capital expenditures in order to preserve the Trust's balance sheet. Fluctuations in commodity prices, other market factors, or growth opportunities may make it necessary to adjust forecasted capital expenditures or distributions 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 assumptions that contribute to cash flow, namely production, operating costs and commodity prices. The implication of this policy is that the Trust is likely to continue to distribute in excess of its net income for any given period. 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 or continuing low commodity prices may impact cash from operating activities, access to credit facilities and the Trust's ability to fund operations and maintain distributions.

Distributions

	Three months ended March 31	
($000s except for percentages)	2009	2008
Cash flow from operating activities	66,546	70,561
Net income	4,724	13,733
Actual cash distributions paid or payable	29,816	44,025
Excess of cash flow from operating activities over cash distribution paid	36,730	26,536
Percentage of cash flow from operations distributed	45%	62%
Excess (shortfall) of net income over cash distributions paid	(25,092)	(30,292)

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 March 31, 2009, funds from operations amounted to $62.0 million, compared with $76.2 million for the three months ended March 31, 2008. The 19 percent decrease is due to lower revenues resulting from lower commodity prices, offset by realized hedging gains of $27.8 million. On a per trust unit basis, funds from operations decreased 23 percent from $0.83 in 2008 to $0.64 in 2009.

Funds from Operations

	Three months ended March 31	
	2009	2008
Funds from operations ($000s)	62,024	76,220
Funds from operations per trust unit	0.64	0.83
Payout ratio based on funds from operations	48%	58%

VARIABLE INTEREST ENTITIES

NAL has no variable interest entities.

CONTRACTUAL OBLIGATIONS

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)	2009	2010	2011	2012	2013
Office lease[(1)]	3,108	3,799	-	-	-
Transportation agreement	2,926	2,320	2,320	-	-
Processing agreement[(2)]	336	428	414	401	384
Convertible debentures[(3)]	-	-	-	79,744	-
Bank debt	-	-	182,951	121,967	-
Total	6,370	6,547	185,685	202,112	384

(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 59 percent) of the expense on a monthly basis.

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

(3) Principal amount.

QUARTERLY INFORMATION

	2009		2008				2007	
($000s, except per unit and production amounts)	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Revenue, net of royalties[(1)]	77,791	161,156	234,993[(3)]	58,861[(4)]	89,611	86,262	78,573	83,268
Per unit	0.81	1.68	2.46	0.63	0.98	0.96	0.95	1.06
Funds from operations[(2)]	62,024	67,040	79,233	88,578	76,220	59,537	50,817	54,156
Per unit	0.64	0.70	0.83	0.94	0.83	0.66	0.61	0.69
Net income (loss)	4,724	55,374	111,045	(17,572)	13,733	10,556	7,801	21,390
Per unit								
basic	0.05	0.58	1.16	(0.19)	0.15	0.12	0.09	0.27
diluted	0.05	0.56	1.11	(0.19)	0.15	0.12	0.09	0.27
Average oil equivalent production (boe/d – 6:1)	23,836	23,984	23,808	23,791	23,601	23,656	20,369	19,094

(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) Excluding the unrealized gain on derivative contracts of $111,053,000; Revenue, net of royalties would be $123,940,000
(4) Excluding the unrealized loss on derivative contracts of $70,148,000; Revenue net of royalties would be $129,009,000

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 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 and that all material information relating to NAL is made known to them by others.

INTERNAL CONTROL OVER FINANCIAL REPORTING ("ICFR")

NAL's certifying officers are responsible for establishing and maintaining ICFR. They have designed ICFR, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. The control framework the officers used to design NAL's ICFR is the *Internal Control – Integrated Framework* ("Framework") published by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

While management believes that NAL's controls provide a reasonable level of assurance with regard to their effectiveness, they do not expect that the DC&P or ICFR will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, but not absolute, assurance that the objectives of the control system are met.

There are no changes in the Trust's ICFR for the quarter ended March 31, 2009 that materially affected the Trust's ICFR.

CRITICAL ACCOUNTING ESTIMATES

The significant accounting policies used by NAL are disclosed in the notes to NAL's December 31, 2008 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, 2008.

