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**FOR IMMEDIATE RELEASE**

## **NAL OIL & GAS TRUST REPORTS THIRD QUARTER RESULTS**

**Media Release No. 30-08**

**November 4, 2008**

CALGARY, ALBERTA – NAL Oil & Gas Trust (“NAL” or the “Trust”) today announced its financial and operational results for the third quarter ended September 30, 2008. All amounts are in Canadian dollars unless otherwise stated.

On NAL’s third quarter results, President and CEO Andrew Wiswell commented: “Over the first nine months of 2008, NAL has generated strong cash flow from operations, paid consistent distributions, added new opportunities within its core portfolio, while maintaining lower payout ratios and a strong balance sheet. These factors position NAL competitively in these challenging economic times.”

### **Summary of Third Quarter**

- Production volumes increased 17 percent in the third quarter to 23,808 barrels per day (boe/d), up from 20,369 in the third quarter 2007, driven primarily by the corporate acquisitions of Seneca Energy Canada Inc. (“Seneca”), Tiberius Exploration Inc. (“Tiberius”) and Spear Exploration Inc. (“Spear”) and the ongoing execution of the Trust’s core business and capital program. Production mix was 51 percent crude oil and natural gas liquids and 49 percent natural gas.
- Funds from operations (“FFO”) equaled \$79.2 million in the quarter, and includes a one-time charge relating to the Trust’s exposure to SemCanada Crude Company of \$6.9 million. On a per unit basis, FFO of \$0.83 (\$0.79 fully diluted) compared favorably with results over the same period in 2007 of \$0.61 (\$0.60 fully diluted), for an increase of 36 percent year-over-year. Excluding the one-time charge, FFO would have been \$86.1 million or \$0.90 on a per unit basis.
- Operating netbacks before corporate hedging programs equaled \$52.10 per boe versus \$31.62 in the third quarter a year earlier, an increase of 65 percent. These higher netbacks are driven primarily by higher commodity prices, NAL’s relatively high quality crude and were achieved despite higher operating costs due to inflationary pressure in the industry.
- Capital expenditures increased to \$53.6 million in the third quarter versus \$34.3 million a year earlier, taking advantage of higher cash flows, broader opportunities in NAL’s asset base and positioning the Trust for the future by directing capital toward land, facilities and infrastructure investment in our core areas.
- Convertible debt outstanding decreased slightly from \$82.3 million to \$79.7 million at the end of the third quarter as \$2.6 million of debentures converted to trust units. At September 30, 2008, total net debt (including convertible debentures) represented approximately 1.2 times annualized third quarter FFO.

### **November Distribution**

The Trust will pay a distribution of \$0.16 per unit on December 15, 2008, to unitholders of record on November 24, 2008. The units will begin trading ex-distribution on November 20, 2008.

### **2008 Guidance and Outlook**

- Based on forecast ranges for the balance of 2008 between US\$60 - \$80 WTI, \$6.00 – \$7.50 per GJ AECO and exchange rate between 1.15 to 1.25, FFO for full year 2008 is expected to be in the range of \$314 - \$321 million or \$3.33 - \$3.40 per unit or \$3.40 - \$3.47 per unit excluding one time charges. This forecast is supported by hedging contracts averaging 47 percent of the Trust’s net after royalty production for the balance of the year at prices above current levels.
- Simple payout ratios are forecast to be 56 to 57 percent and 101 to 103 percent including capital, declining to 94 to 96 percent including the DRIP for 10 months of 2008.

NAL provides the following update to the outlook for full year 2008:

	<b>2008 Full Year Outlook</b>	
	August 6, 2008	November 4, 2008
Production (boe/d)	24,400 <sup>(1)</sup>	23,800-23,900 <sup>(1)</sup>
Net capital expenditures (\$MM)	150 - 160	151
Operating costs (\$/boe)	10.00 – 10.50	10.50 – 10.75

(1) Includes non-controlling interest.

NAL outlines the following 2008 full year financial forecast based upon certain assumptions:

<b>2008 Forecast Assumptions</b>	<b>Key Assumptions</b>	
WTI oil price (U.S.\$/bbl) <sup>(3)</sup>	60.00	80.00
AECO natural gas price (C\$/GJ) <sup>(3)</sup>	6.00	7.50
Exchange rate (Cdn/USD) <sup>(3)</sup>	1.25	1.15
Capital expenditures (C\$ MM) <sup>(4)</sup>	151	151
Production (boe/d)	23,800 <sup>(1)(2)</sup>	23,800 <sup>(1)(2)</sup>
Monthly distribution (\$/unit)	0.16	0.16

(1) Including February 2008 acquisitions of Tiberius/Spear.

(2) Includes non-controlling interest.

(3) Commodity and exchange rate forecast assumptions using estimated actuals for October plus forecast for November-December 2008.

(4) Excludes non-controlling interest capital of \$8 million, resulting in Trust net capital of \$151 million.

<b>2008 Financial Forecasts</b>	<b>Sensitivities</b>	
Funds from operation (\$MM) <sup>(1)</sup>	314	321
Full year weighted average number of units outstanding (MM)	94.4	94.4
Funds from operation (\$/unit – basic)	\$3.33	\$3.40
Funds from operation (\$/unit – fully diluted)	\$3.14	\$3.21
Payout ratio (%)	57	56
Payout with capital (%) <sup>(3)</sup>	103	101
Payout with DRIP (%)	96	94
Debt / cash flow (x)	1.0 / 1.25 <sup>(2)</sup>	0.97 / 1.22 <sup>(2)</sup>

(1) Includes impact of hedging gains and losses and \$6.9 million one time SemCanada write off.

(2) Includes convertible debentures.

(3) Excludes property acquisition capital of \$8 million.

## 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 outlook for full year 2008 and the 2008 full year financial forecasts 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 netbacks.

## CONFERENCE CALL DETAILS

At 3:30 p.m. MST (5:30 p.m. EST) on Tuesday, November 4, 2008, NAL will hold a conference call to discuss the third quarter 2008 results. Mr. Andrew Wiswell, President and CEO, will host the conference call with other members of the Management Team. The call is open to analysts, investors, and all interested parties. If you wish to participate, call 1-866-300-4047 toll free across North America. The conference call will also be accessible through the internet at <http://events.onlinebroadcasting.com/nal/110408/index.php>

A recorded playback of the call will be available until November 11, 2008 by calling 1-800-408-3053, reservation 3265792.

Notes: All amounts are in Canadian dollars unless otherwise stated.

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)

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008	2007	2008	2007
<b>FINANCIAL</b>				
Gross revenue, net of royalties, before hedging	\$139,422	\$78,589	\$405,610	\$230,353
Cash flow from operating activities	98,860	61,266	242,716	170,253
Cash flow per unit - basic	1.03	0.74	2.59	2.13
Cash flow per unit - diluted	0.99	0.72	2.46	2.11
Funds from operations	79,233	50,817	244,031	159,208
Funds from operations per unit - basic	0.83	0.61	2.60	1.99
Funds from operations per unit - diluted	0.79	0.60	2.48	1.98
Net income	111,045	7,801	107,206	45,901
Distributions declared	45,968	39,778	135,295	115,261
Distributions per unit	0.48	0.48	1.44	1.44
Payout ratio:				
based on cash flow from operating activities	46%	65%	56%	68%
based on funds from operations	58%	78%	55%	72%
Units outstanding (000's)				
Period end	95,945	89,886	95,945	89,886
Weighted average	95,664	82,815	93,834	79,982
Capital expenditures	53,562	34,256	117,469	80,240
Corporate acquisitions	14	246,010	58,378	246,010
Net debt <sup>(1)</sup>	298,988	274,513	298,988	274,513
Convertible debentures (at face value)	79,744	100,000	79,744	100,000
<b>OPERATING</b>				
Daily production <sup>(2)</sup>				
Crude Oil (bbl/d)	9,989	9,258	10,176	9,246
Natural gas (mcf/d)	70,425	54,725	68,847	50,148
Natural gas liquids (bbl/d)	2,081	1,990	2,083	2,074
Oil equivalent (boe/d)	23,808	20,369	23,733	19,678
<b>OPERATING NETBACK (boe)</b>				
Revenue before hedging gains (losses)	80.11	53.10	78.12	54.15
Royalties	(16.90)	(11.53)	(16.19)	(11.62)
Operating costs	(11.63)	(10.30)	(10.64)	(9.01)
Other income	0.52	0.35	0.51	0.35
Operating netback before hedging	52.10	31.62	51.80	33.87
Hedging gains (losses)	(7.59)	(0.03)	(6.74)	0.57
Operating netback	44.51	31.59	45.06	34.44

(1) Excluding convertible debentures.

(2) Includes royalty income volumes.

## MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion and analysis ("MD&A") should be read in conjunction with the interim consolidated financial statements for the three and nine month periods ended September 30, 2008 and the audited consolidated financial statements and MD&A for the year ended December 31, 2007 of NAL Oil & Gas Trust ("NAL" or the "Trust"). It contains information and opinions on the Trust's future outlook based on currently available information. All amounts are reported in Canadian dollars, unless otherwise stated. Where applicable, natural gas has been converted to barrels of oil equivalent ("boe") based on a ratio of six thousand cubic feet of natural gas to one barrel of oil. The boe rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. Use of boe in isolation may be misleading.

## NON-GAAP FINANCIAL MEASURES

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

Funds from operations is calculated as cash flow from operating activities before changes in non-cash working capital. Funds from operations does not represent operating cash flows or operating profits for the period and should not be viewed as an alternative to cash flow from operating activities calculated in accordance with GAAP. Funds from operations is considered by Management to be a more meaningful key performance indicator of NAL's ability to generate cash to finance operations and to pay monthly distributions. Funds from operations per unit and cash flow from operations per unit are calculated using the weighted average units outstanding for the period.

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

Net debt to trailing 12 months cash flow is calculated as net debt as a proportion of funds from operations for the previous 12 months. Net debt is defined as bank debt, plus convertible debentures at face value, plus working capital, excluding derivative contracts, notes payable/receivable and future income tax balances.

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

\$(000s)	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008	2007	2008	2007
Cash flow from operating activities	98,860	61,266	242,716	170,253
Add back change in non-cash working capital	(19,627)	(10,449)	1,315	(11,045)
Funds from operations	79,233	50,817	244,031	159,208

## 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" or "resources" are forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources 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; 2008 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; 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.*

*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 risk 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; imprecision of reserve estimates; limited, unfavorable or no access to capital 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 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 the royalty rates, particularly in light of the Alberta government's royalty review; changes in tax laws; including the impact of legislation relating to the taxation of "specified investment flow-through" entities and proposed amendments to the Income Tax Act (Canada) to permit the conversion of income trusts into corporations by the Federal government; 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 and MD&A for the year ended December 31, 2007.*

*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.*

#### **ACQUISITION OF TIBERIUS EXPLORATION INC. AND SPEAR EXPLORATION INC.**

Effective February 27, 2008 the Trust acquired all the issued and outstanding common shares of Tiberius Exploration Inc. ("Tiberius") and Spear Exploration Inc. ("Spear"), which have interests in southeast Saskatchewan.

On February 29, 2008 the Trust transferred the assets into a newly formed limited partnership ("Partnership") in exchange for a 50 percent partnership interest and a note receivable of \$3.7 million. A wholly owned subsidiary of Manulife Financial Corporation ("MFC") acquired the remaining 50 percent share in the Partnership and a note receivable of \$3.7 million, by payment in cash of one half of the total purchase price for Tiberius and Spear. MFC is a related party to the Trust, see "Administrative Services and Cost Sharing Agreement".

The net acquisition cost to the Trust for its 50 percent share in the acquired properties is \$57.8 million, before acquisition costs, comprised of \$28.3 million in cash and \$29.5 million from the issuance of 2.4 million trust units at a price of \$12.24 per unit. The unit price was based on the average market price of the units at the announcement date for the acquisition of February 11, 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. The equivalent carrying amounts of property, plant and equipment related to this interest is recorded on the books of each royalty holder and was removed from the books of the Partnership.

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. 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 are 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.

Consequently, substantially all analysis in the MD&A includes 100 percent of the results of the Partnership, with 50 percent of these results being removed through the non-controlling interest.

The results of operations from the Tiberius and Spear properties have been included in the consolidated financial statements of the Trust commencing February 27, 2008, the closing date of the transaction.

The fair values assigned to the net assets acquired from Tiberius and Spear and the consideration paid by the Trust is as follows:

	Total Acquisition	Disposition to Manulife	Trust, net Acquisition	NPI <sup>(1)</sup>	Net to Trust
Net assets acquired \$(000s):					
Cash	\$9,734	\$-	\$9,734	\$-	\$9,734
Working capital deficiency	(5,622)	-	(5,622)	-	(5,622)
Notes receivable, net from MFC	-	(3,750)	(3,750)	49,599	45,849
Property, plant and equipment	111,258	-	111,258	(49,599)	61,659
Future income taxes	(23,389)	11,588	(11,801)	-	(11,801)
Asset retirement obligations	(1,636)	-	(1,636)	-	(1,636)
Goodwill	26,254	(12,002)	14,252	-	14,252
Non-controlling interest	-	(54,057)	(54,057)	-	(54,057)
	\$116,599	\$(58,221)	\$58,378	\$-	\$58,378
Consideration:					
Cash	\$86,118	\$(57,807)	\$28,311	\$-	\$28,311
Issuance of trust units	29,496	-	29,496	-	29,496
Acquisition costs	985	(414)	571	-	571
	\$116,599	\$(58,221)	\$58,378	\$-	\$58,378

(1) Net profit interest agreement entered into with MFC in exchange for a note receivable.

