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FOR IMMEDIATE RELEASE

NAL OIL & GAS TRUST REPORTS THIRD QUARTER RESULTS – ON TRACK TO DELIVER FULL YEAR GUIDANCE

Media Release No. 27-07

November 7, 2007

CALGARY, ALBERTA (November 7, 2007) - NAL today announced financial and operational results that are on target with 2007 guidance on all key measures. President and CEO Andrew Wiswell said, "We successfully closed the acquisition of Seneca Energy Canada Inc. (Seneca) and integrated its operations with NAL. Our 55 percent oil and liquids weighting, active fourth quarter capital program, and comparatively strong financial position all position NAL positively for a strong finish to 2007 and positive momentum into 2008."

THIRD QUARTER HIGHLIGHTS

- Production volume for the third quarter averaged 20,182 barrels of oil equivalent (boe) per day, an increase of six percent from 19,079 a year earlier. These volumes included 4,346 boe/d from Seneca for the month of September (1,450 boe/d for the third quarter) following the closing of the transaction on August 31, 2007. In addition to these volumes, NAL had 650 boe/d behind pipe and scheduled to be tied-in before year-end. Volumes are expected to continue to grow as we move through the fourth quarter. Our full-year guidance remains 20,500 – 20,800 boe/d of production.
- Operating costs in the third quarter were \$10.40 per boe, driven primarily by a one-time prior period adjustment of \$0.70 per boe in the quarter. Year-to-date operating costs for the nine months ended September 30, 2007 were \$9.08 per boe and NAL's operating costs are expected to be lower in the fourth quarter, which is consistent with historical trends. NAL's guidance remains \$8.90 - \$9.10 per boe for full year 2007.
- Total capital expenditures to date were \$80.2 million and results were on plan for the first nine months. An additional \$35 - \$40 million will be spent in the fourth quarter for a total of \$115 – 120 million in 2007. NAL is currently active with five operated drilling rigs as well as three non-operated exploration wells, two at Monkman, B.C. and another at Peppers/Pedley in West Central Alberta. Drilling and evaluation of these wells should be completed in the fourth quarter, 2007 or early in 2008.
- The \$246 million purchase of Seneca was financed primarily by issuing \$125 million in new equity and \$100 million in convertible debentures. At September 30, 2007, net debt totaled \$364.9 million representing a multiple of 1.3 times annualized nine-month cash flow assuming conversion of the debentures, or 1.7 times when treating the debentures as debt. NAL has one of the best balance sheets among Canadian energy trusts, and also has approximately \$125 million in undrawn lines of credit which positions the Trust to make additional acquisitions as opportunities arise.
- At current commodity prices, NAL's cash flow would not be materially affected by recently announced revisions to Alberta's royalty regime. Approximately 44 percent of our production is located in B.C., Saskatchewan or Ontario, and most of our wells in Alberta are lower productivity wells. Based upon October 2007 annualized production, overall royalty expense would increase less than one percent. We will continue to evaluate these changes and their implications for future capital expenditures as the detailed implementation programs are announced.

At 3:00 pm MST (5:00 pm EST) on Wednesday, November 7, 2007 NAL will conduct a conference call to discuss its third quarter results. Mr. Andrew Wiswell, President and CEO, will host the conference call with other members of the Management Team. The call will be open to analysts, investors and all interested parties. If you wish to participate, call 1-866-542-4238 toll free across North America. A recorded playback of the call will be available until November 14, 2007 by dialing 1-416-695-5800 or 1-800-408-3053 and entering pass code 3240129#.

The conference call will also be accessible by webcast at <http://events.onlinebroadcasting.com/nal/110707/index.php>

Notes:

All amounts are in Canadian dollars unless otherwise stated.

When converting natural gas to equivalent barrels of oil within this report, NAL uses the widely recognized standard of 6 thousand cubic feet (Mcf) to one barrel of oil (boe). However, boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf : 1 bbl 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 2007	2006	Nine months ended Sept. 30 2007	2006
FINANCIAL					
Gross revenue, net of royalties		\$78,573	\$75,798	\$233,072	\$235,058
Net income		7,801	20,473	45,901	39,726 ⁽¹⁾
Distributions declared		39,778	44,061	115,261	129,926
Distributions declared per unit		0.48	0.57	1.44	1.71
Cash flow from operating activities		61,266	60,749	170,253	189,767
Payout ratio based on cash flow		65%	73%	68%	68%
Cash flow per unit		0.74	0.79	2.13	2.50
Funds from operations ⁽²⁾		50,817	54,107	159,208	163,981
Payout ratio based on funds from operations		78%	81%	72%	79%
Funds from operations per unit		0.61	0.70	1.99	2.16
Average number of units outstanding (000s)		82,815	77,247	79,982	75,897
Total debt, net of working capital ⁽³⁾		364,912	211,276	364,912	211,276
Capital expenditures		34,256	41,869	80,240	89,391
Costs per boe (6:1):	Operating	\$10.40	\$8.70	\$9.08	\$8.71
	General and administrative, excluding special retention bonus	1.31	1.49	1.76	1.61
	General and administrative special retention bonus	0.06	-	0.17	-
	Unit-based incentive compensation	0.22	0.11	0.20	0.50
	Management fees	-	-	-	0.25
OPERATING					
Daily production	Oil (bbl)	9,193	9,256	9,195	9,254
	Natural gas (Mcf)	54,073	47,334	49,601	49,360
	Natural gas liquids (bbl)	1,977	1,934	2,057	1,939
	Oil equivalent (boe – 6:1)	20,182	19,079	19,519	19,420
Average pricing, net of transportation charges and before hedging gains and losses					
Liquids:					
	WTI (US\$/bbl)	75.39	70.48	66.19	68.25
	NAL average oil (Cdn\$/bbl)	74.37	71.23	67.74	67.69
	NAL natural gas liquids (Cdn\$/bbl)	51.02	50.17	48.18	50.56
	NAL average oil and natural gas liquids (Cdn\$/bbl)	70.24	67.59	64.16	64.72
Natural gas:					
	AECO (Cdn\$/Mcf) – daily spot	5.14	5.75	6.54	6.45
	AECO (Cdn\$/Mcf) – monthly	5.61	6.03	6.81	7.18
	NAL natural gas Western Canada (Cdn\$/Mcf)	5.30	5.97	6.63	7.03
	NAL natural gas Lake Erie (Cdn\$/Mcf)	6.67	7.02	8.73	8.06
	NAL average natural gas (Cdn\$/Mcf)	5.40	6.06	6.79	7.12
	NAL oil equivalent before hedging gains (losses) (Cdn\$/boe – 6:1)	53.35	54.67	54.23	55.40
Average foreign exchange rate (Cdn\$/US\$)		1.0448	1.1212	1.1048	1.1327
Operating netback before hedging gains (losses) (\$/boe)		31.19	33.50	33.30	34.42
Hedging gains (losses) per boe		(0.03)	0.39	0.58	0.30
Operating netback (\$/boe)		31.16	33.89	33.88	34.72

⁽¹⁾ Includes one time \$27.2 million non-cash management contract restructuring charge.

⁽²⁾ See reconciliation of cash flow from operating activities to funds from operations in the non-GAAP financial measures section

⁽³⁾ Excludes derivative contracts and future income tax asset

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, 2007 and the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2006 of NAL Oil & Gas Trust ("NAL" or the "Trust"). It also 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, net debt to trailing 12 month cash flow, operating netback and cash flow netback. They 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 and financial position. 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 is 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.

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

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2007	2006	2007	2006
Cash flow from operating activities	61,266	60,749	170,253	189,767
Add back charge in non-cash working capital	(10,449)	(6,642)	(11,045)	(25,786)
Funds from operations	50,817	54,107	159,208	163,981

FORWARD-LOOKING INFORMATION

This discussion and analysis contains forward-looking information as to the Trust's internal projections, expectations or 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", "potential", "target", and similar words suggesting future events or future performance.

In particular, this MD&A contains forward-looking information pertaining to the following, without limitation; the amount and timing of cash flows of distributions to unitholders, 2007 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; cost estimates and royalty rates; drilling plans; tie in of wells; future development, exploration, and acquisition and development activities and related expenditures.

Although NAL believes that the expectations reflected in the forward-looking information contained in the MD&A, 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; 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 governments review; changes in tax laws; impact of the new SIFT legislation following the October 31, 2006 announcement 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 Annual information Form and MD&A for the year ended December 31, 2006.

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, and the Trust does not assume any obligation to publicly update or revise it to reflect new events or circumstances except as required by law. The forward looking information contained in the MD&A is expressly qualified by this cautionary statement.

ACQUISITION OF SENECA ENERGY CANADA INC. ("Seneca")

NAL successfully closed the acquisition of Seneca on August 31, 2007 for a price of \$245.1 million plus costs of \$0.9 million. The acquisition added 10.3 million boe proved plus probable reserves and production averaging 4,400 boe/d from September 2007 to year end 2007. This production is weighted 85 percent to natural gas. The transaction also added 157,287 acres of net undeveloped land and growth opportunities to the Trust.

The net cash consideration was financed by the issuance of 10.2 million units at a price of \$12.20 per unit for proceeds of \$125 million (\$118.8 million net of issue costs), \$100 million in 6.75% convertible extendible unsecured subordinated debentures (\$96 million net of issue costs), and \$31.2 million of bank debt.

DEVELOPMENT ACTIVITIES

The Trust participated in drilling 32 (15.5 net) commercial wells during the third quarter, with a success rate of 100 percent. At the end of the quarter, six rigs were drilling and we are expecting to finish 2007 with four to five rigs working.

