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FOR IMMEDIATE RELEASE

NAL OIL & GAS TRUST REPORTS SECOND QUARTER 2009 RESULTS AND INCREASES 2009 CAPITAL PROGRAM

Media Release No. 25-09

August 6, 2009

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

On NAL’s second quarter, Mr. Andrew Wiswell stated “Despite challenging market conditions, in the first half of 2009, I am extremely pleased with the performance of the Trust from both a financial and operational perspective. Operationally, our second quarter volume performance is consistent with management’s expectations and the Trust has added attractive opportunities to our portfolio. As we move into the second half of the year, the Trust is planning to spend \$70 - \$80 million on oil opportunities in Alberta and Saskatchewan and we expect full year production to be at the upper end of our guidance range, setting the Trust up for continued strong performance into 2010.

Financially, the Trust continues to retain more than \$200 million in available credit on its \$450 million credit facility having completed an \$86 million equity financing in the quarter. With new opportunities added to NAL’s portfolio, management has increased the Trust’s capital budget from \$115 million to \$125 - \$135 million. As a result of the increased spending on internal opportunities, the Trust’s 2009 total payout ratio (including capital) is anticipated to be in the 105 – 110 percent range, well within our financial capability”.

2009 MID-YEAR REVIEW & HIGHLIGHTS

In the first half of 2009, NAL delivered overall performance that has exceeded management’s financial, operational and strategic objectives. Highlights include:

- Delivering operational and financial performance on track with increased guidance despite turnarounds and lower capital spending in the second quarter;
- Raising \$86 million in equity in a financing which included institutional participation of 50 percent;
- Retaining a \$450 million credit facility with over \$200 million remaining available at mid year;
- Materially broadening the Trust’s opportunity base and adding significant resource potential to the asset portfolio by:
 - Announcing the corporate acquisition of Spearpoint Energy Corporation including a farm-in arrangement which adds exclusive access to an additional 1,400 sections of oil and natural gas prospective acreage, a portion of which is adjacent to existing Cardium oil lands held by NAL;
 - Closing the Alberta Clipper Energy Inc. acquisition and integrating the Clipper assets by the end of the second quarter;
 - Completing a long term joint venture agreement with a senior industry partner on acreage that is on trend with the Trust’s Cardium oil play at Garrington;
 - Executing the capital program effectively, meeting or exceeding internal targets;
 - Continuing to establish the Cardium tight oil play with horizontal drilling and multi-stage fracture stimulation technology;
 - Increasing the Trust’s total net undeveloped acreage by approximately 120,000 acres plus access to 1,500 gross sections of joint venture and farm-in acreage; and
- Increasing the Trust’s tax pools to \$936 million from \$738 million at year end 2008.

OUTLOOK

Looking forward over the next six months, NAL expects to continue to deliver strong performance and add value added opportunities to its portfolio by:

- Delivering full year production volumes within the upper end of the range of guidance;
- Focusing on continuing to develop tight oil Cardium opportunities and Saskatchewan conventional prospects while deferring future multi-zone and shallow natural gas opportunities;
- Actively managing its balance sheet and payout ratios, while maintaining an attractive debt to cash flow ratio relative to peers; and
- Capturing value added strategic transactions with the Trust's financial partner Manulife.

2009 UPDATED GUIDANCE

Based upon positive second quarter performance and the opportunities added to our portfolio, the Trust has increased its capital guidance for 2009. The capital program is flexible and will be adjusted based on commodity prices.

	January 2009 Guidance	August 2009 Increased Guidance
Production (boe/d)	22,000 – 23,000	23,000 – 24,000
Net capital expenditures (\$MM)	95	125-135
Operating costs (\$/boe)	11.60- 11.90	11.60 – 11.90

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 3:00 p.m. MDT (5:00 p.m. EDT) on August 6, 2009, NAL will hold a conference call to discuss the second 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 1-866-225-2055 toll free across North America. The conference call will also be accessible through the internet at <http://events.onlinebroadcasting.com/nal/080609/index.php>

A recorded playback of the call will be available until August 13, 2009 by calling 1-800-408-3053, reservation 7383861.

- 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(thousands of dollars, except per unit and boe data)
(unaudited)

	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
FINANCIAL				
Revenue ⁽¹⁾	\$82,650	\$187,341	\$163,312	\$332,550
Cash flow from operating activities	63,690	73,295	130,236	143,856
Cash flow per unit - basic	0.63	0.78	1.31	1.55
Cash flow per unit - diluted	0.60	0.74	1.27	1.47
Funds from operations	51,998	88,578	114,022	164,798
Funds from operations per unit - basic	0.51	0.94	1.15	1.77
Funds from operations per unit - diluted	0.50	0.89	1.11	1.68
Net loss	(9,407)	(17,572)	(4,683)	(3,839)
Distributions declared	27,422	45,302	57,238	89,327
Distributions per unit	0.27	0.48	0.58	0.96
Basic payout ratio:				
based on cash flow from operating activities	43%	62%	44%	62%
based on funds from operations	53%	51%	50%	54%
Basic payout ratio including capital expenditures ⁽²⁾ :				
based on cash flow from operating activities	69%	98%	85%	101%
based on funds from operations	84%	81%	97%	88%
Units outstanding (000's)				
Period end	111,865	95,277	111,865	95,277
Weighted average	101,868	94,101	99,040	92,909
Capital expenditures ⁽³⁾	16,952	26,748	53,888	56,071
Property acquisitions (dispositions), net	1,221	966	2,535	7,836
Corporate acquisitions, net	37,350	-	37,350	58,363
Net debt, excluding convertible debentures ⁽⁴⁾	266,894	292,690	266,894	292,690
Convertible debentures (at face value)	79,744	82,259	79,744	82,259
OPERATING				
Daily production				
Crude oil (bbl/d)	9,725	10,286	9,857	10,270
Natural gas (Mcf/d)	67,654	68,890	68,306	68,050
Natural gas liquids (bbl/d)	2,048	2,023	2,199	2,084
Oil equivalent (boe/d)	23,049	23,791	23,440	23,696
OPERATING NETBACK (boe)				
Revenue before hedging gains (losses)	39.40	86.53	38.49	77.11
Royalties	(7.44)	(17.99)	(7.01)	(15.83)
Operating costs	(11.80)	(10.37)	(11.88)	(10.14)
Other income ⁽⁵⁾	0.14	0.24	0.17	0.23
Operating netback before hedging	20.30	58.41	19.77	51.37
Hedging gains (losses)	10.65	(10.04)	11.82	(6.31)
Operating netback	30.95	48.37	31.59	45.06

(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 \$0.5 million (2008 - \$0.4) for the three months ended June 30, 2009 and \$1.1 million (2008 - \$0.4) for the six months ended June 30, 2009, attributable to the Tiberius and Spear properties.

(3) Excludes property and corporate acquisitions.

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

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

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion and analysis ("MD&A") should be read in conjunction with the interim unaudited consolidated financial statements for the three and six month periods ended June 30, 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 and other liabilities excluding derivative contracts, notes payable/receivable and future income tax balances.

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

\$(000s)	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
Cash flow from operating activities	63,690	73,295	130,236	143,856
Add back change in non-cash working capital	(11,692)	15,283	(16,214)	20,942
Funds from operations	51,998	88,578	114,022	164,798

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 and 2010 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, drilling and completion costs; the amount of future asset retirement

obligations; future liquidity and future financial capacity; future results from operations; payout ratios; cost estimates and royalty rates; drilling plans; tie-in of wells; future development, exploration, and acquisition and development activities and related expenditures; and the successful acquisition of Spearpoint Energy Corp.

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 complete the acquisition of Spearpoint Energy Corp.; 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

Acquisition of Spearpoint Energy Corp. ("Spearpoint")

On August 5, 2009, the Trust announced the execution of a Share Purchase and Sale Agreement to acquire all of the issued and outstanding shares of Spearpoint, for total consideration (including the assumption of Spearpoint indebtedness) of \$16.2 million. The assets of Spearpoint include current natural gas production of approximately 350 boe/d and a Farm-in Agreement with a senior industry partner, the benefits and commitments of which will be assumed by the Trust on closing.

The Farm-in Agreement ("Agreement") will be amended at closing to provide for a two year initial commitment commencing July 2009, with minimum capital commitments of \$40 million in the first year and \$57 million in the second year, with an option for a third year, at Spearpoint's election, for an additional \$50 million commitment. The Agreement provides the opportunity to earn an interest in approximately 1,400 gross sections of undeveloped oil and gas rights in Alberta held by the partner. If the capital spending commitments are not met, interests in the acreage will not be earned and the Trust will not be required to pay any unspent amounts under the Agreement.

Subsequent to the closing of the acquisition, the Trust intends to enter into an agreement with Manulife Financial Corporation ("MFC"), pursuant to which MFC will purchase a 40 percent working interest in all of the assets of Spearpoint for approximately \$6.5 million. MFC is a related party to the Trust, see "Related Party Transactions".

It is expected that these transactions will be completed on or before August 31, 2009 and future capital expenditure commitments will be shared on a 60 percent Trust / 40 percent MFC basis.

Disposition of non-operated property

Subsequent to the quarter end, the Trust has agreed to sell a non-operated property for net proceeds of \$15 million. The transaction is expected to close in the third quarter of 2009.

ACQUISITION OF ALBERTA CLIPPER ENERGY INC.

Effective June 1, 2009, the Trust acquired all of the issued and outstanding common shares of Alberta Clipper Energy Inc. ("Clipper"), which has interests in petroleum and natural gas properties and undeveloped land in Alberta and northeast British Columbia.

As consideration the Trust issued 5.7 million trust units at a price of \$6.45 a trust unit for total consideration, before acquisition costs, of \$36.6 million. The trust unit price was based on the weighted average market price of trust units at the date of announcement, being March 23, 2009. This purchase price included the assumption of \$78.9 million in bank debt.

Concurrent with the corporate acquisition, the Trust entered into an Asset Purchase and Sale Agreement ("PSA") with MFC, pursuant to which MFC acquired a 50 percent working interest in all of the Clipper petroleum and natural gas properties for a base price of \$52.5 million payable in cash. The proceeds received from MFC were used to partially repay the assumed bank debt.