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

\$(000s)	Three months ended Sept. 30, 2008 <sup>(1)</sup>	Net Impact to Trust <sup>(2)</sup>	Year-to- date <sup>(1)</sup>	Net Impact to Trust <sup>(2)</sup>
Total production volumes (boes)	69,756	34,878	188,143	94,072
Production volumes (boe/d)	758	379	687	343
Oil, natural gas and liquid sales	\$7,999	\$4,000	\$21,153	\$10,577
Royalties	(1,074)	(537)	(2,446)	(1,223)
Operating costs	(1,295)	(647)	(2,483)	(1,241)
General and administrative	(26)	(13)	(196)	(98)
Unit-based incentive compensation	8	4	(73)	(37)
Interest income, net	1,781	890	4,234	2,116
Bad debt expense	(46)	(23)	(46)	(23)
Depletion, depreciation and accretion	(1,026)	(513)	(1,787)	(893)
Net profit interest expense	(4,020)	(2,010)	(14,141)	(7,071)
Net income	\$2,301	\$1,151	\$4,215	\$2,107

(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 agreement, 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:

\$(000s)	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008	2007	2008	2007
Net profits interest expense	\$2,010	\$-	\$7,071	\$-
Share of net income attributable to MFC	1,151	-	2,107	-
	\$3,161	\$-	\$9,178	\$-

## EXPLORATION & DEVELOPMENT ACTIVITIES

The Trust spent \$39.2 million on drilling, completion and tie in operations during the third quarter of 2008, versus \$26.5 million in 2007 and participated in the drilling of 33 (15.7 net) wells during the third quarter, compared to 32 (15.5 net) wells during the same period in 2007.

Historically, NAL's assets have been concentrated in southeast Saskatchewan and central Alberta. The purchase of Seneca in 2007 added a new core area at Monkman in northeast British Columbia and expanded the Trust's W4M operations in the Hanna and Drumheller area of southeast Alberta. The Tiberius/Spear acquisition added to NAL's Nottingham/Alida operations in southeast Saskatchewan.

### Third Quarter Drilling Activity

	Crude Oil		Natural Gas		Service Wells		Dry & Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Operated wells	16	11.5	3	2.0	0	0	0	0	19	13.5
Non-operated wells	7	0.4	7	1.8	0	0	0	0	14	2.2
Total wells drilled	23	11.9	10	3.8	0	0	0	0	33	15.7

### Year to Date Drilling Activity

	Crude Oil		Natural Gas		Service Wells		Dry & Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Operated wells	56	32.4	12	8.4	0	0	0	0	68	40.8
Non-operated wells	17	1.4	13	2.9	0	0	0	0	30	4.3
Total wells drilled	73	33.8	25	11.3	0	0	0	0	98	45.1

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

In Saskatchewan, there were 13 (5.8 net) oil wells drilled during the third quarter, primarily focused on Mississippian and Tilston targets.

Production volumes from the Weir Hill wells were below expectations and the testing of the two Hoffer wells delivered marginal results. Scheduled follow-on drilling was deferred in these areas and new opportunities were positioned for drilling in the fourth quarter of 2008 and into 2009. The Trust's extensive inventory of opportunities in Saskatchewan allows us the flexibility to move other opportunities forward although the timing of drilling license approvals has slowed considerably with the increased activity levels in the province. The Trust expects to keep two drilling rigs working during the fourth quarter drilling 12 (6 net) wells.

Strong industry activity limited the availability of equipment and manpower in this region and delayed execution of key gathering and water handling projects in Alida and on the Tiberius/Spear properties resulting in about 300 boe/d of production delay from high water cut wells. It is expected that these facilities will be completed and this production will be brought on stream during the fourth quarter.

Construction of the Nottingham gas plant expansion has commenced with large components to be installed before year end and commissioning slated for the end of the first quarter 2009.

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

In Alberta, NAL drilled 20 (9.9 net) wells during the quarter. This program targeted stacked Mannville opportunities and achieved 100 percent drilling success with all wells expected to be completed and on stream in the fourth

quarter, 2008. Most wells were successfully completed in more than one zone with a combination of oil and natural gas production. As a result, some volume has been delayed until formal commingling approvals are received. Production from this drilling program is expected to deliver 700 boe/d over the course of the fourth quarter.

During the fourth quarter, the Trust anticipates drilling three horizontal oil wells in the Sylvan Lake area. The first well (63 percent WI) has been drilled and completed with a successful stimulation over 1000m of horizontal oil pay. It is expected that initial production after 30 - 60 days of flushed volumes will be 300 - 400 boe/d. Continued success in the program would validate this resource and add two to three years inventory for future drilling in the area. The Trust will also drill two Glauconite oil wells in Hussar (40 percent working interest) following up on the new pool discovery earlier in the year.

#### **Northeast British Columbia (Monkman)**

Drilling continued through the quarter on d-27-F (10 percent WI) and c-21-k (10 percent WI). These wells are expected to reach total depth and be rig released by early November. Testing of multiple zones in both wells is expected prior to year end.

Talisman expects to spud a third well (a-2-E Trust WI 20 percent) on a new structure in November or December 2008. This well will be drilling into the summer of 2009.

Availability of interruptible capacity through the Pine River Spectra Gas Plant is expected to be reduced during the fourth quarter which has lowered our volume expectations by 200 boe/d. Significant deliverability still exists behind pipe in the a-26-E well as one zone remains shut in (approximately 30 mmcf/d gross, 5 mmcf/d net). Success in the current wells will firm up additional locations and give us deliverability to evaluate participating in additional processing plans and or take away capacity to another system. It is expected that additional capacity in the current facility may open up by mid 2009 due to normal declines from wells in the area. The availability of capacity is dependant on the amount of successful drilling and firm service ownership of new gas that comes on stream.

#### **CAPITAL EXPENDITURES**

Capital expenditures for the quarter ended September 30, 2008 totaled \$53.6 million compared with \$34.3 million for the quarter ended September 30, 2007. On a year-to-date basis, capital expenditures totaled \$117.5 million compared to \$80.2 million in the same period of 2007.

Capital spending for the quarter and year to date was significantly higher than 2007 as a result of, multi-zone completions from a successful Mannville drilling program and deeper more expensive wells being drilled in Monkman (two wells) and Hoffer (two wells) as well as closing property tuck-in acquisitions. Significant additional capital was also spent on targeted land and facilities projects as compared to the same periods in 2007. Drilling completion and tie in costs increased year-over-year with upward pressure from increases in steel, manpower and fuel costs.

During the quarter, the Trust was successful in adding \$8 million of unbudgeted land purchases in and around core areas which has added significant opportunities to our portfolio. The Trust is positioned to increase its over-all capital program as a result of this success but with recent declines in commodity prices. Management felt it was prudent to hold the line on capital spending and has subsequently deferred \$8 million of drilling and smaller facilities projects maintaining its previous guidance of \$159 million (\$151 million net).

Year-to-date, the Trust has spent 74 percent of its expected capital program with \$42 million targeted to be spent in the fourth quarter. NAL's strategy of building future opportunities into its portfolio for 2009 - 2010 has resulted in 23 percent of its exploitation and development capital being spent on land and facilities in the first nine months of 2008 as compared to 13 percent a year earlier. Over the balance of 2008, NAL expects that trend to continue as it executes its capital program with anticipated spending of \$14 million on land for the full year to add multi-zone opportunities in Saskatchewan and Alberta. This focused land acquisition in core areas is a deliberate strategy to add new opportunities to the asset base.

### Capital Expenditures (\$000s)

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008	2007	2008	2007
Drilling, completion and production equipment	39,237	26,507	79,520	64,356
Plant and facilities	4,542	2,285	11,249	6,680
Seismic	69	32	876	559
Land	8,293	2,672	12,115	2,762
Total exploitation and development	52,141	31,496	103,760	74,357
Office equipment	562	231	1,181	505
Capitalized G&A	824	1,051	3,167	3,487
Capitalized unit-based compensation	(338)	274	1,152	445
Total other capital	1,048	1,556	5,500	4,437
Total capitalized expenditures before acquisitions	53,189	33,052	109,260	78,794
Property acquisitions (dispositions), net	373	1,204	8,209	1,446
Total capitalized expenditures	53,562	34,256	117,469	80,240

### PRODUCTION

Third quarter 2008 production of 23,808 boe/d exceeded production of 20,369 boe/d in the comparable period of 2007 by 17 percent. This increase is attributable to the acquisition of Seneca (only one month of production in 2007), Tiberius and Spear production, as well as the ongoing execution of the Trust's capital program.

For the nine months ended September 30, 2008, production of 23,733 boe/d exceeded the 19,678 boe/d for the comparable period in 2007, by 21 percent, for similar reasons as described above.

Production for the third quarter is below expectations due to delay of new facilities in Saskatchewan associated with optimization of the Tiberius and Spear and Alida high water cut production (300 boe/d average for the quarter), less than expected results mainly in Hoffer and Weir Hill (400 boe/d average for the quarter), and delayed tie in to third party facilities for production from the Pine Creek 3-22 (150 boe/d average for the quarter). Significant unplanned plant outages at Spectra Nevis and Pine River in July also impacted the quarter by 150 boe/d.

Volumes continued to grow through the third quarter with September production exceeding 24,000 boe/d. It is expected that production will remain in the 24,000 boe/d range in the fourth quarter due to the carry over effect of some lower than expected results, reduced capital spending of \$8 million impacting exit rate, lower production in Monkman related to limited interruptible capacity and timing of facilities coming on stream in Saskatchewan. These trends are partially offset by new production from the third quarter Mannville drilling program, volumes from Saskatchewan Mississippian drilling and three Garrington horizontal wells in Alberta.

Full year average production is expected to be 23,800 - 23,900 boe/d with exit rates of 24,000 - 24,300 boe/d. Potential upside exists from timing and results related to the fourth quarter horizontal well program. The Trust's full year average production is approximately two percent below guidance which represents \$5 - 6 million in cash flow net to the Trust for full year 2008.

### Average Daily Production Volumes

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008 <sup>(1)</sup>	2007 <sup>(1)</sup>	2008 <sup>(1)</sup>	2007 <sup>(1)</sup>
Oil (bbl/d)	9,989	9,258	10,176	9,246
Natural gas (Mcf/d)	70,425	54,725	68,847	50,148
NGLs (bbl/d)	2,081	1,990	2,083	2,074
Oil equivalent (boe/d)	23,808	20,369	23,733	19,678

(1) Volumes include royalty income volumes.

The oil equivalent volumes of 23,808 boe/d for the third quarter of 2008 and 23,733 boe/d year-to-date include 379 boe/d and 343 boe/d, respectively, attributable to the non-controlling interest in the Tiberius and Spear properties.

The Trust's net production, after deducting the non-controlling interest, is 23,429 boe/d for the third quarter of 2008 and 23,390 boe/d year-to-date.

For the three months ended September 30, 2008, oil and natural gas liquids totaled 51 percent (52 percent for nine months) of production with natural gas increasing to 49 percent (48 percent for nine months) of production as a result of the natural gas weighted Seneca acquisition.

#### Production Weighting

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008	2007	2008	2007
Oil	42%	45%	43%	47%
Natural gas	49%	45%	48%	42%
NGLs	9%	10%	9%	11%

#### REVENUE

Gross revenue from oil, natural gas and natural gas liquids sales, after transportation costs, totaled \$175.4 million for the three months ended September 30, 2008, 76 percent higher than the third quarter of 2007. The increase is due to a 17 percent increase in production as a result of acquisitions and the ongoing execution of our capital program, as well as a 51 percent increase in the average realized price per boe. The Trust's realized commodity prices increased for all production, highlighted by 54 percent and 52 percent quarter-over-quarter increases in realized crude oil and natural gas prices, respectively.

For the nine month period ended September 30, 2008, revenue after transportation costs totaled \$508.0 million, an increase of 75 percent from the comparable period in 2007. The increase is attributable to a 21 percent increase in production, primarily due to acquisitions, and an increase of 44 percent in the average realized price per boe.

#### Revenue

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008	2007	2008	2007
Revenue <sup>(1)</sup> (\$000s)				
Oil	104,949	62,990	297,894	170,999
Gas	53,152	27,167	165,392	92,664
NGL's	15,034	9,322	41,805	27,195
Sulphur	2,313	19	2,907	14
Total revenue	175,448	99,498	507,998	290,872
\$/boe	80.11	53.10	78.12	54.15

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

#### OIL MARKETING

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

NAL's third quarter average realized Canadian crude oil price per barrel, net of transportation costs, was \$114.20, as compared to \$74.37 for the comparable quarter of 2007. The increase in realized price quarter-over-quarter of 54 percent, or \$39.83/bbl, was primarily driven by a 56 percent increase in WTI (U.S.\$/bbl) over the comparable period.

For the third quarter of 2008, NAL's crude oil price differential was 93 percent, a one percent point decrease from the comparable period in 2007. The differential is calculated as realized price as a percentage of WTI stated in Canadian dollars.

For the nine months ended September 30, 2008, NAL's average oil price was \$106.84 per barrel as compared to \$67.74 for the comparable period in 2007. The increase in realized price was driven by a 71 percent increase in WTI (US\$/bbl). Differentials were unchanged year-over-year at 93 percent.

Natural gas liquids averaged \$78.53/bbl in the third quarter of 2008, a 54 percent increase from \$51.02/bbl realized in 2007. For the nine months ended September 30, 2008, natural gas liquids averaged \$73.25/bbl, an increase of 52 percent from the comparable period in 2007.

On July 22, 2008, SemGroup L.P. ("SemCanada") announced it and certain of its North American subsidiaries had filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code as well as an application for creditor protection under the Companies' Creditors Arrangement Act in Canada. NAL has retained legal counsel to manage this matter. It has been determined that the likelihood of recovering any of the amount owed to the Trust is unlikely. Therefore, the Trust has recorded an expense of \$6.9 million, in the third quarter of 2008, to write off the total amount outstanding from SemCanada. NAL continues to work with legal counsel to attempt to recover amounts due. Any future amounts received will be recorded to income.

## NATURAL GAS MARKETING

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

For the three months ended September 30, 2008, the Trust's natural gas sales averaged \$8.20/mcf compared to \$5.40/mcf in the comparable period of 2007, an increase of 52 percent. The quarter-over-quarter increase in gas prices was attributable to a 49 percent increase in the benchmark AECO daily spot prices.