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	20	8.7	8	6.0	0	0	0	0	28	14.7
Non-operated wells	2	0.5	2	0.3	0	0	0	0	4	0.8
Total wells drilled	22	9.2	10	6.3	0	0	0	0	32	15.5

YTD Drilling Activity

	Crude Oil		Natural Gas		Service Wells		Dry & Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Operated wells	44	20.6	15	10.7	2	1	0	0	61	32.3
Non-operated wells	8	1.0	10	1.1	0	0	0	0	18	2.1
Total wells drilled	52	21.6	25	11.8	2	1	0	0	79	34.4

Southeast Saskatchewan

There were 18 (6.7 net) successful horizontal oil wells drilled during the quarter. Of significance was the 5-11 Bakken well that had a post stimulation initial production rate of 500 bbls/d (125 bbl/d net). NAL was also successful in acquiring 6,000 hectares of trend acreage that the Trust will begin to evaluate in 2008.

A significant turnaround was successfully completed at the Nottingham gas plant which included upgrading the control system for future expansion. Preliminary engineering has been completed on a plant expansion which NAL is considering for 2008. This expansion would capture the opportunity to process additional third party and owned gas that will be developed and tied in over the next year.

All wells drilled during the quarter were tied-in and producing at quarter-end. Three contracted rigs will be drilling continuously across all of our Saskatchewan operating areas for the remainder of the year.

Gas Focus Areas (Nevis, Lacombe, Hanna, Pine Creek, Drumheller)

There were 10 (6.8 net) successful gas wells drilled during the quarter in these areas. Five wells were CBM drills on expiring lands adjacent to our infrastructure in Lacombe, Clive and Hanna. The remaining wells were part of an ongoing successful Mannville development in the Hanna and Pine Creek areas.

Wet ground conditions experienced in the second quarter continued into July which delayed drilling programs. Consequently, there is 250 boe/d net to the Trust behind pipe that will be brought on stream in the fourth quarter. A budgeted turnaround at NAL's Brent gas plant in July resulted in a loss of 150 boe/d net for the month and an unscheduled third party turnaround in September resulted in a loss of 85 boe/d net for the month.

With the acquisition of Seneca, three significant opportunities (two in Monkman and one in Peppers) were added to our 2007 drilling program. All three of these wells were still drilling at the end of the third quarter and are expected to be rig released during the fourth quarter. Testing of these wells will likely occur late in the fourth quarter with the subsequent tie in of any successful wells in the first quarter of 2008. Recompletion work and two drills on Seneca lands around Drumheller will round out the activity in the area for the fourth quarter.

Central Alberta – (Sylvan Lake, Medicine River, Garrington, Westward Ho)

There were four (1.8 net) successful Mannville gas wells drilled during the quarter and a recompletion program (seven wells in the third quarter) is ongoing for Cardium oil across the area. The new well at 8-18 Caroline tested at rates of 3.5 mmcf/d (1.25 mmcf/d net) while two Cardium recompletions had initial production rates of 125 bbls/d (80 bbls/d net).

As with our gas focused areas in Alberta, wet conditions delayed surface access in July and as a result there is 400 boe/d net to the Trust behind pipe that will be brought on stream in the fourth quarter.

CAPITAL EXPENDITURES

Capital expenditures for the quarter ended September 30, 2007 were consistent with expectations and totaled \$34.3 million, compared with \$41.9 million in the quarter ended September 30, 2006. For the nine months ended September 30, 2007 capital expenditures were on plan and totaled \$80.2 million as compared to \$89.4 million in the same period in 2006. Results from the capital program are at or above plan year to date.

Capital Expenditures (\$000s)

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2007	2006	2007	2006
Drilling, completion and production equipment	\$26,507	\$32,697	\$64,356	\$61,752
Plant and facilities	2,285	5,792	6,680	9,883
Seismic	32	515	559	2,224
Land	2,672	60	2,762	5,469
Total exploitation and development	31,496	39,064	74,357	79,328
Office equipment	231	47	505	3,308 ⁽¹⁾
Capitalized G&A	1,051	1,441	3,487	3,515
Capitalized unit-based compensation	274	31	445	1,954
Total other capital	1,556	1,519	4,437	8,777
Property acquisitions (dispositions), net	1,204	1,286	1,446	1,286
Total capital expenditures and property acquisitions	\$34,256	\$41,869	\$80,240	\$89,391

⁽¹⁾ Includes \$2.8 million in assets acquired as part of management agreement restructuring

NAL's capital spending outlook for the full year 2007 has been increased from \$101 million to \$115 - 120 million as a result of adding the opportunities on the Seneca lands. The remaining capital of \$35 - 40 million will be primarily spent on exploration and development activity in our core areas.

PRODUCTION

Third quarter 2007 production of 20,182 boe/d (18,765 boe/d excluding Seneca) exceeded production in the comparable period of 2006 by six percent. The third quarter of 2007 includes Seneca production for the month of September. The average production for September was 23,222 boe/d, which includes 4,346 boe/d related to Seneca.

For the nine months ended September 30, 2007, production at 19,519 boe/d (19,042 boe/d excluding Seneca) exceeded production in the comparable period of 2006 of 19,420 boe/d. To date, NAL has not experienced any shut-in due to Enbridge capacity constraints although trucking volume has increased.

Production volumes (excluding Seneca) were lower in the third quarter as compared to the first and second quarters of 2007 but in line with expectations due to forecasted turnarounds and wet lease conditions carried over from June. An active capital program in the fourth quarter, recent positive drilling results and the ability to tie in 650 boe/d of behind pipe volumes are expected to deliver our full year guidance of 20,500 boe/d to 20,800 boe/d. Specifically, we are forecasting the fourth quarter to average 23,300 - 23,500 boe/d with an exit rate of approximately 23,700 boe/d.

Average Daily Production Volumes

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2007	2006	2007	2006
Oil (bbl/d)	9,193	9,256	9,195	9,254
Natural gas (Mcf/d)	54,073	47,334	49,601	49,360
NGL's (bbl/d)	1,977	1,934	2,057	1,939
Oil equivalent (boe/d)	20,182	19,079	19,519	19,420

Oil and natural gas liquids totaled 55 percent of production in the third quarter with natural gas increasing to 45 percent due to the Seneca acquisition.

Production Weighting

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2007	2006	2007	2006
Oil	45%	49%	47%	48%
Natural gas	45%	41%	42%	42%
NGLs	10%	10%	11%	10%

REVENUE

Gross revenue from oil, natural gas and natural gas liquids sales, after transportation costs, totaled \$99.1 million for the three months ended September 30, 2007, a three percent increase over the third quarter of 2006. The increase is attributable to a six percent increase in production, offset by a two percent decrease in average price per boe. Compared to the third quarter of 2006, average commodity prices decreased by two percent for the third quarter of 2007 due to lower natural gas realized prices, which were partially offset by higher crude and NGL realized prices.

For the nine month period ended September 30, 2007, revenue after transportation costs totaled \$289.0 million, a decrease of two percent from the comparable period in 2006. The decrease is attributable to a two percent decrease in average commodity prices driven by lower natural gas realized prices.

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2007	2006	2007	2006
Revenue ⁽¹⁾ (\$000s)	99,076	95,957	288,996	293,703
\$/boe	53.36	54.67	54.23	55.40

⁽¹⁾ Oil, natural gas and liquid sales less transportation prior to royalties, and excluding gain/loss on derivative contracts (see Risk Management).

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 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 Canadian crude oil price per barrel, net of transportation costs, was \$74.37, as compared to \$71.23 for the comparable quarter of 2006. The increase in realized price quarter over quarter of four percent, or \$3.14 per barrel, was primarily driven by a seven percent increase in WTI (US\$/bbl), over the comparable period (US\$75.39 versus US\$70.48). In addition, NAL's crude differentials compared to WTI priced in Canadian dollars increased realized prices, but were offset by a strengthening Canadian dollar.

For the third quarter of 2007, NAL's realized oil price was 94 percent of WTI in Canadian dollars, an increase of four percent from the 90 percent for the corresponding period in 2006. The increase in the third quarter of 2007 resulted from a narrower differential occurring between WTI and Edmonton and Cromer posted prices, due to greater demand for light crude in Western Canada during that time frame.

For the nine months ended September 30, 2007, NAL's average oil price was \$67.74 per barrel, comparable with the corresponding period in 2006. The realized price remained constant due to differentials improving from 88 percent in 2006 to 93 percent in 2007, offset by a three percent decrease in WTI (US\$/bbl) and a two percent unfavorable exchange rate change.

Natural gas liquids prices averaged \$51.02 per barrel in the third quarter of 2007, comparable with the third quarter of 2006. For the nine month period ending September 30, 2007, natural gas liquids pricing averaged \$48.18, five percent lower than the comparable period in 2006.

NATURAL GAS MARKETING

Approximately 93 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 seven percent tied to NYMEX or other indexed referenced prices. Seven percent of the Trust's gas sales are from its Lake Erie property and receives a higher price due to the proximity to the Ontario and northeastern U.S. markets.

For the three months ended September 30, 2007, the Trust's gas sales averaged \$5.40/Mcf, compared to \$6.06/Mcf for the comparable quarter in 2006, a decrease of 11 percent. The quarter-over-quarter decrease in gas prices was attributable to an 11 percent decrease in the benchmark AECO prices. Natural gas sales from the Lake Erie property averaged \$6.67/Mcf in the third quarter of 2007, compared to \$7.02/Mcf in 2006, a decrease of five percent.

For the nine months ended September 30, 2007, NAL averaged \$6.79/Mcf, a five percent decrease from the \$7.12/Mcf realized in the comparable period of 2006. The decrease in realized price, despite the AECO spot increasing by one percent, is attributable to marketing a portion of gas based on the monthly AECO price, which decreased five percent year over year. During the nine months ended September 30, 2007, the spread between the spot and monthly AECO prices was \$0.27/Mcf compared to \$0.73/Mcf for the comparable period in 2006.