Included within the PSA is a base price adjustment clause that ensures the Trust and MFC share equally in all assets or liabilities related to Clipper that pertain to periods on or prior to the effective date of the acquisition, regardless of their date of discovery or disclosure. The base price adjustment calculation will adjust the purchase price that MFC pays the Trust for any change in working capital from amounts determined at the time the base price of \$52.5 million was established. In addition, the costs associated with contracts outstanding at the date of acquisition will be equally shared between both parties on an ongoing basis, as the obligations are settled by the Trust. The amounts due under this base price adjustment clause are to be settled no more frequently than quarterly commencing December 2009. As at June 30, 2009, the Trust had a receivable from MFC of \$0.2 million relating to these price adjustments.

As a result, after taking into effect the MFC disposition and MFC's share of the assets and liabilities to be settled under the base price adjustment clause, the Trust acquired property, plant and equipment of \$54.5 million, a future tax asset (reflecting the excess of tax pools over book value) of \$17.9 million, representing assets totaling \$72.4 million, and assumed liabilities including asset retirement obligations of \$7.3 million, bank debt of \$26.2 million and a lease obligation of \$1.5 million, for consideration of \$37.4 million, including estimated acquisition costs of \$0.8 million.

EXPLORATION & DEVELOPMENT ACTIVITIES

The Trust spent \$7.6 million on drilling, completion and tie-in operations during the second quarter of 2009, compared to \$17.8 million during the second quarter of 2008 and drilled five (2.7 net) wells in the second quarter, compared to 23 (11.1 net) wells during the same period in 2008.

Drilling in the quarter consisted of horizontal wells in Saskatchewan and Alberta and it is expected that the remaining operated drilling program for 2009 will be focused on horizontal oil prospects. The Trust has drilled 31(12.5 net) wells year-to-date and is planning to drill an additional 38 (23 net) horizontal oil wells for the remainder of the year. It is anticipated that there will be less non-operated activity as other operators defer drilling resulting in the gross well count being lower than previously expected. Consequently, the net well count will move up significantly with go forward activity almost exclusively targeting higher working interest operated properties.

Second Quarter Drilling Activity

	Crude Oil		Natural Gas		Service Wells		Dry & Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Operated wells	5	2.7	0	0	0	0	0	0	5	2.7
Non-operated wells	0	0	0	0	0	0	0	0	0	0
Total wells drilled	5	2.7	0	0	0	0	0	0	5	2.7

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

In Saskatchewan, there were three (1.3 net) horizontal oil wells drilled during the second quarter. Activity was focused on the Mississippian in Parkman and Star Valley with results meeting expectations. The Trust intends to drill 15 (7.5 net) horizontal Mississippian oil wells across its significant land base focusing on Alida, Nottingham, Midale, Torquay, Whitebear and Hoffer. Construction on the expansion of the Nottingham gas plant has resumed with all skid supply issues having been resolved and start up expected in November 2009.

Alberta (Garrington, Westward Ho, Drumheller, Pine Creek, Lacombe, Medicine River, Sylvan Lake)

In Alberta, NAL participated in drilling two (1.4 net) locations in the Cardium at Garrington and Pine Creek in the second quarter with production expected by August. Going forward, the Trust intends to drill 23 (15.5 net) horizontal Cardium oil wells in Garrington and Pine Creek for the remainder of the year. This activity will consist of five wells on the recently announced Spearpoint farm-in lands at Garrington and Pine Creek, three Cardium wells on the new joint venture lands announced in the first quarter located south of Garrington and 15 wells in the Garrington and Pine Creek areas on legacy NAL acreage. Reduced drilling and completion costs coupled with execution efficiency gains are forecast to generate a 20 percent operating cost reduction compared to the fourth quarter of 2008. The Trust will continue to test additional optimization strategies including drilling multiple wells from single pads and changing from oil to water based fracs in Garrington to gain further cost efficiencies.

Northeast British Columbia (Sukunka)

NAL and its partner Talisman have successfully completed and tied in the d-27-F well with gross raw initial production rates of 43 mmcf/d. Production is expected to be limited somewhat due to the hydraulics of the gathering system and plant capacity at Pine River. The Trust expects its 10 percent share of d-27-F to add 200 boe/d of incremental gas production which will support a flat production profile from the Sukunka area for the remainder of the year. This well will fill additional capacity that opens up due to declining production from existing wells. The Trust expects to reach total depth and test the current well drilling at a-100-C (Trust working interest is 20 percent) by the end of the third quarter of 2009.

CAPITAL EXPENDITURES

Capital expenditures, before property acquisitions, for the quarter ended June 30, 2009 totaled \$17.0 million compared with \$26.7 million for the quarter ended June 30, 2008. The decrease in capital spending year-over-year related to the second quarter is directly attributable to less drilling activity. A significant first quarter drilling program was completed despite challenging commodity prices and market conditions with the understanding that capital spending would be revisited at the end of the first quarter and through break up. The second quarter capital program was on plan and the Trust was able to evaluate production from new wells related to first quarter drilling in order to validate significant programs and build inventory from recent acquisitions for the remainder of the year. As we move into the third quarter, oil prices have recovered from earlier lows, although natural gas prices continue to be weak. The Trust has an expanding inventory of oil prospects through organic development and major partnerships that have recently been secured. NAL added \$20 million of capital at the end of the first quarter to support this activity and expects to spend an incremental \$10 - 20 million to support drilling on the wide area farm-in related to the recently announced Spearpoint acquisition. Full year capital is now expected to be \$125 - 135 million depending on commodity prices and timing of program execution.

On a year-to-date basis, capital expenditures, before property acquisitions, totaled \$53.9 million compared to \$56.1 million in the comparable period of 2008.

Capital Expenditures (\$000s)

	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
Drilling, completion and production equipment	7,622	17,754	38,086	40,284
Plant and facilities	5,531	3,476	8,390	6,707
Seismic	158	51	247	807
Land	486	2,828	2,461	3,822
Total exploitation and development	13,797	24,109	49,184	51,620
Office equipment	142	303	380	618
Capitalized G&A	1,835	1,401	2,994	2,343
Capitalized unit-based compensation	1,178	935	1,330	1,490
Total other capital	3,155	2,639	4,704	4,451
Total capitalized expenditures before acquisitions	16,952	26,748	53,888	56,071
Property acquisitions (dispositions), net	1,221	966	2,535	7,836
Total capitalized expenditures	18,173	27,714	56,423	63,907

PRODUCTION

Second quarter 2009 production was 23,049 boe/d, compared to production of 23,791 boe/d in the same period of 2008. Volumes were slightly ahead of our plan in the second quarter and the Trust remains well positioned to meet the higher end of full year guidance (23,000 - 24,000 boe/d). Lower year-over-year production in the second quarter is directly related to lower commodity prices and challenging market conditions. As in previous years, second quarter production tends to be the lowest of the year due to turnaround activities and limited access for well operations due to spring break up. The Trust actively manages and anticipates these activities and the impacts on production during the quarter were in line with expectations. On a year-to-date basis, production was 23,440 boe/d, compared to 23,696 boe/d for the comparable period of 2008.

The addition of incremental capital added throughout the second half of the year does not impact the 2009 annual average production significantly. Provided commodity prices remain favourable, the Trust is expecting growth in production for 2010 such that full year average volumes would be between 24,300 - 25,300 boe/d.

Average Daily Production Volumes

	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
Oil (bbl/d)	9,725	10,286	9,857	10,270
Natural gas (Mcf/d)	67,654	68,890	68,306	68,050
NGLs (bbl/d)	2,048	2,023	2,199	2,084
Oil equivalent (boe/d)	23,049	23,791	23,440	23,696

The oil equivalent volumes of 23,049 boe/d for the second quarter of 2009 and 23,440 boe/d year-to-date include 423 boe/d (2008 - 438 boe/d) and 432 boe/d (2008 - 325 boe/d), respectively, attributable to the non-controlling interest in the Tiberius and Spear properties (see "Related Party Transactions"). The Trust's net production, after deducting the non-controlling interest, is 22,626 boe/d for the second quarter of 2009 (2008: 23,353 boe/d), and 23,008 boe/d (2008: 23,371 boe/d) year-to-date.

Oil and natural gas liquids totaled 51 percent of production with natural gas at 49 percent during the first half of 2009.

Production Weighting

	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
Oil	42%	43%	42%	43%
Natural gas	49%	48%	49%	48%
NGLs	9%	9%	9%	9%

REVENUE

Gross revenue from oil, natural gas and natural gas liquids sales, after transportation costs and prior to hedging, totaled \$82.7 million for the three months ended June 30, 2009, 56 percent lower than the second quarter of 2008. The decrease is due to a three percent decrease in production and a 54 percent decrease in the average realized price per boe, driven by a 47 percent decrease in the realized crude oil price and a 65 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 second quarter of 2009.

For the six month period ended June 30, 2009, revenue after transportation costs totaled \$163.3 million, a decrease of 51 percent from the comparable period in 2008. The decrease is attributable to a 50 percent decrease in the average realized price per boe and a one percent decrease in production. The decrease in realized price reflects lower WTI, partially offset by a weaker Canadian dollar, and lower AECO prices in 2009.

	Revenue		Revenue	
	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
Revenue ⁽¹⁾ (\$000s)				
Oil	54,798	109,057	95,481	192,945
Gas	21,540	63,444	54,116	112,240
NGL's	6,152	14,363	13,130	26,771
Sulphur	160	477	585	594
Total revenue	82,650	187,341	163,312	332,550
\$/boe	39.40	86.53	38.49	77.11

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

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 second quarter average realized Canadian crude oil price per barrel, net of transportation costs excluding hedging, was \$61.92, as compared to \$116.51 for the comparable quarter of 2008. The decrease in realized price quarter-over-quarter of 47 percent, or \$54.59/bbl, was primarily driven by a 52 percent decrease in WTI (U.S.\$/bbl) over the comparable period, partially offset by a 16 percent decrease in the value of the Canadian dollar.

For the second quarter of 2009, NAL's crude oil price differential was 89 percent, a decrease of four percentage points 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 second quarter.

For the six months ended June 30, 2009, NAL's average oil price was \$53.52 per barrel as compared to \$103.23 for the comparable period in 2008. The decrease in realized price was driven by a 54 percent decrease in WTI (US\$/bbl) and a decrease in crude oil differentials to 86 percent from 92 percent in 2008, partially offset by a 20 percent decrease in the value of the Canadian dollar.

Natural gas liquids averaged \$33.01/bbl in the second quarter of 2009, a 58 percent decrease from the \$78.01/bbl realized in 2008. For the six months ended June 30, 2009, natural gas liquids averaged \$32.99/bbl, a decrease of 53 percent from the comparable period in 2008.

NATURAL GAS MARKETING

Approximately 74 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 26 percent tied to NYMEX or other indexed reference prices.