NEW ACCOUNTING STANDARD

Goodwill and Intangible Assets

Effective January 1, 2009, the Trust implemented the provisions of CICA Handbook Section 3064, "Goodwill and Intangible Assets". Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets. Standards concerning goodwill are unchanged from the previous standards, resulting in no impact to the consolidated financial statements of the Trust from the implementation of this Section.

FUTURE ACCOUNTING CHANGES

International Financial Reporting Standards ("IFRS")

The Trust continues to prepare for the forthcoming conversion to IFRS. 2009 activities to date have concentrated on an in-depth review of the significant Canadian GAAP differences and their related policy choices. Other areas being addressed include the impacts on information systems, internal controls, financial reporting, debt covenants and compensation arrangements. For further details on the transition plan please refer to the annual MD&A.

Dated: May 5, 2009

CONSOLIDATED BALANCE SHEETS

(thousands of dollars) (unaudited)

	As at March 31, 2009	As at December 31, 2008
Assets		
Current assets		
Cash	**$12,615**	$5,584
Accounts receivable and other	**48,557**	57,825
Note receivable (Note 3)	**-**	49,599
Derivative contracts (Note 11)	**48,085**	65,680
	109,257	178,688
Derivative contracts (Note 11)	**25**	-
Goodwill	**14,722**	14,722
Property, plant and equipment (Note 4)	**1,013,022**	1,017,187
	$1,137,026	$1,210,597
Liabilities and Unitholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	**$72,212**	$84,732
Note payable (Note 3)	**9,814**	9,609
Distributions payable to unitholders	**8,656**	15,389
Future income tax liability	**11,731**	16,788
	102,413	126,518
Bank debt (Note 5)	**304,918**	282,332
Convertible debentures (Note 6)	**74,382**	74,004
Derivative contracts (Note 11)	**1,208**	274
Unit-based incentive compensation (Note 7)	**1,361**	890
Asset retirement obligations (Note 8)	**92,345**	90,844
Future income tax liability	**21,034**	22,092
Non-controlling interest (Note 9)	**7,194**	56,380
	604,855	653,334
Unitholders' equity		
Unitholders' capital (Note 10)	**1,042,183**	1,042,183
Equity component of convertible debentures (Note 6)	**4,592**	4,592
Deficit (Note10)	**(514,604)**	(489,512)
	532,171	557,263
	$1,137,026	$1,210,597
Subsequent event (Note 12)		
Trust units outstanding (000s)	**96,181**	96,181

See accompanying notes.

CONSOLIDATED STATEMENTS OF INCOME, COMPREHENSIVE INCOME AND DEFICIT

Three months ended March 31,

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

	2009	2008
Revenue		
Oil, natural gas and liquid sales	**$81,703**	$146,143
Crown royalties	**(10,611)**	(21,848)
Freehold and other royalties	**(3,523)**	(7,463)
	67,569	116,832
Gain (loss) on derivative contracts (Note 11):		
Realized gain (loss)	**27,762**	(5,491)
Unrealized loss	**(18,504)**	(22,535)
	9,258	(28,026)
Other income	**964**	805
	77,791	89,611
Expenses		
Operating	**25,640**	21,273
Transportation	**1,041**	934
General and administrative	**2,627**	3,737
Unit-based incentive compensation (Note 7)	**293**	1,108
Interest on bank debt	**1,963**	3,981
Interest and accretion on convertible debentures	**1,724**	2,142
Depletion, depreciation and amortization	**43,208**	45,712
Accretion on asset retirement obligations	**1,828**	1,798
	78,324	80,685
Income (loss) before taxes and non-controlling interest	**(533)**	8,926
Income tax recovery	**1**	4
Future income tax reduction	**6,115**	6,528
Total income tax reduction	**6,116**	6,532
Income before non-controlling interest	**5,583**	15,458
Non-controlling interest (Note 9)	**(859)**	(1,725)
Net income and comprehensive income	**4,724**	13,733
Deficit, beginning of period	**(489,512)**	(470,630)
Net income	**4,724**	13,733
Distributions declared	**(29,816)**	(44,025)
Deficit, end of period	**$(514,604)**	$(500,922)
Net income per trust unit (Note 10)		
Basic	**$0.05**	$0.15
Diluted	**$0.05**	$0.15
Weighted average trust units outstanding (000s)	**96,181**	91,717

See accompanying notes.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Three months ended March 31,
(thousands of dollars) (unaudited)