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

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2007	2006	2007	2006
Liquids				
WTI (US\$/bbl)	75.39	70.48	66.19	68.25
NAL average oil (Cdn\$/bbl)	74.37	71.23	67.74	67.69
NAL natural gas liquids (Cdn\$/bbl)	51.02	50.17	48.18	50.56
Natural Gas (Cdn\$/Mcf)				
AECO – daily spot	5.14	5.75	6.54	6.45
AECO – monthly	5.61	6.03	6.81	7.18
NAL Western Canada natural gas	5.30	5.97	6.63	7.03
NAL Lake Erie natural gas	6.67	7.02	8.08	8.06
NAL average natural gas	5.40	6.06	6.79	7.12
NAL Oil Equivalent before hedging (Cdn\$/boe – 6:1)	53.35	54.67	54.23	55.40
Average Foreign Exchange Rate (Cdn\$/US\$)	1.0448	1.1212	1.1048	1.1327

RISK MANAGEMENT

NAL employs risk management practices to assist in managing cash flows and support capital programs and distributions. NAL's management is authorized to hedge up to 50 percent of its annual net of royalty production. NAL's risk management programs are scaled in over time using a combination of swaps and collars. During the first nine months of 2007, 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 for the quarter and year to date:

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2007	2006	2007	2006
Average crude volumes hedged (bbl/d)	3,833	3,499	2,816	2,901
Crude oil realized gain (loss) (\$000's)	\$(2,314)	\$(12)	\$623	\$(12)
Gain (loss) per bbl hedged	\$(6.56)	\$(0.04)	\$0.81	\$(0.02)
Average natural gas volumes hedged (GJ/d)	16,000	2,000	15,505	2,000
Natural gas realized gain (\$000's)	\$2,267	\$696	\$2,452	\$1,589
Gain per GJ hedged	\$1.54	\$3.78	\$0.58	\$2.91
Average BOE hedged (boe/d)	6,362	3,815	5,266	3,217
Total realized gain (loss) (\$000's)	\$(47)	\$684	\$3,075	\$1,577
Gain (loss) per boe hedged	\$(0.08)	\$1.95	\$2.14	\$1.80
Gain (loss) per boe	\$(0.03)	\$0.39	\$0.58	\$0.30

The Trust has recorded the fair value of risk management contracts on the balance sheet effective January 1, 2007 in accordance with new accounting standards, issued by the Canadian Institute of Chartered Accountants ("CICA"), addressing financial instruments and hedges. These standards require all derivative instruments to be recorded on the balance sheet at fair value, with changes in the fair value recognized in net income unless specific hedge criteria are met. The Trust has not designated any of its derivative contracts as effective accounting hedges, even though the Trust considers all commodity

contracts to be effective economic hedges. Therefore, changes in the fair value of the derivative contracts are recognized in net income for the period.

The gain on derivative contracts presented in the income statement includes realized gains and losses, unrealized gains and losses since January 1, 2007, and a reclassification from other comprehensive income. The realized gain/loss represents actual cash settlements or receipts under the respective contracts. The unrealized gain/loss represents the change in the fair value of the contracts during the period. The reclassification from other comprehensive income represents the amortization of the fair value of the contracts on transition to the new accounting standards, over the term of the contracts. On January 1, 2007, the fair value of the outstanding contracts of \$4.5 million was recorded as an asset with the offset being recorded in accumulated other comprehensive income, a component of unitholders equity. The amount recorded in accumulated other comprehensive income will be reclassified to net income over the term of the derivative contracts, of which \$0.9 million was reclassified in the third quarter of 2007 and \$3.6 million year to date.

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 and market valuations provided by third party sources. 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, 2007 was a liability of \$1.4 million. The fair value of \$1.4 million at September 30, 2007 was comprised of a \$5.8 million asset on gas contracts offset by a \$7.2 million liability on oil contracts.

Third quarter income of 2007 includes a \$1.5 million unrealized loss on derivatives resulting from the change in the fair value of the derivative contracts during the quarter from an asset of \$137,000 at June 30, 2007 to a liability of \$1.4 million at September 30, 2007. The \$1.5 million unrealized loss in income was comprised of a \$3.1 million unrealized gain on natural gas contracts, offset by a \$4.6 million unrealized loss on crude oil contracts. The unrealized loss in the third quarter income is primarily attributable to stronger crude oil forward prices compared to June 30, 2007 and an increase in derivative instruments held.

For the nine months ended September 30, 2007, income includes a \$5.9 million unrealized loss resulting from the change in the fair value of the derivative contracts during the nine months. The unrealized loss was comprised of a \$9.9 million loss on oil contracts, offset by a \$4.0 million gain on gas contracts.

The gain/loss on derivative contracts for the quarter is as follows:

Gain (loss) on Derivative Contracts (\$000's)

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2007	2006	2007	2006
Unrealized gain (loss)				
Crude oil contracts	(4,580)	-	(9,920)	-
Natural gas contracts	3,072	-	4,028	-
Unrealized loss	(1,508)	-	(5,892)	-
Realized gain (loss)	(47)	684	3,075	1,577
Reclassification from other comprehensive income	874	-	3,647	-
Gain (loss) on derivative contracts	(681)	684	830	1,577

Risk Management Contracts Summary

For the remainder of 2007, NAL has the following risk management contracts outstanding:

CRUDE OIL		NATURAL GAS	
Swap (bbls)	171,700	Swap (GJ)	1,010,000
Swap (bbl/d)	1,866	Swap (GJ/d)	10,978
\$US/bbl	\$67.92	\$Cdn/GJ	\$7.28
Collars (bbls)	193,200	Collars (GJ)	828,000
Collars (bbl/d)	2,100	Collars (GJ/d)	9,000
\$US/bbl	\$63.95 - \$70.07	\$Cdn/GJ	\$6.61 - \$8.48
Total (bbls)	364,900	Total (GJ)	1,838,000
Total (bbl/d)	3,966	Total (GJ/d)	19,978

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

CRUDE OIL		NATURAL GAS	
Swap (bbls)	374,500	Swap (GJ)	2,514,500
Swap (bbl/d)	1,023	Swap (GJ/d)	6,870
\$US/bbl	\$77.76	\$Cdn/GJ	\$7.52
Collars (bbls)	383,000	Collars (GJ)	455,000
Collars (bbl/d)	1,046	Collars (GJ/d)	1,243
\$US/bbl	\$71.65 - \$79.30	\$Cdn/GJ	\$8.32 - \$10.09
Total (bbls)	757,500	Total (GJ)	2,969,500
Total (bbl/d)	2,070	Total (GJ/d)	8,113

ROYALTY EXPENSES

Crown, freehold and overriding royalties were \$21.8 million for the three months ended September 30, 2007. Expressed as a percentage of gross sales, before gain/loss on derivative contracts and transportation costs, the net royalty rate was consistent with budget at 21.9 percent, down from 22.6 percent for the same period last year.

On a year-to-date basis, royalties were \$63.1 million, down from \$65.1 million in the comparable period of 2006. Expressed as a percentage of gross sales, the royalty rate is consistent year-over-year at 21.7 percent as compared to 22.0 percent in the prior year.

On October 25, 2007, Premier Stelmach announced the new royalty regime for Alberta, effective January 2009. This new framework will affect NAL in that conventional oil and gas royalties will now be on a sliding scale that is determined by commodity price and productivity. Natural gas royalties will increase from a cap of 35 percent to 50 percent, with rate caps at \$16.59/GJ. Crude oil royalty rates will increase from the current maximum of 35 percent to 50 percent, with rate caps raised to \$120/bbl.

The Trust has assessed the impact of these new royalties on its production and the impact is considered modest given the low level of crude oil production in Alberta and a significant weighting towards low producing gas wells. For the nine months ended September 30, 2007, 24 percent of crude oil and 84 percent of natural gas production is from Alberta.

Royalty Expenses

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2007	2006	2007	2006
Net royalties (\$000s)	21,849	21,883	63,126	65,074
As % of revenue ⁽¹⁾	21.9	22.6	21.7	22.0
\$/boe	11.77	12.47	11.85	12.27

⁽¹⁾ Oil and natural gas and liquid sales before transportation and gains/losses on derivative contracts.

OPERATING COSTS

For the quarter ended September 30, 2007, total operating costs were higher compared to the similar period a year earlier. On a unit of production basis, operating costs averaged \$10.40/boe compared to \$8.70/boe for the quarter ended September 30, 2006. On a year-to-date basis, operating costs are consistent with guidance at \$9.08/boe compared with \$8.71/boe for 2006.

NAL owns and operates facilities associated with a large percentage of its production, which results in 60 - 70 percent of operating costs being fixed. This high percentage of fixed costs creates a similar operating cost profile year over year independent of volume. Costs are traditionally lower in the first four months of the year and rise significantly May through September, reflecting high maintenance and turnaround activity, and then decline through the fourth quarter. The current full year guidance range (\$8.90 - \$9.10/boe) was established with this historical profile and NAL expected costs to be \$9.80/boe in the third quarter due to turn around activities at the Nottingham and Brent gas plants, as well as overhauls at various field compression sites.

A one time prior period accounting adjustment of \$1.3 million (\$0.70/boe for Q3, \$0.17/boe for full year 2007) from a third party processor during the month of August was the main driver in higher than expected operating costs for the quarter. Consistent with historical trends, NAL's operating costs are forecast to be lower in the fourth quarter (excluding Seneca).

The Trust assumed full responsibility for the Seneca properties in September and has since undertaken significant operating cost related projects some of which had been deferred during the sale process. These activities include turnarounds, pipeline replacements, pump changes and corrosion inhibition programs, which will translate into higher operating costs for the fourth quarter. In 2008, the Trust expects cost savings through the integration and synergy of operations with NAL's current assets and manpower in the Drumheller area.

Near term expectations for higher costs from the Seneca properties are forecast to be offset by lower overall costs on the Trust base volumes for the fourth quarter. As a result, full year guidance remains unchanged at \$8.90 - \$9.10/boe.