For the three months ended June 30, 2009, the Trust's natural gas sales averaged \$3.50/Mcf compared to \$10.12/Mcf in the comparable period of 2008, a decrease of 65 percent. The quarter-over-quarter decrease in gas prices was attributable to a 66 percent decrease in the benchmark AECO daily spot prices.

Prices for Lake Erie natural gas decreased to \$5.16/Mcf in the second quarter of 2009, compared to \$12.12/Mcf in 2008, a decrease of 57 percent. Lake Erie production of 3.2 mmcf/d accounted for five percent of the Trust's natural gas production in the second 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 proximity of the Ontario and Northeastern U.S. markets.

For the six months ended June 30, 2009, NAL averaged \$4.38/Mcf, a 52 percent decrease from the \$9.06 realized in the comparable period of 2008. The decrease in natural gas prices was attributable to a 54 percent decrease in the benchmark AECO daily spot prices.

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

	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
Liquids				
WTI (US\$/bbl)	59.62	123.99	51.35	110.94
NAL average oil (Cdn\$/bbl)	61.92	116.51	53.52	103.23
NAL natural gas liquids (Cdn\$/bbl)	33.01	78.01	32.99	70.58
Natural Gas (Cdn\$/mcf)				
AECO – daily spot	3.44	10.20	4.18	9.09
AECO – monthly	3.66	9.35	4.65	8.21
NAL Western Canada natural gas	3.42	10.01	4.31	8.98
NAL Lake Erie natural gas	5.16	12.12	5.75	10.67
NAL average natural gas	3.50	10.12	4.38	9.06
NAL Oil Equivalent before hedging (Cdn\$/boe – 6:1)	39.40	86.53	38.49	77.11
Average Foreign Exchange Rate (Cdn\$/US\$)	1.167	1.010	1.206	1.007

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 June 30, 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 June 30, 2009, NAL had several interest rate swaps outstanding with a total notional value of \$139 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 June 30, 2009, NAL had several exchange rate swaps outstanding with a total notional value of U.S.\$75.5 million.

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

All derivative contracts are recorded on the balance sheet at fair value based upon forward curves at June 30, 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 June 30, 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 June 30, 2009 was a net asset of \$17.8 million, comprised of a \$2.9 million asset on interest rate swaps, a \$13.1 million asset on gas contracts and a \$2.1 million asset on foreign exchange contracts, partially offset by a \$0.3 million liability on oil contracts.

Second quarter income for 2009 includes a \$29.5 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 \$46.9 million at March 31, 2009 and a \$0.4 million unrealized gain acquired with Clipper, to an unrealized gain of \$17.8 million at June 30, 2009. The \$29.5 million unrealized loss was comprised of a \$34.8 million unrealized loss on crude oil contracts, partially offset by a \$3.8 million unrealized gain on interest rate swaps and a \$1.5 million unrealized gain on foreign exchange swaps.

For the six months ended June 30, 2009, income includes an unrealized loss of \$48.0 million, resulting from the change in the fair value of the derivative contracts during the period, from an unrealized gain of \$65.4 million at December 31, 2008 and a \$0.4 million unrealized gain acquired with Clipper, to an unrealized gain of \$17.8 million at June 30, 2009. The unrealized loss was comprised of a \$56.0 million unrealized loss on crude oil contracts, partially offset by a \$2.7 million unrealized gain on natural gas contracts, a \$3.2 million unrealized gain on interest rate swaps and a \$2.1 million unrealized gain on foreign exchange swaps.

The risk management policies for 2010 are expected to remain consistent with 2009. The Trust's current positions are summarized in the tables below.

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

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

	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
Unrealized gain (loss):				
Crude oil contracts	(34,769)	(53,893)	(55,967)	(57,656)
Natural gas contracts	(10)	(16,255)	2,691	(35,027)
Interest rate swaps	3,828	-	3,150	-
Exchange rate swaps	1,467	-	2,138	-
Unrealized loss	(29,484)	(70,148)	(47,988)	(92,683)
Realized gain (loss):				
Crude oil contracts	15,901	(18,001)	36,653	(25,032)
Natural gas contracts	4,507	(3,729)	11,463	(2,189)
Interest rate swaps	(178)	-	(207)	-
Exchange rate swaps	1,929	-	2,012	-
Realized gain (loss)	22,159	(21,730)	49,921	(27,221)
Gain (loss) on derivative contracts	(7,325)	(91,878)	1,933	(119,904)

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

Realized Gain (Loss) on Derivative Contracts

	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
Commodity contracts:				
Average crude volumes hedged (bbl/d)	4,737	4,833	4,173	4,516
Crude oil realized gain (loss) (\$000s)	15,901	(18,001)	36,653	(25,032)
Gain (loss) per bbl hedged (\$)	36.88	(40.93)	48.52	(30.45)
Average natural gas volumes hedged (GJ/d)	10,484	29,330	19,691	25,085
Natural gas realized gain (\$000s)	4,507	(3,729)	11,463	(2,189)
Gain per GJ hedged (\$)	4.72	(1.40)	3.22	(0.48)
Average BOE hedged (boe/d)	6,394	9,466	7,284	8,479
Total realized commodity contracts gain (\$000s)	20,408	(21,730)	48,116	(27,221)
Gain (loss) per boe hedged (\$)	35.07	(25.23)	36.50	(17.64)
Gain (loss) per boe (\$)	9.73	(10.04)	11.35	(6.31)
Interest rate swaps realized gain (\$000s)	(178)	-	(207)	-
Loss per boe (\$)	(0.08)	-	(0.05)	-
Exchange rate swaps realized loss (\$000s)	1,929	-	2,012	-
Gain per boe (\$)	0.92	-	0.47	-
Total realized gain (loss) (\$000s)	22,159	(21,730)	49,921	(27,221)
Gain (loss) per boe (\$)	10.57	(10.04)	11.77	(6.31)

Average hedged boes for the second quarter of 2009 were 6,394 as compared to 8,185 for the first quarter of 2009.

NAL has the following interest rate risk management contracts outstanding:

INTEREST RATE	Remaining Term	Amount (Cdn\$ MM) ⁽¹⁾	Trust Fixed Rate	Counterparty Floating Rate
Swaps-floating to fixed	July 2009 – Dec 2011	\$39.0	1.5864%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	July 2009 – Jan 2013	\$22.0	1.3850%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	July 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	July 2009 – Nov 2009	\$10.0	1.2730	BofC Average Noon Rate
Swaps-floating to fixed	July 2009 – Nov 2009	\$10.0	1.2875	BofC Average Noon Rate
Swaps-floating to fixed	July 2009 – Nov 2009	\$10.0	1.2625	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1585	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1100	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1200	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1225	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1300	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1420	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1525	BofC Average Noon Rate

(1) Notional US\$ denominated commodity sales

NAL has the following commodity risk management contracts outstanding:

CRUDE OIL	Q3-09	Q4-09	Q1-10	Q2-10	Q3-10	Q4-10
<u>US\$ Collar Contracts</u>						
\$US WTI Collar Volume (bbl/d)	400	300	3,200	3,000	1,800	1,600
Bought Puts – Average Strike Price (\$US/bbl)	\$74.50	\$62.67	\$60.86	\$61.25	\$62.22	\$62.19
Sold Calls – Average Strike Price (\$US/bbl)	\$93.26	\$71.85	\$71.76	\$72.05	\$72.75	\$72.97
<u>US\$ Swap Contracts</u>						
\$US WTI Swap Volume (bbl/d)	1,633	1,700	200	200	-	-
Average WTI Swap Price (\$US/bbl)	\$61.60	\$61.94	\$75.00	\$75.00	-	-
<u>Cdn\$ Collar Contracts</u>						
\$Cdn WTI Collar Volume (bbl/d)	1,100	1,500	300	-	-	-
Bought Puts – Average Strike Price (\$Cdn/bbl)	\$121.56	\$102.07	\$66.00	-	-	-
Sold Calls – Average Strike Price (\$Cdn/bbl)	\$170.81	\$137.63	\$80.17	-	-	-
<u>Cdn\$ Swap Contracts</u>						
\$Cdn WTI Swap Volume (bbl/d)	1,600	1,300	-	-	-	-
Average WTI Swap Price (\$Cdn/bbl)	\$97.94	\$92.55	-	-	-	-
Total Oil Volume (bbl/d)	4,733	4,800	3,700	3,200	1,800	1,600
<hr/>						
NATURAL GAS	Q3-09	Q4-09	Q1-10	Q2-10	Q3-10	Q4-10
<u>Collar Contracts</u>						
AECO Collar Volume (GJ/d)	5,000	1,685	-	-	-	-
Bought Puts – AECO Average Strike Price (\$Cdn/GJ)	\$8.90	\$8.90	-	-	-	-
Sold Calls – AECO Average Strike Price (\$Cdn/GJ)	\$11.44	\$11.44	-	-	-	-
<u>Swap Contracts</u>						
AECO Swap Volume (GJ/d)	18,130	27,663	26,000	23,000	24,000	7,337
AECO Average Price (\$Cdn/GJ)	\$6.03	\$5.95	\$5.97	\$5.75	\$5.76	\$6.19
Total Natural gas Volume (GJ/d)	23,130	29,348	26,000	23,000	24,000	7,337

For the remainder of 2009, the Trust has outstanding contracts representing approximately 42 percent of its net liquids and natural gas production after royalties, assuming a royalty rate of 17.5 percent.

ROYALTY EXPENSES

Crown, freehold and overriding royalties were \$15.6 million for the three months ended June 30, 2009. Expressed as a percentage of gross sales net of transportation costs, before gain/loss on derivative contracts, the net royalty rate was 18.9 percent for the quarter ended June 30, 2009, a decrease from the 20.8 percent experienced in the same period of the previous year.

Royalties decreased to \$7.44 per boe for the second quarter of 2009, a decrease of 59 percent compared to the second quarter of 2008. The decrease is attributable to lower commodity prices on a quarter-over-quarter basis.

On a year-to-date basis, royalties were \$29.7 million, down from \$68.3 million in the comparable period of 2008. Expressed as a percentage of gross sales net of transportation costs, before gain/loss on derivative contracts, the net royalty rate was 18.2 percent as compared to 20.5 percent in the comparable period of 2008.

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. On June 25, 2009, the Government of Alberta announced a one year extension to the drilling royalty credit and new well incentive program to March 31, 2011. The five percent royalty rate incentive will be reported within royalties and the \$200 per metre drilling credit will be reported against capital. For the second quarter of 2009, no benefit of these incentives has yet been accrued.