	2009	2008
Operating Activities		
Net income	**$4,724**	$13,733
Items not involving cash:		
Depletion, depreciation and amortization	**43,208**	45,712
Accretion on asset retirement obligations	**1,828**	1,798
Unrealized loss on derivative contracts	**18,504**	22,535
Future income tax reduction	**(6,115)**	(6,528)
Non-cash accretion expense on convertible debentures	**378**	477
Non-controlling interest	**616**	247
Abandonment and environmental expenditures	**(1,119)**	(1,754)
Change in non-cash working capital	**4,522**	(5,659)
	66,546	70,561
Financing Activities		
Distributions paid to unitholders	**(36,549)**	(36,376)
Increase in bank debt	**22,586**	37,740
Issue of trust units, net of issue costs	**-**	(14)
Note repayment from MFC (Note 3)	**49,599**	-
Partnership distribution paid to MFC	**(49,802)**	-
Change in non-cash working capital	**33**	(426)
	(14,133)	924
Investing Activities		
Additions to property, plant and equipment	**(36,936)**	(29,323)
Property acquisitions	**(1,314)**	(6,870)
Acquisition of Tiberius and Spear	**-**	(76,984)
Disposition of Tiberius and Spear	**-**	58,107
Acquisition of Seneca	**-**	337
Change in non-cash working capital	**(7,132)**	(2,969)
	(45,382)	(57,702)
Increase in cash	**7,031**	13,783
Cash, beginning of period	**5,584**	1,394
Cash, end of period	**$12,615**	$15,177
Supplementary disclosure of cash flow information:		
Cash paid (received) during the period for:		
Interest	**$4,678**	$6,522
Tax	**$(72)**	$-

See accompanying notes.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Three months ended March 31, 2009
(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, 2008. 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, 2008.

2. PLAN OF ARRANGEMENT

On March 23, 2009 NAL and Alberta Clipper Energy Inc. ("Alberta Clipper") entered into an arrangement agreement pursuant to which NAL will indirectly acquire all of the issued and outstanding common shares of Alberta Clipper by way of a Plan of Arrangement. Under the arrangement, Alberta Clipper shareholders will receive 0.078875 trust units of NAL for each share of Alberta Clipper held, resulting in the expected issuance of approximately 5.7 million trust units. The transaction is subject to the approval of the Alberta Clipper shareholders, the Court of Queens Bench of the Province of Alberta and regulatory authorities, and is expected to close on or about June 1, 2009.

Concurrent with the execution of the arrangement agreement, the Trust entered into a letter of agreement with Manulife Financial Corporation ("MFC"), pursuant to which MFC has agreed, subject to the satisfaction of certain conditions, including the preparation of definitive documentation, to purchase a 50% working interest in all the oil and gas assets of Alberta Clipper for a cash purchase price of approximately $52.5 million. It is expected that the closing of the sale of assets to MFC will occur immediately following completion of the acquisition of Alberta Clipper by the Trust.

3. RELATED PARTY TRANSACTIONS

The Trust is managed by NAL Resources Management Limited (the "Manager"). The Manager is a wholly-owned subsidiary of MFC and manages on their 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 $1.9 million (2008 - $2.9 million) for the reimbursement of G&A expenses during the first quarter. 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. During the first quarter, $2.4 million was paid relating to notional units that vested on November 30, 2008 (2008 - $1.8 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 note receivable bore interest at prime plus three percent. 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).

As at March 31, 2009, there is a note payable of $9.8 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 on these notes of $0.5 million for the first quarter of 2009 (2008 - $0.3 million) was received by the Trust and is reported as other income.

The following amounts are due to and from related parties as at March 31, 2009 and have been included in accounts receivable, note receivable, accounts payable and accrued liabilities and note payable on the balance sheet:

	March 31, 2009	December 31, 2008
Due to NAL Resources Limited	**$(1,146)**	$(10,042)
Due to NAL Resources Management Limited	**(1,185)**	(3,881)
Due (to) from Manulife Financial Corporation[1]	**(10,886)**	45,512
	$(13,217)	$31,589

(1) Included on consolidation, eliminated through non-controlling interest. Represents note payable $9.8 million (2008: $9.6 million), plus amounts due from (to) MFC of ($1.1) million (2008: $5.5 million), presented in accounts receivable, relating to the net interest and NPI amounts due.

