



BUILDING
opportunity
ON STRONG
performance

ANNUAL REPORT 07



Abbreviations

bbls	barrels	MMcf/d	million cubic feet per day
bbls/d	barrels per day	MMbtu	millions of British Thermal Units
boe	barrels of oil equivalent	D/CF	Debt to cash flow
boe/d	barrels of oil equivalent per day	P+P	Proved plus probable
Mbbl	thousands of barrels	Hz	Horizontal
Mboe	thousands of barrels of oil equivalent	\$MM	Million dollars
Mcf	thousand cubic feet	Cdn\$	Canadian dollars
Mcf/d	thousand cubic feet per day	US\$	US dollars
MMcf	million cubic feet	FX	foreign exchange

Conversion Factors

To Convert From

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
barrels	cubic metres	0.159
cubic metres	barrels	6.293
feet	metres	0.305
metres	feet	3.281
miles	kilometers	1.609
kilometers	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

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Photography by: Karl B. Staddon, John Gaucher
and Karey Bergh.

what
does
opportunity
and
performance
mean to NAL?





it's

building on a proven track record

NAL consistently delivers operating and financial performance for its unitholders. Since 1996, NAL has generated high netbacks from its core areas due to high quality crude oil and lower operating costs. Our ongoing focus on efficiency, optimization, and detailed cost management ensures we continue to generate value for our unitholders. NAL has the ability, the right people, and the right infrastructure in place to ensure the assets we add will enhance our current operations.



it's

leveraging our core assets

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NAL continues to enjoy strong core performance from our quality asset base, and our strong technical and operating teams continue to generate new opportunities. NAL operates core assets and infrastructure in southeast Saskatchewan and central Alberta, and is involved in higher impact non-operated areas of northeast British Columbia. NAL remains focused on leveraging its infrastructure and core assets to add volumes and other revenues. As a result, NAL expects an increased level of activity in 2008 in all three core areas.



it's
adding technical capability

NAL added experienced technical, operating, and financial personnel in 2007. This exceptional technical expertise enhances NAL's exploration and opportunity identification capabilities, which is essential in positioning NAL to become a dividend-paying oil and gas corporation by 2011. We plan to add additional capability and empower our teams so they can build on their success and continue to identify new opportunities.

Photo courtesy of Talisman Energy

it's

growing through strategic acquisitions

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NAL's acquisition of Seneca is a key step in our journey. This acquisition added an average of 4,400 boe/d over the last three months of 2007, 10.3 million boe of proved plus probable reserves and \$127 million in incremental tax pools. The transaction increased undeveloped land and growth opportunities in central Alberta and the new high impact core area of northeast British Columbia. We continue to be active in future acquisition analysis but remain selective and disciplined to ensure value added to our unitholders.

Keith Steeves
CFO & VP Finance



Marlon McDougall
VP Operations



it's

empowering the right people

NAL's teams work actively towards clearly defined goals and objectives while remaining accountable to each other and our unitholders. NAL's new management team has now spent a year working together and charting new courses for the organization. The team has set the direction and is continuing to work to ensure the right people are in place to deliver results. This focus has contributed to an open, learning and growing environment at NAL where new ideas are welcomed, support is offered and training provided.



The theme for the 2007 Annual Report captures management's vision of NAL's corporate direction - building opportunities to complement strong performance from our core areas.

Andrew Wiswell
President & CEO

President's Message

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2007 Performance

NAL was successful in achieving all of its key performance objectives for 2007. The Trust delivered strong operating and financial performance, added opportunities, improved reserve replacement, lowered finding and development costs, completed a strategic acquisition and maintained financial flexibility.

As to our total return performance, NAL was one of the top performers in the Trust sector with a 10.6 percent* total return, driven primarily by our positive operating performance and our consistent distributions throughout 2007.

*source: Thomson, incorporates reinvestment of distributions.

Looking back to 2007, we met or exceeded all of our key objectives and targets:

Objective	Target	2007 Performance
Deliver operating & financial performance	<ul style="list-style-type: none"> • Above original guidance • Improve F&D performance 	<ul style="list-style-type: none"> • Above original guidance • Positive reserves & F&D performance
Identify new core area opportunities	<ul style="list-style-type: none"> • Evaluate existing areas for new opportunities 	<ul style="list-style-type: none"> • New prospects & locations added in all core areas
Enhance reserves added & capital efficiency	<ul style="list-style-type: none"> • Grow reserves • Improve F&D performance 	<ul style="list-style-type: none"> • Replaced 234% of production • Delivered \$17.71 F&D cost per boe
Complete value added acquisition	<ul style="list-style-type: none"> • Accretive transaction/opportunity focused 	<ul style="list-style-type: none"> • Completed \$246 Million accretive Seneca acquisition/added significant gas opportunities
Maintain financial flexibility	<ul style="list-style-type: none"> • Retain competitive balance sheet, credit lines 	<ul style="list-style-type: none"> • Increased credit lines to \$400 million • Termed out \$100 million in convertible debentures • Increased tax pools by 41%
Build organizational capability	<ul style="list-style-type: none"> • Add experienced technical, prospecting & financial personnel 	<ul style="list-style-type: none"> • Added new geological/geophysical & financial expertise
Continue strong safety, environmental & community performance	<ul style="list-style-type: none"> • Sustain top quartile performance and stewardship reporting 	<ul style="list-style-type: none"> • Achieved targets & retained "top of mind attitude"

Future Direction and Outlook for 2008

As we look forward into 2008, NAL will focus on delivering top quartile performance, generating new attractive opportunities, and growing through acquisitions, while maintaining our financial capability. We are evaluating a variety of structural alternatives for the Trust post-2010 but the federal government is still developing details of the regulations for any transition. The most likely scenario would see NAL convert to a dividend-paying corporation as we approach 2011. Our 2008 plans and strategies are particularly focused on adding opportunities to deliver sustained production and reserve growth over the long term while maintaining distributions at current levels.

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What does building opportunity look like at NAL?

– It's building on a proven track record

NAL has a strong track record of delivering consistent operating and financial performance for its unitholders since its inception.

The Trust is well financed, conservatively managed and continues to deliver an attractive yield for investors.

We continue to generate high netbacks from our core areas due to our high quality crude oil and lower operating costs. Our ongoing focus on efficiency, optimization and detailed cost management has allowed us to maintain relatively low operating costs.

NAL performed well in 2007 and exited the year with a strong balance sheet and \$100 million in available lines of credit. Our debt to cash flow ratio also remains very attractive compared to our peers and with our positive bank relationships, we are positioned to continue to grow through ongoing acquisitions. With a strong financial partner in Manulife, we are able to maintain a stronger technical team and be more competitive in sizeable transactions.

NAL also continues to manage and uphold its reputation as a quality operator. Management and our staff take our corporate responsibility seriously and we are firmly committed to safety, the environment, and the communities where we operate. I encourage you to further explore NAL's award-winning track record of responsibility in our 2008 Stewardship Report.

– It's leveraging our core assets

NAL operates core assets and infrastructure in Western Canada concentrated in southeast Saskatchewan and central Alberta with higher impact non-operated areas in northeastern British Columbia.

In central Alberta, NAL experienced success in 2007 by evaluating the potential of multi-horizon drilling targets in the Mannville formation.

As a stacked opportunity, the Viking, Cardium, Ellerslie and Ostracod horizons provide a great deal of potential based on recent infill drilling and recompletion success in the Cardium and Ellerslie, NAL foresees increased activity in this region in 2008. We also enjoyed continued success in the Pine Creek region of west central Alberta. The Cardium and Cadomin formations offer future development potential for both oil and gas recovery and new land acquired from Seneca provides numerous exploration prospects for 2008.

As to our Saskatchewan operations, NAL is also very active in developing the Bakken formation – a prolific formation that is present over a large portion of southeastern Saskatchewan.

In 2007, NAL successfully used horizontal well completions and large sand-fracture completions in low permeability reservoirs to add significant new production.

NAL remains focused on leveraging infrastructure to add volumes and other revenues. Consistent with our commitment to facilities, we plan to expand the Nottingham gas plant in 2008 in order to increase natural gas recoveries and process NAL's and other operators' volumes.

– It's adding technical capability

NAL added experienced technical, operating, and financial personnel in 2007. This enhanced capability makes NAL more opportunity-driven and we plan to continue strengthening our structure to empower our technical teams to build on their success.

– It's growing through strategic acquisitions

The Seneca acquisition is a key step in NAL's journey. This acquisition came on the heels of strong performance in the first six months of 2007 and added an average of 4,400 boe/d over the last three months of 2007, 10.3 million boe of proved plus probable reserves and \$127 million in incremental tax pools. The transaction also added significant undeveloped land and growth opportunities in central Alberta and the new high impact core area of northeast British Columbia. As a result of the acquired production being 85 percent natural gas, NAL became equally weighted between liquids and natural gas.