For the six months ended June 30, 2009, 28 percent of crude oil and 68 percent of natural gas production is from Alberta.

Royalty Expenses

	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
Royalties (\$000s)	15,608	38,941	29,742	68,252
As % of revenue	18.9	20.8	18.2	20.5
\$/boe	7.44	17.99	7.01	15.83

OPERATING COSTS

Operating costs averaged \$11.80 per boe for the quarter ended June 30, 2009, up from \$10.37 per boe for the quarter ended June 30, 2008. Year-over-year operating cost increases are a direct result of the run up in commodity prices and the resulting inflation in costs during the first half of 2008. Operating expenses for the second quarter are in line with internal expectations. However, an aggressive program of cost reduction coupled with the natural cost responses to lower commodity prices are now starting to impact costs favourably. We expect operating costs to continue to decline as we move through the third and fourth quarters.

On a year-to-date basis, operating costs were \$11.88 per boe compared to \$10.14 per boe in 2008.

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

Operating Costs

	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
Operating costs (\$000s)	24,759	22,443	50,399	43,716
As a % of revenue	30.0	12.0	30.9	13.1
\$/boe	11.80	10.37	11.88	10.14

OTHER INCOME

Other income was \$0.08 per boe for the second quarter of 2009 compared to \$0.65 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"). The note receivable from MFC was settled in the first quarter of 2009, resulting in interest expense on the note payable in the second quarter of 2009 of \$0.1 million, as compared to net interest income of \$0.9 million in the second quarter of 2008. On a year-to-date basis interest totaled \$0.4 million compared to \$1.2 million for the comparable period of 2008, the decrease being attributable to the note repayment in March 2009.

Other Income

	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
Interest on notes with MFC (\$000s)	(129)	897	414	1,220
Other (\$000s)	308	486	729	968
Total other income (\$000s)	179	1,383	1,143	2,188
As a % of revenue	0.2	0.7	0.7	0.7
Interest on notes with MFC (\$/boe)	(0.06)	0.41	0.10	0.28
Other (\$/boe)	0.14	0.24	0.17	0.23
Total other income (\$/boe)	0.08	0.65	0.27	0.51

OPERATING NETBACK

For the quarter ended June 30, 2009, NAL's operating netback before hedging gains was \$20.30 per boe, a decrease of 65 percent from \$58.41 per boe for the quarter ended June 30, 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 \$10.65 per boe in the second quarter of 2009, as compared to a loss of \$10.04 per boe in 2008, attributable mainly to lower realized commodity prices in 2009.

On a year-to-date basis, similar trends resulted in an operating netback, before hedging, of \$19.77 per boe compared to \$51.37 per boe in 2008. Hedging gains, related to commodity and exchange rate derivative contracts, were \$11.82 for the six months ended June 30, 2009, as compared to a loss of \$6.31 per boe in 2008, attributable mainly to lower realized commodity prices in 2009.

Operating Netback (\$/boe)

	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
Revenue	39.40	86.53	38.49	77.11
Royalties	(7.44)	(17.99)	(7.01)	(15.83)
Operating expenses	(11.80)	(10.37)	(11.88)	(10.14)
Other income ⁽¹⁾	0.14	0.24	0.17	0.23
Operating netback, before hedging	20.30	58.41	19.77	51.37
Hedging gains (losses) ⁽²⁾	10.65	(10.04)	11.82	(6.31)
Operating netback, after hedging	30.95	48.37	31.59	45.06

(1) Excludes interest on notes with MFC.

(2) Realized hedging gains/losses on commodity and exchange rate derivative contracts

GENERAL AND ADMINISTRATIVE EXPENSES

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

For the three months ended June 30, 2009, G&A expenses were \$4.0 million, compared with \$4.5 million in the comparable quarter of 2008. In addition, \$1.8 million of G&A costs relating to exploitation and development activities were capitalized in the second quarter of 2009, compared with \$1.4 million in the second quarter of 2008. G&A expense per boe was \$1.92 in the quarter, as compared to \$2.10 for the same period in 2008.

For the six months ended June 30, 2009, G&A expenses decreased 20 percent to \$6.7 million from \$8.3 million in the comparable period in 2008. In addition, on a year-to-date basis \$3.0 million of G&A costs relating to exploitation and development activities were capitalized, compared with \$2.3 million in the comparable period of 2008. G&A expense per boe was \$1.57 in 2009, as compared to \$1.92 in 2008.

The year-over-year six month decrease in total G&A of \$1.0 million is attributable to a lower payout under the 2008 short term incentive plan than was provided for at year end, December 31, 2008 (\$0.8 million), plus other cost saving measures within G&A expenses.

General and Administrative Expenses

	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
G&A expenses (\$000s)				
G&A	4,031	4,494	6,658	8,135
Retention bonus	-	45	-	141
Expensed G&A (\$000s)	4,031	4,539	6,658	8,276
Capitalized G&A (\$000s)	1,835	1,401	2,994	2,343
Total G&A (\$000s)	5,866	5,940	9,652	10,619
Expensed G&A costs:				
G&A, excluding retention bonus (\$/boe)	1.92	2.08	1.57	1.89
Retention bonus (\$/boe)	-	0.02	-	0.03
Total G&A expenses (\$/boe)	1.92	2.10	1.57	1.92
As % of revenue	4.9	2.4	4.1	2.5
Per trust unit (\$)	0.04	0.05	0.07	0.09

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 second quarter of 2009, the Trust recorded a \$3.9 million charge for unit-based incentive compensation that reflects the impact of vesting, an increase in the unit price and an increase in the PTU performance multipliers. The unit price of the Trust increased by 38 percent, from \$6.80 at March 31, 2009 to \$9.37 at June 30, 2009. An increase in unit price results in previously accrued amounts being increased.

Unit-based incentive compensation increased by 40 percent compared to the second quarter of 2008, from \$2.8 million in 2008 to \$3.9 million in 2009. Period-over-period this increase is a reflection of a 38 percent increase in unit price and increased relative performance factors used to determine the compensation.

On a year-to-date basis, the Trust has accrued \$4.4 million compared to \$4.5 million in the comparable period of 2008.

At June 30, 2009, the unit price used to determine unit-based incentive compensation was \$9.37. The closing unit price of the Trust on the Toronto Stock Exchange on August 5, 2009 was \$10.25.

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

At June 30, 2009, the Trust has recorded a total accumulated liability for unit-based incentive compensation in the amount of \$8.3 million, of which \$4.2 million is recorded as current as it is payable in December 2009, and \$4.1 million is long-term as it is payable in December 2010 and December 2011.

Unit-Based Compensation

	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
Unit-based compensation (\$000s):				
Expensed	2,767	1,889	3,060	2,997
Capitalized	1,178	935	1,330	1,490
Total unit-based compensation	3,945	2,824	4,390	4,487
Expensed unit-based compensation:				
As % of revenue	3.3	1.0	1.9	0.9
\$/boe	1.32	0.87	0.72	0.69
Per trust unit (\$)	0.03	0.02	0.03	0.03

RELATED PARTY TRANSACTIONS

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

The Manager provides certain services to the Trust and its subsidiary entities pursuant to an Administrative Services and Cost Sharing Agreement (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 \$3.4 million (2008 - \$3.5 million) for the reimbursement of G&A expenses during the second quarter and \$5.3 million (2008 - \$6.5 million) year-to-date. The Trust also pays the Manager its share of unit-based incentive compensation expense when cash compensation is paid to employees under the terms of the Plan, of which \$2.3 million was paid in the first quarter of 2009, representing units that vested on November 30, 2008 (2008 - \$1.8 million). These reimbursements are included in the G&A and unit-based compensation amounts discussed above.

At June 30, 2009 the Trust owed the Manager \$1.6 million for the reimbursement of G&A and had a payable to NAL Resources of \$0.7 million, \$0.9 million relating to capital expenditures less net operating revenues, less a \$0.2 million receivable relating to the base price adjustment clause arising from the disposition of 50 percent of the working interest of Clipper to MFC.

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 June 30, 2009, there is a note payable of \$9.6 million with MFC arising from the Tiberius and Spear acquisition. The note payable is included on consolidation of the Partnership, but is effectively eliminated through the non-controlling interest. The note is due on demand, unsecured and bears interest at prime plus three percent. The amount of the note payable to MFC is adjusted to reflect MFC's share of the capital expenditures of the Partnership which MFC has funded, less any loan repayments made.

Net interest expense on these notes of \$0.1 million was payable by the Trust for the second quarter of 2009 (2008 - \$0.9 million net interest income), and net interest income of \$0.4 million, year-to-date (2008 - \$1.2 million), 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 second quarter of 2009 was \$3.0 million, a decrease of \$0.9 million from \$3.9 million for the comparable period in 2008. The decrease was due to a lower average effective interest rate and lower average debt levels. Average outstanding bank debt for the second quarter of 2009 was \$293.4 million, \$20.2 million lower than the \$313.6 million outstanding for the second quarter of 2008. NAL's effective interest rate averaged 4.05 percent during the second quarter of 2009, compared to 4.87 percent during the comparable period in 2008. The decrease in the rate from the second quarter of 2008 is attributable to lower overall borrowing rates in the market. NAL's interest is calculated based upon a floating rate.

Similar trends are noted for the six months ended June 30, 2009, as interest on bank debt decreased \$3.0 million to \$4.9 million, compared to \$7.9 million in 2008. Average outstanding debt for the six months ended June 30, 2009 decreased to \$294.9 million, compared to \$304.6 million for the corresponding period of 2008, and the effective interest rate averaged 3.37 percent in 2009, compared to 5.10 percent in 2008.

Interest on convertible debentures represents interest charges of \$1.3 million for the three months ended June 30, 2009 (\$2.7 million for the six months ended June 30, 2009) compared to \$1.6 million (\$3.3 million for the six months ended June 30, 2008), based on interest at 6.75 percent, and accretion of the debt discount of \$0.4 million (2008 - \$0.5 million) for the three months ended June 30, 2009, and \$0.8 million (2008 - \$0.9 million) for the six months ended June 30, 2009. The decrease in interest and accretion in 2009 is due to conversions of the debentures to trust units that occurred during 2008.