Prices for Lake Erie natural gas increased to \$9.98/mcf in the third quarter of 2008, compared to \$6.67/mcf in 2007, an increase of 50 percent. Lake Erie production of 3.49 mmcf/d accounted for five percent of the Trust's natural gas production in the third quarter of 2008, compared to seven percent in the same period of 2007. The Seneca acquisition effective September 1, 2007 reduced the weighing of gas produced in Lake Erie. Natural gas sales from the Lake Erie property generally receive a higher price due to the close proximity to the Ontario and Northeastern U.S. markets.

For the nine months ended September 30, 2008, NAL averaged \$8.77/mcf, a 29 percent increase from the \$6.79/mcf realized in the comparable period in 2007. The year-over-year increase in gas prices was attributable to a 32 percent increase in the benchmark AECO daily spot prices.

### Average Pricing (net of transportation charges)

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008	2007	2008	2007
<b>Liquids</b>				
WTI (US\$/bbl)	<b>117.98</b>	75.39	<b>113.29</b>	66.19
NAL average oil (Cdn\$/bbl)	<b>114.20</b>	74.37	<b>106.84</b>	67.74
NAL natural gas liquids (Cdn\$/bbl)	<b>78.53</b>	51.02	<b>73.25</b>	48.18
<b>Natural Gas (Cdn\$/Mcf)</b>				
AECO – daily spot	<b>7.73</b>	5.14	<b>8.64</b>	6.54
AECO – monthly	<b>9.25</b>	5.61	<b>8.55</b>	6.81
NAL Western Canada natural gas	<b>8.11</b>	5.30	<b>8.68</b>	6.63
NAL Lake Erie natural gas	<b>9.98</b>	6.67	<b>10.44</b>	8.08
NAL average natural gas	<b>8.20</b>	5.40	<b>8.77</b>	6.79
NAL Oil Equivalent before hedging (Cdn\$/boe – 6:1)	<b>80.11</b>	53.10	<b>78.12</b>	54.15
Average Foreign Exchange Rate (Cdn\$/U.S.\$)	<b>1.0418</b>	1.0448	<b>1.0186</b>	1.1048

## RISK MANAGEMENT

NAL employs risk management practices to assist in managing cash flows and to support capital programs and distributions. 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 hedging program is layered in using a combination of swaps and collars. As at September 30, 2008, NAL had several financial WTI oil contracts and AECO natural gas contracts in place.

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

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008	2007	2008	2007
Average crude volumes hedged (bbl/d)	<b>5,100</b>	3,833	<b>4,712</b>	2,816
Crude oil realized gain (loss) (\$000's)	<b>(13,119)</b>	(2,314)	<b>(38,151)</b>	623
Gain (loss) per bbl hedged	<b>(27.96)</b>	(6.56)	<b>(29.55)</b>	0.81
Average natural gas volumes hedged (GJ/d)	<b>30,000</b>	16,000	<b>26,735</b>	15,505
Natural gas realized gain (loss) (\$000's)	<b>(3,508)</b>	2,267	<b>(5,697)</b>	2,452
Gain (loss) per GJ hedged	<b>(1.27)</b>	1.54	<b>(0.78)</b>	0.58
Average BOE hedged (boe/d)	<b>9,839</b>	6,362	<b>8,936</b>	5,266
Total realized gain (loss) (\$000's)	<b>(16,627)</b>	(47)	<b>(43,848)</b>	3,075
Gain (loss) per boe hedged	<b>(18.37)</b>	(0.08)	<b>(17.91)</b>	2.14
Gain (loss) per boe	<b>(7.59)</b>	(0.03)	<b>(6.74)</b>	0.57

All derivative contracts are recorded on the balance sheet at fair value based upon the forward curve at September 30, 2008. 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. Accordingly, the magnitude of the unrealized gain or loss will continue to fluctuate with changes in commodity prices.

The fair value of the derivatives at September 30, 2008 was a net asset of \$8.8 million, comprised of a \$0.3 million asset on oil contracts and an \$8.5 million asset on gas contracts.

Third quarter income for 2008 includes a \$111.1 million unrealized gain on derivatives resulting from the change in the fair value of the derivative contracts during the quarter from an unrealized loss of \$102.3 million at June 30, 2008 to an unrealized gain of \$8.8 million at September 30, 2008. The \$111.1 million unrealized gain was comprised of a \$70.9 million unrealized gain on crude oil contracts, and a \$40.2 million unrealized gain on natural gas contracts. The unrealized gain in the third quarter is attributable to lower crude oil and natural gas forward prices compared to June 30, 2008. Average hedged boes for the third quarter were 9,839 as compared to 9,466 for the second quarter of 2008.

For the nine months ended September 30, 2008, income includes an unrealized gain of \$18.4 million, resulting from the change in the fair value of the derivatives during the period. The unrealized gain was comprised of a \$13.2 million unrealized gain on crude oil contracts, and a \$5.2 million unrealized gain on natural gas contracts. The unrealized gain in the period is reflective of additional contracts entered into during the first half of 2008 at higher commodity prices.

The gain/loss on derivative contracts is as follows:

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

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008	2007	2008	2007
Unrealized gain (loss)				
Crude oil contracts	70,892	(4,580)	13,236	(9,920)
Natural gas contracts	40,161	3,072	5,134	4,028
Unrealized gain (loss)	111,053	(1,508)	18,370	(5,892)
Realized gain (loss)	(16,627)	(47)	(43,848)	3,075
Reclassification from other comprehensive income	-	874	-	3,647
Gain (loss) on derivative contracts	94,426	(681)	(25,478)	830

For the remainder of 2008, NAL has the following risk management contracts outstanding:

CRUDE OIL	U.S.\$	CDN\$
Swap (bbls)	153,400	196,200
Swap (bbl/d)	1,667	2,133
\$/bbl	\$94.22	\$91.40
Collars (bbls)	55,200	64,400
Collars (bbl/d)	600	700
\$/bbl	\$84.17 - \$95.75	\$91.93 - \$109.03
Total (bbls)	208,600	260,600
Total (bbl/d)	2,267	2,833

NATURAL GAS	CDN\$
Swap (GJ)	1,997,000
Swap (GJ/d)	21,707
\$/GJ	\$7.39
Collars (GJ)	763,000
Collars (GJ/d)	8,293
\$/GJ	\$7.94 - \$9.54
Total GJ	2,760,000
Total (GJ/d)	30,000

For 2009, NAL has the following risk management contracts outstanding:

CRUDE OIL	U.S.\$	CDN\$
Swap (bbls)	254,800	227,200
Swap (bbl/d)	698	623
\$/bbl	\$105.79	\$101.47
Collars (bbls)	364,500	105,900
Collars (bbl/d)	999	290
\$/bbl	\$109.91 - \$156.39	\$105.60 - \$125.82
Total (bbls)	619,300	333,100
Total (bbl/d)	1,697	913

NATURAL GAS	CDN\$
Swap (GJ)	2,148,000
Swap (GJ/d)	5,885
\$/GJ	\$8.03
Collars (GJ)	2,510,000
Collars (GJ/d)	6,877
\$/GJ	\$8.44 - \$10.36
Total GJ	4,658,000
Total (GJ/d)	12,762

For the balance of 2008, the Trust has outstanding contracts representing approximately 47 percent of the net liquids and natural gas production after royalty, assuming a royalty rate of 21 percent.

## ROYALTY EXPENSES

Crown, freehold and overriding royalties were \$37.0 million for the three months ended September 30, 2008. Expressed as a percentage of gross sales net of transportation costs, before gain/loss on derivative contracts, the net royalty rate was 21.1 percent for the quarter ended September 30, 2008, comparable to the 21.7 percent experienced in the same period of the previous year.

Royalties increased to \$16.90 per boe for the third quarter of 2008, an increase of 47 percent compared to the third quarter of 2007. The increase is attributable to higher commodity prices on a quarter-over-quarter basis.

On a year-to-date basis, royalties were \$105.3 million, up from \$62.4 million in the comparable period of 2007. Expressed as a percentage of gross sales net of transportation costs, before gain/loss on derivative contracts, the net royalty rate was 20.7 percent, as compared to 21.5 percent in the comparable period in 2007.

### Royalty Expenses

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008	2007	2008	2007
Royalties (\$000s)	<b>37,015</b>	21,600	<b>105,267</b>	62,401
As % of revenue	<b>21.1</b>	21.7	<b>20.7</b>	21.5
\$/boe	<b>16.90</b>	11.53	<b>16.19</b>	11.62

## OPERATING COSTS

Operating costs averaged \$11.63 per boe for the quarter ended September 30, 2008, a 13 percent increase from the \$10.30 per boe for the quarter ended September 30, 2007. On a year-to-date basis, operating costs were \$10.64 per boe as compared to \$9.01 in 2007.

Approximately \$0.75 per boe is due to significant increases in fuel, power, and processing costs which would be directly related to cost pressures driven by increased commodity prices.

In Saskatchewan, industry costs are up 20 percent year-over-year due to the levels of activity and limited availability of equipment, services and people. Despite currently lower commodity prices, strong activity levels are expected to continue in the near term due to relatively high netbacks and royalty holidays resulting in favorable economics.

Operating costs on the acquired Seneca properties are up 15 percent due to higher third party processing costs.

As to the full year outlook, the Trust expects costs to be similar to the \$10.64 per boe for the first nine months with a range of \$10.50 - \$10.75 per boe.

### Operating Costs

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008	2007	2008	2007
Operating costs (\$000s)	<b>25,463</b>	19,301	<b>69,179</b>	48,379
As a % of revenue	<b>14.51</b>	19.40	<b>13.62</b>	16.63
\$/boe	<b>11.63</b>	10.30	<b>10.64</b>	9.01

## OPERATING NETBACK

For the quarter ended September 30, 2008, NAL's operating netback before hedging gains (losses) was \$52.10 per boe, an increase of \$20.48 from \$31.62 per boe for the quarter ended September 30, 2007. The increase was due to higher revenues driven by stronger commodity prices, partially offset by increases in royalties and operating expenses. Hedging losses were \$7.59 per boe in the third quarter of 2008, as compared to \$0.03 per boe in 2007.

On a year-to-date basis, similar trends resulted in an operating netback, before hedging, of \$51.80 per boe as compared to \$33.87 per boe in 2007.

### Operating Netback (\$/boe)

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008	2007	2008	2007
Revenue	80.11	53.10	78.12	54.15
Royalties	(16.90)	(11.53)	(16.19)	(11.62)
Operating expenses	(11.63)	(10.30)	(10.64)	(9.01)
Other income	0.52	0.35	0.51	0.35
Operating netback, before hedging	52.10	31.62	51.80	33.87
Hedging gains (losses)	(7.59)	(0.03)	(6.74)	0.57
Operating netback, after hedging	44.51	31.59	45.06	34.44

### 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 September 30, 2008, G&A expenses were \$3.7 million, compared with \$2.5 million in the comparable quarter of 2007. In addition, \$0.8 million of G&A costs relating to exploitation and development activities were capitalized in the third quarter of 2008 compared with \$1.1 million in the third quarter of 2007. G&A expense per boe, excluding retention bonus, was \$1.69 in the quarter, as compared to \$1.30 for the same period in 2007. The increase is mainly due to budgeted process improvement costs and increased costs of IT and geological software.

For the nine months ended September 30, 2008, G&A expense increased 17 percent to \$12.0 million from \$10.3 million in the comparable period in 2007. In addition, on a year-to-date basis, \$3.2 million of G&A costs relating to exploitation and development activities were capitalized, compared with \$3.5 million in 2007. The retention bonus program concluded on June 30, 2008, (\$0.02 per boe year-to-date) and there will be no further expense relating to this program. G&A expense per boe, excluding one-time retention bonus was \$1.82 for the nine months ended September 30, 2008, as compared to \$1.75 for the same period in 2007, an increase of \$0.07 per boe for similar reasons as noted above.

### General and Administrative Expenses

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008	2007	2008	2007
G&A expenses (\$000s)				
G&A	3,709	2,445	11,844	9,420
Retention bonus	(35)	104	106	888
Expensed G&A (\$000s)	3,674	2,549	11,950	10,308
Capitalized G&A (\$000s)	824	1,051	3,167	3,487
Total G&A (\$000s)	4,498	3,600	15,117	13,795
Expensed G&A costs:				
G&A, excluding retention bonus (\$/boe)	1.69	1.30	1.82	1.75
Retention bonus (\$/boe)	(0.01)	0.06	0.02	0.17
Total G&A expenses (\$/boe)	1.68	1.36	1.84	1.92
As % of revenue	2.1	2.6	2.4	3.5
Per trust unit (\$)	0.04	0.03	0.13	0.13

### 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 one third on November 30 in each of three years after grant date. PTUs vest on November 30, three years after their 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 third quarter of 2008, the Trust recorded a recovery of \$0.8 million of unit-based incentive compensation as compared to a \$0.7 million charge in the comparable quarter of 2007. The recovery in unit-based compensation in the third quarter of 2008 reflects a 26 percent decrease in the unit price of the Trust, from \$16.89 at June 30, 2008 to \$12.53 a unit at September 30, 2008. A decrease in unit price results in previously accrued amounts being reversed although partially offset by the impact of additional vesting.

On a year-to-date basis, the Trust has accrued \$3.7 million compared to \$1.5 million in the comparable period in 2007. The increase in unit-based compensation in 2008 is primarily a result of an increase in the unit price as compared to December 31, 2007.

At September 30, 2008, the unit price used to determine unit-based incentive compensation was \$12.53. Currently the unit price of the Trust is \$9.78 as at close on November 3, 2008.

This calculation 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 September 30, 2008, the Trust has recorded a liability for unit-based incentive compensation in the amount of \$6.9 million, of which \$2.6 million is recorded as a current liability as it is payable in December 2008, and \$4.3 million is long-term liability as it is payable in December 2009 and December 2010.