Operating Costs

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2007	2006	2007	2006
Operating costs (\$000s)	19,301	15,265	48,379	46,168
As % of revenue	19.5	15.9	16.7	15.7
\$/boe	10.40	8.70	9.08	8.71

OPERATING NETBACK

For the quarter ended September 30, 2007, NAL's operating netback, before realized gains on derivative contracts, was \$31.19 per boe, a decrease of seven percent from \$33.50 for the quarter ended September 30, 2006. The decrease was due to lower revenue and higher operating costs, offset by a decrease in royalties.

Similar trends are noted for the nine month period ended September 30, 2007, with operating netback before hedging at \$33.30 per boe, a decrease of three percent from \$34.42 per boe for the comparable period in 2006.

Operating Netback (\$/boe)

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2007	2006	2007	2006
Revenue ⁽¹⁾	53.36	54.67	54.23	55.40
Royalties, net	(11.77)	(12.47)	(11.85)	(12.27)
Operating expenses	(10.40)	(8.70)	(9.08)	(8.71)
Operating netback, before hedging	31.19	33.50	33.30	34.42
Realized gains (losses) on derivative contracts	(0.03)	0.39	0.58	0.30
Operating netback, after hedging	31.16	33.89	33.88	34.72

(1) Oil, natural gas and liquids sales less transportation

GENERAL AND ADMINISTRATIVE EXPENSES

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

For the three months ended September 30, 2007, G&A expenses were \$2.5 million, compared with \$2.6 million in the comparable quarter in 2006. In addition, \$1.1 million of G&A costs relating to exploitation and development activities were capitalized in the third quarter of 2007, compared with \$1.4 million in the third quarter of 2006.

For the nine months ended September 30, 2007, G&A expenses increased 21 percent to \$10.3 million from \$8.6 million. In addition, on a year-to-date basis \$3.5 million of G&A costs relating to exploration and development activities were capitalized, consistent with 2006.

Total G&A increased \$1.7 million from \$12.1 million to \$13.8 million in the first nine months of 2007 due to increased compensation costs associated with hiring, compensating and retaining staff. Included in G&A expenses in 2007 is a retention bonus of \$0.9 million associated with an employee retention program established at year end 2006. This represents a \$0.17 per boe charge in the first nine months of 2007. Due to the program paying out in two equal installments, at June 30, 2007 and June 30, 2008, the expense for the second half of 2007 is substantially less than the first six months, resulting in an expected average of \$0.13 per boe for full year 2007. G&A excluding the retention bonus and unit-based compensation plan is \$1.76 per boe for the first nine months of 2007, consistent with our full year guidance at \$1.75 - \$1.95 per boe.

General and Administrative Expenses

	Three months ended Sept. 30 2007	2006	Nine months ended Sept. 30 2007	2006
G&A expenses (\$000s)				
G&A	2,445	2,623	9,420	8,551
Retention bonus	104	—	888	—
Expensed G&A	2,549	2,623	10,308	8,551
Capitalized G&A (\$000s)	1,051	1,441	3,487	3,515
Total G&A (\$000s)	3,600	4,064	13,795	12,066
Expensed G&A costs:				
G&A, excluding retention bonus (\$/boe)	1.31	1.49	1.76	1.61
Retention bonus (\$/boe)	0.06	—	0.17	—
Total G&A expenses (\$/boe)	1.37	1.49	1.93	1.61
As % of revenue	2.6	2.7	3.6	2.9
Per Trust unit (\$)	0.03	0.03	0.13	0.11

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 at the end of three years. Distributions paid during the vesting period are assumed to be reinvested in notional units on the date of distribution. Upon vesting, the employee is entitled to a cash payout based on the unit price at 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 units held at vesting.

During the third quarter of 2007, the Trust accrued \$0.7 million of unit-based incentive compensation charges as compared to \$0.2 million in the comparable quarter of 2006.

On a year-to-date basis, the Trust has accrued \$1.5 million compared to \$4.6 million in the comparable period in 2006. The reduction in unit-based compensation in 2007 is a reflection of a decrease in the unit price and a decrease in the performance factors attached to the PTUs. These reductions have resulted in the reversal of amounts accrued prior to December 31, 2006 for units vesting in 2007 and 2008.

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

At September 30, 2007, the Trust has recorded a liability for unit-based incentive compensation in the amount of \$3.5 million, of which \$1.3 million is expected to be paid in December 2007. The remaining balance represents the long-term portion of the Trust’s estimated liability for the unit-based incentive plan as at September 30, 2007. This amount is payable in December 2008 and December 2009.

Unit-Based Compensation

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2007	2006	2007	2006
Unit-based compensation:				
Expensed (\$000s)	408	193	1,072	2,626
Capitalized (\$000s)	274	31	445	1,954
Total unit-based compensation (\$000s)	682	224	1,517	4,580
Expensed unit-based compensation:				
As % of revenue	0.4	0.2	0.4	0.9
\$/boe	0.22	0.11	0.20	0.50
Per Trust unit (\$)	0.00	0.00	0.01	0.03

MANAGEMENT CONTRACT AND FEES

The Trust is managed by NAL Resources Management Limited (the "Manager"). The Manager is a wholly-owned subsidiary of Manulife Financial Corporation ("MFC") and manages, on their behalf, NAL Resources Limited ("NAL Resources"), another wholly-owned subsidiary of MFC. NAL Resources and the 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 is 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 pursuant to a Management Contract. During the nine months ended September 30, 2006, the Trust paid \$1.4 million for management fees. The management contract was restructured effective May 31, 2006, after which no further management fees are payable.

The Trust paid \$2.4 million (2006 - \$1.7 million) for the reimbursement of G&A expenses incurred by the Manager on behalf of the Trust pursuant to the Management Contract during the third quarter and \$8.4 million (2006 - \$5.3 million) year to date. The increase in charges from the Manager is due to increased compensation charges, see General and Administrative Expenses. 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, on a year to date basis, \$2.2 million was paid in the first quarter of 2007 relating to notional units that vested November 30, 2006.

INTEREST

Interest on bank debt includes charges on borrowings plus standby fees on the unused portion of the bank credit facility. NAL's average outstanding bank debt for the third quarter of 2007 was \$246.8 million, compared to \$196.8 million for the third quarter of 2006. NAL's effective interest rate averaged 5.46 percent in 2007, compared with 4.96 percent in the third quarter of 2006. NAL's interest is at floating rate. The increase in the rate from the third quarter of 2006 is attributable to rate increases in the market.

For the nine months ended September 30, 2007 NAL's average debt was \$234.9 million, compared to \$199.6 million for the corresponding period in 2006. NAL's effective interest rate in 2007 averaged 5.29 percent compared with 4.75 percent in 2006 due to rate increases in the market.

Interest on bank debt for the third quarter increased to \$3.5 million compared to \$2.5 million for the comparable period in 2006, due to higher interest rates and increased average debt levels in 2007. A similar trend is noted for the nine months ended September 30, 2007.

Interest on convertible debentures represents interest charges since the issuance of the debentures on August 28, 2007 at 6.75% of \$629,000 and accretion of the debt discount of \$158,000.

Interest and Debt (\$000s)

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2007	2006	2007	2006
Interest on bank debt	3,540	2,496	9,536	7,204
Interest on convertible debentures	787	-	787	-
Total interest	4,327	2,496	10,323	7,204
Bank debt outstanding at period end	256,485	208,193	256,485	208,193
Convertible debentures	90,399	-	90,399	-

CASH FLOW NETBACK

For the quarter ended September 30, 2007, NAL's cash flow netback was \$27.24 per boe, a 12 percent decrease from \$30.87 for the comparable period in 2006. The decrease is attributable to an eight percent decrease in operating netback, after hedging, and higher interest charges.

A similar trend is noted for the nine months ended September 30, 2007 as the cash flow netback decreased to \$29.81 per boe from \$31.00 in 2006.

Cash Flow Netback (\$/boe)

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2007	2006	2007	2006
Operating netback, after hedging	31.16	33.89	33.88	34.72
Management fees	-	-	-	(0.25)
G&A expenses, excluding retention bonus	(1.31)	(1.49)	(1.76)	(1.61)
Retention bonus	(0.06)	-	(0.17)	-
Unit-based incentive compensation	(0.22)	(0.11)	(0.20)	(0.50)
Interest and fees on bank debt	(1.91)	(1.42)	(1.79)	(1.36)
Interest on convertible debentures	(0.42)	-	(0.15)	-
Cash flow netback	27.24	30.87	29.81	31.00

⁽¹⁾ *Net bank debt is bank debt net of working capital excluding derivative contracts.*

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

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

For the quarter ended September 30, 2007, depletion on property, plant and equipment and accretion on the asset retirement obligation increased by 29 percent over the comparable period in 2006 due to a six percent increase in production, the inclusion of property, plant and equipment from the Seneca acquisition since September 1, 2007 and a ten percent increase in the DDA rate per boe of production for existing trust properties. As part of the Seneca acquisition, the Trust acquired undeveloped land with a fair value of \$28 million. These costs have been excluded from the depletion calculation for the three months ended September 30, 2007.

Similar trends are noted for the nine months ended September 30, 2007.

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

Depletion, Depreciation and Accretion Expenses

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2007	2006	2007	2006
Depletion and depreciation (\$000s)	43,254	33,213	112,504	97,354
Accretion of asset retirement obligation	1,370	1,247	3,969	3,726
Total DDA (\$000s)	44,624	34,460	116,473	101,080
DDA rate per boe (\$)	24.03	19.63	21.86	19.07

TAXES

Taxes include federal and provincial capital and income taxes relating to the Trust and its subsidiary companies.

In the third quarter of 2007, NAL had a future income tax reduction of \$1.1 million compared with \$0.2 million provision in the corresponding period of the prior year.

For the nine months ended September 30, 2007, NAL had a future income tax reduction of \$1.3 million compared to \$0.9 million in 2006.