Interest and Debt

	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
Interest on bank debt (\$000s) ⁽¹⁾	2,962	3,879	4,925	7,860
Interest and accretion on convertible debentures (\$000s)	1,725	2,071	3,449	4,213
Total interest (\$000)	4,687	5,950	8,374	12,073
Bank debt outstanding at period end (\$000s)	244,323	308,115	244,323	308,115
Convertible debentures at period end (\$000s)*	74,762	75,561	74,762	75,561
\$/boe:				
Interest on bank debt	1.41	1.79	1.16	1.82
Interest on convertible debentures	0.64	0.74	0.63	0.76
Accretion on convertible debentures	0.18	0.22	0.18	0.22
Total interest	2.23	2.75	1.97	2.80

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

(1) Excludes interest rate hedge impact.

CASH FLOW NETBACK

For the quarter ended June 30, 2009, NAL's cash flow netback was \$25.52 per boe, a 41 percent decrease from \$43.28 per boe for the comparable period in 2008. The decrease was due to a lower operating netback after hedging, higher G&A expenses, including unit-based incentive compensation, the swing from interest income to interest expense on the notes with MFC, partially offset by lower interest charges.

For the six months ended June 30, 2009, NAL's cash flow netback was \$27.56 per boe, a 31 percent decrease from \$40.15 per boe in 2008. The decrease was due to a lower operating netback after hedging, offset by lower G&A expenses, including unit-based incentive compensation and lower interest charges.

Cash Flow Netback (\$/boe)

	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
Operating netback, after hedging	30.95	48.37	31.59	45.06
G&A expenses, including unit-based incentive compensation	(3.24)	(2.97)	(2.29)	(2.61)
Interest on bank debt and convertible debentures ⁽¹⁾	(2.05)	(2.53)	(1.79)	(2.58)
Interest on notes with MFC ⁽²⁾	(0.06)	0.41	0.10	0.28
Realized loss on interest rate derivative contracts	(0.08)	-	(0.05)	-
Cash flow netback	25.52	43.28	27.56	40.15

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

(2) Reported as other income.

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

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

For the quarter ended June 30, 2009, depletion on property, plant and equipment and accretion on the asset retirement obligations was \$21.29 per boe, six percent lower than the \$22.71 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. Similar trends are noted for the six months ended June 30, 2009.

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

Depletion, Depreciation and Accretion Expenses

	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
Depletion and depreciation (\$000s)	42,779	47,347	85,987	93,059
Accretion of asset retirement obligation (\$000s)	1,886	1,827	3,714	3,625
Total DDA (\$000s)	44,665	49,174	89,701	96,684
DDA rate per boe (\$)	21.29	22.71	21.14	22.42

TAXES

In the second quarter of 2009, NAL had a future income tax recovery of \$12.2 million compared to a \$12.8 million recovery in the corresponding period of the prior year. For the six month period June 30, 2009, NAL had a future income tax recovery of \$18.4 million compared to \$19.3 million in 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 June 30, 2009, the Trust’s (including all subsidiaries) estimated tax pools (unaudited) available for deduction from future taxable income approximated \$936 million, of which approximately 36 percent represented COGPE, 23 percent represented UCC, with the remaining balance represented by CEE, CDE, trust unit issue costs and non-capital loss carry forwards.

Estimated Tax Pools (\$ millions)

	June 30, 2009	December 31, 2008
Canadian exploration expense	44	12
Canadian development expense	243	202
Canadian oil and gas property expense	340	301
Undepreciated capital costs	216	209
Other (including loss carry forwards)	93	14
Total estimated tax pools	936	738

Based on current strip prices at June 30, 2009, the Trust is not expected to be taxable in 2009.

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

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:

\$(000s)	Three months ended June 30		Six months ended June 30	
	2009 ⁽¹⁾	Net Impact to Trust ⁽²⁾	2009 ⁽¹⁾	Net Impact to the Trust ⁽²⁾
Total production volumes (boes)	76,989	38,495	156,517	78,258
Production volumes (boe/d)	846	423	865	432
Oil, natural gas and liquid sales	4,507	2,254	8,137	4,069
Royalties	(587)	(294)	(1,077)	(538)
Operating costs	(1,089)	(544)	(2,424)	(1,212)
General and administrative	(99)	(50)	(161)	(81)
Unit-based incentive compensation	(91)	(46)	(102)	(51)
Interest income, net	(258)	(129)	829	414
Depletion, depreciation and accretion	(1,110)	(555)	(2,212)	(1,106)
Net profit interest income (expense)	(1,089)	(545)	(1,575)	(787)
Net income	183	92	1,415	708

(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

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

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

Non-Controlling Interest (\$000s)

	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
Net profits interest expense	544	3,583	787	5,061
Share of net income attributable to MFC	92	709	708	956
	636	4,292	1,495	6,017

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 loss for the second quarter of 2009 was \$9.4 million compared to \$17.6 million for the comparable period in 2008. The improvement of \$8.2 million was mainly due to decreased losses on derivative contracts (\$84.6 million), decreased non-controlling interest (\$3.7 million) and decreased DD&A expense (\$4.6 million), largely offset by decreased revenues net of royalties, (\$81.3 million) and increased operating costs (\$2.3 million).

Net loss for the six months ended June 30, 2009 of \$4.7 million was \$0.8 million greater than the comparable period of 2008. The greater loss in 2009 is attributable to decreased revenues net of royalties (\$130.6 million) and increased operating costs (\$6.7 million), partly offset by decreased losses on derivative contracts (\$121.8 million), decreased non-controlling interest (\$4.5 million), decreased DD&A expense (\$7.1 million) and decreased interest expense (\$3.7 million).

Net Loss (\$000s)

	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
Net loss	(9,407)	(17,572)	(4,683)	(3,839)

CAPITAL RESOURCES AND LIQUIDITY

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

As at June 30, 2009, NAL had 111,865,175 trust units outstanding, compared with 96,181,397 at December 31, 2008. The increase from December 31, 2008 is attributable to 5,675,834 units issued on the acquisition of Clipper, 9,602,500 issued under an equity offering, and 405,444 units issued under the distribution reinvestment program ("DRIP").

On May 28, 2009, the Trust closed an equity offering of 9,602,500 trust units at a price of \$9.00 per trust unit for total gross proceeds of \$86.4 million, which included the fully subscribed over allotment option granted to the underwriters.

Under 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 participation in the DRIP has averaged 12 percent since reinstatement.

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 June 30, 2009, the Trust had net debt of \$346.6 million (net of working capital and other liabilities, excluding derivative contracts, note payable with MFC and future income taxes) including convertible debentures at face value of \$79.7 million. Excluding the convertible debentures, net debt was \$266.9 million, compared with \$319.9 million at December 31, 2008. The decrease in net debt, excluding convertible debentures, of \$53.0 million during 2009 is attributable to decreased bank debt of \$38.0 million, and a positive change in working capital of \$15.0 million.

Bank debt outstanding was \$244.3 million at June 30, 2009 compared with \$282.3 million as at December 31, 2008. Of the \$244.3 million outstanding at June 30, 2009, all is outstanding under the production facility.

At the end of the second quarter, the Trust had a net debt (excluding convertible debentures) to 12 months trailing cash flow ratio of 1.03 times and a total net debt (including convertible debentures) to 12 months trailing cash flow ratio of 1.33 times.

During the second quarter, 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 second quarter of 2009 and \$0.8 million (2008 - \$0.9 million) year-to-date.

As at August 5, 2009, the Trust has 112,035,512 trust units and \$79.7 million in convertible debentures outstanding.

Capitalization

	June 30, 2009	December 31, 2008	June 30, 2008
Trust unit equity (\$000s)	618,335	557,263	471,221
Bank debt (\$000s)	244,323	282,332	308,115
Working capital deficit (surplus) ⁽¹⁾ (\$000s)	22,571	37,602	(15,425)
Net debt excluding convertible debentures	266,894	319,934	292,690
Convertible debentures (\$000s) ⁽²⁾	79,744	79,744	82,259
Net debt	346,638	399,678	374,949
Net debt excluding convertible debentures to trailing 12-month cash flow ⁽³⁾	1.03	1.03	1.06
Total net debt to trailing 12-month cash flow ⁽³⁾	1.33	1.28	1.36
Trust units outstanding (000s)	111,865	96,181	95,277

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

(2) Convertible debentures included at face value.

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

The 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 not more than 110 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 \$244 million is drawn down at June 30, 2009, leaving available capacity of \$206 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 six months of 2009. Volumes are hedged at an average floor price of \$88.14 per boe. For natural gas, remaining 2009 hedges total approximately 42 percent of net budgeted production volumes hedged at an average floor price in excess of \$6.35 per GJ (or \$6.70 per Mcf).

NAL's capital program for 2009 has been designed to be scalable and flexible in response to commodity prices and market conditions. The initial plan for a \$110 million capital program, with the expectation to drill approximately 82 (40 net) wells, was reduced in February by \$15 million in response to weaker commodity prices. Based upon

positive second quarter performance and the opportunities added, the Trust has increased its capital program to \$125 - \$135 million. 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, and 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 the remainder of 2009 and 2010, the Trust has approximately \$970 million of available safe harbour all of which is currently available.

ASSET RETIREMENT OBLIGATION

At June 30, 2009, the Trust reported an asset retirement obligation (“ARO”) balance of \$100.8 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 \$7.3 million relating to the acquisition of Clipper, \$1.1 million due to liabilities incurred and revisions to estimates and \$3.7 million from accretion expense, and was reduced by \$2.1 million for actual abandonment and environmental expenditures incurred during the first six months.

DISTRIBUTIONS TO UNITHOLDERS

For the three and six months ended June 30, 2009, the Trust distributed 43 percent and 44 percent of its cash flow from operating activities, respectively, as compared to 62 percent for the same periods 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 have 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, and growth opportunities may make it necessary to adjust forecasted capital expenditures or distribution levels.

NAL intends to continue to make cash distributions to unitholders. However, these cash distributions cannot be guaranteed. The primary drivers of the level of distributions are the assumptions that contribute to cash flow, namely production, operating costs and commodity prices. 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

(\$000s except for percentages)	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
Cash flow from operating activities	63,690	73,295	130,236	143,856
Net loss	(9,407)	(17,572)	(4,683)	(3,839)
Actual cash distributions paid or payable	27,422	45,302	57,238	89,327
Excess of cash flow from operating activities over cash distribution paid	36,268	27,993	72,998	54,529
Percentage of cash flow from operations distributed	43%	62%	44%	62%
Excess (shortfall) of net income over cash distributions paid	(36,829)	(62,874)	(61,921)	(93,166)

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

For the three months ended June 30, 2009, funds from operations amounted to \$52.0 million, compared with \$88.6 million for the three months ended June 30, 2008. The 41 percent decrease is due to lower revenues resulting from lower commodity prices, offset by realized hedging gains of \$22.2 million. On a per trust unit basis, funds from operations decreased 46 percent from \$0.94 in 2008 to \$0.51 in 2009.