#### Unit-Based Compensation

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008	2007	2008	2007
Unit-based compensation (\$000s):				
Expensed	(478)	408	2,519	1,072
Capitalized	(338)	274	1,152	445
Total unit-based compensation	(816)	682	3,671	1,517
Expensed unit-based compensation:				
As % of revenue	(0.27)	0.41	0.49	0.36
\$/boe	(0.22)	0.22	0.39	0.20
Per trust unit (\$)	(0.01)	0.00	0.03	0.01

#### ADMINISTRATIVE SERVICES AND COST SHARING AGREEMENT<sup>(1)</sup> AND 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 provides for no base or performance fees and requires the Trust to reimburse the Manager at cost for general and administrative and unit-based compensation expenses incurred by the Manager on behalf of the Trust calculated on a unit of production basis.

The Trust paid \$3.1 million (2007 - \$2.4 million) for the reimbursement of G&A expenses during the third quarter, and \$9.6 million (2007 - \$8.4 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 \$1.8 million has been paid year-to-date, representing units that vested November 30, 2007 (2007 - \$2.2 million).

At September 30, 2008 the Trust owed the Manager \$1.0 million for the reimbursement of G&A and had a receivable from NAL Resources of \$2.9 million, relating to net operating revenues less capital expenditures due to the Trust.

In addition, there are notes outstanding with MFC arising from the Tiberius and Spear acquisition. These notes are included on consolidation of the Partnership though are effectively eliminated through the non-controlling interest. At September 30, 2008, there is a note payable of \$8.2 million and a note receivable of \$49.6 million. Both notes are due on demand and bear interest at prime plus three percent. Net interest of \$0.9 million for the third quarter, \$2.1 million year-to-date was received by the Trust and is reported as other income. 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.

(1) Previously called "Management Contract".

## 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 third quarter of 2008 was \$3.3 million, a decrease of \$0.2 million from \$3.5 million for the comparable period in 2007. The decrease was due to a decrease in the average effective interest rate, partially offset by an increase in the average debt levels. Average outstanding bank debt for the third quarter of 2008 was \$294.7 million, \$47.9 million higher than the \$246.8 million outstanding for the third quarter of 2007. NAL's effective interest rate averaged 4.44 percent during the third quarter of 2008, compared to 5.46 percent during the comparable period in 2007. The decrease in the rate from the third quarter of 2007 is attributable to rate decreases in the market. NAL's interest is at a floating rate.

For the nine months ended September 30, 2008, interest on bank debt was \$11.2 million, an increase of \$1.6 million from the comparable period in 2007. The increase was due to higher average debt levels, partially offset by a decrease in the average effective interest rate. Average debt was \$301.3 million, compared to \$234.9 million for the corresponding period in 2007. NAL's effective interest rate averaged 4.88 percent in 2008, compared to 5.29 percent in 2007.

Interest on convertible debentures represents interest charges of \$1.4 million for the three months ended September 30, 2008 as compared to \$0.6 million for the same period in 2007, based on interest at 6.75 percent, and accretion of the debt discount of \$0.3 million (2007 - \$0.2 million). For the nine months ended September 30, 2008 the interest charge on the convertible debentures was \$4.6 million as compared to \$0.6 million for the comparable period in 2007. Accretion of the debt discount was \$1.3 million for the nine months September 30, 2008 as compared to \$0.2 million for the same period in 2007. The debentures were issued on August 28, 2007.

### Interest and Debt

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008	2007	2008	2007
Interest on bank debt (\$000s)	3,295	3,540	11,155	9,536
Interest and accretion on convertible debentures (\$000s)	1,739	787	5,952	787
Total interest (\$000)	5,034	4,327	17,107	10,323
Bank debt outstanding at period end (\$000s)	270,982	256,485	270,982	256,485
Convertible debentures at period end (\$000s)*	73,628	90,399	73,628	90,399
\$/boe:				
Interest on bank debt	1.50	1.89	1.72	1.78
Interest on convertible debentures	0.62	0.34	0.71	0.12
Accretion on convertible debentures	0.17	0.08	0.21	0.03
Total interest	2.29	2.31	2.64	1.93

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

## CASH FLOW NETBACK

For the quarter ended September 30, 2008, NAL's cash flow netback was \$40.93 per boe, a 47 percent increase from \$27.78 for the comparable period in 2007. The increase is due to higher operating netbacks after hedging in 2008, lower G&A expenses including unit-based incentive compensation and lower interest charges.

For the nine months ended September 30, 2008, NAL's cash flow netback increased 33 percent to \$40.40 per boe from \$30.42 per boe for the comparable period in 2007. The increase is due to higher operating netbacks after

hedging in 2008, partially offset by increases in G&A expenses, including unit-based incentive compensation and interest charges for bank debt and the convertible debentures.

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

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008	2007	2008	2007
Operating netback, after hedging	44.51	31.59	45.06	34.44
G&A expenses, including unit-based incentive compensation	(1.46)	(1.58)	(2.23)	(2.12)
Interest on bank debt and convertible debentures <sup>(1)</sup>	(2.12)	(2.23)	(2.43)	(1.90)
Cash flow netback	40.93	27.78	40.40	30.42

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

#### 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 September 30, 2008, depletion on property, plant and equipment and accretion on the asset retirement obligations was consistent with the comparable period of the prior year at \$23.71 per boe.

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

For the nine months ended September 30, 2008, the DDA rate per boe was \$22.85 as compared to \$21.68 for the same period in 2007. The increase in the DDA rate per boe is largely attributable to the acquisition of Seneca in August 2007.

#### Depletion, Depreciation and Accretion Expenses

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008	2007	2008	2007
Depletion and depreciation (\$000s)	50,092	43,254	143,151	112,504
Accretion of asset retirement obligation (\$000s)	1,833	1,370	5,458	3,969
Total DDA (\$000s)	51,925	44,624	148,609	116,473
DDA rate per boe (\$)	23.71	23.81	22.85	21.68

#### TAXES

In the third quarter of 2008, NAL had a future income tax expense of \$27.5 million compared with a \$1.1 million recovery in the corresponding period for the prior year. For the nine month period ended September 30, 2008, NAL had a future income tax expense of \$8.1 million compared to a \$1.3 million recovery in 2007.

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. The Trust does not expect to incur any cash taxes in 2008.

As at September 30, 2008, the Trust’s (including all subsidiaries) estimated tax pools (unaudited) available for deduction from future taxable income approximated \$708.9 million, of which approximately 44 percent represented COGPE and 29 percent UCC, with the remaining balance represented by CEE, CDE, trust unit issue costs and non-capital loss carry forwards.

Based on current strip prices at September 30, 2008, and our forecast for year-end tax pools, the Trust is not expected to be taxable in 2008.

On June 22, 2007, the *Budget Implementation Act, 2007* (Canada) was enacted to, among other things, implement the October 31, 2006 announcement of the changes to taxability of income trusts made by the Department of

Finance. Under this legislation, distributions to unitholders will not be deductible by publicly traded income trusts and, as a result, the Trust will be taxed on its income similar to corporations. These measures are now considered enacted for purposes of GAAP. Accordingly, the Trust has measured future income tax assets and liabilities associated with this new tax. Year-to-date, and in total, the Trust has recognized \$5.0 million of future income tax liability in the financial statements associated with this new tax (\$nil in the third quarter). It is expected that all remaining taxable temporary differences will reverse prior to January 1, 2011, the date the taxation changes take effect. The scheduling of the reversal of temporary differences is based on management's best estimates and current assumptions, which may change.

Effective for the fourth quarter of 2008, the Trust income tax rate is expected to decrease by three percent from the current 29.5 percent to 26.5 percent once the new provincial SIFT tax rate is enacted. The impact of this rate reduction is not expected to be significant for the Trust.

## 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 depletion, accretion, unrealized gains or losses on derivative contracts and future income taxes.

Net income for the third quarter of 2008 was \$111.0 million compared to \$7.8 million for the comparable period in 2007. The increase of \$103.2 million is due to an increased gain on derivative contracts (\$95.1 million), increased revenue, net of royalties (\$60.8 million), partially offset by increases in operating costs (\$6.2 million), DD&A (\$6.8 million), future income tax expense (\$28.6 million) and a bad debt expense in 2008 (\$6.9 million).

Net income for the nine months ended September 30, 2008 of \$107.2 million was \$61.3 million greater than the \$45.9 million from the comparable period in 2007. The increase of \$61.3 million is due to higher revenue, net of royalties (\$175.3 million), offset by an increased loss on derivative contracts (\$26.3 million), and increases in operating costs (\$20.8 million), future income tax expense (\$9.5 million), DD&A (\$30.6 million), interest on debentures (\$5.2 million) and a bad debt expense in 2008 (\$6.9 million).

### Net Income (\$000s)

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008	2007	2008	2007
Net income (loss)	111,045	7,801	107,206	45,901

## CAPITAL RESOURCES AND LIQUIDITY

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

As at September 30, 2008, NAL had 95,945,090 trust units outstanding, compared with 90,494,151 trust units at December 31, 2007. The increase from December 31, 2007 is attributable to 2,408,898 trust units issued on the acquisition of Tiberius and Spear, 1,446,844 trust units issued on the conversion of outstanding convertible debentures and 1,595,197 trust units issued under the Trust's distribution reinvestment program ("DRIP").

Under the equity issuance associated with the acquisition of Tiberius and Spear, 2.4 million trust units were issued at a price of \$12.24 per trust unit for a total consideration of \$29.5 million.

For the nine months ended September 30, 2008, the DRIP resulted in 1.6 million trust units being issued at an average price of \$13.08 per trust unit for total proceeds of \$20.9 million.

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 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.

Due to market conditions, relatively low unit prices, and the strength of the balance sheet, the Trust suspended the DRIP program effective October 9, 2008. The Trust will assess reinstatement of the plan on an ongoing basis.

The Premium DRIP program has been suspended since March 10, 2006.

As at September 30, 2008 the Trust had net debt of \$378.7 million (net of working capital and excluding derivative contracts, notes payable/receivable with MFC and future income tax asset), including convertible debentures at face value of \$79.7 million. Excluding the convertible debentures, net debt was \$299.0 million, compared with \$291.1 million at December 31, 2007, and \$274.5 million as at September 30, 2007. The increase in net debt, excluding convertible debentures, of \$7.9 million during the first nine months of 2008 is attributable to a \$12.6 million negative change in working capital offset by decreased bank debt of \$4.6 million.

Bank debt outstanding was \$271.0 million at September 30, 2008 compared with \$275.6 million as at December 31, 2007. The \$271.0 million outstanding is all under the production facility with no amounts outstanding under the working capital facility. The decrease in the bank debt during the first nine months of 2008 is due to debt repayments, offset by the acquisition of Tiberius and Spear, of which \$28.3 million was funded by debt. During the third quarter, the Trust reduced bank debt by \$37.1 million.

At the end of the third quarter, the Trust had a net debt (excluding convertible debentures) to 12 months trailing cash flow ratio of 0.98 times and a total net debt (including convertible debentures) to 12 months trailing cash flow ratio of 1.25 times.

The credit facility has increased by \$50 million to \$450 million. Concurrent with this increase two new banks have been added to the banking syndicate. The credit facility is a fully secured, extendible, revolving facility and will revolve until April 29, 2009 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 four equal quarterly installments commencing May 2010.

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. During the first nine months of 2008, face value \$20.3 million in debentures were converted at \$14.00 per unit into 1,446,844 trust units (179,640 trust units during the third quarter). 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. Assuming conversion of all outstanding debentures 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 \$0.3 million (2007 - \$0.5 million) of accretion of the debt discount in the third quarter of 2008 and \$1.3 million (2007 - \$0.6 million) year-to-date.

As at November 4, 2008, the Trust has 96,181,397 trust units and \$79.7 million in convertible debentures outstanding.

## Capitalization

	Sept. 30, 2008	Dec 31, 2007	Sept. 30, 2007
Trust unit equity (\$000s)	545,551	504,717	531,706
Bank debt (\$000s)	270,982	275,630	256,485
Working capital deficit (surplus) <sup>(1)</sup> (\$000s)	28,006	15,429	18,028
Net debt	298,988	291,059	274,513
Convertible debentures (\$000s) <sup>(2)</sup>	79,744	100,000	100,000
Total Net debt <sup>(2)</sup>	378,732	391,059	374,513
Net debt to trailing 12 month cash flow <sup>(3)</sup>	0.98	1.33	1.28
Total Net debt to trailing 12 month cash flow <sup>(2)</sup>	1.25	1.79	1.74
Trust units outstanding (000s)	95,945	90,494	89,886

(1) Working capital excludes derivative contracts, the future income tax asset, and notes payable/receivable with MFC.

(2) Convertible debentures included at face value.

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

Subject to fluctuations in commodity prices, the Trust anticipates that it will continue to maintain adequate liquidity to fund planned capital spending during 2008 through a combination of funds from operations and bank debt.

If assumptions underlying the forecast, such as commodity prices and production, change, the Trust may be required to reconsider its financing, distribution level or capital expenditures.

Under the tax legislation regarding the change in the taxability 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 remaining three months of 2008, the Trust has approximately \$547 million of available safe harbour and, for each of 2009 and 2010, an additional \$285 million, for a total of \$1.117 billion.

### ASSET RETIREMENT OBLIGATION

At September 30, 2008, the Trust reported an asset retirement obligation (“ARO”) balance of \$92.6 million (\$89.6 million as at December 31, 2007) for future abandonment and reclamation of the Trust’s oil and gas properties and facilities. The ARO balance was increased by \$1.6 million due to the Tiberius and Spear acquisitions, \$0.9 million due to liabilities incurred and revisions to estimates, and \$5.5 million from accretion expense and was reduced by \$5.0 million for actual abandonment and environmental expenditures incurred in 2008.

### DISTRIBUTIONS TO UNITHOLDERS

For the three and nine months ended September 30, 2008 the Trust distributed 46 percent and 56 percent of its cash flow from operating activities, as compared to 65 percent and 68 percent for the same periods in 2007. 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. In the third quarter of 2008, the Trust distributed 41 percent of net income, resulting in excess net income of \$65.1 million over distributions paid. On a year-to-date basis, the Trust has distributed in excess of its net income by \$28.1 million. The Trust usually distributes in excess of its net income each period, due to the non-cash charges included in net income (loss). However, in the third quarter of 2008, an \$111.1 million unrealized gain on derivative contracts ensured net income exceeded cash flow from operating activities. Cash flow from operations usually exceeds net income, as net income includes non-cash charges such as depletion, depreciation, accretion, future income tax expense and unrealized gains and losses on derivative contracts.