We will continue to be active in future acquisition analysis but remain selective and disciplined to ensure value added for our unitholders.

– It's empowering the right people

At NAL, we work actively in teams at all levels toward clearly defined goals and objectives and we remain accountable to each other and our unitholders. NAL's new management team has spent more than a year working together and charting new courses for the organization.

The team has set the direction for the organization and is continuing to work to ensure an open, learning and growing environment at NAL where new ideas are welcomed, support is offered, and training provided.

This positive working environment will allow NAL to continue to attract and retain experienced and qualified professionals who bring with them experience and new ideas. The quality and commitment of our staff has truly driven positive 2007 performance and will continue to allow us to deliver our credible plans for 2008.

Summary

In closing, NAL's executive team extends sincere appreciation for the commitment, capability and performance delivered by our teams in 2007. We appreciate the positive input and support of the Board of Directors in working with management to enhance the business plans of the Trust in the new environment. We are confident we will continue to deliver strong performance and distributions for our unitholders and we look forward to reporting on our progress as we move through 2008.



Andrew B. Wiswell
President and CEO

2008 Guidance

On January 23, 2008, NAL provided guidance for full year 2008 with production volumes and funds from operations forecast to be higher than in 2007. The capital program will be consistent with 2007 spending levels while rig and service costs are expected to be lower. NAL has increased its inventory of opportunities significantly by adding new prospecting capability, broadening opportunities and extensions in our core areas, and working through the new prospects acquired in the Seneca acquisition. NAL expects to be able to maintain distributions assuming current commodity prices, and has an active hedging program which has locked in average prices above our base case forecast. The Trust's debt to cash flow ratios are expected to improve in 2008, and NAL has over \$100.0 million of available committed bank lines to take advantage of opportunities as they become available.

2008 Guidance

Average total production (boe/d)	23,000 – 24,000
Capital expenditures (\$ millions)	110 – 120
Operating costs (\$/boe)	9.50 – 9.80
G&A (\$/boe)	1.90 – 2.10

Sensitivity Analysis

In our January 23, 2008 press release outlining 2008 guidance, NAL provided a base and sensitivity case based upon different commodity price scenarios. We have updated the scenarios including production from the recent acquisition announced in February 2008 and adjusted the gas and exchange rate in the Sensitivity case.

Key Assumptions

	Base Case	Sensitivity Case
Production (boe/d)	24,000	24,000
WTI Oil Price (US\$/bbl)	80.00	90.00
AECO Natural Gas Price (Cdn\$/GJ)	6.50	7.50
Exchange Rate (Cdn/US)	1.00	1.00

2008 Pro Forma Financial Results

	Base Case*	Sensitivity Case*
Funds from Operations (\$MM)	267	298
Funds from Operations (\$ per unit)	\$2.85	\$3.18
Weighted average Units Outstanding (MM)	93.7	93.7
Debt / Cash Flow	1.2 / 1.6**	1.0 / 1.3**

* Includes realized hedging gains (losses).

** Including convertible debentures.

Impact on 2008 Funds from Operations*

	Change	Amount (000s)	Per Unit
Commodity Prices			
WTI oil (US\$/bbl)	\$ 1.00	\$ 3,000	\$ 0.03
AECO natural gas (Cdn\$/GJ)	\$ 0.10	\$ 2,300	\$ 0.02
Volume Changes			
Oil	100 bbl/d	\$ 1,800	\$ 0.02
Natural gas	1,000 Mcf/d	\$ 1,600	\$ 0.02
Rates			
Exchange Rate – Cdn\$/US\$	\$ 0.01	\$ 2,400	\$ 0.03
Interest Rate – Bank prime lending rate	1%	\$ 2,900	\$ 0.03

* Compared to base case.



Operations Overview

With capital expenditures of \$119.4 million in 2007, NAL added over 4,000 boe/d production and participated in a total of 126 gross wells (49.8 net). NAL's properties are located in Alberta, Saskatchewan, British Columbia and Ontario where we have year-round access to production infrastructure and oilfield services. The Trust has high working interests in these lands and operates more than 80 percent of its production.

In 2007, production was relatively balanced with crude oil and natural gas liquids, representing 55 percent, and natural gas, 45 percent of production. All of our oil production is light and medium gravity crude which attracts premium prices. NAL's most concentrated core areas are in central Alberta, which offers multi-zone potential, and southeast Saskatchewan, where NAL has substantially increased its land holdings. In 2007, new geological and geophysical expertise was added to NAL's staff, our technical teams identified new prospects, and locations were added in all core areas. Also, as a result of the acquisition of Seneca, NAL added a new natural gas focused core area in northeast British Columbia and added to its inventory of opportunities in Alberta.

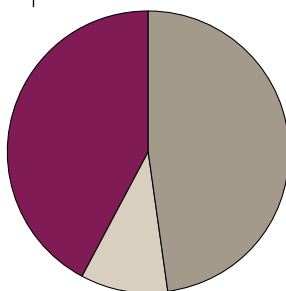
2008 Outlook

In 2008, NAL will augment its acquisition and development strategy with an organic approach to adding value by purchasing land, and pursuing new play concepts within our core areas. With the expertise of our technical teams, NAL will focus 55 percent of this year's capital on oil projects and 45 percent on natural gas opportunities.



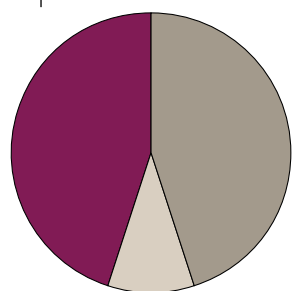
2006 Production Mix

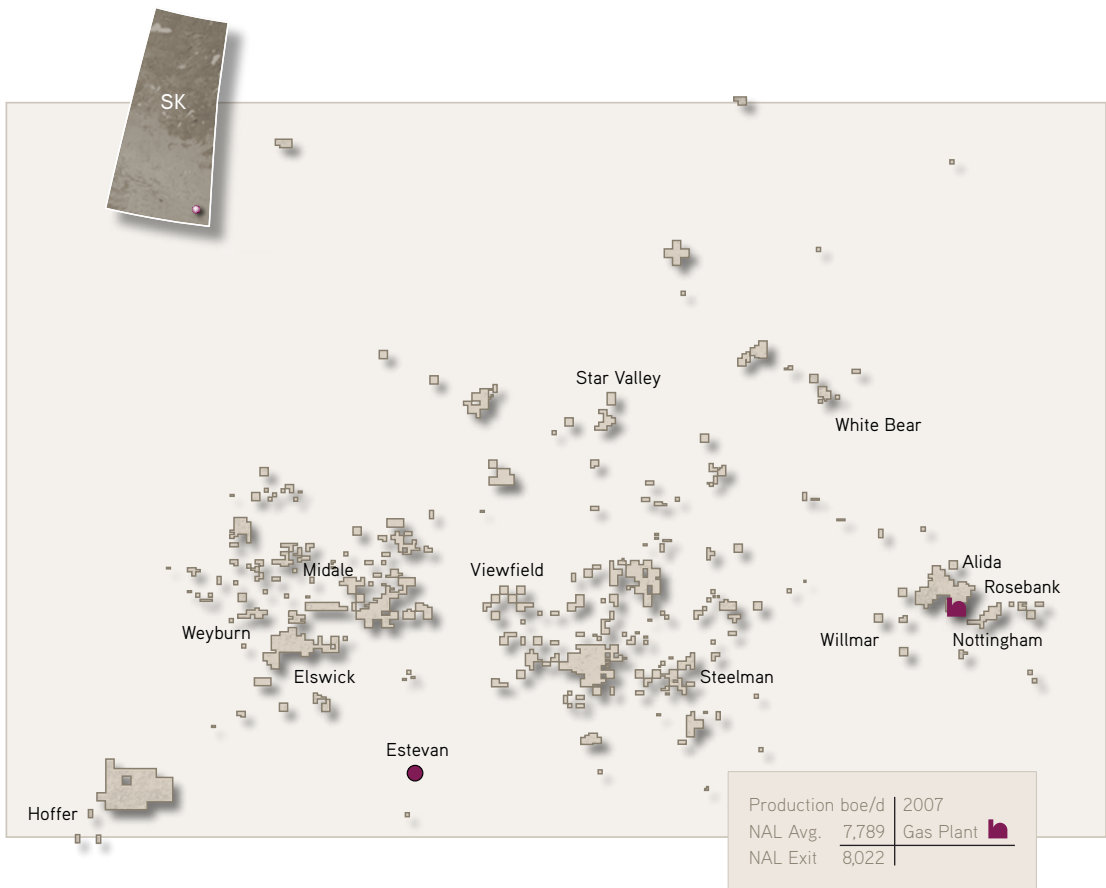
Crude Oil ● 48%
Natural Gas ● 42%
Natural Gas Liquids ● 10%



2007 Production Mix

Crude Oil ● 45%
Natural Gas ● 45%
Natural Gas Liquids ● 10%





Southeast Saskatchewan – Exploring New Horizons

In Saskatchewan, NAL continued its successful development program across several of its existing pools, bringing onstream in excess of 4,000 boe/d (2,000 boe/d net to the Trust). In addition to its development program, NAL tested several new play concepts on its land base, drilling a total of 46 gross wells in 2007.