4. PROPERTY, PLANT AND EQUIPMENT

	March 31, 2009	December 31, 2008
Petroleum and natural gas properties, at cost	**$1,948,567**	$1,909,524
Less: Accumulated depletion and depreciation	**(935,545)**	(892,337)
	$1,013,022	$1,017,187

Costs associated with undeveloped land of $40.1 million (2008 - $31.2 million) have been excluded from the depletion calculation for the three months ended March 31, 2009.

Future development costs for proved reserves of $46.3 million (2008 - $49.8 million) have been included in the depletion calculation.

During the three months ended March 31, 2009, the Trust capitalized $1.2 million (2008 - $0.9 million) of G&A costs and $0.2 million (2008 - $0.6 million) of unit-based incentive compensation that were directly related to exploitation and development programs.

5. BANK DEBT

	March 31, 2009	December 31, 2008
Production loan facility	**$298,961**	$281,984
Working capital facility	**5,957**	348
Total debt outstanding	**$304,918**	$282,332

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 $440 million production facility and a $10 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 28, 2010 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 2010, 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 April 29, 2011.

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 March 31, 2009 and December 31, 2008 all amounts outstanding were in Canadian dollars.

On March 31, 2009 the effective interest rate on amounts outstanding under the credit facility was 1.80 percent (2008 – 5.26 percent). The Trust's interest charge includes this fixed interest rate component, plus a standby fee, a stamping fee and the fee for renewal.

6. CONVERTIBLE DEBENTURES

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

	Principal amount of debentures	Debt component of debentures	Equity component of debentures
Balance, December 31, 2007	$100,000	$90,876	$5,759
Conversion to trust units	(20,256)	(18,568)	(1,167)
Accretion	-	1,696	-
Balance, December 31, 2008	$79,744	$74,004	$4,592
Accretion	-	378	-
Balance, March 31, 2009	$79,744	$74,382	$4,592

7. UNIT-BASED INCENTIVE COMPENSATION PLAN

The Trust recorded a total compensation expense of $0.5 million in the first three months of 2009, of which $0.3 million was recorded as an expense and $0.2 million as property, plant and equipment ($1.8 million was expensed and $0.8 million recorded as property, plant and equipment for the year ended December 31, 2008). The compensation expense was based on the March 31, 2009 trust unit price of $6.80 (December 31, 2008 - $8.05), 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:

	Three months ended March 31, 2009	Year ended December 31, 2008
Balance, beginning of period	**$5,802**	$4,996
Increase in liability	**488**	2,573
Cash payout, relating to units vested	**(2,362)**	(1,767)
Balance, end of period	**3,928**	$5,802
Current portion of liability[(1)]	**2,567**	$4,912
Long-term liability	**$1,361**	$890

(1) Included in accounts payable and accrued liabilities.

8. ASSET RETIREMENT OBLIGATIONS

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

	Three months ended March 31, 2009	Year ended December 31, 2008
Balance, beginning of period	**$90,844**	$89,602
Accretion expense	**1,828**	7,299
Revisions to estimates	**558**	(262)
Liabilities incurred	**234**	1,422
Liabilities acquired	**-**	1,636
Liabilities settled	**(1,119)**	(8,853)
Balance, end of period	**$92,345**	$90,844

NAL's estimated credit-adjusted risk-free rate of nine percent (2008 – eight to nine percent) and an inflation rate of two percent (2008 – 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 (Note 3). The non-controlling interest on the balance sheet represents 50 percent of the net assets of the Partnership as follows:

	Three months ended March 31, 2009	Year ended December 31, 2008
Non-controlling interest, beginning of period	**$56,380**	$-
Non-controlling interest on acquisition	**-**	54,057
Net income attributable to non-controlling interest	**616**	3,823
Distributions to MFC	**(49,802)**	(1,500)
Non-controlling interest, end of period	**$7,194**	$56,380

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

	Three months ended March 31	
	2009	2008
Net profits interest	**$243**	$1,478
Share of net income attributable to MFC	**616**	247
	$859	$1,725

10. UNITHOLDERS EQUITY

Units Issued:

	Three months ended March 31, 2009		Year ended December 31, 2008	
	Units	**Amount**	Units	Amount
Balance, beginning of the period	**96,181**	**$1,042,183**	90,494	$969,588
Issued on corporate acquisitions	**-**	**-**	2,409	29,496
Less issue expenses	**-**	**-**	-	(29)
Issued from Distribution Reinvestment Plan	**-**	**-**	1,831	23,393
Issued on conversion of debentures	**-**	**-**	1,447	19,735
Balance, end of the period	**96,181**	**$1,042,183**	96,181	$1,042,183

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 excludes the convertible debentures as the trust units potentially issuable on the conversion of the convertible debentures are anti-dilutive for the three months ended March 31, 2009 and 2008. 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 months ended March 31, 2009 were 5,696,000 (2008 – 7,142,857). As at March 31, 2009, the total convertible debentures outstanding were immediately convertible to 5,696,000 trust units.

Deficit
The deficit is comprised of the following:

	Three months ended March 31, 2009	Year ended December 31, 2008
Accumulated income	**$557,755**	$553,031
Accumulated cash distributions	**(1,072,359)**	(1,042,543)
	($514,604)	($489,512)

11. FINANCIAL RISK MANAGEMENT

Foreign currency exchange rate risk
During 2009 the Trust has entered into foreign exchange rate derivative contracts. NAL's management has authorization to fix the exchange rate on up to 50 percent of the Trust's U.S. dollar exposure for periods of up to 24 months.

NAL has the following foreign exchange rate derivative contracts outstanding:

EXCHANGE RATE	Remaining Term	Amount (US$ MM)(1)	Trust Fixed Rate	Counterparty Floating Rate
Swaps-floating to fixed	Apr 2009 – Nov 2009	$16.0	1.2730	BofC Average Noon Rate
Swaps-floating to fixed	Apr 2009 – Nov 2009	$16.0	1.2875	BofC Average Noon Rate
Swaps-floating to fixed*	Apr 2009 – Nov 2009	$16.0	1.2625	BofC Average Noon Rate

**Entered into subsequent to quarter-end*
(1) Notional US$ denominated commodity sales

Commodity price risk
NAL has the following commodity derivative contracts outstanding:

CRUDE OIL	Q2-09	Q3-09	Q4-09	Q1-10	Q2-10	Q3-10	Q4-10
US$ Collar Contracts							
$US WTI Collar Volume (bbl/d)	200	100	-	1,300	1,100	400	400
Bought Puts – Average Strike Price ($US/bbl)	$110.00	$110.00	-	$57.88	$58.41	$60.00	$60.00
Sold Calls – Average Strike Price ($US/bbl)	$154.95	$157.50	-	$69.29	$69.61	$70.61	$70.61
US$ Swap Contracts							
$US WTI Swap Volume (bbl/d)	-	900	900	-	-	-	-
Average WTI Swap Price ($US/bbl)	-	$59.22	$59.22	-	-	-	-
Cdn$ Collar Contracts							
$Cdn WTI Collar Volume (bbl/d)	1,567	1,100	1,500	300	-	-	-
Bought Puts – Average Strike Price ($Cdn/bbl)	$127.27	$121.56	$102.07	$66.00	-	-	-
Sold Calls – Average Strike Price ($Cdn/bbl)	$168.57	$170.81	$137.63	$80.17	-	-	-
Cdn$ Swap Contracts							
$Cdn WTI Swap Volume (bbl/d)	2,970	1,600	1,300	-	-	-	-
Average WTI Swap Price ($Cdn/bbl)	$92.49	$97.94	$92.55	-	-	-	-
Total Oil Volume (bbl/d)	4,737	3,700	3,700	1,600	1,100	400	400

NATURAL GAS	Q2-09	Q3-09	Q4-09	Q1-10	Q2-10	Q3-10
Collar Contracts						
AECO Collar Volume (GJ/d)	5,000	5,000	1,685	-	-	-
Bought Puts – AECO Average Strike Price ($Cdn/GJ)	$8.90	$8.90	$8.90	-	-	-
Sold Calls – AECO Average Strike Price ($Cdn/GJ)	$11.44	$11.44	$11.44	-	-	-
Swap Contracts						
AECO Swap Volume (GJ/d)	5,319	17,630	27,000	22,000	15,000	15,000
AECO Average Price ($Cdn/GJ)	$7.54	$6.01	$5.95	$5.95	$5.60	$5.60
Total Natural gas Volume (GJ/d)	10,319	22,630	28,685	22,000	15,000	15,000

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 March 31, 2009, if oil and natural gas liquids prices had been $1.00 per barrel lower and natural gas prices $0.10 per Mcf lower, with all other variables held constant, net income for the year would have been $2.1 million higher, due to changes in the fair value of the derivative contracts. An equal and opposite effect would have occurred to net income had oil and natural gas liquids prices been $1.00 per barrel higher and natural gas $0.10 per Mcf higher.