The Trust bases its distributions on the cash flow of the Trust, commodity prices, financial market conditions, internal capital investment opportunities and the resulting impact on taxability. The Trust develops an annual forecast, which is updated regularly by management. The Board sets distributions at a level it believes will be sustainable for a period of time and formally reviews distribution levels quarterly.

Given that distributions exceed net income on a year-to-date basis, 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 2008 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 proceeds from the DRIP and debt. Over the medium term, fluctuations in commodity prices, other market factors, or development opportunities may make it necessary to fund the excess of distributions and capital expenditures over cash, from the credit facility. The credit facility and other sources of cash are expected to be sufficient to meet NAL's near term capital requirements, sustain distributions and provide for the resources to pursue potential growth opportunities.

NAL intends to continue to make cash distributions to unitholders. However, these cash distributions cannot be guaranteed. The intent is to continue to distribute a certain proportion of cash flow from operating activities, the level of distributions being dependent on the drivers of cash flow, namely production and commodity prices. The implication of this policy is that the Trust is likely to continue to distribute in excess of its net income for any given period. The future sustainability of this distribution policy will be dependent upon maintaining productive capacity through both capital expenditures and acquisitions. A significant decrease in commodity prices could impact cash from operating activities, access to credit facilities and the Trust's ability to fund operations and maintain distributions.

	<b>Distributions</b>			
	Three months ended Sept. 30		Nine months ended Sept. 30	
(\$000s except for percentages)	<b>2008</b>	2007	<b>2008</b>	2007
Cash flow from operating activities	<b>98,860</b>	61,266	<b>242,716</b>	170,253
Net income	<b>111,045</b>	7,801	<b>107,206</b>	45,901
Actual cash distributions paid or payable	<b>45,968</b>	39,778	<b>135,295</b>	115,261
Excess of cash flow from operating activities over cash distribution paid	<b>52,892</b>	21,488	<b>107,421</b>	54,992
Percentage of cash flow from operations distributed	<b>46%</b>	65%	<b>56%</b>	68%
Excess (shortfall) of net income over cash distributions paid	<b>65,077</b>	(31,977)	<b>(28,089)</b>	(69,360)

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 September 30, 2008, funds from operations amounted to \$79.2 million, compared with \$50.8 million for the three months ended September 30, 2007. The 56 percent increase is due to increased revenue driven by higher production and pricing offset partially by higher costs. On a per trust unit basis, funds from operations increased 36 percent from \$0.61 in 2007 to \$0.83 in 2008, the increase in funds from operations being partially offset by the increase in the number of trust units outstanding due to equity issuances associated with the acquisitions of Seneca, Tiberius and Spear. Funds from operations was negatively impacted, in the third quarter of 2008, by the bad debt expense (\$6.9 million) recognized for the write off of the SemCanada receivable.

For the nine months ended September 30, 2008, funds from operations increased 53 percent to \$244.0 from \$159.2 for the comparable period in 2007. The increase is primarily due to increased revenues driven by higher prices and production.

## Funds from Operations

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008	2007	2008	2007
Funds from operations (\$000s)	79,233	50,817	244,031	159,208
Funds from operations per trust unit	0.83	0.61	2.60	1.99
Payout ratio based on funds from operations	58%	78%	55%	72%

### VARIABLE INTEREST ENTITIES

NAL has no variable interest entities.

### CONTRACTUAL OBLIGATIONS

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

(\$000s)	2008	2009	2010	2011	2012	Thereafter
Office lease <sup>(1)</sup>	1,009	4,036	3,700	-	-	-
Transportation agreement	484	882	882	-	-	-
Processing agreement <sup>(2)</sup>	118	446	428	414	401	384
<b>Total</b>	<b>1,611</b>	<b>5,364</b>	<b>5,010</b>	<b>414</b>	<b>401</b>	<b>384</b>

(1) Represents the full amount of office lease commitments, including both base rent and operating costs, in relation to the lease held by the Manager, of which the Trust is allocated a pro rata share (currently approximately 58 percent) of the expense on a monthly basis.

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

### QUARTERLY INFORMATION

(\$000s, except per unit and production amounts)	2008				2007			2006
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Revenue, net of royalties	234,993 <sup>(2)</sup>	58,861 <sup>(3)</sup>	89,611	86,262	78,573	83,268	71,231	75,358
Per unit	2.46	0.63	0.98	0.96	0.95	1.06	0.91	0.97
Funds from operations <sup>(1)</sup>	79,233	88,578	76,220	59,537	50,817	54,156	54,234	55,795
Per unit	0.83	0.94	0.83	0.66	0.61	0.69	0.69	0.72
Net income (loss)	111,045	(17,572)	13,733	10,556	7,801	21,390	16,710	20,472
Per unit								
basic	1.16	(0.19)	0.15	0.12	0.09	0.27	0.21	0.26
diluted	1.11	(0.19)	0.15	0.12	0.09	0.27	0.21	0.26
Average oil equivalent production (boe/d – 6:1)	23,808	23,791	23,601	23,656	20,369	19,094	19,561	19,517

(1) Represents cash flow from operating activities prior to the change in non-cash working capital items.

(2) Excluding the unrealized gain on derivative contracts of \$111,053; Revenue, net of royalties would be \$123,940.

(3) Excluding the unrealized loss on derivative contracts of \$70,148; Revenue net of royalties would be \$129,009.

### FINANCIAL REPORTING DISCLOSURE CONTROLS

Management has designed and evaluated the effectiveness of the Trust's financial reporting disclosure controls and procedures as at September 30, 2008 and has concluded that such controls and procedures were effective as at that date.

While NAL's management believes that the Trust's disclosure controls and procedures provide a reasonable level of assurance with respect to their effectiveness, they do not expect that such controls and procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, provides only reasonable, and not absolute assurance that the objectives of the control system are met.

### INTERNAL CONTROL OVER FINANCIAL REPORTING

Management has designed or caused to be designed under its supervision, internal controls over financial reporting related to the Trust and its subsidiaries, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP.

There were no changes to the Trust's internal controls over financial reporting since December 31, 2007 that have materially affected, or are reasonably likely to materially affect, the Trust's internal control over financial reporting.

### **CRITICAL ACCOUNTING ESTIMATES**

The significant accounting policies used by NAL are disclosed in the notes to NAL's December 31, 2007 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, 2007.

### **NEW ACCOUNTING STANDARDS**

Effective January 1, 2008, the Trust implemented the provisions of CICA Handbook Section 1535 "Capital Disclosures", Section 3862 "Financial Instruments – Disclosures", and Section 3863 "Financial Instruments – Presentation".

Section 1535 establishes standards for disclosing information about an entity's capital and how it is managed. This Section specifies disclosure about objectives, policies and processes for managing capital, quantitative data about what the entity regards as capital, whether the entity has complied with any capital requirements, and if it has not complied, the consequences of such non-compliance. Sections 3862 and 3863 establish standards for the presentation and disclosure of information that enable users to evaluate the significance of financial instruments to the entity's financial position, and the nature and extent of risks arising from financial instruments and how the entity manages those risks.

The implementation of these new standards did not impact the Trust's financial results but did, however, result in additional disclosures.

### **FUTURE ACCOUNTING CHANGES**

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

In February 2008, the Canadian Accounting Standards Board ("AcSB"), confirmed that the changeover to IFRS from Canadian GAAP will be required for publicly accountable enterprises' interim and annual financial statements effective for fiscal years beginning on or after January 1, 2011. The AcSB issued the "omnibus" exposure draft of IFRS in March 2008. The eventual changeover to IFRS represents a change due to new accounting standards. The transition from current Canadian GAAP to IFRS is a significant undertaking that may materially affect the Trust's reported financial results.

The International Accounting Standards Board ("IASB") has issued an exposure draft with comments due by January 23, 2009 relating to certain amendments and exemptions to IFRS 1 in order to make it more useful to Canadian entities adopting IFRS for the first time. One such exemption relating to full cost oil and gas accounting is expected to reduce the administrative burden in the transition from the current Canadian Accounting Guideline 16 to IFRS. The amendment, if implemented, will permit the Trust to apply IFRS prospectively to its full cost pool, rather than performing retrospective assessment of capitalized exploration and development expenses, with the provision that a ceiling test, under IFRS standards, be conducted at the transition date.

Although the Trust has not completed its IFRS changeover plan, an initial evaluation of IFRS 1 has been completed and progress has been made in the review of the significant differences between IFRS and Canadian GAAP as they apply to the Trust. During the remainder of 2008, NAL will finalize its changeover plan, which will include project structure and governance, resourcing and training, a complete analysis of key GAAP differences and a phased plan to assess accounting policies under IFRS, as well as potential IFRS 1 exemptions. The Trust anticipates completing its project scoping, which will include a timetable for assessing the impact on data systems, internal controls over financial reporting, and business activities, such as financing and compensation arrangements, by the end of 2008.

Dated: November 4, 2008

## CONSOLIDATED BALANCE SHEETS

(thousands of dollars) (unaudited)

	As at September 30, 2008	As at December 31, 2007
<b>Assets</b>		
Current assets		
Cash and cash equivalents	\$2,509	\$1,394
Accounts receivable and other	82,104	70,791
Note receivable (Note 3)	49,599	-
Derivative contracts (Note 12)	9,388	3,389
Future income tax asset	-	2,602
	<b>143,600</b>	<b>78,176</b>
Derivative contracts (Note 12)	7,445	-
Future income tax asset	-	4,096
Goodwill (Note 3)	14,252	-
Property, plant and equipment (Notes 3 and 5)	1,018,582	980,888
	<b>\$1,183,879</b>	<b>\$1,063,160</b>
<b>Liabilities and Unitholders' Equity</b>		
Current liabilities		
Accounts payable and accrued liabilities	\$97,268	\$73,135
Note payable (Note 3 and 4)	8,193	-
Distributions payable to unitholders	15,351	14,479
Derivative contracts (Note 12)	6,503	12,973
Future income tax liability	1,150	-
	<b>128,465</b>	<b>100,587</b>
Bank debt (Note 6)	270,982	275,630
Convertible debentures (Note 7)	73,628	90,876
Derivative contracts (Note 12)	1,544	-
Unit-based incentive compensation (Note 8)	4,341	1,748
Asset retirement obligations (Note 9)	92,611	89,602
Future income tax liability	12,093	-
	<b>583,664</b>	<b>558,443</b>
Non-controlling interest (Note 10)	54,664	-
Unitholders' equity		
Unitholders' capital (Note 11)	1,039,678	969,588
Equity component of convertible debentures (Note 7)	4,592	5,759
Deficit	(498,719)	(470,630)
	<b>545,551</b>	<b>504,717</b>
	<b>\$1,183,879</b>	<b>\$1,063,160</b>
Trust units outstanding (000s)	95,945	90,494

See accompanying notes.

## CONSOLIDATED STATEMENTS OF INCOME, COMPREHENSIVE INCOME AND DEFICIT

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

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008	2007	2008	2007
<b>Revenue</b>				
Oil, natural gas and liquid sales	\$176,437	\$100,189	\$510,877	\$292,754
Crown royalties	(27,415)	(15,874)	(78,097)	(45,660)
Freehold and other royalties	(9,600)	(5,726)	(27,170)	(16,741)
	<b>139,422</b>	78,589	<b>405,610</b>	230,353
Gain (loss) on derivative contracts (Note 12):				
Realized gain (loss)	(16,627)	(47)	(43,848)	3,075
Unrealized gain (loss)	111,053	(1,508)	18,370	(5,892)
Reclassification from other comprehensive income	-	874	-	3,647
	<b>94,426</b>	(681)	<b>(25,478)</b>	830
Other income	1,145	665	3,333	1,889
	<b>234,993</b>	78,573	<b>383,465</b>	233,072
<b>Expenses</b>				
Operating	25,463	19,301	69,179	48,379
Transportation	989	691	2,879	1,882
General and administrative	3,674	2,549	11,950	10,308
Unit-based incentive compensation (Note 8)	(478)	408	2,519	1,072
Interest on bank debt	3,295	3,540	11,155	9,536
Interest and accretion on convertible debentures	1,739	787	5,952	787
Bad debt expense (Note 12)	6,901	-	6,901	-
Depletion, depreciation and amortization	50,092	43,254	143,151	112,504
Accretion on asset retirement obligations	1,833	1,370	5,458	3,969
	<b>93,508</b>	71,900	<b>259,144</b>	188,437
Income before taxes and non-controlling interest	<b>141,485</b>	6,673	<b>124,321</b>	44,635
Income tax recovery (provision)	209	25	203	(83)
Future income tax reduction (provision)	(27,488)	1,103	(8,140)	1,349
Total income tax reduction (provision)	(27,279)	1,128	(7,937)	1,266
Income before non-controlling interest	<b>114,206</b>	7,801	<b>116,384</b>	45,901
Non-controlling interest (Note 10)	(3,161)	-	(9,178)	-
Net income	<b>111,045</b>	7,801	<b>107,206</b>	45,901
Other comprehensive income:				
Reclassification to net income, net of tax	-	(613)	-	(2,559)
Comprehensive income	<b>111,045</b>	7,188	<b>107,206</b>	43,342
Deficit, beginning of period	(563,796)	(405,869)	(470,630)	(368,486)
Net income	111,045	7,801	107,206	45,901
Distributions declared	(45,968)	(39,778)	(135,295)	(115,261)
Deficit, end of period	<b>\$(498,719)</b>	\$(437,846)	<b>\$(498,719)</b>	\$(437,846)
Net income per trust unit (Note 11)				
Basic	\$1.16	\$0.09	\$1.14	\$0.57
Diluted	\$1.11	\$0.09	\$1.13	\$0.57
Weighted average trust units outstanding (000s)	<b>95,664</b>	82,815	<b>93,834</b>	79,982

*See accompanying notes.*

## CONSOLIDATED STATEMENTS OF CASH FLOWS

(thousands of dollars) (unaudited)