For the six months ended June 30, 2009, funds from operations decreased 31 percent to \$114.0 from \$164.8 million for the comparable period of 2008. The decrease is primarily due to lower revenues driven by lower commodity prices, offset by realized hedging gains of \$49.9 million.

Funds from Operations

	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
Funds from operations (\$000s)	51,998	88,578	114,022	164,798
Funds from operations per trust unit	0.51	0.94	1.15	1.77
Payout ratio based on funds from operations	53%	51%	50%	54%

VARIABLE INTEREST ENTITIES

NAL has no variable interest entities.

CONTRACTUAL OBLIGATIONS

Joint Venture Partnership Agreement:

Effective April 20, 2009, the Trust and MFC entered into a joint venture partnership agreement with a senior industry partner. The arrangement consists of a three year commitment to spend \$50 million to earn an interest in freehold and crown acreage. The Trust has a 65 percent interest in this agreement and MFC a 35 percent interest and therefore the Trust's net commitment is \$32.5 million. The agreement is exclusive and structured to be extendible for up to an additional six years for a total potential commitment of \$150 million (\$97.5 million net) to 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 partner.

Flow-through shares:

In conjunction with the acquisition of Clipper, the Trust assumed flow-through share obligations related to common shares issued by Clipper on December 4, 2008. As a result, the Trust must incur qualifying resource expenditures amounting to \$7.5 million before December 31, 2009. The related tax impact was recorded on the acquisition of Clipper. The qualifying expenditures were renounced to shareholders of Clipper as at December 31, 2008. The obligation remaining for this flow-through share issue was \$7.0 million as at June 30, 2009.

Other:

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

(\$000s)	2009	2010	2011	2012	2013
Office lease ⁽¹⁾	2,072	3,798	-	-	-
Office lease – Clipper ⁽²⁾	346	692	699	703	234
Transportation agreement	737	1,317	1,317	306	-
Processing agreement ⁽³⁾	168	428	414	401	384
Convertible debentures ⁽⁴⁾	-	-	-	79,744	-
Bank debt	-	-	146,594	97,729	-
Total	3,323	6,235	149,024	178,883	618

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

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

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

(4) Principal amount.

QUARTERLY INFORMATION

(\$000s, except per unit and production amounts)	2009				2008			2007
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Revenue, net of royalties ⁽¹⁾	60,922	77,791	161,156	234,993	58,861	89,611	86,262	78,573
Per unit	0.60	0.81	1.68	2.46	0.63	0.98	0.96	0.95
Funds from operations ⁽²⁾	51,998	62,024	67,040	79,233	88,578	76,220	59,537	50,817
Per unit	0.51	0.64	0.70	0.83	0.94	0.83	0.66	0.61
Net income (loss)	(9,407)	4,724	55,374	111,045	(17,572)	13,733	10,556	7,801
Per unit								
basic	(0.09)	0.05	0.58	1.16	(0.19)	0.15	0.12	0.09
diluted	(0.09)	0.05	0.56	1.11	(0.19)	0.15	0.12	0.09
Average oil equivalent production (boe/d – 6:1)	23,049	23,836	23,984	23,808	23,791	23,601	23,656	20,369

(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

DISCLOSURE CONTROLS AND PROCEDURES (“DC&P”)

NAL’s certifying officers have designed DC&P, or caused them to be designed under their supervision, to provide reasonable assurance that all material information required to be disclosed by NAL in its interim filings is processed, summarized and reported within the time periods specified in applicable securities legislation.

INTERNAL CONTROL OVER FINANCIAL REPORTING (“ICFR”)

NAL’s certifying officers are responsible for establishing and maintaining ICFR. 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 material changes in the Trust’s ICFR for the quarter ended June 30, 2009.

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 STANDARDS

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.

Financial Instruments - Disclosures

In May 2009, the CICA amended Section 3862, "Financial Instruments – Disclosures", to include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three level hierarchy that reflects the significance of the inputs used in making the fair value measurements. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. These amendments are effective for NAL on December 31, 2009.

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: August 6, 2009

CONSOLIDATED BALANCE SHEETS

(thousands of dollars) (unaudited)

	As at June 30, 2009	As at December 31, 2008
Assets		
Current assets		
Cash and cash equivalents	\$9,981	\$5,584
Accounts receivable and other	56,874	57,825
Note receivable (Note 3)	-	49,599
Derivative contracts (Note 12)	20,210	65,680
	87,065	178,688
Derivative contracts (Note 12)	3,615	-
Future income tax asset	3,490	-
Goodwill	14,722	14,722
Property, plant and equipment (Notes 2 and 4)	1,043,153	1,017,187
	\$1,152,045	\$1,210,597
Liabilities and Unitholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	\$74,221	\$84,732
Note payable (Note 3)	9,586	9,609
Distributions payable to unitholders	10,068	15,389
Future income tax liability	4,988	16,788
	98,863	126,518
Bank debt (Note 5)	244,323	282,332
Convertible debentures (Note 6)	74,762	74,004
Derivative contracts (Note 12)	5,999	274
Other liabilities (Note 7)	5,137	890
Asset retirement obligations (Note 9)	100,840	90,844
Future income tax liability	-	22,092
Non-controlling interest (Note 10)	3,786	56,380
	533,710	653,334
Unitholders' equity		
Unitholders' capital (Note 11)	1,165,176	1,042,183
Equity component of convertible debentures (Note 6)	4,592	4,592
Deficit (Note 11)	(551,433)	(489,512)
	618,335	557,263
	\$1,152,045	\$1,210,597
Commitments (Note 13)		
Subsequent events (Note 14)		
Trust units outstanding (000s)	111,865	96,181

See accompanying notes.

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

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

	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
Revenue				
Oil, natural gas and liquid sales	\$83,676	\$188,297	\$165,379	\$334,440
Crown royalties	(10,743)	(28,834)	(21,354)	(50,682)
Freehold and other royalties	(4,865)	(10,107)	(8,388)	(17,570)
	68,068	149,356	135,637	266,188
Gain (loss) on derivative contracts (Note 12):				
Realized gain (loss)	22,159	(21,730)	49,921	(27,221)
Unrealized loss	(29,484)	(70,148)	(47,988)	(92,683)
	(7,325)	(91,878)	1,933	(119,904)
Other income	179	1,383	1,143	2,188
	60,922	58,861	138,713	148,472
Expenses				
Operating	24,759	22,443	50,399	43,716
Transportation	1,026	956	2,067	1,890
General and administrative	4,031	4,539	6,658	8,276
Unit-based incentive compensation (Note 8)	2,767	1,889	3,060	2,997
Interest on bank debt	2,962	3,879	4,925	7,860
Interest and accretion on convertible debentures	1,725	2,071	3,449	4,213
Depletion, depreciation and amortization	42,779	47,347	85,987	93,059
Accretion on asset retirement obligations	1,886	1,827	3,714	3,625
	81,935	84,951	160,259	165,636
Loss before taxes and non-controlling interest	(21,013)	(26,090)	(21,546)	(17,164)
Income tax recovery (expense)	-	(10)	1	(6)
Future income tax reduction	12,242	12,820	18,357	19,348
Total income tax reduction	12,242	12,810	18,358	19,342
Income (loss) before non-controlling interest	(8,771)	(13,280)	(3,188)	2,178
Non-controlling interest (Note 10)	(636)	(4,292)	(1,495)	(6,017)
Net loss and comprehensive loss	(9,407)	(17,572)	(4,683)	(3,839)
Deficit, beginning of period	(514,604)	(500,922)	(489,512)	(470,630)
Net loss	(9,407)	(17,572)	(4,683)	(3,839)
Distributions declared	(27,422)	(45,302)	(57,238)	(89,327)
Deficit, end of period	\$(551,433)	\$(563,796)	\$(551,433)	\$(563,796)
Net loss per trust unit (Note 11)				
Basic and diluted	\$(0.09)	\$(0.19)	\$(0.05)	\$(0.04)
Weighted average trust units outstanding (000s)	101,868	94,101	99,040	92,909

See accompanying notes.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(thousands of dollars) (unaudited)

	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
Operating Activities				
Net loss	\$(9,407)	\$(17,572)	\$(4,683)	\$(3,839)
Items not involving cash:				
Depletion, depreciation and amortization	42,779	47,347	85,987	93,059
Accretion on asset retirement obligations	1,886	1,827	3,714	3,625
Unrealized loss on derivative contracts	29,484	70,148	47,988	92,683
Future income tax reduction	(12,242)	(12,820)	(18,357)	(19,348)
Non-cash accretion expense on convertible debentures	380	464	758	941
Non-controlling interest	92	709	708	956
Abandonment and environmental expenditures	(974)	(1,525)	(2,093)	(3,279)
Change in non-cash working capital	11,692	(15,283)	16,214	(20,942)
	63,690	73,295	130,236	143,856
Financing Activities				
Distributions paid to unitholders	(22,801)	(38,256)	(59,350)	(74,632)
Increase (decrease) in bank debt	(139,447)	(5,255)	(116,861)	32,485
Issue of trust units, net of issue costs	82,017	-	82,017	(14)
Note repayment from MFC (Note 3)	-	-	49,599	-
Partnership distribution paid to MFC	(3,500)	-	(53,302)	-
Change in non-cash working capital	48	-	81	(426)
	(83,683)	(43,511)	(97,816)	(42,587)
Investing Activities				
Additions to property, plant and equipment	(16,952)	(26,748)	(53,888)	(56,071)
Property acquisitions	(1,485)	(1,006)	(2,799)	(7,876)
Proceeds from dispositions	264	40	264	40
Acquisition of Clipper (Note 2)	(748)	-	(748)	-
Disposition of Clipper (Note 2)	52,657	-	52,657	-
Acquisition of Tiberius and Spear	-	(371)	-	(77,355)
Disposition of Tiberius and Spear	-	115	-	58,222
Acquisition of Seneca	-	-	-	337
Change in non-cash working capital	(16,377)	(4,124)	(23,509)	(7,093)
	17,359	(32,094)	(28,023)	(89,796)
Increase (decrease) in cash and cash equivalents	(2,634)	(2,310)	4,397	11,473
Cash and cash equivalents, beginning of period	12,615	15,177	5,584	1,394
Cash and cash equivalents, end of period	\$9,981	\$12,867	\$9,981	\$12,867
Supplementary disclosure of cash flow information:				
Cash paid (received) during the period for:				
Interest	\$4,600	\$3,342	\$9,278	\$9,864
Tax	\$-	\$1,971	\$(72)	\$2,579
Cash and cash equivalents is comprised of:				
Cash	\$3,982	\$2,864	\$3,982	\$2,864
Short term investments	5,999	10,003	5,999	10,003
	\$9,981	\$12,867	\$9,981	\$12,867

Refer to Notes 2, 9 and 11 for significant non-cash amounts not included in the cash flow statement.