The Trust is a taxable trust 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, and issue costs. In addition, Canadian Exploration Expense ("CEE"), Canadian Development Expense ("CDE") and Undepreciated Capital Cost ("UCC") are incurred and are 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 income taxes in 2007.

As at September 30, 2007, the Trust's (including all subsidiaries) estimated tax pools (unaudited) available for deduction from future taxable income approximate \$664.8 million, of which approximately 46 percent represents COGPE and 29 percent UCC, with the remaining balance represented by CEE, CDE, trust unit issue costs and non-capital loss carry forwards.

On June 12, 2007, Bill C52, released by the Department of Finance on December 21, 2006 to implement its October 31, 2006 announcement of the changes to taxability of Income Trusts, received third reading in the House of Commons. 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. As a result of passing third reading, these measures are now considered substantially enacted for purposes of Canadian generally accepted accounting principles. Accordingly, the Trust measured, in the second quarter of 2007, future income tax assets and liabilities associated with this new tax. In addition, the Trust re-measured future income tax assets and liabilities associated with this new tax in the third quarter of 2007, following the acquisition of Seneca. There is no impact on the future tax recognized in the financial statements, resulting from the implementation of this tax legislation as it is expected that all existing taxable temporary differences will reverse prior to January 1, 2011, the date the taxation changes take effect. Accordingly, all taxable temporary differences have been recognized at a zero taxation rate. The scheduling of the reversal of temporary differences is based on management's best estimates and current assumptions, which may change.

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 gain or loss on derivative contracts and future income taxes.

Net income for the third quarter of 2007 was \$7.8 million compared to \$20.5 million for the comparable period in 2006. The decrease in net income of \$12.7 million is primarily due to a \$10 million increase in

depletion, increased operating costs of \$4.0 million and increased interest expense of \$1.8 million, partially offset by higher revenues, net of royalties, of \$2.8 million and lower taxes.

Net income for the nine months ended September 30, 2007 of \$45.9 million was \$6.2 million higher than the same period in 2006. In 2006, net income includes a non-cash expense of \$27.3 million relating to the restructuring of the management contract. Excluding this amount net income decreased period over period by \$21.1 million, due to a \$15 million increase in depletion, increased interest expense of \$3.1 million, a \$2 million decrease in revenues, net of royalties, and a \$2.2 million increase in operating costs, offset by a \$1.4 million decrease in management fees.

Net Income				
	Three months ended Sept. 30		Nine months ended Sept. 30	
	2007	2006	2007	2006
Net income	7,801	20,473	45,901	39,726

CAPITAL RESOURCES AND LIQUIDITY

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

As at September 30, 2007, NAL had 89,885,824 units outstanding, compared with 77,971,268 units at December 31, 2006. The increase from December 31, 2006 is attributable to 10,246,000 units issued on close of the equity offering on August 31, 2007, and units issued under the distribution reinvestment program.

Under the equity offering, 10.2 million units were issued at a price of \$12.20 per unit for net proceeds, after issue costs, of \$118.8 million.

For the nine months ended September 30, 2007, the distribution reinvestment ("DRIP") plan resulted in 1,668,561 units being issued at an average price of \$11.83 per unit, for total proceeds of \$19.7 million.

Unitholders electing to reinvest distributions or make optional cash payments to acquire trust units from treasury under the DRIP may do so at 95 percent of the average market price, with no additional fees or commissions. The premium distribution reinvestment ("Premium DRIP") plan allows unitholders to exchange such units for a cash payment from the Plan Broker equal to 102 percent of the monthly distribution.

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

The participation rate in the regular DRIP averaged 17 percent over the past nine months, consistent with recent experience. The Trust continues to monitor the participation in this plan in conjunction with its capital requirements.

As at September 30, 2007 the Trust had total debt of \$364.9 million, including convertible debentures of \$90.4 million and a working capital deficit of \$18.0 million (excluding derivative contracts). Excluding the convertible debentures, net debt is \$274.5 million, compared with \$223.1 million at December 31, 2006, and \$211.3 million as at September 30, 2006.

At the end of the third quarter, the Trust had a net debt to equity ratio of 0.69 compared to 0.49 at December 31, 2006. In addition, at the end of the third quarter, the Trust had a net debt (excluding convertible debentures) to twelve months trailing cash flow of 1.28 and a total net debt to trailing cash flow of 1.70.

In conjunction with the acquisition of Seneca, the Trust increased its credit facility from \$325 million to \$400 million. The credit facility is fully secured, extendible, and revolving and will revolve until April 30, 2008, 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 \$390 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, a portion of the cash flow otherwise available to unitholders would be used to repay the facility in four equal quarterly installments commencing May 2009.

Bank debt amounted to \$256.5 million at September 30, 2007 compared with \$220.8 million as at December 31, 2006. Of the debt outstanding at September 30, 2007, \$256.5 million was outstanding under the production facility and zero under the working capital facility.

Bank debt increased from \$220.8 million as at December 31, 2006 to \$256.5 million as at September 30, 2007 mainly due to \$31.2 million required for the acquisition of Seneca.

On August 28, 2007, in connection with the acquisition of Seneca, the Trust issued \$100 million principal amount of 6.75% convertible extendible unsecured subordinated debentures. Interest on these debentures is paid semi-annually in arrears, on February 28 and August 31, and the debentures are convertible at the option of the holder, at any time, into fully paid trust units at a conversion price of \$14.00 per trust unit. The debentures mature on August 31, 2012 at which time they are due and payable. The debentures are redeemable by the Trust at a price of \$1,050 per debenture on or after September 1, 2010 and on or before August 31, 2011, and at a price of \$1,025 per debenture on or after September 1, 2011 and on or before August 31, 2012. On redemption or maturity the Trust may opt to satisfy its obligation to repay the principal by issuing trust units.

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 will be 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 caption interest and accretion on convertible debentures in the consolidated statements of income.

The Trust recognized \$158,000 of accretion of the debt discount in the third quarter of 2007.

As at November 7, 2007 the Trust has 90,088,068 units and \$100 million in convertible debentures outstanding.

Capitalization

	Sept. 30, 2007	Dec. 31, 2006	Sept. 30, 2006
Trust unit equity (\$000s)	531,706	456,500	467,817
Bank debt (\$000s)	256,485	220,785	208,193
Working capital ⁽¹⁾ (\$000s)	18,028	2,276	3,083
Net debt excluding convertible debentures	274,513	223,061	211,276
Convertible debentures (\$000s)	90,399	-	-
Net debt	364,912	223,061	211,276
Net debt to equity	0.69	0.49	0.45
Net debt excluding convertible debentures to trailing 12-month cash flow ⁽²⁾	1.28	1.01	0.92
Net debt to trailing 12-month cash flow ⁽²⁾	1.70	1.01	0.92
Units outstanding (000s)	89,886	77,971	77,425

(1) Working capital excludes derivative contracts and future income tax asset.

(2) Calculated as net debt 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 2007 through a contribution of funds from operations, funds received from its distribution reinvestment program and bank borrowings.

ASSET RETIREMENT OBLIGATION

At September 30, 2007, the Trust reported an Asset Retirement Obligation (“ARO”) balance of \$75.6 million (\$65.6 million at December 31, 2006) for future abandonment and reclamation of the Trust’s oil and gas properties and facilities. The ARO balance was increased by \$10.4 million due to the Seneca acquisition, \$4.0 million from accretion expense in the first nine months of 2007 (\$3.7 million in the first nine months of 2006) and reduced by \$4.2 million for actual abandonment and environmental expenditures incurred in the first nine months of 2007 (\$3.0 million in the first nine months of 2006).

DISTRIBUTIONS TO UNITHOLDERS

For the three months ended September 30, 2007 the Trust distributed 65% of its cash flow from operating activities and 68% year to date, as compared to 71% in 2006 and 73% in 2005. The Trust has distributed in excess of its net income each period, due to the non-cash charges included in net income. Cash flow from operations usually exceeds net income as net income includes non-cash charges such as 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, 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 whilst 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 2007 capital program is not projected to 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 acquisition. NAL’s productive capacity and future cash flow will be dependent on its ability to acquire assets and find reserves at appropriate economics. 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 distribution reinvestment plan 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.

Distributions

	Three months ended Sept. 30 2007	Nine months ended Sept. 30 2007	Year ended	
			2006	2005
Cash flow from operating activities	61,266	170,253	238,445	195,285
Net income	7,801	45,901	60,198	98,538
Actual cash distributions paid or payable	39,778	115,261	169,589	142,050
Excess (shortfall) of cash flow from operating activities over cash distribution paid	21,488	54,992	68,856	53,235
Percentage of cash flow from operations distributed	65%	68%	71%	73%
Excess (shortfall) of net income over cash distributions paid	(31,977)	(69,360)	(109,391)	(43,512)

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, 2007, funds from operations amounted to \$50.8 million compared with \$54.1 million for the three months ended September 30, 2006. The decrease is due to increased operating costs and higher interest charges in 2007. On a per unit basis funds from operations decreased 13 percent from \$0.70 in 2006 to \$0.61 due to the increase in units from the equity offering associated with the acquisition of Seneca.

For the nine months ended September 30, 2007, funds from operations decreased three percent, and eight percent on a per unit basis from \$2.16 to \$1.99, from the comparable period in 2006. The decrease of three percent is primarily due to lower revenues with a decrease on a per unit basis due to the equity offering and units issued under the DRIP.

Funds from Operations

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2007	2006	2007	2006
Funds from operations	50,817	54,107	159,208	163,981
Funds from operations per unit	0.61	0.70	1.99	2.16
Payout ratio based on funds from operations	78%	81%	72%	79%

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)	2007	2008	2009	2010	2011
Office Lease (1)	697	3,206	3,206	2,939	—
Transportation	456	1,007	908	84	—
Processing Agreement (2)	123	469	446	428	414
Drilling rigs (3)	494	494	—	—	—
Retention bonus (4)	-	644	—	—	—

- (1) Represents the full amount of office lease commitments, including office space acquired with the Seneca acquisition, both base rent and operating costs, held by the Manager, of which the Trust is allocated a pro rata share (currently approximately 54 percent) of the expense on a monthly basis.
- (2) Represents a gas processing agreement with a take or pay arrangement.
- (3) Represents the Trust's share of minimum payments required under drilling rig contracts held by NAL Resources.
- (4) Represents the Trust's share of the expected future payments under a staff retention program.