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008	2007	2008	2007
<b>Operating Activities</b>				
Net income	\$111,045	\$7,801	\$107,206	\$45,901
Items not involving cash:				
Depletion, depreciation and amortization	50,092	43,254	143,151	112,504
Accretion on asset retirement obligations	1,833	1,370	5,458	3,969
Unrealized loss (gain) on derivative contracts	(111,053)	1,508	(18,370)	5,892
Reclassification from other comprehensive income	-	(874)	-	(3,647)
Future income tax provision (reduction)	27,488	(1,103)	8,140	(1,349)
Non-cash accretion expense on convertible debentures	379	158	1,320	158
Non-controlling interest	1,151	-	2,107	-
Abandonment and environmental expenditures	(1,702)	(1,297)	(4,981)	(4,220)
Change in non-cash working capital	19,627	10,449	(1,315)	11,045
	<b>98,860</b>	<b>61,266</b>	<b>242,716</b>	<b>170,253</b>
<b>Financing Activities</b>				
Distributions paid to unitholders	(38,918)	(38,050)	(113,550)	(113,355)
Issue of trust units, net of issue costs	-	125,029	(14)	138,194
Increase (decrease) in bank debt	(37,133)	22,968	(4,648)	35,700
Issuance of convertible debentures	-	96,000	-	96,000
Partnership distribution paid to MFC (Note 4)	(1,500)	-	(1,500)	-
Change in non-cash working capital	-	-	(426)	915
	<b>(77,551)</b>	<b>205,947</b>	<b>(120,138)</b>	<b>157,454</b>
<b>Investing Activities</b>				
Acquisition of Tiberius and Spear (Note 3)	(14)	-	(77,369)	-
Disposition of Tiberius and Spear (Note 3)	-	-	58,221	-
Acquisition of Seneca	-	(246,728)	337	(246,728)
Additions to property, plant and equipment	(53,189)	(33,052)	(109,260)	(78,794)
Property acquisitions	(373)	(1,204)	(8,249)	(1,472)
Proceeds from dispositions	-	-	40	26
Change in non-cash working capital	21,909	14,794	14,817	(942)
	<b>(31,667)</b>	<b>(266,190)</b>	<b>(121,463)</b>	<b>(327,910)</b>
Increase (decrease) in cash and cash equivalents	(10,358)	1,023	1,115	(203)
Cash and cash equivalents, beginning of period	12,867	5,069	1,394	6,295
Cash and cash equivalents, end of period	\$2,509	\$6,092	\$2,509	\$6,092
Supplementary disclosure of cash flow information:				
Cash paid (received) during the period for:				
Interest	\$4,913	\$4,816	\$14,777	\$12,136
Tax	\$2,202	\$(25)	\$6,905	\$83
Cash and cash equivalents is comprised of:				
Cash	\$2,509	\$1,102	\$2,509	\$1,102
Short term investments	-	4,990	-	4,990
	<b>\$2,509</b>	<b>\$6,092</b>	<b>\$2,509</b>	<b>\$6,092</b>

See accompanying notes.

## **NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS**

Nine months ended September 30, 2008

*(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, 2007, except as described below. 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, 2007.

### **2. CHANGES IN ACCOUNTING POLICIES**

#### **New Accounting Standards**

Effective January 1, 2008 the Trust implemented the provisions of CICA Handbook Section 1535 “Capital Disclosures”, Section 3862 “Financial Instruments – Disclosures”, and Section 3863 “Financial Instruments – Presentation”.

Section 1535 establishes standards for disclosing information about an entity’s capital and how it is managed. This Section specifies disclosure about objectives, policies and processes for managing capital, quantitative data about what the entity regards as capital, whether the entity has complied with all capital requirements, and if it has not complied, the consequences of such non-compliance. Sections 3862 and 3863 establish standards for the presentation and disclosure of information that enable users to evaluate the significance of financial instruments to the entity’s financial position, and the nature and extent of risks arising from financial instruments and how the entity manages those risks.

The implementation of these new standards did not impact the Trust’s financial results but did, however, result in additional disclosures, as provided in Note 12.

#### **International Financial Reporting Standards (“IFRS”)**

In February 2008, the AcSB, confirmed that the changeover to IFRS from Canadian GAAP will be required for publicly accountable enterprises’ interim and annual financial statements effective for fiscal years beginning on or after January 1, 2011. The AcSB issued the “omnibus” exposure draft of IFRS in March 2008. The eventual changeover to IFRS represents a change due to new accounting standards. The transition from current Canadian GAAP to IFRS is a significant undertaking that may materially affect the Trust’s reported financial position and results of operations.

The IASB has issued an exposure draft with comments due by January 23, 2009, relating to certain amendments and exemptions to IFRS 1 in order to make it more useful to Canadian entities adopting IFRS for the first time. One such exemption relating to full cost oil and gas accounting is expected to reduce the administrative burden in the transition from the current Canadian Accounting Guideline 16 to IFRS. The amendment, if implemented, will permit the Trust to apply IFRS prospectively to its full cost pool, rather than the performing retrospective assessment of capitalized exploration and development expenses, with the provision that a ceiling test, under IFRS standards, be conducted at the transition date.

Although the Trust has not completed its IFRS changeover plan, an initial evaluation of IFRS 1 has been completed and progress has been made in the review of the significant differences between IFRS and Canadian GAAP as they apply to the Trust. During the remainder of 2008, NAL will finalize the changeover plan, which will include project structure and governance, resourcing and training, a complete analysis of key GAAP differences and a phased plan to assess accounting policies under IFRS as well as potential IFRS 1 exemptions. The Trust anticipates completing its project scoping, which will include a timetable for assessing the impact on data systems, internal controls over financial reporting, and business activities, such as financing and compensation arrangements, by the end of 2008.

### **Basis of Presentation**

The Trust's financial statements include the accounts of the Trust and all its subsidiaries and partnerships. All inter-entity transactions and balances have been eliminated. Non-controlling interests in subsidiaries and partnerships are presented as separate line items on the consolidated balance sheet and the consolidated statement of income, comprehensive income and deficit.

### **Goodwill**

Goodwill is recorded on a business acquisition when the total purchase price exceeds the fair value of the net identifiable assets and liabilities of the acquired business. The goodwill balance is not amortized but, instead, is assessed for impairment annually at year end, or more frequently if events or changes in circumstances indicate the asset might be impaired. To assess impairment, the fair value of the reporting entity, deemed to be the consolidated Trust, is compared to the carrying value of the reporting entity. If the fair value of the Trust is less than the carrying value, then a second test is performed to determine the amount of impairment. Any impairment is measured by allocating the fair value of the consolidated Trust to the identifiable assets and liabilities as if the Trust had been acquired in a business combination for a purchase price equal to its fair value. The excess of the fair value of the consolidated Trust over the amounts assigned to the identifiable assets and liabilities is the implied value of the goodwill. Any excess of the book value of goodwill over the implied value of goodwill is the impairment amount. Any impairment is charged to net income in the period in which it occurs.

### **Comparative Information**

Certain comparative figures have been reclassified to conform with current period presentation.

## **3. CORPORATE ACQUISITIONS**

Effective February 27, 2008 the Trust acquired all the issued and outstanding common shares of Tiberius Exploration Inc ("Tiberius") and Spear Exploration Inc. ("Spear"), which have interests in southeast Saskatchewan.

On February 29, 2008, the Trust transferred the assets into a limited partnership ("Partnership") in exchange for a 50 percent partnership interest and a note receivable of \$3.7 million. A wholly owned subsidiary of Manulife Financial Corporation ("MFC") acquired the remaining 50 percent share in the Partnership and a note receivable of \$3.7 million, by payment in cash of one half of the total purchase price for Tiberius and Spear. Accordingly, the net acquisition cost to the Trust for its 50 percent share in the acquired properties is \$57.8 million, before acquisition costs, comprised of \$28.3 million in cash and \$29.5 million from the issuance of 2.4 million trust units at a price of \$12.24 per unit. The unit price was based on the weighted average market price of the units at the announcement date for the acquisition of February 11, 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. The equivalent carrying amount of property, plant and equipment related to this interest in the reserves is recorded on the books of each royalty holder.

The results of operations from these properties have been included in the consolidated financial statements of the Trust commencing February 27, 2008. A subsidiary of the Trust is the general partner under the partnership agreement governing the Partnership and therefore controls the Partnership. As a result, the Trust is required to consolidate the results into its consolidated financial statements, with the share of net income and net assets attributable to MFC presented as a non-controlling interest.

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:	Total Acquisition	Disposition to Manulife	Trust, net Acquisition	NPI <sup>(1)</sup>	Net to Trust
Cash	\$9,734	\$-	\$9,734	\$-	\$9,734
Working capital deficiency	(5,622)	-	(5,622)	-	(5,622)
Notes receivable, net from MFC	-	(3,750)	(3,750)	49,599	45,849
Property, plant and equipment	111,258	-	111,258	(49,599)	61,659
Future income taxes	(23,389)	11,588	(11,801)	-	(11,801)
Asset retirement obligations	(1,636)	-	(1,636)	-	(1,636)
Goodwill	26,254	(12,002)	14,252	-	14,252
Non-controlling interest	-	(54,057)	(54,057)	-	(54,057)
	<b>\$116,599</b>	<b>\$(58,221)</b>	<b>\$58,378</b>	<b>\$-</b>	<b>\$58,378</b>
<b>Consideration:</b>					
Cash	\$86,118	\$(57,807)	\$28,311	\$-	\$28,311
Issuance of trust units	29,496	-	29,496	-	29,496
Acquisition costs	985	(414)	571	-	571
	<b>\$116,599</b>	<b>\$(58,221)</b>	<b>\$58,378</b>	<b>\$-</b>	<b>\$58,378</b>

(1) Net profits interest agreement entered into with MFC, in exchange for a note receivable.

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.

#### 4. RELATED PARTY TRANSACTIONS

The Trust is managed by the Manager. The Manager is a wholly-owned subsidiary of MFC and manages on their behalf NAL Resources Limited (“NAL Resources”), another wholly-owned subsidiary of Manulife. The disposition of a 50 percent interest in the Partnership holding the Tiberius and Spear assets was to MFC, as outlined in Note 3.

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 \$3.1 million (2007 - \$2.4 million) for the reimbursement of G&A expenses during the third quarter, and \$9.6 million (2007 - \$8.4 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 Plan, of which \$1.8 million has been paid year-to-date, representing units that vested on November 30, 2007 (2007 - \$2.2 million).

The notes payable and receivable due to/from MFC, are due on demand and bear interest at prime plus three percent. Net interest of \$2.1 million relating to these notes was received by the Trust for the nine months ended September 30, 2008 and is reported as other income. 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.

During 2008 the Partnership paid a distribution to its partners, MFC’s share being \$1.5 million.

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

	September 30, 2008	December 31, 2007
Due from NAL Resources Limited	<b>\$2,915</b>	\$14,203
Due to NAL Resources Management Limited	<b>(974)</b>	(2,826)
Due from Manulife Financial Corporation <sup>(1)</sup>	<b>44,987</b>	-
	<b>\$46,928</b>	\$11,377

(1) Included on consolidation, eliminated through non-controlling interest.

## 5. PROPERTY, PLANT AND EQUIPMENT

	September 30, 2008	December 31, 2007
Petroleum and natural gas properties, at cost	\$1,868,176	\$1,687,331
Less: Accumulated depletion and depreciation	(849,594)	(706,443)
	<b>\$1,018,582</b>	\$980,888

Costs associated with undeveloped land of \$34.3 million (2007 - \$28.0) have been excluded from the depletion calculation for the nine months ended September 30, 2008.

Future development costs for proved reserves of \$49.8 million (2007 - \$37.4 million) have been included in the depletion calculation.

During 2008, the Trust capitalized \$3.2 million (2007 - \$3.5 million) of G&A costs and \$1.2 million (2007 - \$0.4 million) of unit-based incentive compensation that were directly related to exploitation and development programs.

## 6. BANK DEBT

	September 30, 2008	December 31, 2007
Production loan facility	\$270,982	\$273,528
Working capital facility	-	2,102
Total debt outstanding	<b>\$270,982</b>	\$275,630

The Trust maintains a fully secured, extendible, revolving term credit facility with a syndicate of Canadian chartered banks. The credit facility has increased by \$50 million to \$450 million. 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 a function of the net present value of the Trust's oil and gas reserves and other assets.

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 29, 2009 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 2009, the amounts outstanding at that time will be converted to a two-year term loan. The term loan will be payable in four equal quarterly installments commencing May 2010 with a final residual payment, if any, in May 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 September 30, 2008 and December 31, 2007 all amounts outstanding were in Canadian dollars.

On September 30, 2008 the effective interest rate on amounts outstanding under the credit facility was 4.52 percent (2007 - 5.78 percent).

## 7. 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
August 28, 2007 issuance	\$100,000	\$94,241	\$5,759
Issue costs	-	(4,000)	-
Accretion	-	635	-
Balance, December 31, 2007	100,000	90,876	5,759
Conversion to trust units	(20,256)	(18,568)	(1,167)
Accretion	-	1,320	-
<b>Balance, September 30, 2008</b>	<b>\$79,744</b>	<b>\$73,628</b>	<b>\$4,592</b>

## 8. UNIT-BASED INCENTIVE COMPENSATION PLAN

The Trust recorded a total compensation expense of \$3.7 million in the first nine months of 2008, of which \$2.5 million was recorded as an expense and \$1.2 million as property, plant and equipment (\$2.1 million expensed and \$0.9 million as property, plant and equipment for the year ended December 31, 2007). The compensation expense was based on the September 30, 2008 trust unit price of \$12.53 (2007 - \$11.60), 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:

	<b>Nine months ended September 30, 2008</b>	Year ended December 31, 2007
Balance, beginning of period	<b>\$4,996</b>	\$4,153
Increase in liability	<b>3,671</b>	3,027
Cash payout, relating to units vested	<b>(1,767)</b>	(2,184)
Balance, end of period	<b>\$6,900</b>	\$4,996
Current portion of liability <sup>(1)</sup>	<b>\$2,559</b>	\$3,248
Long-term liability	<b>\$4,341</b>	\$1,748

(1) Included in accounts payable and accrued liabilities.