See accompanying notes.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Six months ended June 30, 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.

Financial Instruments - Disclosures

In May 2009, the CICA amended Section 3862, “Financial Instruments – Disclosures”, to include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three level hierarchy that reflects the significance of the inputs used in making the fair value measurements. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. These amendments are effective for NAL on December 31, 2009.

2. ACQUISITION OF ALBERTA CLIPPER ENERGY INC.

Effective June 1, 2009, the Trust acquired all of the issued and outstanding common shares of Alberta Clipper Energy Inc. (“Clipper”), which has interests in petroleum and natural gas properties and undeveloped land in Alberta and northeast British Columbia.

As consideration the Trust issued 5.7 million trust units at a price of \$6.45 a trust unit for total consideration, before acquisition costs, of \$36.6 million. The trust unit price was based on the weighted average market price of trust units at the date of announcement, being March 23, 2009. This purchase price included the assumption of \$78.9 million in bank debt.

The results of Clipper have been included in the accounts of the Trust from June 1, 2009. The transaction was accounted for using the purchase method of accounting. The fair values assigned to the net assets, and the consideration paid by the Trust, are as follows:

Net Assets acquired:	
Working capital deficiency (including cash of \$2)	\$(498)
Derivative contract	408
Property, plant and equipment	114,472
Future income taxes	17,858
Excess office lease obligation ⁽¹⁾	(1,446)
Asset retirement obligations	(14,592)
Bank debt	(78,852)
	<hr/>
	\$37,350
Consideration:	
Issuance of trust units	\$36,600
Acquisition costs	750
	<hr/>
	\$37,350

(1) Represents the present value of an office lease obligation, in excess of the value of a sublease.

The above amounts are estimates made by management based on currently available information. Amendments may be made to the purchase allocation as cost estimates and balances are finalized.

Concurrent with the acquisition, the Trust entered into a Purchase and Sale Agreement (“PSA”) with Manulife Financial Corporation (“MFC”), pursuant to which MFC acquired a 50% working interest in the Clipper petroleum and natural gas properties for a cash base price of \$52.5 million. The cash received from MFC was used to partially repay the assumed bank debt.

Included within the PSA is a base price adjustment clause that ensures the Trust and MFC share equally in all assets or liabilities related to Clipper that pertain to periods on or prior to the effective date of the acquisition, regardless of their date of discovery or disclosure. The base price adjustment calculation will adjust the purchase price that MFC pays the Trust for any change in working capital from amounts determined at the time the base price of \$52.5 million was established. In addition, the costs associated with contracts outstanding at the date of acquisition will be equally shared between both parties on an ongoing basis as the obligations are settled by the Trust. The amounts due under this base price adjustment clause are to be settled no more than quarterly commencing December 2009. As at June 30, 2009, the Trust had a receivable from MFC of \$0.2 million relating to the base price adjustment.

As a result, after taking into effect the MFC disposition and MFC’s share of the assets and liabilities to be settled under the base price adjustment clause, the Trust acquired property, plant and equipment of \$54.5 million, a future tax asset of \$17.9 million and assumed asset retirement obligations of \$7.3 million, bank debt of \$26.2 million and a lease obligation of \$1.5 million for consideration of \$37.4 million, including estimated acquisition costs.

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 also 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 \$3.4 million (2008 - \$3.5 million) for the reimbursement of G&A expenses during the second quarter and \$5.3 million (2008 - \$6.5 million) year-to-date. The Trust also pays the Manager its share of unit-based compensation expense when cash compensation is paid to employees under the terms of the Manager’s incentive compensation plans, of which, \$2.3 million has been paid year-to-date 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 10).

As at June 30, 2009, there is a note payable of \$9.6 million with MFC arising from the Tiberius and Spear acquisition. The note payable is included on consolidation of the Partnership, but is effectively eliminated through the non-controlling interest. The note is due on demand, unsecured and bears interest at prime plus three percent. The amount of the note payable to MFC is adjusted to reflect MFC’s share of the capital expenditures of the Partnership which MFC has funded, less any loan repayments made.

Net interest expense on these notes of \$0.1 million was payable by the Trust for the second quarter of 2009 (2008 - \$0.9 million net interest income), and net interest income of \$0.4 million (2008 - \$1.2 million), year-to-date, was received by the Trust, and is reported as other income.

The following amounts are due to and from related parties as at June 30, 2009 and December 31, 2008 and have been included in accounts receivable, note receivable, accounts payable and accrued liabilities and note payable on the balance sheet:

	June 30, 2009	December 31, 2008
Due to NAL Resources Limited ⁽¹⁾	\$(769)	\$(10,042)
Due to NAL Resources Management Limited	(1,551)	(3,881)
Due (to) from Manulife Financial Corporation ⁽²⁾	(10,034)	45,512
	\$(12,354)	\$31,589

(1) Includes base price adjustment due (to) from MFC, relating to the Clipper asset disposition to MFC, of \$0.2 million (Note 2).

(2) Included on consolidation, eliminated through non-controlling interest. Represents note payable \$9.6 million (2008: \$9.6 million), plus amounts due from (to) MFC of (\$0.4) million (2008: \$5.5 million), presented in accounts payable/ accounts receivable, relating to the net interest and NPI amounts due.

4. PROPERTY, PLANT AND EQUIPMENT

	June 30, 2009	December 31, 2008
Petroleum and natural gas properties, at cost	\$2,021,477	\$1,909,524
Less: Accumulated depletion and depreciation	(978,324)	(892,337)
	\$1,043,153	\$1,017,187

Costs associated with undeveloped land of \$45.1 million (2008 - \$26.7 million) have been excluded from the depletion calculation for the six months ended June 30, 2009.

Future development costs for proved reserves of \$41.8 million (2008 - \$49.8 million) have been included in the depletion calculation.

During the six months ended June 30, 2009, the Trust capitalized \$3.0 million (2008 - \$2.3 million) of G&A costs and \$1.3 million (2008 - \$1.5 million) of unit-based incentive compensation that were directly related to exploitation and development programs.

5. BANK DEBT

	June 30, 2009	December 31, 2008
Production loan facility	\$244,323	\$281,984
Working capital facility	-	348
Total debt outstanding	\$244,323	\$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 June 30, 2009 and December 31, 2008 all amounts outstanding were in Canadian dollars.

On June 30, 2009 the effective interest rate on amounts outstanding under the credit facility was 4.36 percent (2008 – 4.57 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	-	758	-
Balance, June 30, 2009	\$79,744	\$74,762	\$4,592

7. OTHER LIABILITIES

	June 30, 2009	December 31, 2008
Unit-based incentive compensation	4,152	890
Excess office lease obligation (Note 2) ⁽¹⁾	985	-
	5,137	890

(1) Represents the present value of the long-term portion of the office lease obligation, in excess of a sub-lease, assumed on the acquisition of Clipper. MFC will reimburse the Trust for 50 percent of the obligation under the base price adjustment clause (Note 2).

8. UNIT-BASED INCENTIVE COMPENSATION PLAN

The Trust recorded a total compensation expense of \$4.4 million in the first six months of 2009, of which \$3.1 million was recorded as an expense and \$1.3 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 June 30, 2009 trust unit price of \$9.37 (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:

	Six months ended June 30, 2009	Year ended December 31, 2008
Balance, beginning of period	\$6,274	\$5,311
Increase in liability	4,390	2,730
Cash payout, relating to units vested	(2,322)	(1,767)
Balance, end of period	\$8,342	\$6,274
Current portion of liability ⁽¹⁾	4,190	\$5,384
Long-term liability ⁽²⁾	\$4,152	\$890

(1) Included in accounts payable and accrued liabilities.

(2) Included in other liabilities.

9. ASSET RETIREMENT OBLIGATIONS

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

	Six months ended June 30, 2009	Year ended December 31, 2008
Balance, beginning of period	\$90,844	\$89,602
Accretion expense	3,714	7,299
Revisions to estimates	559	(262)
Liabilities incurred	520	1,422
Liabilities acquired, net (Note 2)	7,296	1,636
Liabilities settled	(2,093)	(8,853)
Balance, end of period	\$100,840	\$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.

10. 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:

	Six months ended June 30, 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	708	3,823
Distributions to MFC ⁽¹⁾	(53,302)	(1,500)
Non-controlling interest, end of period	\$3,786	\$56,380

(1) Includes \$49.6 million distribution paid following settlement of note receivable (Note 3).

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

	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
Net profits interest expense	\$544	\$3,583	\$787	\$5,061
Share of net income attributable to MFC	92	709	708	956
	\$636	\$4,292	\$1,495	\$6,017

11. UNITHOLDERS EQUITY

Units Issued:

	Six months ended June 30, 2009		Year ended December 31, 2008	
	Units	Amount	Units	Amount
Balance, beginning of the period	96,181	\$1,042,183	90,494	\$969,588
Equity offering	9,603	86,422	-	-
Issued on corporate acquisition (Note 2)	5,676	36,600	2,409	29,496
Less issue expenses (net of tax of \$1,167)	-	(3,238)	-	(29)
Issued from Distribution Reinvestment Plan	405	3,209	1,831	23,393
Issued on conversion of debentures	-	-	1,447	19,735
Balance, end of the period	111,865	\$1,165,176	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 and six months ended June 30, 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 and six months

ended June 30, 2009 were 5,696,000 (2008 – 6,815,850) and 5,696,000 (2008 – 6,979,354), respectively. As at June 30, 2009, the total convertible debentures outstanding were immediately convertible to 5,696,000 trust units.

Deficit

The deficit is comprised of the following:

	Six months ended June 30, 2009	Year ended December 31, 2008
Accumulated income	\$548,348	\$553,031
Accumulated cash distributions	(1,099,781)	(1,042,543)
	\$(551,433)	(\$489,512)

12. 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.