QUARTERLY INFORMATION

(\$000s, except per unit and production amounts)	2007				2006			2005
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Revenue, net of royalties	78,573	83,268	71,231	75,694	75,798	77,988	81,272	95,643
Per unit	0.95	1.06	0.91	0.97	0.98	1.03	1.08	1.30
Cash flow from operating activities	61,266	56,021	52,966	48,678	60,749	60,221	68,798	72,463
Per unit	0.74	0.71	0.68	0.63	0.79	0.79	0.92	0.99
Net income	7,801	21,390	16,710	20,472	20,473	(5,357) ⁽¹⁾	24,610	30,777
Per unit	0.09	0.27	0.21	0.26	0.27	(0.07)	0.33	0.42
Average oil equivalent production (boe/d – 6:1)	20,182	18,946	19,422	19,517	19,079	19,012	20,181	20,514

⁽¹⁾ Includes non-cash management restructuring fee of \$27.2 million.

FINANCIAL REPORTING DISCLOSURE CONTROLS

Management has evaluated the effectiveness of the Trust's financial reporting disclosure controls and procedures as at September 30, 2007, and has concluded that such financial reporting disclosure controls and procedures were effective as at that date.

CHANGES TO INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no changes to the Trust's internal control over financial reporting since December 31, 2006 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, 2006 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 to 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, 2006.

NEW ACCOUNTING POLICIES

Effective January 1, 2007 the Trust implemented the provisions of CICA Handbook Section 3855 "Financial Instruments – recognition and measurement", Section 3861 "Financial Instruments – disclosure and presentation", Section 3865 "Hedges", Section 1530 "Comprehensive Income", and certain provisions of Section 3251 "Equity".

These standards address the recognition and measurement of financial assets, financial liabilities and non-financial derivatives. Financial instruments are classified into one of four categories, each category

determines how an instrument is measured and when and where gains and losses are recognized. Instruments are either measured at fair value or amortized cost, which is determined using the effective interest method. The hedging standard provides guidance on when and how hedge accounting may be performed and section 1530 provides standards on the reporting and display of comprehensive income and its components.

These standards have been applied by the Trust, on a prospective basis, in accordance with the relevant transitional provisions. For full details on the implications to the Trust of these standards, see Note 2 to the interim consolidated financial statements.

FUTURE ACCOUNTING CHANGES

The CICA issued new accounting standards; Section 1535 “Capital Disclosures”, Section 3862 “Financial Instruments”, and Section 3863 “Financial Instruments – Disclosures”. These standards will be effective January 1, 2008.

Section 1535 “Capital Disclosures” establishes standards for disclosing information about an entity’s capital and how it is managed. The 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.

Section 3862 and 3863, establish standards to revise and enhance disclosure on financial instruments. These standards require entities to provide disclosure in their financial statements that enable users to evaluate the significance of financial instruments to the entity’s financial position and performance, and the nature and extent of risks arising from financial instruments and how the entity manages those risks. The standards establish presentation guidelines for financial instruments and non-financial derivatives and deals with the classification of financial instruments from the perspective of the issuer, between liabilities and equity, the classification of related interest, dividends, losses and gains, and the circumstances in which financial assets and liabilities are offset.

The Trust has not yet assessed the impact of these standards on its financial statements.

Dated: November 7, 2007

CONSOLIDATED BALANCE SHEETS
(thousands of dollars) (unaudited)

As at September 30, 2007 As at December 31, 2006

Assets		
Current assets		
Cash and cash equivalents	\$6,092	\$6,295
Accounts receivable and other	52,613	44,467
Derivative contracts (Note 4)	3,394	-
Future income tax asset	1,344	
	63,443	50,762
Derivative contracts (Note 4)	2,437	-
Future income tax asset	3,089	3,345
Property, plant and equipment, net (Notes 2 and 3)	971,439	742,795
	\$1,040,408	\$796,902
Liabilities and Unitholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	\$62,351	\$40,563
Distributions payable to unitholders	14,382	12,475
Derivative contracts (Note 4)	6,650	-
	83,383	53,038
Derivative contracts (Note 4)	552	-
Convertible debentures (Note 6)	90,399	-
Bank debt (Note 5)	256,485	220,785
Unit-based incentive compensation (Note 7)	2,234	1,005
Asset retirement obligations (Note 8)	75,649	65,574
	508,702	340,402
Unitholders' equity		
Unitholders' capital (Note 9)	963,180	824,986
Equity component of convertible debentures (Note 6)	5,759	-
Deficit	(437,846)	(368,486)
Accumulated other comprehensive income	613	-
Deficit and accumulated other comprehensive income	(437,233)	(368,486)
Unitholders' equity	531,706	456,500
Liabilities and unitholders' equity	\$1,040,408	\$796,902
Commitments (Note 10)		
Units outstanding (000s)	89,886	77,971

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	
	2007	2006	2007	2006
Revenue				
Oil, natural gas and liquids sales	\$99,767	\$96,580	\$290,878	\$295,630
Crown royalties	(15,874)	(16,342)	(45,660)	(48,414)
Freehold and other royalties	(5,975)	(5,541)	(17,466)	(16,660)
	77,918	74,697	227,752	230,556
Gain (loss) on derivative contracts (Note 4):				
Realized gain (loss)	(47)	684	3,075	1,577
Unrealized loss	(1,508)	-	(5,892)	-
Reclassification from other comprehensive income	874	-	3,647	-
	(681)	684	830	1,577
Royalty and other income	1,336	417	4,490	2,925
	78,573	75,798	233,072	235,058
Expenses				
Operating	19,301	15,265	48,379	46,168
Transportation	691	623	1,882	1,927
General and administrative	2,549	2,623	10,308	8,551
Unit-based incentive compensation (Note 7)	408	193	1,072	2,626
Management fees	-	-	-	1,350
Restructuring fee	-	-	-	27,299
Interest on bank debt	3,540	2,496	9,536	7,204
Interest and accretion on convertible debentures	787	-	787	-
Depletion, depreciation and amortization	43,254	33,213	112,504	97,354
Accretion on asset retirement obligations	1,370	1,247	3,969	3,726
	71,900	55,660	188,437	196,205
Income before taxes	6,673	20,138	44,635	38,853
Income and capital taxes (provision)	25	542	(83)	(74)
Future income tax reduction (provision)	1,103	(207)	1,349	947
Total income and capital taxes	1,128	335	1,266	873
Net income	7,801	20,473	45,901	39,726
Other comprehensive income:				
Reclassification to net income, net of tax (Notes 4 and 9)	(613)	-	(2,559)	-
Comprehensive Income	7,188	20,473	43,342	39,726
Deficit, beginning of period	(405,869)	(325,707)	(368,486)	(259,095)
Net income	7,801	20,473	45,901	39,726
Distributions declared	(39,778)	(44,061)	(115,261)	(129,926)
Deficit, end of period	\$(437,846)	\$(349,295)	\$(437,846)	\$(349,295)
Net income per Trust unit – basic and diluted (Note 9)	\$0.09	\$0.27	\$0.57	\$0.52
Weighted average units outstanding (000s)	82,815	77,247	79,982	75,897

See accompanying notes

CONSOLIDATED STATEMENTS OF CASH FLOWS
(thousands of dollars) (unaudited)

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2007	2006	2007	2006
Operating Activities				
Net income	\$7,801	\$20,473	\$45,901	\$39,726
Items not involving cash:				
Depletion, depreciation and amortization	43,254	33,213	112,504	97,354
Accretion on asset retirement obligations	1,370	1,247	3,969	3,726
Unrealized loss on derivative contracts	1,508	-	5,892	-
Reclassification from other comprehensive income	(874)	-	(3,647)	-
Future income tax provision (reduction)	(1,103)	207	(1,349)	(947)
Non-cash accretion expense on convertible debentures	158		158	-
Restructuring fee	-	-	-	27,159
Abandonment and environmental expenditures	(1,297)	(1,033)	(4,220)	(3,037)
Change in non-cash working capital	10,449	6,642	11,045	25,786
	61,266	60,749	170,253	189,767
Financing Activities				
Distributions to unitholders	(38,050)	(43,995)	(113,355)	(129,271)
Issue of Trust units, net of issue costs	125,029	6,671	138,194	33,527
Increase (decrease) in bank debt	22,968	16,868	35,700	(12,326)
Issue of convertible debentures	96,000	-	96,000	-
Change in non-cash working capital	-	1,311	915	2,055
	205,947	(19,145)	157,454	(106,015)
Investing Activities				
Acquisition of Seneca Energy Canada Inc. (Note 2)	(246,728)	-	(246,728)	-
Additions to property, plant and equipment	(33,052)	(40,569)	(78,794)	(85,127)
Property acquisitions	(1,204)	(1,300)	(1,472)	(1,423)
Proceeds from dispositions	-	14	26	137
Reclamation reserve	-	(102)	-	(396)
Change in non-cash working capital	14,794	(3,108)	(942)	9,122
	(266,190)	(45,065)	(327,910)	(77,687)
Increase (decrease) in cash and cash equivalents	1,023	(3,461)	(203)	6,065
Cash and cash equivalents, beginning of period	5,069	10,650	6,295	1,124
Cash and cash equivalents, end of period	\$6,092	\$7,189	\$6,092	\$7,189
Supplementary disclosure of cash flow information:				
Cash paid (received) during the period for:				
Interest	\$4,816	\$2,458	\$12,136	\$7,090
Taxes	\$(25)	\$(542)	\$83	\$74

See accompanying notes

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Nine months ended September 30, 2007

(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, 2006, except for the implementation of new standards addressing financial instruments, hedging and comprehensive income 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, 2006.