## 9. ASSET RETIREMENT OBLIGATIONS

The total future asset retirement obligation was estimated by the Manager based on the Trust's net ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities, estimated costs to remediate, reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. NAL has estimated the net present value of its asset retirement obligations to be \$92.6 million as at September 30, 2008 (2007 - \$89.6 million) based on a total undiscounted and inflated amount of cash flows required to settle its asset retirement obligations of \$278.5 million (2007 - \$270.5 million). These costs are expected to be made over the next 44 years with the majority of the costs incurred between 2008 and 2033. NAL's estimated credit-adjusted risk-free rate of eight percent (2007 - eight percent) and an inflation rate of two percent (2007 - two percent) were used to calculate the present value of the asset retirement obligations.

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

	<b>Nine months ended September 30, 2008</b>	Year ended December 31, 2007
Balance, beginning of period	<b>\$89,602</b>	\$65,574
Accretion expense	<b>5,458</b>	5,533
Revisions to estimates	<b>(261)</b>	10,294
Liabilities incurred	<b>1,157</b>	1,079
Liabilities acquired (Note 3)	<b>1,636</b>	12,625
Liabilities settled	<b>(4,981)</b>	(5,503)
<b>Balance, end of period</b>	<b>\$92,611</b>	\$89,602

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

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008	2007	2008	2007
Net profits interest	\$2,010	\$-	\$7,071	\$-
Share of net income attributable to MFC	1,151	-	2,107	-
	\$3,161	\$-	\$9,178	\$-

## 11. UNITHOLDERS EQUITY

### Units Issued:

	Nine months ended September 30, 2008		Year ended December 31, 2007	
	Units	Amount	Units	Amount
Balance, beginning of the period	90,494	\$969,588	77,971	\$824,986
Issued on corporate acquisition (Note 3)	2,409	29,496	10,246	125,001
Less issue expenses		(14)		(7,134)
Issued from Distribution Reinvestment Plan	1,595	20,873	2,277	26,735
Issued on conversion of debentures	1,447	19,735	-	-
Balance, end of the period	95,945	\$1,039,678	90,494	\$969,588

### Per Unit Information

Basic net income per trust unit is calculated using the weighted average number of trust units outstanding. The calculation of diluted net income per trust unit includes the weighted average trust units potentially issuable on the conversion of the convertible debentures. For the three and nine month periods ended September 30, 2008, an additional 5,723,975 (2007 – 2,639,752) and 6,557,840 (2007 – 889,587) trust units, respectively, were included in the diluted net income per trust unit calculation. Interest charges of \$1.7 million (2007 - \$0.8 million) for the quarter and \$6.0 million (2007 - \$0.8 million) year-to-date were included in the diluted net income per trust unit calculation as additions to net income.

## 12. FINANCIAL RISK MANAGEMENT

### Overview

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

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

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

### Credit Risk

Credit risk is the risk of financial loss to the Trust if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Trust's receivables. The Trust is managed by the Manager. The Manager is a wholly-owned subsidiary of MFC and manages on their behalf 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 operator. As a result, a significant portion of the Trust's net operating revenues represent joint operations from NAL Resources. Accordingly, accounts receivable include amounts due from NAL Resources for oil, natural gas and natural gas liquids sales. Oil and gas marketing is conducted by the Manager on behalf of the Trust and NAL

Resources generally with large creditworthy purchasers, for which the Trust views the credit risk as low. Except as noted below, NAL Resources, and ultimately the Trust, have not historically experienced any collection issues with its oil and gas marketers. The Manager does not obtain collateral from oil and natural gas marketers or joint venture partners.

Cash and cash equivalents consist of cash bank balances and short-term deposits maturing in less than 90 days. Derivative contracts consist of commodity contracts denominated in U.S. or Canadian dollars for periods of up to two years. The Trust manages the credit exposure related to short-term investments and derivative contracts by selecting established counter parties with high credit ratings and monitors all investments, avoiding complex investment vehicles with higher risks such as asset backed commercial paper.

On July 22, 2008 SemCanada Crude Company (“SemCanada”) filed application for creditor protection under the Companies Creditors Arrangement Act in Canada. SemCanada marketed a portion of the Trust’s oil, butane and condensate sales. It has been determined that the full amount due from SemCanada is unlikely to be received. Accordingly, the Trust has recorded a bad debt expense of \$6.9 million to write off the entire amount due to the Trust. NAL continues to work with legal counsel to attempt to recover amounts due. Any future amounts received will be recorded to income. NAL continues to sell to SemCanada with cash received in advance of delivery.

NAL management has concluded that its existing credit policy remains appropriate but has implemented more regular review of purchasers. The events for the SemCanada insolvency were not foreseen. However, management is currently reviewing all existing purchasers against its credit policy to ensure credit worthiness given the current market conditions.

The Trust does not have any receivable balances past due as at September 30, 2008.

### Liquidity Risk

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

The Trust prepares annual capital expenditure budgets, which are regularly monitored and updated as necessary. As well, the Manager utilizes authorizations for expenditure on both operated and non-operated projects. Furthermore, the Manager operates a high percentage of the Trust’s properties, which allows for significant control over future expenditures. To support the capital spending program, the Trust maintains a fully secured, extendible, revolving term credit facility, as outlined in Note 6.

The following are the contractual maturities of financial liabilities and associated interest payments as at September 30, 2008.

Financial Liability	<1 Year	1 – 2 Years	2 – 5 Years
Accounts payable and accrued liabilities	\$97,268	\$-	\$-
Distributions payable	15,351	-	-
Unit-based incentive compensation <sup>(1)</sup>	-	3,329	1,012
Note payable	8,193	-	-
Derivative contracts	6,503	1,544	-
Bank debt, principal (May 2010)	-	135,491	135,491
Convertible debentures, principal	-	-	79,744
<b>Total</b>	<b>\$127,315</b>	<b>\$140,364</b>	<b>\$216,247</b>

(1) Amount due within one year classified in accounts payable and accrued liabilities.

### Market risk

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

### Foreign currency exchange rate risk

Foreign currency exchange rate risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in foreign exchange rates. Although substantially all of the Trust's oil and natural gas sales are denominated in Canadian dollars, the underlying market prices in Canada for oil and natural gas are impacted by changes in the exchange rate between the Canadian and U.S. dollar. As at September 30, 2008, if the Canadian dollar had weakened \$0.10 against the U.S. dollar, with all other variables held constant, net income would have been \$0.5 million lower due to changes in the foreign exchange component of U.S. dollar denominated commodity contracts. An equal and opposite impact would have occurred to net income had the Canadian dollar improved \$0.10 against the U.S. dollar.

The Trust had no material foreign exchange related derivative contracts in place as at, or during the nine months ended, September 30, 2008.

### Commodity price risk

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by not only the relationship between the Canadian and U.S. dollar, but also macroeconomic events that dictate the levels of supply and demand. The Trust has attempted to mitigate commodity price risk by entering into financial derivative contracts. The Trust's policy is to enter into commodity contracts to a maximum of 50 percent of forecasted, net of royalty, production volumes for a period of up to two years.

NAL currently has the following WTI oil contracts in place for 2008, denominated in U.S. dollars:

Term	Contract	Volume Bbls/d	Total Volume Bbls	Bought Put U.S.\$/bbl	Sold Call U.S.\$/bbl	Swap U.S.\$/bbl
<b>COLLARS</b>						
October-December	2-way	100	9,200	85.00	100.00	-
October-December	2-way	100	9,200	83.00	100.00	-
October-December	2-way	100	9,200	75.00	85.50	-
October-December	2-way	100	9,200	76.00	87.00	-
October-December	2-way	100	9,200	94.00	100.50	-
October-December	2-way	100	9,200	92.00	101.50	-
<b>Weighted Average</b>			<b>55,200</b>	<b>84.17</b>	<b>95.75</b>	<b>-</b>

Term	Contract	Volume Bbls/d	Total Volume Bbls	Bought Put U.S.\$/bbl	Sold Call U.S.\$/bbl	Swap U.S.\$/bbl
<b>SWAPS</b>						
October	swap	100	3,100	-	-	73.50
October-December	swap	100	9,200	-	-	94.00
October-December	swap	100	9,200	-	-	92.18
October-December	swap	100	9,200	-	-	87.10
October	swap	100	3,100	-	-	79.10
October	swap	100	3,100	-	-	71.00
October-December	swap	100	9,200	-	-	80.75
October	swap	100	3,100	-	-	88.10
October-December	swap	100	9,200	-	-	94.50
October-December	swap	100	9,200	-	-	94.04
October-December	swap	100	9,200	-	-	92.00
October-December	swap	100	9,200	-	-	98.50
October-December	swap	100	9,200	-	-	98.25
October-December	swap	100	9,200	-	-	98.10
October-December	swap	100	9,200	-	-	97.25
October-December	swap	100	9,200	-	-	96.75
October-December	swap	100	9,200	-	-	100.00
November-December	swap	100	6,100	-	-	100.03
November-December	swap	100	6,100	-	-	103.00
October-December	swap	100	9,200	-	-	108.00
<b>Weighted Average</b>			<b>153,400</b>	<b>-</b>	<b>-</b>	<b>94.22</b>

NAL currently has the following WTI oil contracts in place for 2008, denominated in Canadian dollars:

Term	Contract	Volume Bbls/d	Total Volume Bbls	Bought Put Cdn\$/bbl	Sold Call Cdn\$/bbl	Swap Cdn\$/bbl
<b>COLLARS</b>						
October-December	2-way	100	9,200	85.00	94.40	-
October-December	2-way	100	9,200	85.00	96.00	-
October-December	2-way	100	9,200	87.10	97.35	-
October-December	2-way	100	9,200	72.40	77.54	-
October-December	2-way	100	9,200	103.00	132.75	-
October-December	2-way	100	9,200	104.00	134.75	-
October-December	2-way	100	9,200	107.00	130.45	-
<b>Weighted Average</b>			<b>64,400</b>	<b>91.93</b>	<b>109.03</b>	<b>-</b>

Term	Contract	Volume Bbls/d	Total Volume Bbls	Bought Put Cdn\$/bbl	Sold Call Cdn\$/bbl	Swap Cdn\$/bbl
<b>SWAPS</b>						
October-December	swap	100	9,200	-	-	84.90
October-December	swap	100	9,200	-	-	90.05
October-December	swap	100	9,200	-	-	90.15
October-December	swap	100	9,200	-	-	90.05
October-December	swap	100	9,200	-	-	90.20
October-December	swap	100	9,200	-	-	89.05
October-December	swap	100	9,200	-	-	87.00
October-December	swap	100	9,200	-	-	83.80
October-December	swap	100	9,200	-	-	73.55
October-December	swap	100	9,200	-	-	93.00
October-December	swap	100	9,200	-	-	90.70
October-December	swap	100	9,200	-	-	91.00
October	swap	100	3,100	-	-	87.50
October-December	swap	100	9,200	-	-	96.50
October-December	swap	100	9,200	-	-	97.00
October-December	swap	100	9,200	-	-	94.00
October-December	swap	200	18,400	-	-	97.00
October-December	swap	100	9,200	-	-	98.50
October-December	swap	100	9,200	-	-	110.50
November-December	swap	100	6,100	-	-	93.80
November-December	swap	100	6,100	-	-	84.20
November-December	swap	100	6,100	-	-	87.15
<b>Weighted Average</b>			<b>196,200</b>	<b>-</b>	<b>-</b>	<b>91.40</b>

NAL currently has the following AECO natural gas contracts in place for 2008:

Term	Contract	Volume GJ/d	Total Volume GJ	Bought Put Cdn\$/GJ	Sold Call Cdn\$/GJ	Swap Cdn\$/GJ
<b>COLLARS</b>						
November-December	2-way	1,000	61,000	7.30	8.50	-
November-December	2-way	1,000	61,000	7.75	9.05	-
November-December	2-way	1,000	61,000	7.55	9.10	-
November-December	2-way	1,000	61,000	7.55	9.05	-
November-December	2-way	1,000	61,000	7.30	8.60	-
November-December	2-way	1,000	61,000	7.85	9.25	-
November-December	2-way	1,000	61,000	8.00	9.50	-
November-December	2-way	1,000	61,000	8.00	9.50	-
November-December	2-way	1,000	61,000	8.25	9.50	-
November-December	2-way	1,000	61,000	8.25	9.75	-
November-December	2-way	1,000	61,000	8.25	10.00	-
October	2-way	1,000	31,000	8.50	11.00	-
November-December	2-way	1,000	61,000	9.00	12.00	-
<b>Weighted Average</b>			<b>763,000</b>	<b>7.94</b>	<b>9.54</b>	<b>-</b>

Term	Contract	Volume GJ/d	Total Volume GJ	Bought Put Cdn\$/GJ	Sold Call Cdn\$/GJ	Swap Cdn\$/GJ
<b>SWAPS</b>						
October-December	swap	2,000	184,000	-	-	7.60
October-December	swap	1,000	92,000	-	-	7.40
October-December	swap	2,000	184,000	-	-	7.40
October-December	swap	1,000	92,000	-	-	7.31
October-December	swap	2,000	184,000	-	-	7.26
October-December	swap	1,000	92,000	-	-	7.05
October-December	swap	1,000	92,000	-	-	7.20
October-December	swap	1,000	92,000	-	-	7.10
October-December	swap	1,000	92,000	-	-	7.15
October-December	swap	1,000	92,000	-	-	7.10
October-December	swap	1,000	92,000	-	-	7.05
October-December	swap	1,000	92,000	-	-	7.23
October	swap	1,000	31,000	-	-	7.35
October	swap	1,000	31,000	-	-	7.60
October	swap	1,000	31,000	-	-	7.85
October-December	swap	1,000	92,000	-	-	7.30
October	swap	1,000	31,000	-	-	7.65
October	swap	1,000	31,000	-	-	7.43
October-December	swap	1,000	92,000	-	-	7.10
October	swap	1,000	31,000	-	-	7.20
October	swap	1,000	31,000	-	-	7.09
October	swap	1,000	31,000	-	-	7.80
November-December	swap	1,000	61,000	-	-	8.66
October	swap	1,000	31,000	-	-	7.90
October	swap	1,000	31,000	-	-	8.02
October	swap	1,000	31,000	-	-	8.25
October	swap	1,000	31,000	-	-	8.40
<b>Weighted Average</b>			<b>1,997,000</b>	<b>-</b>	<b>-</b>	<b>7.39</b>