NAL is excited about developing its Bakken assets, most significantly at Viewfield, in the heart of the Bakken fairway. Five wells were successfully drilled and completed with two wells delivering initial production of over 600 boe/d, clearly validating NAL’s multi-well development program for 2008.

NAL was also active in land acquisitions, purchasing 31,013 gross (15,531 net) acres of undeveloped land, including a block of 23,040 gross (11,520 net) acres of contiguous land in the Hoffer area. A large seismic program was conducted across the prospective Hoffer lands in the fourth quarter of 2007. Two vertical exploratory wells will be drilled to test the Hoffer prospect in 2008, which could create multiple long-term development opportunities.

A successful waterflood program initiated in the Rosebank pool in 2007 has offset declines and added incremental oil production and reserves with attractive economics. Further work on this waterflood program is anticipated for 2008.

NAL has drilled over 175 wells in southeast Saskatchewan in the last four years, gaining significant knowledge on many producing horizons. Applying this knowledge has allowed us to look at older fields and recognize new opportunities. Drilling efforts in the Steelman area resulted in two successful wells (>200 boe/d) in 2007, and four follow-up wells are planned for 2008.

NAL will continue to develop its productive core assets in Alida, Steelman, Nottingham, and Elswick, with more than 30 development wells planned for 2008. Following up on the Bakken success in Viewfield, NAL plans to drill another three development wells in this area, applying the technical expertise that has been gained to date. Six Bakken step out wells, with the potential of multiple development locations, are planned for 2008 and beyond.

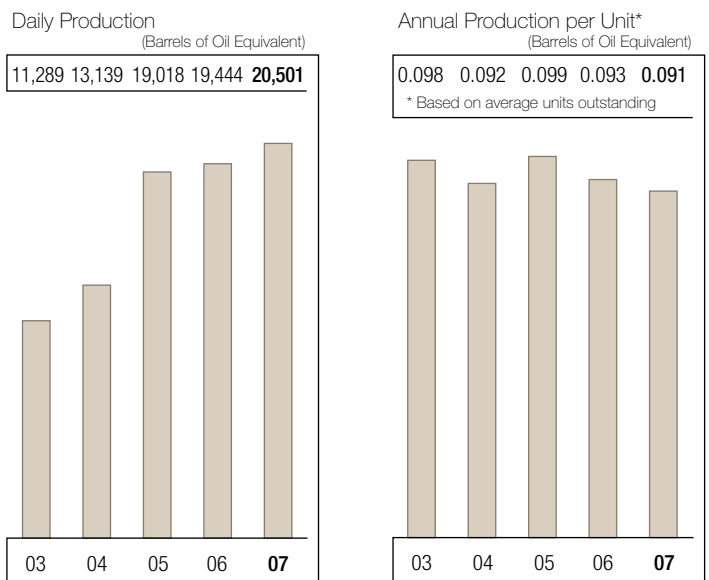
NAL also plans to expand its Nottingham gas plant to a processing capacity of 18 MMcf/d from an existing capacity of 13 MMcf/d. This expansion will allow NAL to handle its growing solution gas volumes, and process third party production to add incremental revenues over time.

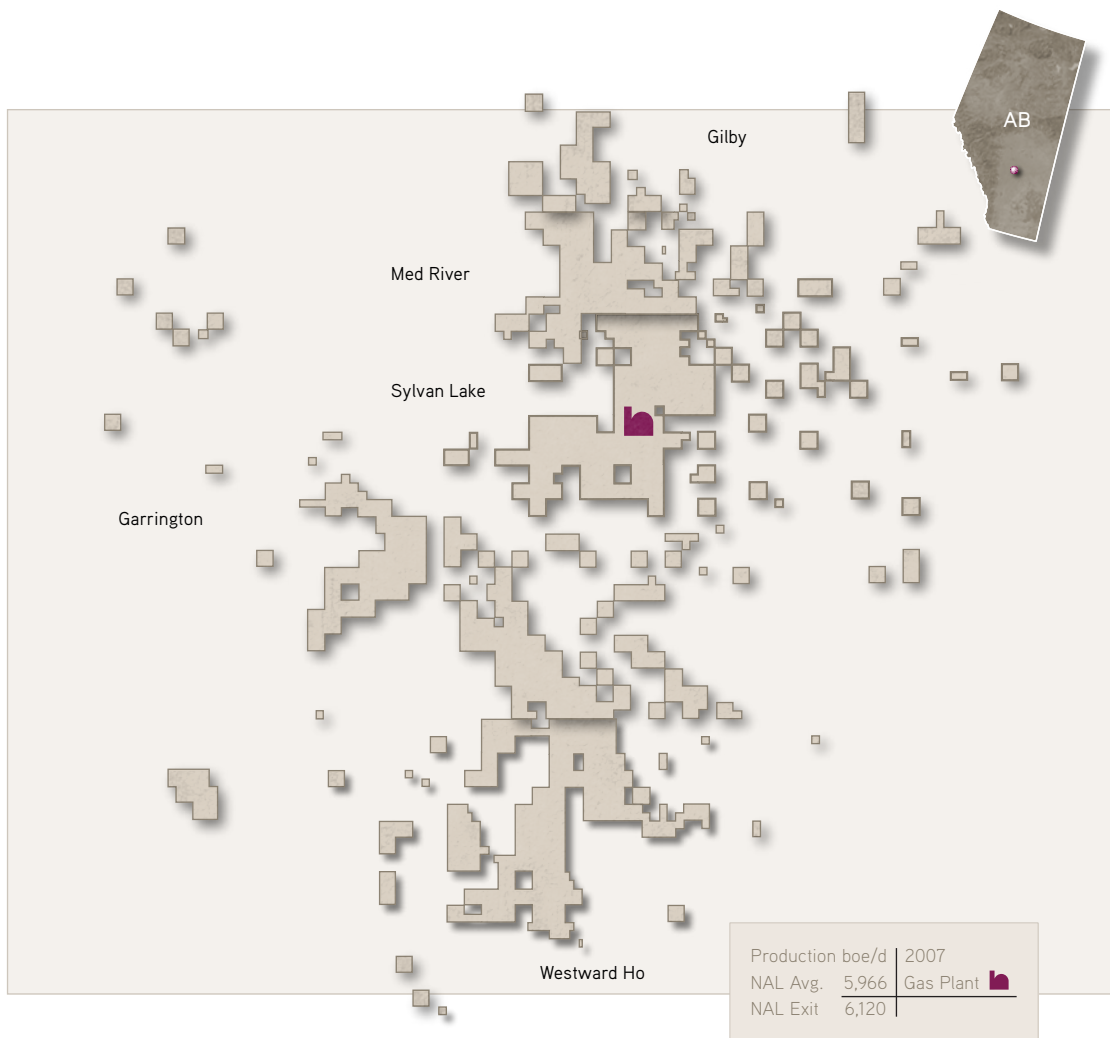
Work on the Elswick Super-Battery will continue in 2008 and will include Butane Blending Facilities, resulting in higher netbacks. A planned expansion of the oil handling side will also allow the tie-in of existing production from Elswick North and Midale South, which will reduce operating costs throughout this region, and allow for additional solution gas volumes to be captured and processed.

CO₂ Potential

NAL has reviewed a number of reservoirs for CO₂ potential and is continuing to advance opportunities in the Steelman, Alida, Nottingham, and Rosebank areas. Preliminary work suggests incremental recoveries of between five and 12 percent of Original Oil In Place (OOIP) in the Steelman area with Nottingham, Alida, and Rosebank offering similarly attractive opportunities.