Interest rate risk

NAL has the following interest rate derivative contracts outstanding:

INTEREST RATE	Remaining Term	Amount (millions)[1]	Trust Fixed Rate	Counterparty Floating Rate
Swaps-floating to fixed	Apr 2009 – Dec 2011	$39.0	1.5864%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Apr 2009 – Jan 2013	$22.0	1.3850%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Apr 2009 – Jan 2014	$22.0	1.5100%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Mar 2010 – Mar 2013	$14.0	1.8500%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Mar 2010 – Mar 2013	$14.0	1.8750%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Mar 2010 – Mar 2014	$14.0	1.9300%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	Mar 2010 – Mar 2014	$14.0	1.9850%	CAD-BA-CDOR (3 months)

(1) Notional debt amount

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$49.66 per barrel to US$68.82 per barrel for oil and $3.78 per GJ to $7.20 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 1.166 percent to 1.539 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 1.2560 to 1.2606) as of the balance sheet date, using the notional commodity sale amount and outstanding term of the swap. The fair value of the derivative contracts is as follows:

	Three months ended March 31, 2009	Year ended December 31, 2008
Fair value of commodity contracts	**$47,183**	$65,680
Fair value of interest rate swaps	**(952)**	(274)
Fair value of foreign exchange rate swaps	**671**	-
	$46,902	$65,406

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

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

	Three months ended March 31	
	2009	2008
Unrealized gain (loss):		
Crude oil contracts	**(21,198)**	(3,763)
Natural gas contracts	**2,701**	(18,772)
Interest rate swaps	**(678)**	-
Exchange rate swaps	**671**	-
Unrealized gain (loss)	**(18,504)**	(22,535)
Realized gain (loss):		
Crude oil contracts	**20,752**	(7,031)
Natural gas contracts	**6,956**	1,540
Interest rate swaps	**(29)**	-
Exchange rate swaps	**83**	-
Realized gain (loss)	**27,762**	(5,491)
Gain (loss) on derivative contracts	**9,258**	(28,026)

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

	Three months ended March 31, 2009	Year ended December 31, 2008
Long term unrealized loss on derivative contracts	**$(1,208)**	$(274)
Long term unrealized gain on derivative contracts	**25**	-
Net long term unrealized loss on derivative contracts	**(1,183)**	(274)
Current unrealized gain on derivative contracts	**48,085**	65,680
Net fair value of derivative contracts	**$46,902**	$65,406

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

	Three months ended March 31	
	2009	2008
Unrealized gain (loss), beginning of period	**65,406**	$(9,584)
Unrealized gain (loss), end of period	**46,902**	(32,119)
Unrealized loss for the period	**(18,504)**	(22,535)
Realized gain (loss) in the period	**27,762**	(5,491)
Gain (loss) on derivative contracts	**9,258**	$(28,026)

12. SUBSEQUENT EVENT

Effective April 20, 2009, the Trust and MFC entered into a joint venture partnership agreement with a senior industry player. The arrangement consists of a three year commitment to spend $50 million, on or before August 31, 2012, that provides the Trust and MFC an opportunity 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. The three year commitment net to the Trust 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, or a $97.5 million net commitment 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 freehold and crown acreage will not be earned and the Trust will not be required to pay unspent commitment amounts to the senior industry player.

TRADING PERFORMANCE

	For the Quarter Ended			
	31-Mar-09	31-Dec-08	31-Mar-08	31-Dec-07
PRICE				
High	$8.99	$13.14	$13.47	$12.90
Low	$5.38	$5.90	$10.81	$10.94
Close	$6.80	$8.05	$13.25	$11.60
Daily Average Volume	359,591	475,410	321,650	291,677

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: 403.294.3600
Toll Free: 888.223.8792
Fax: 403.294.3601
Email: Investor.Relations@nal.ca
Website: www.nal.ca