For 2009, NAL has the following WTI oil contracts in place, denominated in U.S. dollars:

Term	Contract	Volume Bbls/d	Total Volume Bbls	Bought Put U.S.\$/bbl	Sold Call U.S.\$/bbl	Swap U.S.\$/bbl
<b>COLLARS</b>						
January-December	2-way	100	36,500	92.00	101.50	-
January-June	2-way	100	18,100	94.00	100.50	-
January-June	2-way	100	18,100	95.00	105.00	-
January-June	2-way	100	18,100	110.00	152.40	-
April-September	2-way	100	18,300	110.00	157.50	-
January-June	2-way	100	18,100	115.00	162.00	-
April-September	2-way	100	18,300	110.00	170.00	-
January-June	2-way	200	36,200	110.00	176.50	-
July-December	2-way	200	36,800	115.00	164.25	-
January-June	2-way	200	36,200	115.00	167.65	-
July-December	2-way	200	36,800	110.00	173.00	-
January-December	2-way	100	36,500	120.00	175.00	-
July-December	2-way	100	18,400	120.00	181.50	-
January-June	2-way	100	18,100	120.00	182.25	-
<b>Weighted Average</b>			<b>364,500</b>	<b>109.91</b>	<b>156.39</b>	<b>-</b>

Term	Contract	Volume Bbls/d	Total Volume Bbls	Bought Put U.S.\$/bbl	Sold Call U.S.\$/bbl	Swap U.S.\$/bbl
<b>SWAPS</b>						
January-June	swap	100	18,100	-	-	97.25
January-December	swap	100	36,500	-	-	96.75
January-June	swap	100	18,100	-	-	100.00
January-June	swap	100	18,100	-	-	100.03
January-June	swap	100	18,100	-	-	103.00
January-December	swap	100	36,500	-	-	102.00
January-June	swap	100	18,100	-	-	102.00
January-March	swap	100	9,000	-	-	101.50
April-June	swap	100	9,100	-	-	103.25
April-June	swap	100	9,100	-	-	103.27
January-June	swap	100	18,100	-	-	104.25
July-September	swap	100	9,200	-	-	105.00
July-December	swap	200	36,800	-	-	134.89
<b>Weighted Average</b>			<b>254,800</b>	<b>-</b>	<b>-</b>	<b>105.79</b>

For 2009, NAL has the following WTI oil contracts in place, denominated in Canadian dollars:

Term	Contract	Volume Bbl/d	Total Volume Bbls	Bought Put Cdn\$/bbl	Sold Call Cdn\$/bbl	Swap Cdn\$/bbl
<b>COLLARS</b>						
January-June	2-way	100	18,100	100.00	115.00	-
January-June	2-way	100	18,100	100.00	114.00	-
January-June	2-way	100	18,100	100.00	113.05	-
January-May	2-way	100	15,100	103.00	132.75	-
January-December	2-way	100	36,500	115.00	140.50	-
<b>Weighted Average</b>			<b>105,900</b>	<b>105.60</b>	<b>125.82</b>	<b>-</b>

Term	Contract	Volume Bbl/d	Total Volume Bbls	Bought Put Cdn\$/bbl	Sold Call Cdn\$/bbl	Swap Cdn\$/bbl
<b>SWAPS</b>						
January-September	swap	100	27,300	-	-	96.50
January-December	swap	200	73,000	-	-	97.00
January-September	swap	100	27,300	-	-	97.00
January-March	swap	100	9,000	-	-	102.00
January-March	swap	100	9,000	-	-	102.75
January-March	swap	100	9,000	-	-	106.10
April-June	swap	100	9,100	-	-	105.10
January-March	swap	100	9,000	-	-	105.02
January-March	swap	100	9,000	-	-	106.05
April-June	swap	100	9,100	-	-	105.50
April-September	swap	100	18,300	-	-	108.00
January-June	swap	100	18,100	-	-	116.10
<b>Weighted Average</b>			<b>227,200</b>	<b>-</b>	<b>-</b>	<b>101.47</b>

For 2009, NAL has the following AECO natural gas contracts in place:

Term	Contract	Volume GJ/d	Total Volume GJ	Bought Put Cdn\$/GJ	Sold Call Cdn\$/GJ	Swap Cdn\$/GJ
<b>COLLARS</b>						
January-March	2-way	1,000	90,000	8.00	9.50	-
January-March	2-way	1,000	90,000	7.75	9.05	-
January-March	2-way	1,000	90,000	7.85	9.25	-
January-March	2-way	1,000	90,000	7.55	9.10	-
January-March	2-way	1,000	90,000	7.55	9.05	-
January-March	2-way	1,000	90,000	7.30	8.60	-
January-March	2-way	1,000	90,000	7.30	8.50	-
January-March	2-way	1,000	90,000	8.00	9.50	-
January-March	2-way	1,000	90,000	8.25	9.50	-
January-March	2-way	1,000	90,000	8.25	9.75	-
January-March	2-way	1,000	90,000	8.25	10.00	-
January-March	2-way	1,000	90,000	8.50	10.00	-
January-March	2-way	1,000	90,000	8.50	9.50	-
January-March	2-way	1,000	90,000	8.65	9.75	-
January-March	2-way	1,000	90,000	8.75	9.75	-
January-March	2-way	1,000	90,000	9.00	12.00	-
April-October	2-way	1,000	214,000	8.50	11.26	-
April-October	2-way	1,000	214,000	9.00	11.25	-
April-October	2-way	1,000	214,000	9.00	11.55	-
April-October	2-way	1,000	214,000	9.00	12.10	-
April-October	2-way	1,000	214,000	9.00	11.05	-
<b>Weighted Average</b>			<b>2,510,000</b>	<b>8.44</b>	<b>10.36</b>	<b>-</b>

Term	Contract	Volume GJ/d	Total Volume GJ	Bought Put Cdn\$/GJ	Sold Call Cdn\$/GJ	Swap Cdn\$/GJ
<b>SWAPS</b>						
January-March	swap	1,000	90,000	-	-	7.40
January-March	swap	1,000	90,000	-	-	7.05
January-March	swap	1,000	90,000	-	-	7.05
January-March	swap	1,000	90,000	-	-	7.10
January-March	swap	1,000	90,000	-	-	7.15
January-March	swap	1,000	90,000	-	-	7.23
January-March	swap	1,000	90,000	-	-	7.31
January-March	swap	1,000	90,000	-	-	7.30
January-March	swap	1,000	90,000	-	-	8.66
January-March	swap	1,000	90,000	-	-	9.00
January-March	swap	1,000	90,000	-	-	9.10
January-March	swap	1,000	90,000	-	-	9.16
January-March	swap	1,000	90,000	-	-	9.23
April-October	swap	1,000	214,000	-	-	8.00
April-October	swap	1,000	214,000	-	-	10.00
April-December	swap	1,000	275,000	-	-	7.56
April-December	swap	1,000	275,000	-	-	7.51
<b>Weighted Average</b>			<b>2,148,000</b>	<b>-</b>	<b>-</b>	<b>8.03</b>

These contracts and the contracts that expired in the nine months ended September 30, 2008 resulted in settlement losses of \$43.8 million (2007 - \$3.1 million gain). The fair value of 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 September 30, 2008, if oil and natural gas liquids prices had been \$1.00 per barrel lower and natural gas prices \$0.10 per mcf lower, with all other variables held constant, net income for the period would have been \$1.8 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 oil and natural gas liquids prices been \$1.00 per barrel higher and natural gas \$0.10 per mcf higher.

#### Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Trust is exposed to interest rate fluctuations on its bank debt, which bears a floating rate of interest. As at September 30, 2008, if interest rates had been one percentage point lower, with all other variables held constant,

net income for the quarter would have been \$0.6 million (\$1.9 million for the nine months ended September 30, 2008) higher, due to lower interest expense. An equal and opposite impact would have occurred to net income had interest rates been one percentage point higher.

The Trust had no interest related derivative contracts in place as at, or during the nine months ended, September 30, 2008.

### Fair Values

The carrying amount of the Trust's financial instruments, including accounts receivable, accounts payable and accrued liabilities, and distributions payable, approximate their fair value due to their short term to maturity.

The notes payable and receivable due to/from MFC, are due on demand and bear interest at prime plus three percent. As the notes bear interest at a floating market rate, the fair market value approximates the carrying amount.

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

The fair value of the Trust's convertible debentures at September 30, 2008 was \$78.6 million, based on market price.

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 derivative contracts is determined by discounting the difference between the contracted prices and published forward curves as of the balance sheet date, using the remaining contracted oil and natural gas volumes.

	Nine months ended September 30, 2008	Year ended December 31, 2007
Long term unrealized gain on derivative contracts	\$7,445	\$-
Long term unrealized loss on derivative contracts	(1,544)	-
Net long term unrealized gain on derivative contracts	5,901	-
Current unrealized gain on derivative contracts	9,388	3,389
Current unrealized loss on derivative contracts	(6,503)	(12,973)
Net current unrealized gain (loss) on derivative contracts	2,885	(9,584)
Net fair value of derivative contracts	<b>\$8,786</b>	\$(9,584)

As at September 30, 2008, the total fair value of derivative contracts was a net asset of \$8.8 million. The change in the fair value for nine months ended September 30, 2008 of \$18.4 million has been recognized as an unrealized gain in the statement of income.

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

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2008	2007	2008	2007
Unrealized gain (loss), beginning of period	\$(102,267)	\$137	\$(9,584)	\$-
Unrealized gain on adoption of new accounting standards	-	-	-	4,521
Unrealized gain (loss), end of period	<b>8,786</b>	(1,371)	<b>8,786</b>	(1,371)
Unrealized gain (loss)	<b>111,053</b>	(1,508)	<b>18,370</b>	(5,892)
Realized gain (loss) in the period	<b>(16,627)</b>	(47)	<b>(43,848)</b>	3,075
Reclassification from other comprehensive income	-	874	-	3,647
Gain (loss) on derivative contracts	<b>\$94,426</b>	\$(681)	<b>\$(25,478)</b>	\$830

### Capital Management

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

The Trust manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying oil and natural gas assets. The Trust considers its capital structure to include unitholders' capital, bank debt, convertible debentures and working capital (excluding derivative contracts, notes with MFC and future income tax) as shown below. In order to maintain or adjust its capital structure, the Trust may adjust the amount of distributions paid to unitholders, issue new trust units, adjust its capital spending to modify debt levels, or suspend/resume its DRIP or premium DRIP programs.

The Trust monitors its capital based on the ratio of its net debt to 12 months trailing funds from operations. This ratio is calculated as net debt as a proportion of funds from operations for the previous 12 months. Funds from operations is defined as cash flow from operating activities prior to the change in non-cash working capital. Net debt is defined as bank debt, plus convertible debentures at face value, plus working capital (excluding derivative contracts, notes with MFC and future income tax balances). Net debt is measured with and without convertible debentures. The Trust's strategy is to maintain a conservative net debt to 12 month trailing funds from operations as compared to other oil and gas trusts, both before and after taking into account the convertible debentures. The Trust will, for the appropriate opportunity, increase its debt to funds from operations ratio above the Trust's average. In order to facilitate the management of this ratio, the Trust prepares an annual budget which is approved by the Board of Directors. On a monthly basis a reforecast for the year is prepared based on updated commodity prices, results of operational activity and other events. The monthly forecast is provided to the Board of Directors.

As at September 30, 2008, the Trust had a total net debt to 12 months trailing funds from operations ratio of 1.25, as calculated in the table below. At December 31, 2007, the Trust had a total net debt to 12 months trailing funds from operations ratio of 1.79, primarily attributable to borrowings incurred to fund the Seneca acquisition.

The credit facility is determined by reference to the reserves of the Trust (see Note 6) and is therefore commodity price sensitive. The Trust is restricted under its 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. As at September 30, 2008, the Trust is in full compliance with this external restriction on distributions.

The Trust has no restrictions on the issuance of units other than the authorized limit of 500 million.

There has been no change in the approach to capital management during 2008.

### Capitalization

	<b>September 30, 2008</b>	December 31, 2007
Trust unit equity (\$000s)	<b>545,551</b>	504,717
Bank debt (\$000s)	<b>270,982</b>	275,630
Working capital deficit (surplus) <sup>(1)</sup> (\$000s)	<b>28,006</b>	15,429
Net debt	<b>298,988</b>	291,059
Convertible debentures (\$000s) <sup>(2)</sup>	<b>79,744</b>	100,000
Total net debt (\$000s) <sup>(2)</sup>	<b>378,732</b>	391,059
Cash flow from operating activities for last 12 months (\$000s)	<b>287,827</b>	215,364
Add back change in non-cash working capital (\$000s)	<b>15,741</b>	3,381
Trailing 12 months funds from operations (\$000s)	<b>303,568</b>	218,745
Net debt to trailing 12 month funds from operations <sup>(3)</sup>	<b>0.98</b>	1.33
Total net debt to trailing 12-month funds from operations <sup>(2)</sup>	<b>1.25</b>	1.79

(1) Working capital excludes derivative contracts, the future income tax asset and the notes receivable/payable with MFC.

(2) Convertible debentures included at face value.

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

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**TRADING PERFORMANCE**

	30-Sept-08	For the Quarter Ended		30-Jun-07
		30-Jun-08	30-Sept-07	
<b>PRICE</b>				
High	\$17.10	\$17.09	\$13.65	\$13.80
Low	\$11.50	\$13.12	\$11.52	\$11.45
Close	\$12.53	\$16.89	\$12.22	\$12.57
Daily Average Volume	380,141	447,401	284,893	247,533

*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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