Corporate Production Data

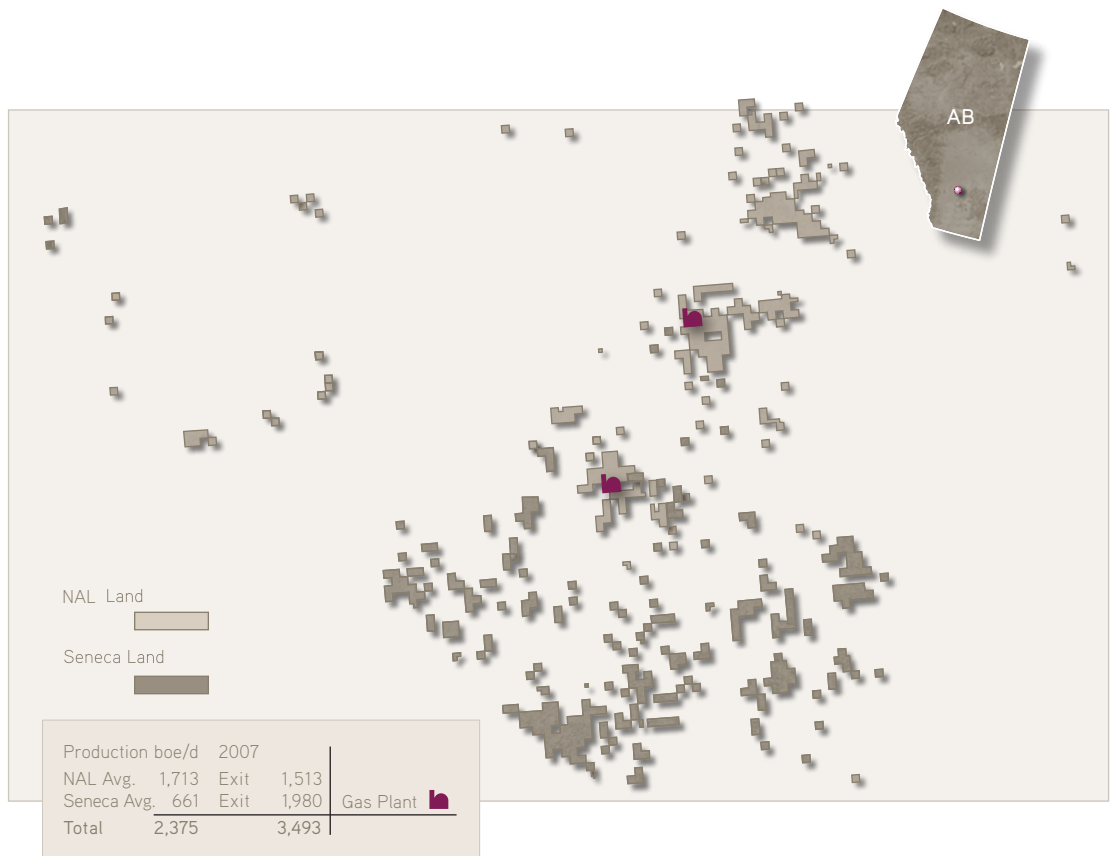




Sylvan Lake, Alberta – Chasing the Mannville

NAL experienced a great deal of success in this area in 2007, capturing multi-zone potential for both crude oil and liquids rich natural gas in the Mannville formation. Multiple producing horizons allowed us to add volumes and reserves from recompletions in existing well bores. NAL accomplished 17 (8 net) recompletions in the Glauconite, Cardium and Edmonton horizons to add incremental volumes and reserves. The success of these recompletions has further set up NAL’s drilling program and we forecast significant activity in this region for 2008.

NAL also executed a successful turnaround of its Sylvan Lake gas plant in 2007. It was accomplished under budget, on schedule, and without incident. NAL successfully re-routed production and kept volumes online during the turnaround due to our connections to other infrastructure in the area. NAL also completed de-bottlenecking in Westward Ho, by connecting three compressors to broaden our access to facilities, resulting in added flexibility, reduced downtime, and more efficient use of equipment.

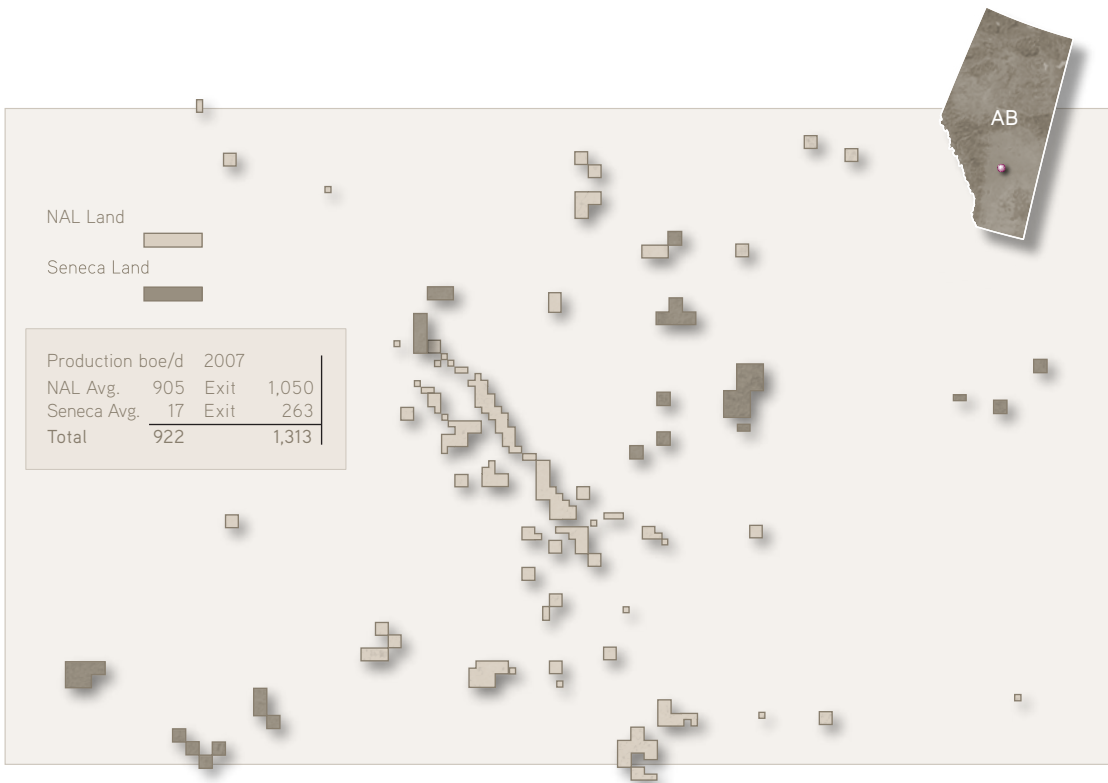


Central Alberta – Leveraging Re Completions

Numerous high value recompletion and reactivation projects in the Drumheller area delivered incremental volumes and attractive capital efficiency. Through the Seneca acquisition, NAL added to its existing land in this area, which produced a total of 3,493 boe/d in 2007. During the year, these activities added 250 boe/d for the area. In 2008, NAL is proposing a \$2.5 million expansion of the Stanmore waterflood by adding injectors to recover additional reserves, and more fluid handling capability by way of facilities to handle the additional production from new wells. In addition, the Trust will spend \$2 million targeting recompletions in the Mannville and Second White Specks formations in 2008.

Hanna

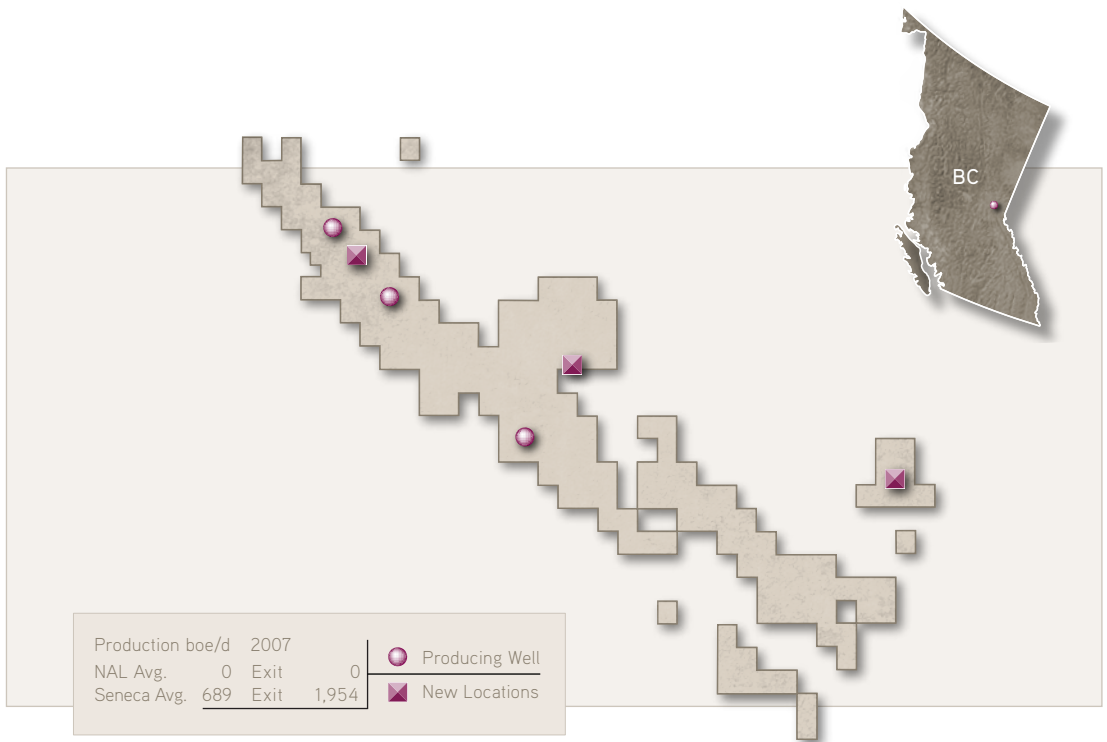
NAL continued to exploit the Mannville formation in Hanna in 2007. Two additional wells were drilled in this emerging play and both were successful. Four more wells are planned for 2008, which will further delineate the play.