Financial Instruments, Hedges, Comprehensive Income

Effective January 1, 2007 the Trust implemented the provisions of CICA Handbook Section 3855 "Financial Instruments – recognition and measurement", Section 3861 "Financial Instruments – disclosure and presentation", Section 3865 "Hedges", Section 1530 "Comprehensive Income" and certain provisions of Section 3251 "Equity".

Section 3855 establishes standards for recognizing and measuring financial assets, financial liabilities and non-financial derivatives. Financial instruments are classified into one of four categories, each category determines how an instrument is measured and when and where gains and losses are recognized. Instruments are either measured at fair value or amortized cost, which is determined using the effective interest method. Section 3865 provides guidance on when and how hedge accounting may be used. Section 1530 provides standards on the reporting and display of comprehensive income and its components. Other comprehensive income comprises revenues, expenses, gains and losses not included in net income. Section 3251 provides guidance on the presentation and disclosure of the components of equity, including accumulated other comprehensive income.

These standards have been applied on a prospective basis, in accordance with the relevant transitional provisions.

The Trust has entered into certain derivative contracts in order to reduce its exposure to market risks from fluctuations in commodity prices. These instruments are not used for trading or speculative purposes. In accordance with Section 3855, all derivative instruments are recorded on the balance sheet at fair value, with changes in the fair value recognized in net income, unless specific hedge criteria are met.

The Trust has not designated its derivative contracts as effective accounting hedges under Section 3865, even though the Trust considers all commodity contracts to be effective economic hedges. Therefore, changes in the fair value of the derivative instruments are recognized in net income for the period. Proceeds and costs realized from holding the derivative contracts are recognized in net income at the time each transaction under a contract is settled.

On January 1, 2007, the Trust had derivative contracts in place with a fair value of \$4.5 million. The transitional provisions of the new standards allow for NAL's derivatives to be recorded as an asset on January 1, 2007 with the offset being recorded in accumulated other comprehensive income ("AOCI"), a component of unitholders' equity. The amount recorded in AOCI will be reclassified to net income over the remaining term of the derivatives.

Accordingly, on January 1, 2007, the fair value of the derivatives of \$4.5 million was recorded as an asset on the balance sheet with a corresponding increase in AOCI.

The fair value of these derivative instruments is based on an approximation of the amounts that would be received or paid to settle these instruments at the end of the period, with reference to forward

prices and market valuations provided by third party sources.

Transaction costs are frequently attributed to the issue of a financial asset or liability. Section 3855 requires that such transaction costs incurred related to held for trading financial instruments be expensed immediately. For other financial instruments, an entity can adopt an accounting policy of either expensing transaction costs as they occur or adding such transaction costs to the fair value of the financial instrument. The Trust has chosen a policy of adding transaction costs to the fair value initially recognized for financial assets and liabilities. In accordance with this policy convertible debentures are presented net of issue costs of \$4 million.

In accordance with Section 3855, bank debt is presented net of deferred interest payments, with interest recognized in net income on an effective interest basis. Previously, interest was recognized on a straightline basis with the deferred amount included in accounts receivable. There was no impact at January 1, 2007 resulting from this change.

2. ACQUISITION

On August 31, 2007 the Trust acquired all the issued and outstanding shares of Seneca Energy Canada Inc. ("Seneca"), which has interests in oil and natural gas properties and undeveloped land in East Central Alberta, Northeast British Columbia and Saskatchewan. The results of operations from these properties have been included in the consolidated financial statements commencing September 1, 2007. The transaction was accounted for using the purchase method of accounting with the fair values assigned to net assets and consideration paid as follows:

Net assets acquired:	
Working capital deficiency (including bank indebtedness of \$718)	(4,571)
Property, plant and equipment	260,937
Asset retirement obligations	(10,356)
	246,010
Consideration:	
Cash	245,110
Acquisition costs	900
	246,010

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.

3. PROPERTY, PLANT AND EQUIPMENT

	September 30, 2007	December 31, 2006
Oil and natural gas properties, at cost	\$1,635,002	\$1,293,854
Less: Accumulated depletion and depreciation	(663,563)	(551,059)
	\$971,439	\$742,795

Costs associated with undeveloped land of \$28 million (2006 - \$nil) have been excluded from the depletion calculation for the nine months ended September 30, 2007.

Future development costs for proved reserves of \$37.4 million (2006 - \$49.3 million) have been included in the depletion calculation.

During 2007, the Trust capitalized \$3.5 million (2006 - \$4.3 million) of general and administrative costs and \$0.4 million (2006 - \$1.7 million) of unit based incentive compensation that were directly related to exploitation and development programs.

4. DERIVATIVE CONTRACTS AND RISK MANAGEMENT

Commodity Price Risk Management

NAL employs risk management practices to assist in managing cash flows and support capital programs and distributions. NAL's management is authorized to hedge up to 50% of its annual net production. NAL's risk management programs tend to be scaled-in over time using a combination of swaps and collars.

As at September 30, 2007, the Trust had entered into the following derivatives to protect its cash flow from the volatility of oil and natural gas commodity prices.

For the balance of 2007, NAL has the following WTI oil contracts in place:

Term	Contract	Volume Bbls/d	Total Volume Bbls	Bought Put US\$/bbl	Sold Call US\$/bbl	Swap US\$/bbl
COLLARS						
Oct-Dec	2-way	500	46,000	62.00	68.25	-
Oct-Dec	2-way	200	18,400	64.00	71.00	-
Oct-Dec	2-way	300	27,600	62.00	69.75	-
Oct-Dec	2-way	200	18,400	63.00	68.50	-
Oct-Dec	2-way	200	18,400	62.50	69.50	-
Oct-Dec	2-way	200	18,400	64.00	70.45	-
Oct-Dec	2-way	100	9,200	66.00	72.25	-
Oct-Dec	2-way	100	9,200	67.00	71.75	-
Oct-Dec	2-way	100	9,200	68.00	71.50	-
Oct-Dec	2-way	100	9,200	68.00	72.00	-
Oct-Dec	2-way	100	9,200	71.00	74.50	-
Weighted Average	Collars		193,200	63.95	70.07	-
SWAPS						
Oct-Dec	Swap	100	9,200	-	-	69.10
Oct-Dec	Swap	500	46,000	-	-	65.05
Oct-Dec	Swap	500	46,000	-	-	72.33
Oct-Dec	Swap	300	27,600	-	-	61.07
Oct-Dec	Swap	100	9,200	-	-	69.00
Oct-Dec	Swap	100	9,200	-	-	69.30
Oct-Dec	Swap	100	9,200	-	-	70.14
Oct-Dec	Swap	100	9,200	-	-	72.80
Nov-Dec	Swap	100	6,100	-	-	71.00
Weighted Average	Swaps		171,700	-	-	67.92

For the balance of 2007, NAL has the following AECO natural gas contracts in place:

Term	Contract	Volume	Total Volume		Bought Put	Sold Call	Swap
		GJ/d	GJ		Cdn\$/GJ	Cdn\$/GJ	Cdn\$/GJ
COLLARS							
Oct-Dec	2-way	3,000		276,000	6.00	8.10	-
Oct-Dec	2-way	1,000		92,000	6.50	8.85	-
Oct-Dec	2-way	1,000		92,000	7.00	8.70	-
Oct-Dec	2-way	1,000		92,000	6.75	8.60	-
Oct-Dec	2-way	2,000		184,000	7.00	8.70	-
Oct-Dec	2-way	1,000		92,000	7.25	8.51	-
Weighted Average	Collars			828,000	6.61	8.48	-
SWAPS							
Oct-Dec	Swap	3,000	276,000	-	-	6.77	
Oct-Dec	Swap	1,000	92,000	-	-	7.90	
Oct-Dec	Swap	1,500	138,000	-	-	7.20	
Oct-Dec	Swap	1,500	138,000	-	-	7.43	
Nov-Dec	Swap	2,000	122,000	-	-	7.26	
Nov-Dec	Swap	2,000	122,000	-	-	7.60	
Nov-Dec	Swap	2,000	122,000	-	-	7.40	
Weighted Average	Swaps		1,010,000	-	-	7.28	

NAL currently has the following WTI oil contracts in place for fiscal 2008:

Term	Contract	Volume	Total Volume	Bought Put	Sold Call	Swap
		Bbls/d	Bbls	US\$/bbl	US\$/bbl	US\$/bbl
COLLARS						
January-June	2-way	200	36,400	64.00	72.26	-
January-March	2-way	100	9,100	66.00	71.90	-
January-June	2-way	200	36,400	68.50	73.00	-
January-June	2-way	100	18,200	70.00	76.25	-
April-June	2-way	100	9,100	69.00	74.25	-
January-March	2-way	100	9,100	68.00	73.60	-
January-March	2-way	100	9,100	68.00	74.35	-
January-June	2-way	100	18,200	69.00	74.00	-
January-June	2-way	100	18,200	70.00	75.05	-
January-June	2-way	100	18,200	70.00	75.00	-
January-December	2-way	100	36,600	70.50	75.50	-
January-June	2-way	100	18,200	71.00	78.50	-
January-June	2-way	100	18,200	72.00	78.00	-
January-June	2-way	100	18,200	73.00	79.00	-
January-June	2-way	100	18,200	75.00	81.00	-
January-December	2-way	100	36,600	76.00	87.00	-
July-December	2-way	100	18,400	75.00	85.50	-
January-December	2-way	100	36,600	83.00	100.00	-
Weighted Average	Collars		383,000	71.65	79.30	-
SWAPS						
January-March	Swap	100	9,100	-	-	69.35
January-March	Swap	100	9,100	-	-	71.30
January-June	Swap	100	18,200	-	-	73.47
January-June	Swap	100	18,200	-	-	72.50
April-June	Swap	100	9,100	-	-	71.90
January-December	Swap	100	36,600	-	-	71.00
January-December	Swap	100	36,600	-	-	73.25
January-December	Swap	100	36,600	-	-	73.50
January-June	Swap	100	18,200	-	-	76.30
January-June	Swap	100	18,200	-	-	78.00
January-December	Swap	100	36,600	-	-	79.10
January-December	Swap	100	36,600	-	-	80.75
January-December	Swap	100	36,600	-	-	83.00
January-December	Swap	100	36,600	-	-	87.10
January-June	Swap	100	18,200	-	-	92.00
Weighted Average	Swaps		374,500	-	-	77.76