EXCHANGE RATE	Remaining Term	Amount ⁽¹⁾ (US\$ MM)	Trust Fixed Rate	Counterparty Floating Rate
Swaps-floating to fixed	July 2009 – Nov 2009	\$10.0	1.2730	BofC Average Noon Rate
Swaps-floating to fixed	July 2009 – Nov 2009	\$10.0	1.2875	BofC Average Noon Rate
Swaps-floating to fixed	July 2009 – Nov 2009	\$10.0	1.2625	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1585	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1100	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1200	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1225	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1300	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1420	BofC Average Noon Rate
Swaps-floating to fixed	Dec 2009 – Dec 2010	\$6.5	1.1525	BofC Average Noon Rate

(1) Notional US\$ denominated commodity sales

The fair value of foreign exchange derivative contracts has been included on the balance sheet with changes in the fair value reported separately on the statement of income as unrealized gain (loss). As at June 30, 2009, if exchange rates had strengthened by \$0.01, with all other variables held constant, net income for the period would have been \$0.8 million higher, due to changes in the fair value of the derivative contracts. An equal and opposite effect would have occurred to net income had exchange rates been \$0.01 weaker.

Commodity price risk

NAL has the following commodity risk management contracts outstanding:

CRUDE OIL	Q3-09	Q4-09	Q1-10	Q2-10	Q3-10	Q4-10
<u>US\$ Collar Contracts</u>						
\$US WTI Collar Volume (bbl/d)	400	300	3,200	3,000	1,800	1,600
Bought Puts – Average Strike Price (\$US/bbl)	\$74.50	\$62.67	\$60.86	\$61.25	\$62.22	\$62.19
Sold Calls – Average Strike Price (\$US/bbl)	\$93.26	\$71.85	\$71.76	\$72.05	\$72.75	\$72.97
<u>US\$ Swap Contracts</u>						
\$US WTI Swap Volume (bbl/d)	1,633	1,700	200	200	-	-
Average WTI Swap Price (\$US/bbl)	\$61.60	\$61.94	\$75.00	\$75.00	-	-
<u>Cdn\$ Collar Contracts</u>						
\$Cdn WTI Collar Volume (bbl/d)	1,100	1,500	300	-	-	-
Bought Puts – Average Strike Price (\$Cdn/bbl)	\$121.56	\$102.07	\$66.00	-	-	-
Sold Calls – Average Strike Price (\$Cdn/bbl)	\$170.81	\$137.63	\$80.17	-	-	-
<u>Cdn\$ Swap Contracts</u>						
\$Cdn WTI Swap Volume (bbl/d)	1,600	1,300	-	-	-	-
Average WTI Swap Price (\$Cdn/bbl)	\$97.94	\$92.55	-	-	-	-
Total Oil Volume (bbl/d)	4,733	4,800	3,700	3,200	1,800	1,600

NATURAL GAS	Q3-09	Q4-09	Q1-10	Q2-10	Q3-10	Q4-10
<u>Collar Contracts</u>						
AECO Collar Volume (GJ/d)	5,000	1,685	-	-	-	-
Bought Puts – AECO Average Strike Price (\$Cdn/GJ)	\$8.90	\$8.90	-	-	-	-
Sold Calls – AECO Average Strike Price (\$Cdn/GJ)	\$11.44	\$11.44	-	-	-	-
<u>Swap Contracts</u>						
AECO Swap Volume (GJ/d)	18,130	27,663	26,000	23,000	24,000	7,337
AECO Average Price (\$Cdn/GJ)	\$6.03	\$5.95	\$5.97	\$5.75	\$5.76	\$6.19
Total Natural gas Volume (GJ/d)	23,130	29,348	26,000	23,000	24,000	7,337

The fair value of commodity derivative contracts has been included on the balance sheet with changes in the fair value reported separately on the statement of income as unrealized gain (loss). As at June 30, 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 period would have been \$2.9 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	July 2009 – Dec 2011	\$39.0	1.5864%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	July 2009 – Jan 2013	\$22.0	1.3850%	CAD-BA-CDOR (3 months)
Swaps-floating to fixed	July 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

The fair value of interest rate derivative contracts has been included on the balance sheet with changes in the fair value reported separately on the statement of income as unrealized gain (loss). As at June 30, 2009, if interest rates had been one percent lower, with all other variables held constant, net income for the period would have been \$4.2 million lower, due to changes in the fair value of the derivative contracts. An equal and opposite effect would have occurred to net income had interest rates been one percent higher.

Fair Value of Derivative Contracts

Derivative contracts are recorded at fair value on the balance sheet as current or long-term, assets or liabilities, based on their fair values on a contract by contract basis. The fair value of commodity contracts is determined as the difference between the contracted prices and published forward curves (ranging from US\$69.89 per barrel to US\$76.69 per barrel for oil and \$3.84 per GJ to \$6.96 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 1.863 percent to 2.588 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 1.1575 to 1.1619) as of the balance sheet date, using the notional U.S. dollar amount and outstanding term of the swap. The fair value of the derivative contracts is as follows:

	Six months ended June 30, 2009	Year ended December 31, 2008
Fair value of commodity contracts	\$12,811	\$65,680
Fair value of interest rate swaps	2,877	(274)
Fair value of foreign exchange rate swaps	2,138	-
	\$17,826	\$65,406

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

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

	Three months ended June		Six months ended June 30	
	2009	2008	2009	2008
Unrealized gain (loss):				
Crude oil contracts	(34,769)	(53,893)	(55,967)	(57,656)
Natural gas contracts	(10)	(16,255)	2,691	(35,027)
Interest rate swaps	3,828	-	3,150	-
Exchange rate swaps	1,467	-	2,138	-
Unrealized loss	(29,484)	(70,148)	(47,988)	(92,683)
Realized gain (loss):				
Crude oil contracts	15,901	(18,001)	36,653	(25,032)
Natural gas contracts	4,507	(3,729)	11,463	(2,189)
Interest rate swaps	(178)	-	(207)	-
Exchange rate swaps	1,929	-	2,012	-
Realized gain (loss)	22,159	(21,730)	49,921	(27,221)
Gain (loss) on derivative contracts	(7,325)	(91,878)	1,933	(119,904)

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

	June 30, 2009	December 31, 2008
Long term unrealized loss on derivative contracts	\$(5,999)	\$(274)
Long term unrealized gain on derivative contracts	3,615	-
Net long term unrealized loss on derivative contracts	(2,384)	(274)
Current unrealized gain on derivative contracts	20,210	65,680
Net fair value of derivative contracts	\$17,826	\$65,406

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

	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
Unrealized gain (loss), beginning of period	\$46,902	\$(32,119)	\$65,406	\$(9,584)
Unrealized gain acquired ⁽¹⁾	408	-	408	-
Unrealized gain (loss), end of period	17,826	(102,267)	17,826	(102,267)
Unrealized loss for the period	(29,484)	(70,148)	(47,988)	(92,683)
Realized gain (loss) in the period	22,159	(21,730)	49,921	(27,221)
Gain (loss) on derivative contracts	\$(7,325)	\$(91,878)	\$1,933	\$(119,904)

(1) Assumed on acquisition of Clipper (Note 2)

13. COMMITMENTS

i) Joint Venture Partnership Agreement

Effective April 20, 2009, the Trust and MFC entered into a joint venture partnership agreement with a senior industry partner. The arrangement consists of a three year commitment to spend \$50 million on or before August 31, 2012, that provides the 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 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 (\$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 under the arrangement. No amount was spent against this commitment in the six months ended June 30, 2009.

ii) Flow-through Shares

In conjunction with the acquisition of Clipper, the Trust assumed flow-through share obligations related to common shares issued by Clipper on December 4, 2008. As a result, the Trust must incur qualifying resource expenditures amounting to \$7.5 million before December 31, 2009. The related tax impact was recorded on the acquisition of Clipper. The qualifying expenditures were renounced to shareholders of

Clipper as at December 31, 2008. The obligation remaining for this flow-through share issue was \$7.0 million as at June 30, 2009.

iii) Other

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

(\$000s)	2009	2010	2011	2012	2013
Office lease ⁽¹⁾	2,072	3,798	-	-	-
Office lease – Clipper ⁽²⁾	346	692	699	703	234
Transportation agreement	737	1,317	1,317	306	-
Processing agreement ⁽³⁾	168	428	414	401	384
Convertible debentures ⁽⁴⁾	-	-	-	79,744	-
Bank debt	-	-	146,594	97,729	-
Total	3,323	6,235	149,024	178,883	618

- (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 58 percent) of the expense on a monthly basis.
- (2) Represents the full amount of the office lease assumed with the acquisition of Clipper. MFC will reimburse the Trust for 50 percent of the obligation under the base price adjustment clause (Note 2).
- (3) Represents a gas processing agreement with a take or pay component.
- (4) Principal amount.

14. SUBSEQUENT EVENTS

i) Acquisition of Spearpoint Energy Corp. (“Spearpoint”)

On August 5, 2009, the Trust announced the execution of a Share Purchase and Sale Agreement to acquire all of the issued and outstanding shares of Spearpoint, for total consideration (including the assumption of Spearpoint indebtedness) of \$16.2 million. The assets of Spearpoint include current natural gas production of approximately 350 boe/d and a Farm-in Agreement with a senior industry partner, the benefits and commitments of which will be assumed by the Trust on closing.

The Farm-in Agreement (“Agreement”) will be amended at closing to provide for a two year initial commitment commencing July 2009, with minimum capital commitments of \$40 million in the first year and \$57 million in the second year, with an option for a third year, at Spearpoint’s election, for an additional \$50 million commitment. The Agreement provides the opportunity to earn an interest in approximately 1,400 gross sections of undeveloped oil and gas rights in Alberta held by the partner. If the capital spending commitments are not met, interests in the acreage will not be earned and the Trust will not be required to pay any unspent amounts under the Agreement.

Subsequent to the closing of the acquisition, the Trust intends to enter into an agreement with MFC, pursuant to which MFC will purchase a 40 percent working interest in all of the assets of Spearpoint for approximately \$6.5 million.

It is expected that these transactions will be completed on or before August 31, 2009 and future capital expenditure commitments will be shared on a 60 percent Trust / 40 percent MFC basis.

ii) Disposition of non-operated property

Subsequent to the quarter end, the Trust has agreed to sell a non-operated property for net proceeds of \$15 million. The transaction is expected to close in the third quarter.

TRADING PERFORMANCE

	For the Quarter Ended			
	30-Jun-09	31-Mar-09	30-Jun-08	31-Mar-08
PRICE				
High	\$10.53	\$8.99	\$17.09	\$13.47
Low	\$6.63	\$5.38	\$13.12	\$10.81
Close	\$9.37	\$6.80	\$16.89	\$13.25
Daily Average Volume	459,603	359,591	447,401	321,650

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".

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