Pine Creek, Alberta – It's All About the Cardium

In 2007, NAL experienced continued success by infill drilling and extending known trends in the Cardium formation. The area is defined by long linear pools that produce significant oil and gas volumes on a spacing of four wells per section. NAL has been focused on oil development in this area and successfully identified additional new pool development potential in 2007.

The Trust has ownership in a large contiguous land base that offers significant infilling drilling potential, and recent success in deeper gas targets has added multi-year exploitation opportunities for the Pine Creek area.



Monkman, British Columbia – Exploring High Impact Plays

With the purchase of Seneca, NAL added 129,800 (27,600 net) acres of undeveloped land in northeastern British Columbia. These properties are operated by Talisman Energy, an experienced operator in the area. These lands provide NAL with exposure to high impact gas exploration opportunities, with working interest ranging from 6.6 percent to 33 percent, and averaging 20 percent. Current production is 12.4 MMcf/d (net) sales from three wells.

NAL also acquired two wells, a-26-E and b-44-B, that were in the process of being drilled when the Seneca acquisition closed in August 2007.

The a-26-E well encountered two productive sheets in the Permian Belcourt formation. The lower sheet tested 30 MMcf/d of raw gas and the upper sheet tested 35 MMcf/d. NAL has a 20 percent working interest in the well and has forecast it to be onstream in April 2008 at approximately 27 MMcf/d raw or 22 MMcf/d sales gas, representing 700 boe/d net to NAL. Evaluation of the b-44-B well, in which NAL has an 8.55 percent interest, is currently underway.

To expand our opportunities in northeastern British Columbia, NAL entered into a land pooling arrangement that provides additional access to the Triassic as well as deeper Permian targets. Drilling operations commenced on the a-31-K well, in which NAL has a 10 percent working interest, in January 2008 and will be evaluated later in the year.

NAL also participated in a Crown land sale at the end of 2007 in which we successfully acquired 16,760 gross (1,967 net) acres of new lands. Total capital spending in 2007 on assets in northeastern British Columbia was \$4.2 million.

Oil and Gas Reserves

NAL's 2007 year end reserves were evaluated by McDaniel & Associates Consultants Ltd. ("McDaniels"), independent engineering consultants in Calgary, in accordance with National Instrument ("NI") 51-101. At December 31, 2007, the Trust's proved reserves totaled 49.6 million barrels of oil equivalent ("boe") and proved plus probable ("P+P") reserves amounted to 68.2 million boe.

The following tables summarize NAL's estimated reserves volumes and values using McDaniels price forecasts as of January 1, 2008. Gross reserves volumes are based on the Trust's working interests before deduction of royalties payable, and exclude any wells or properties in which NAL has only a royalty interest. Net reserves represent the Trust's working interest reserves after deducting royalties payable, plus royalty interest reserves.

Numbers in the tables which follow may not add exactly due to rounding. More details on NAL's year end reserves are available in our Annual Information Form.

Summary of Oil and Gas Reserves As at December 31, 2007

Forecast Prices and Costs

Reserves Category	Reserves							
	Light and Medium Oil		Natural Gas		Natural Gas Liquids		Total boe (6:1)	
	Gross (Mbbbl)	Net (Mbbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mbbbl)	Net (Mbbbl)
Proved								
Developed Producing	19,616	17,174	138,075	116,702	4,629	3,388	47,258	40,012
Developed Non-Producing	199	173	3,580	2,898	104	73	900	730
Undeveloped	595	547	4,691	3,965	83	60	1,459	1,268
Total Proved	20,410	17,894	146,347	123,565	4,816	3,522	49,618	42,010
Probable	7,242	6,354	56,244	46,553	1,979	1,428	18,595	15,540
Total Proved Plus Probable	27,652	24,248	202,590	170,118	6,795	4,949	68,212	57,550

Net Present Values of Future Net Revenue

Forecast Prices and Costs

Reserves Category	Before Income Taxes, Discounted at (percent/year)			
	0% (million \$)	5% (million \$)	10% (million \$)	15% (million \$)
Proved				
Developed Producing	1,487	1,181	988	856
Developed Non-Producing	28	21	17	14
Undeveloped	32	24	18	14
Total Proved	1,547	1,226	1,023	885
Probable	639	382	259	190
Total Proved Plus Probable	2,186	1,608	1,282	1,075

The table above shows the before-tax net present value ("NPV") of the Trust's reserves at various discount rates. It should not be assumed that the estimated future net revenue is representative of the fair market value of the properties of the Trust. There is no assurance that such price and cost assumptions will be attained and variances could be material.

A sensitivity case of the reserves evaluation was done to incorporate the impact of the proposed new Alberta royalty regime. Using McDaniel's published price forecasts of January 1, 2008, the sensitivity case showed a slight increase to the before-tax NPV discounted at 10 percent (from \$1,282 million to \$1,286 million) due to the benefit of reduced royalties on shallow gas wells.

Summary of Pricing and Inflation Rate Assumptions As at December 31, 2007

Forecast Prices and Costs

Year	Oil			Natural Gas AECO Spot Price (Cdn\$/MMBtu)	Natural Gas Liquids Edmonton Mix (Cdn\$/bbl)	Inflation Rates Percent/Year	Exchange Rate (US\$/Cdn)
	WTI Cushing Oklahoma (US\$/bbl)	Edmonton Par Price 40° API (Cdn\$/bbl)	Cromer Medium 29.3° API (Cdn\$/bbl)				
2008	90.00	89.00	78.20	6.80	61.60	2.0	1.000
2009	86.70	85.70	75.30	7.38	60.20	2.0	1.000
2010	83.20	82.20	72.20	7.38	58.00	2.0	1.000
2011	79.60	78.50	69.00	7.38	55.80	2.0	1.000
2012	78.50	77.40	68.00	7.49	55.20	2.0	1.000
2013	77.30	76.20	66.90	7.70	54.70	2.0	1.000
Thereafter*	+2%/yr	+2%/yr	+2%/yr	+3%/yr	+2%/yr	2.0	1.000

* Price escalation rates are approximate.

Reconciliation of Company Gross Reserves By Principal Product Type

Forecast Prices and Costs

Factors	Light and Medium Oil		Associated and Non-Associated Gas		Natural Gas Liquids		Total boe	
	Proved (Mbbbl)	Proved + Probable (Mbbbl)	Proved (MMcf)	Proved + Probable (MMcf)	Proved (Mbbbl)	Proved + Probable (Mbbbl)	Proved (Mboe)	Proved + Probable (Mboe)
December 31, 2006	18,291	26,494	109,580	152,626	4,250	6,282	40,804	58,214
Improved Recovery*	1,731	1,947	8,575	15,059	342	524	3,502	4,981
Technical Revisions	2,542	894	13,568	4,886	827	530	5,630	2,238
Acquisitions	1,242	1,714	34,616	50,011	152	213	7,164	10,262
Dispositions	0	0	0	0	0	0	0	0
Production	(3,396)	(3,396)	(19,992)	(19,992)	(754)	(754)	(7,483)	(7,483)
December 31, 2007	20,410	27,652	146,347	202,590	4,816	6,795	49,618	68,212

* Improved Recovery includes discoveries, extensions, infill drilling and well recompletions.

NET ASSET VALUE

(\$000s, except per unit data)	December 31, 2007		December 31, 2006	
	Using Forecast Prices ⁽⁴⁾		Using Forecast Prices ⁽⁵⁾	
Proved plus probable reserves (before tax, discounted at 10%)	1,282,473		1,017,713	
Undeveloped land and seismic ⁽¹⁾	83,758		47,800	
Working capital (deficiency) ⁽²⁾	(15,429)		(2,276)	
Long-term debt	(368,254)		(221,790)	
Asset retirement obligation ⁽³⁾	(55,986)		(34,191)	
Net asset value	926,562		807,256	
Units outstanding (000s)	90,494		77,971	
NAV per unit	\$ 10.24		\$ 10.35	

(1) Internal estimate.