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

Term	Contract	Volume GJ/d	Total Volume GJ	Bought Put Cdn\$/GJ	Sold Call Cdn\$/GJ	Swap Cdn\$/GJ
COLLARS						
January-March	2-way	2,000	182,000	8.40	10.25	-
January-March	2-way	1,000	91,000	8.40	10.15	-
January-March	2-way	1,000	91,000	8.40	10.40	-
January-March	2-way	1,000	91,000	8.00	9.40	-
Weighted Average	Swaps		455,000	8.32	10.09	-
SWAPS						
January-March	Swap	1,000	91,000	-	-	8.90
January-March	Swap	1,500	136,500	-	-	7.20
January-March	Swap	1,000	91,000	-	-	9.13
January-December	Swap	2,000	732,000	-	-	7.26
January-December	Swap	2,000	732,000	-	-	7.60
January-December	Swap	2,000	732,000	-	-	7.40
Weighted Average	Swaps		2,514,500	-	-	7.52

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

The fair value of the Trust's convertible debentures at September 30, 2007 was \$97.5 million.

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.

	September 30, 2007	December 31, 2006
Current unrealized gain on derivative contracts	\$3,394	\$-
Current unrealized loss on derivative contracts	(6,650)	-
Long-term unrealized gain on derivative contracts	2,437	-
Long-term unrealized loss on derivative contracts	(552)	-
Net unrealized loss on derivative contracts	\$(1,371)	\$-

On transition to Section 3865 on January 1, 2007, the fair value of the outstanding contracts of \$4.5 million was recorded in accumulated other comprehensive income, with related tax of \$1.3 million, and will be transferred to net income over the term of the respective contracts. During the first nine months of 2007, \$3.6 million has been reclassified to net income and is included in the gain (loss) on derivative contracts.

As at September 30, 2007, the total fair value of derivative contracts was a liability of \$1.4 million. The change in the fair value for the nine months of \$5.9 million has been recognized as an unrealized loss in the income statement.

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	
	2007	2006	2007	2006
Unrealized gain, beginning of period	\$137	\$-	\$-	\$-
Unrealized gain on adoption of new accounting standards (Note 1)	-	-	4,521	-
Unrealized loss, end of period	(1,371)	-	(1,371)	-
Unrealized loss	(1,508)	-	(5,892)	-
Realized gain (loss) in the period	(47)	684	3,075	1,577
Reclassification from other comprehensive income	874	-	3,647	-
Gain (loss) on derivative contracts	\$(681)	\$684	\$830	\$1,577

5. BANK DEBT

In conjunction with the acquisition of Seneca, the Trust, through its subsidiary NAL Ventures Trust, increased its credit facility to \$400 million from \$325 million. The facility is fully secured, extendible, and is a revolving term credit facility with a syndicate of Canadian chartered banks. This facility consists of a \$390 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 present and after acquired properties and assets of the Trust and its subsidiary and affiliated entities. The facility will revolve until April 30, 2008 and is extendible at that time 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 2008, 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 2009 with a final residual payment in May 2010.

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. based 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.

On September 30, 2007, the effective interest rate on amounts outstanding under the credit facility was 5.78 percent.

6. CONVERTIBLE DEBENTURES

On August 28, 2007 the Trust issued \$100 million principal amount of 6.75% convertible extendible unsecured subordinated debentures, at a price of \$1,000 per debenture. 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 anytime into trust units at a conversion price of \$14.00 per unit. The debentures mature on August 31, 2012 at which time they are due and payable. The debentures are redeemable by the Trust at a price of \$1,050 per debenture on or after September 1, 2010 and on or before August 31, 2011, and at a price of \$1,025 per debenture on or after September 1, 2011 and on or before August 31, 2012. On redemption or maturity the Trust may opt to satisfy its obligation to repay the principal by issuing trust units.

The 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 will be 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

caption interest and accretion on convertible debentures in the consolidated statements of income.

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)	-
	100,000	90,241	5,759
Accretion	-	158	-
Balance, September 30, 2007	\$100,000	\$90,399	\$5,759

7. UNIT-BASED INCENTIVE COMPENSATION

The Trust recorded a total compensation expense of \$1.5 million in the first nine months of 2007 of which \$1.1 was recorded as an expense and \$0.4 as property, plant and equipment (\$2.5 million as an expense and \$1.7 million as property, plant and equipment for full year 2006). The compensation expense was based on the September 30, 2007 unit price of \$12.22 (\$12.95 in 2006), accrued distributions, performance factors, and the number of units vesting on maturity.

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

	Nine months ended September 30, 2007	Year ended December 31, 2006
Balance, beginning of period	\$4,153	\$—
Increase in liability	1,518	4,153
Cash payout, relating to units vested November 30, 2006	(2,184)	—
Balance, end of period	\$3,487	\$4,153
Current portion of liability ⁽¹⁾	1,253	3,148
Long-term liability	2,234	1,005

(1) Included in accounts payable and accrued liabilities.

8. 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 \$75.6 million as at September 30, 2007, based on a total undiscounted amount of cash flows required to settle its asset retirement obligations of \$190.4 million (December 31, 2006 - \$165.2 million). These costs are expected to be incurred over the next 46 years with the majority of the costs incurred between 2007 and 2033. NAL's credit-adjusted risk-free rate of eight percent (2006 – eight percent) and an inflation rate of two percent (2006 – two percent) were used to calculate the present value of the asset retirement obligations.

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

	Nine months ended		Year ended	
	September 30, 2007		December 31, 2006	
Balance, beginning of period	\$65,574		\$61,908	
Accretion expense	3,969		4,984	
Revisions to estimates	(738)		39	
Liabilities incurred	708		3,078	
Liabilities acquired (Note 2)	10,356		-	
Liabilities settled	(4,220)		(4,435)	
Balance, end of period	\$75,649		\$65,574	

9. UNITHOLDERS' EQUITY

Units Issued:

	Nine months ended		Year ended	
	September 30, 2007		December 31, 2006	
	Units	Amount	Units	Amount
Balance, beginning of period	77,971	\$824,986	73,977	\$753,585
Issued for cash	10,246	125,001	-	-
Issued under management agreement restructuring	-	-	1,592	30,000
Less: Issue expenses	-	(6,553)	-	(29)
Issued from Distribution Reinvestment Plan	1,669	19,746	2,402	41,430
Balance, end of period	89,886	\$963,180	77,971	\$824,986

Accumulated Other Comprehensive Income:

	Nine months ended		Year ended	
	September 30, 2007		December 31, 2006	
Balance, beginning of period	\$-		—	
Fair value of derivative instruments on transition to new accounting standards, net of tax of \$1,349 (Note 1)	3,172		—	
Reclassification to net income in period, net of tax of \$1,088 (Note 1)	(2,559)		—	
Balance, end of period	\$613		—	

Cash Distributions

The Trust is required to make a distribution of distributable cash flow each calendar month, pursuant to the Trust Indenture. The distributable cash flow is defined as cash flow of the Trust less a discretionary amount, which the Trustee, upon recommendations of the Manager, considers it necessary to retain.

Per Unit Information

Basic net income per trust unit is calculated using the weighted average number of trust units outstanding. The calculation of diluted net income per trust unit excludes the convertible debentures as the units potentially issuable on the conversion of the convertible debentures are anti-dilutive for

the three and nine months ended September 30, 2007. Total weighted average trust units issuable on conversion of the convertible debentures and excluded from the diluted net income per trust unit calculation for the three and nine months ended September 30, 2007 were 2,639,752 and 889,587 respectively. As at September 30, 2007, the total convertible debentures outstanding were immediately convertible to 7,142,857 trust units.

10. COMMITMENTS

At September 30, 2007 the Trust had the following contractual obligations and commitments:

(\$000s)	2007	2008	2009	2010	2011
Office Lease ⁽¹⁾	697	3,206	3,206	2,939	—
Transportation	456	1,007	908	84	—
Processing Agreement ⁽²⁾	123	469	446	428	414
Drilling rigs ⁽³⁾	494	494	—	—	—
Retention bonus ⁽⁴⁾	-	644	—	—	—

⁽¹⁾ Represents the full amount of office lease commitments, including office space acquired with the Seneca acquisition, both base rent and operating costs, held by the Manager, of which the Trust is allocated a pro rata share (currently approximately 54 percent) of the expense on a monthly basis.

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

⁽³⁾ Represents the Trust's share of minimum payments required under drilling rig contracts held by NAL Resources.

⁽⁴⁾ Represents the Trust's share of the expected future payments under a staff retention program.

TRADING PERFORMANCE

Price (\$)	For the Quarter Ended			
	30-Sept-07	30-Jun-07	30-Sept-06	30-Jun-06
High	13.65	13.80	21.70	20.67
Low	11.52	11.45	16.14	18.26
Close	12.22	12.57	17.57	20.00
Volume	17,663,336	15,594,573	12,786,792	11,319,677

NAL Oil & Gas Trust is an open-end investment trust that generates distributions through the acquisition, development, production and marketing of oil, natural gas and natural gas liquids. The Trust owns high quality assets in Alberta, Saskatchewan and Ontario. Trust units trade on the Toronto Stock Exchange under the symbol "NAE.UN".

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