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

(3) The Asset Retirement Obligation ("ARO") is calculated based on the same methodology that was used to calculate the ARO on NAL's year-end financial statements, with two exceptions. Future expected ARO costs are discounted at 10 percent and a deduction is made for abandonment costs incorporated in the value of the proved plus probable reserves. The balance on the year end balance sheets, \$89.6 million for 2007 and \$65.6 million for 2006, when discounted at 10 percent, results in total discounted ARO of \$75.1 million and \$54.0 million, at the respective balance sheet dates. These balances are further reduced by \$19.1 million and \$19.8 million, respectively, relating to abandonment costs incorporated in the reserves value.

(4) McDaniels price forecasts as of January 1, 2008.

(5) McDaniels price forecasts as of January 1, 2007.

FINDING, DEVELOPMENT AND ACQUISITION COSTS

Finding and Development (F&D) costs are reported excluding the effects of acquisitions and dispositions, but including changes in future development costs as per NI 51-101 guidelines. The aggregate of the development costs incurred during the year and the change in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year. As such, we provide a three-year weighted average as an indicator of the longer-term capital effectiveness as it relates to reserves development.

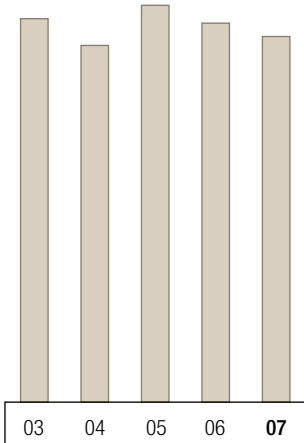
F&D (\$/boe)	2007	3 year weighted average
Proved	\$ 13.99	\$ 17.87
Proved + Probable	\$ 17.71	\$ 24.89

Finding, Development and Acquisition (FD&A) costs include the effects of properties acquired or disposed during the year. During 2007, NAL completed the acquisition of Seneca along with some minor properties in Alberta. There were no property dispositions done during the year.

FD&A (\$/boe)	2007	3 year weighted average
Proved	\$ 23.20	\$ 21.79
Proved + Probable	\$ 21.67	\$ 19.24

Reserve Life Index
Proved + Probable Reserves (Years)

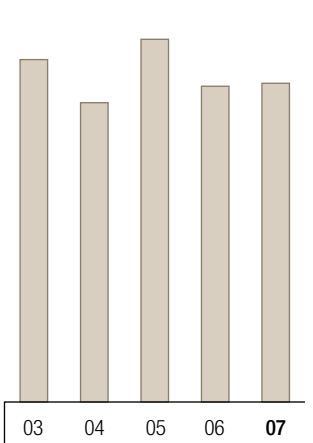
8.6	8.0	8.9	8.5	8.2
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Proved + Probable Reserves/Unit*
(Barrels of Oil Equivalent)

0.810	0.708	0.858	0.747	0.754
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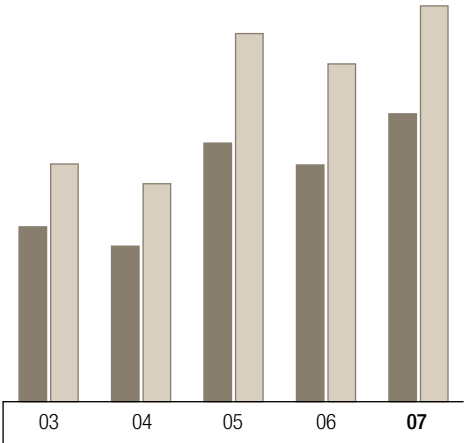
* Based on units outstanding at year-end



Reserves (Mboe)

■ Proved ■ Proved + Probable

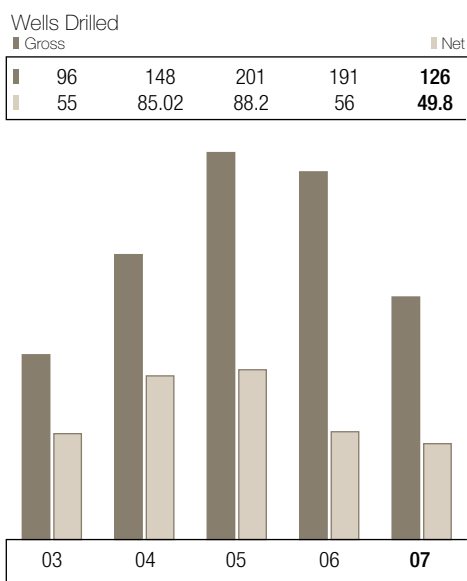
30,139	26,801	44,566	40,804	49,618
40,967	37,565	63,442	58,214	68,212



DRILLING

In 2007, NAL drilled 126 gross (49.8 net) wells versus 191 gross (87.6 net) wells in 2006. Drilling of shallow gas and coalbed methane wells was deferred because of low natural gas prices. At year end 2007, the Trust had interests in approximately 6,560 gross (1,841.3 net) producing and non-producing oil and gas wells.

Wells Drilled	2007		2006	
	Gross	Net	Gross	Net
Oil	80	31.05	71	27.70
Gas	46	18.75	110	57.21
Service	0	0.00	7	2.00
Dry	0	0.00	3	0.64
Total	126	49.80	191	87.55
Working Interest		39.5%		45.8%



LAND

The acquisition of Seneca Energy Canada Inc. in 2007 added significantly to NAL's undeveloped land base in Western Canada. The Trust also has a 20 percent working interest (non-operated) in the Lake Erie, Ontario natural gas project. Its average working interest in Western Canada undeveloped lands is 46.1 percent.

Undeveloped Lands, Acres	2007			2006		
	Gross	Net	WI	Gross	Net	WI
Alberta	302,259	168,426	55.7%	206,136	89,417	43.4%
Saskatchewan	90,057	46,117	51.2%	85,502	43,499	50.9%
British Columbia	127,153	25,109	19.7%	0	0	-
Ontario	325,764	64,827	19.9%	362,733	73,000	20.1%
Total	845,232	304,479	36.0%	654,371	205,916	31.5%

how
does NAL
sustain
performance?





we

practice strong corporate governance

NAL's independent Board of Directors and management team are committed to the comprehensive principles of good governance and employ a variety of policies, programs, and practices to ensure compliance and accountability. The Board reviews, approves, and provides guidance on the Trust's strategic plan and monitors its implementation. Board members seek ongoing assurance that internal control and management information systems are in place and operating effectively.



we

take responsibility and commit to Stewardship

26

NAL remains responsible and committed to safety and the environment, and continues to manage and uphold its reputation as a quality operator. NAL fully supports the Canadian Association of Petroleum Producers (CAPP) Stewardship initiative, which focuses on continuous improvement and transparent reporting of environmental, health, safety, and social performance. NAL has achieved Platinum status, the highest level, of Stewardship reporting since 2003.



We
actively participate in our communities

NAL consistently supports the communities it operates in and strives to build mutually beneficial partnerships based on trust, respect, and accountability. We eagerly engage all stakeholders in our endeavours and our enthusiastic staff continually volunteer and fundraise for a number of causes in Alberta and Saskatchewan. NAL also actively participates in a number of synergy groups and is committed to being a contributing member of these groups in the community.



we

attract and retain capable staff

28

NAL continues to attract experienced and qualified professionals who are encouraged to take on new challenges and to implement their innovative ideas. New initiatives and unique contributions are recognized and rewarded, and ongoing training and support is provided so that staff can continue to learn and grow both personally and professionally.

The background of the top half of the page is a blue-tinted photograph. It shows a close-up of a metal paperclip on the left side, which is slightly out of focus. To the right, there is a document with some text, including the word 'AMOUNT' at the top right, followed by '1.1', '1.2', and a list of '(a)' items. The overall aesthetic is professional and financial.

we

maintain a strong financial position

29

NAL continued to maintain a strong balance sheet and increased credit lines in 2007. We are positioned to continue to grow through acquisitions and with a strong financial position and a strategic partner in Manulife, we are able to be more competitive in larger transactions.

Governance

The Board of Directors and senior management of NAL consider good corporate governance to be central to the effective operation of the Trust and a critical factor in defining our integrity, sustaining relationships with unitholders and employees and in achieving business success. NAL's independent Board of Directors and management team are committed to the comprehensive principles of good governance and we employ a variety of policies, programs, and practices to ensure compliance and accountability. The corporate governance structure of the Trust is not the same as that of a corporation. The Trust and its subsidiaries are managed by the Manager. However, NAL's Board of Directors is responsible for the overall governance of the Trust and its subsidiaries and is therefore, in effect, responsible for the overall stewardship and governance of the Trust. The Board reviews, approves, and provides guidance on the Trust's strategic plan and it monitors its implementation. The Board, which meets a minimum of five times per year, also identifies the Trust's principal risks and seeks assurance that all internal control and management information systems are in place and operating effectively. For complete information on our corporate governance practices and our committees, please refer to our 2008 Management Information Circular and Proxy Statement.

The Board of Directors is of the view that its approach to corporate governance is appropriate and complies with the objectives and guidelines relating to corporate governance set forth in National Policy 58-201 – Corporate Governance Guidelines. NAL has, among other things, a majority of independent directors, a written board mandate, written position descriptions, a code of business conduct and ethics and a nominating committee. The directors also complete regular Board assessments. The Board does not have a compensation committee, as the Trust does not set the compensation of the senior management of the Manager. It does, however, reimburse the Manager for all general and administrative expenses incurred by the Manager for and on behalf of the Trust, which includes a portion of the aggregate compensation paid to the senior management of the Manager.

In developing its corporate governance practices we also consider, and adopt as appropriate, the corporate governance guidelines developed by the Canadian Coalition for Good Governance (CCGG). In accordance with these guidelines, NAL has a majority of independent directors, a separate Chair and Chief Executive Officer, and a written Board mandate and charters for the Audit, Reserves and Nominating committees, which are available on our website at www.nal.ca, together with our Disclosure Policy, and a link to our independently operated Ethics Reporting Program. A detailed statement of corporate governance practices is contained in the management information circular that is mailed annually to unitholders.

NAL's Board of Directors continues to monitor ongoing trends in governance as well as third party assessments and evaluations. We will remain focused on continuous improvement as we move forward.

Environment, Health and Safety

Environment

NAL continues to focus on environmentally responsible practices throughout its operations. From spills, to waste, to land reclamation - NAL monitors, tracks, and reports on some 20 other environmental measures to gauge our operations and business performance. These measures are used to identify areas for improvement that we can incorporate into our planning cycle and are used to educate our staff on important environmental issues. Key initiatives in 2007 are profiled here.

Greenhouse Gas Emissions

Greenhouse gas (GHG) emissions continue to be of concern to stakeholders. NAL has established many specific internal practices for minimizing GHG emissions and has been voluntarily submitting its action plan to the Canadian Standards Association's Canadian GHG Voluntary Challenge Registry since 2002. In 2007, NAL maintained its Gold Level reporting status, the highest evaluation level achievable. NAL provides opportunities for individual employees to reduce GHG emissions at work through specific training on energy and emissions management. A few of our internal practices include:

- Using energy efficient equipment – from lighting to lean burn engines
- Assigning costs to fuel gas use, flaring, and venting when calculating project economics
- Installing vapour recovery units to capture vapours from tanks

A total of 58 GHG reduction initiatives were implemented at NAL in 2007, resulting in improved efficiencies and an estimated reduction of 21,367 CO₂E tonnes of greenhouse gas emissions.

Water

Fresh water is a precious and increasingly scarce resource and its use among competing interests is an issue of concern to a wide range of stakeholders. At NAL we are conscious of this reality and use only that which is required. NAL uses only a small portion of the allotted surface water and groundwater licensed to us by Alberta Environment. The company has a mandate to reduce fresh water usage at our facilities and uses produced water whenever possible. Of our industrial water use in Alberta, for instance, 93 percent is recycled. NAL has decreased its overall fresh water usage by 65 percent over the last 10 years.

To read more about NAL's environmental initiatives in 2007, refer to our Stewardship Report, which is available online at www.nal.ca.



Safety

Safety is an attitude at NAL that involves beliefs, values, and a disposition to act in a certain way to ensure that everyone can conduct their business activity in a safe manner.

- Participation, commitment and improvement form the basis for NAL's successful safety management system.
- All staff and contractors play a part in ensuring NAL's safety management system proactively protects people.
- We are accountable to each other, to our contractors, our service companies, and the public.

NAL's management team actively promotes a culture of safety and our staff and contractors embrace our policies and procedures. Our safety awards program also encourages staff and contract personnel to better their individual safety performance. A total of 539 safety awards were handed out in 2007 to staff and contractors.

NAL continuously monitors its safety program and participates in yearly safety audits. We set annual safety priorities and regularly discuss opportunities for improvement. In 2007, NAL achieved an overall external Certificate of Recognition (COR) audit score of 96 percent. Since 2000, NAL has routinely achieved a grade of 80 percent or better. In 2007, we continued to reduce the contractor Lost Time Incidents (LTI) frequency rate. Since 2001, NAL has seen an 84 percent reduction in contractor LTI despite NAL's continuous growth.

NAL maintains a safe work environment in communities where we operate by assessing hazards, reporting incidents and implementing precautionary measures on every site. We also have extensive Emergency Response Plans that prescribe what measures will be taken to actively protect our people, the public, and the environment, should an emergency situation occur.

Our focus on safety has helped us become a recognized safety leader in the oil and gas industry and NAL's excellent injury prevention track record and high safety standards have earned us the reputation of being a safe and trustworthy company in the communities where we operate.

NAL subscribes to the Canadian Association of Petroleum Producers (CAPP) Stewardship Initiative. NAL fully supports this reporting framework, which focuses on continuous improvement and transparent reporting of environmental, health, safety, and social performance. NAL has achieved Platinum status, the highest level, in Stewardship reporting since 2003. A complete copy of our Stewardship Report and more news on our environmental, health, safety, and community engagement initiatives is available online at www.nal.ca.



Community Involvement

NAL is committed to building mutually beneficial partnerships based on trust, respect, and accountability, and we strive to involve local government, industry regulators, landowners, and the greater community in our endeavours.

NAL consistently supports the communities it operates in by sponsoring and donating to community initiatives. Staff is committed to volunteering and fundraising for a number of causes in Alberta and southeastern Saskatchewan. The Trust supports numerous community groups and events in an effort to build positive relationships with stakeholders. NAL also donates extensively in communities where it has operations. Each field office decides where support will be directed. Through its field offices, NAL employees support numerous organizations at the local level, including local youth hockey teams, 4-H clubs, hospitals, various sports clubs, family centres, schools, and libraries.

NAL promotes volunteerism and supports community development. For the last 15 years, NAL has actively participated in United Way campaigns, and in 2007 received a second Award of Excellence for companies with fewer than 500 employees. The award recognizes outstanding organizations and their employees who have demonstrated a minimum three-year history of comprehensive employee campaigns, which include exceptional commitment and leadership. In 2007, 96 percent of our staff participated in our Calgary campaign. We increased our participation in the community and we raised a total of \$164,418 for the United Way – 19 percent above target and a 25 percent increase over the previous year.

Working together toward common goals often achieves better results than working alone. A positive example of this principle is NAL's active participation in the Sindre Petroleum Operator's Group (SPOG). Members of the group include representatives from 30 oil and gas companies, 15 community groups in the Sindre/Caroline area and the Energy Resources Conservation Board. NAL joined SPOG in 2005 after acquiring property in the Sindre area and is committed to being a contributing member of both the group and the community. One of SPOG's biggest events is the annual Neighbour's Day. NAL has participated every year since 2005 and has donated both time and money to help make the event possible.

NAL also actively participates in the Canadian Association of Petroleum Producers (CAPP) Energy in Action initiative. This year, our staff helped teach Midale Central School students in Midale, Saskatchewan about the meaning of Stewardship and how the term encompasses environmental protection, community enhancement, and safety at home and at work.



NAL promotes volunteerism and supports community development. Throughout the year, staff participate in several Days of Caring (shown above) in an effort to build and maintain positive relationships in the communities where NAL operates.

**ENERGY IN
ACTION**



United Way
of Calgary and Area

BUILDING STRONGER COMMUNITIES





Human Resources

A. Brent Grebinski

Delivering operating and financial performance

Brent started with NAL four years ago as an exploitation engineer in the Saskatchewan Business Unit. Today, he is the Alberta Business Unit Manager. Under his lead, his business unit successfully executed plans, delivering strong operating and financial success in 2007.

B. Alex Tworo

Evaluating new core area opportunities

Alex joined NAL in June of 2007 as Manager, Geosciences. Since his arrival Alex has played a key role in developing new prospects and activity with our business units on our land base in our core areas. Alex provides technical support, evaluates all company-wide geological and geophysical projects, and makes recommendations to management. He also provides geological support for our Acquisitions and Development team.

C. Cory Bergh

Completing value-added acquisitions

In his eight months as Manager, Financial Planning & Analysis, Cory has been involved with evaluating and completing acquisitions – most significantly the Seneca acquisition in 2007. His financial analysis in mergers and acquisitions ensures transactions add value to the Trust. Throughout the year, he is also involved in planning, budgeting, forecasting and valuation analysis.

D. Tracy Wood

Maintaining financial flexibility

As NAL's Controller, Tracy is responsible for financial accounting and reporting. When she is not finalizing monthly and year end results, she is implementing new financial systems and processes to ensure that NAL retains its strong adherence to financial reporting and controls.

E. Angèle Mullins

Building organizational capability

For the last 11 years, Angèle has been involved in all aspects of Human Resources. As NAL's Director, Human Resources & Administration she ensures our workforce is ready and capable to deliver strong performance. With support from her team and management, she has been instrumental in attracting new people to the company and in adding experienced technical and financial expertise. She is also responsible for training and development, compensation, facilities, and office services.

F. Keith Keck

Continuing strong safety, environmental and community performance

Keith has been involved with NAL for seven years. Today, as Coordinator, Health and Safety, Keith has played a major role in NAL's ability to sustain top quartile safety performance and Stewardship reporting. He has achieved these results through developing, implementing, and evaluating NAL's comprehensive safety program. His involvement in several industry initiatives and his commitment to staff training and development has helped NAL achieve excellent safety performance and ensure an ongoing attitude of improvement.

Management's Discussion & Analysis

The following discussion and analysis ("MD&A") should be read in conjunction with the audited consolidated financial statements for the years ended December 31, 2007 and December 31, 2006 of NAL Oil & Gas Trust ("NAL" or the "Trust"). It contains information and opinions on the Trust's future outlook based on currently available information. All amounts are reported in Canadian dollars, unless otherwise stated. Where applicable, natural gas has been converted to barrels of oil equivalent ("boe") based on a ratio of six thousand cubic feet of natural gas to one barrel of oil. The boe rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. Use of boe in isolation may be misleading.

Non-GAAP Financial Measures

Throughout this discussion and analysis, management uses the terms funds from operations, funds from operations per unit, payout ratio, net debt to trailing 12 month cash flow, operating netback and cash flow netback. These are considered useful supplemental measures as they provide an indication of the results generated by the Trust's principal business activities. Management uses the terms to facilitate the understanding of the results of operations 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. Net debt is defined as bank debt, plus convertible debentures at face value, plus working capital, excluding derivative contracts and future income tax balances.

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

	2007	2006
Cash flow from operating activities	215,364	238,445
Add back change in non-cash working capital	3,381	(18,669)
Funds from operations	218,745	219,776

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 addition, statements relating to "reserves" or "resources" are forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities estimated and can be profitably produced in the future.

With respect to forward-looking statements contained in this MD&A, we have made assumptions regarding, among other things: future oil and gas prices; future capital expenditure levels; future oil and natural gas production levels; future exchange rates; the amount of future cash distributions that we intend to pay; the cost of expanding our property holdings; our ability to obtain equipment in a timely manner to carry out development activities; our ability to market our oil and natural gas successfully to current and new customers; the impact of increasing competition; our ability to obtain financing on acceptable terms, future tax treatment of the Trust; and our ability to add production and reserves through our development and exploitation activities.

Although NAL believes that the expectations reflected in the forward-looking information contained in the MD&A, and the 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 government's review; changes in tax laws; the 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 Trust's current Annual Information Form and MD&A for the year ended December 31, 2007.

NAL cautions that the foregoing list of factors that may affect future results is not exhaustive. The forward-looking information contained in the MD&A is made as of the date of this MD&A, 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 \$245.7 million including costs of \$0.6 million. The acquisition added 10.3 million boe of P+P 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 trust unit for proceeds of \$125 million (\$117.9 million net of issue costs), \$100 million in 6.75 percent convertible extendible unsecured subordinated debentures (\$96 million net of issue costs), and \$31.8 million of bank debt.

Exploration & Development Activities

The Trust spent \$95.3 million on drilling in 2007 versus \$87.9 million in 2006, plus another \$10.0 million on plant and facilities construction, and \$6.0 million on land and seismic data acquisition.

The Trust participated in the drilling of 126 gross (49.8 net) wells during the year, compared to 191 gross (87.6 net) in 2006. Drilling for shallow gas in Lake Erie, Ontario and the Lacombe, Alberta areas was deferred due to low natural gas prices.

Historically, NAL's assets have been concentrated in southeast Saskatchewan and central Alberta, while the purchase of Seneca in 2007 added a new core area at Monkman in northeast British Columbia. These areas are accessible year-round and are well serviced by both production infrastructure and oilfield services.

2007 Full Year Drilling Activity

	Crude Oil		Natural Gas		Service Wells		Dry & Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Operated wells	64	29.50	20	14.40	-	-	-	-	84	43.90
Non-operated wells	16	1.55	26	4.35	-	-	-	-	42	5.90
Total wells drilled	80	31.05	46	18.75	-	-	-	-	126	49.80

Southeast Saskatchewan

NAL drilled 46 wells in southeast Saskatchewan in 2007, testing new exploration play concepts and adding over 2,000 boe/d of production net to the Trust. Five of those wells were drilled to test the Bakken formation in the Viewfield area, and results exceeded expectations. NAL was also active in land acquisition, purchasing 31,013 gross acres (15,531 net) of undeveloped land, including a block of 23,040 gross (11,520 net) acres of contiguous land in the Hoffer area.

Central Alberta

Through the purchase of Seneca, NAL added significant new land holdings adjacent to its properties in the Brent, Hanna and Provost areas. During the year, the Trust completed a number of cost-efficient recompletion projects in the Drumheller area delivering attractive returns and capital efficiency. The Trust now produces 2,050 boe/d in the Drumheller area (as of December 2007).

Sylvan Lake, Alberta

NAL completed a successful turnaround of its Sylvan Lake gas plant in 2007 with minimal impact on production volumes. Immediately south of Sylvan Lake in the Garrington and Westward Ho areas, the Trust enjoyed success from the drilling of both crude oil and natural gas wells in the Mannville formation. A total of 17 wells were recompleted in the Glauconite, Cardium and Edmonton horizons.

Pine Creek, Alberta

NAL enjoyed continued success drilling infill wells in the Cardium formation in the Pine Creek area of west central Alberta. The Trust participated in a deep, Devonian exploration well late in the year, and that well is expected to be put on-stream as a natural gas producer at the beginning of the second quarter of 2008.

Monkman, British Columbia

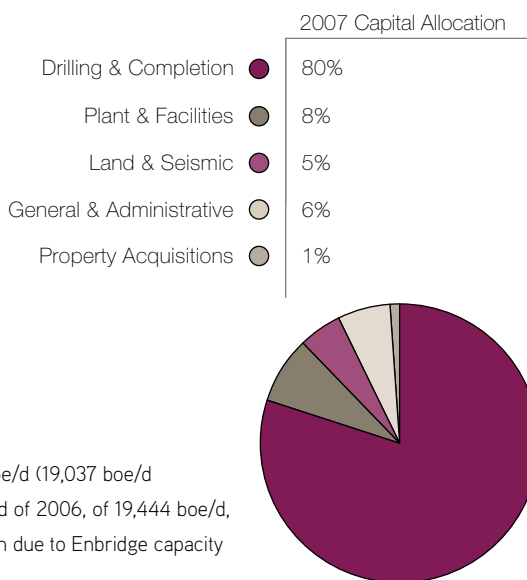
Through the purchase of Seneca, NAL added a large block of contiguous land in the Monkman area of northeast British Columbia. There were already three natural gas wells on the property producing a combined 12.4 million cubic feet of gas or 2,060 boe/d net to the Trust. During the year NAL participated in the drilling of two additional deep tests, at 20 percent and 8.5 percent working interests respectively, both of which were being evaluated at year end. In December 2007, NAL bought interests in an additional 16,760 gross (1,967 net) acres of exploratory acreage at the provincial Crown sale.

Capital Expenditures

Capital expenditures for the year ended December 31, 2007 totaled \$119.4 million as compared to \$124.0 million for the same period in 2006. Included in capital expenditures is \$8.7 million relating to the Seneca properties for 2007.

Capital Expenditures (\$000s)

	2007	2006
Drilling, completion and production equipment	95,327	87,901
Plant and facilities	9,988	14,598
Seismic	708	2,628
Land	5,330	7,730
Total exploitation and development	111,353	112,857
Office equipment	1,297	4,080
Capitalized G&A	4,486	4,275
Capitalized unit-based compensation	875	1,659
Total other capital	6,658	10,014
Property acquisitions (dispositions), net	1,423	1,171
Total capitalized expenditures	119,434	124,042



Production

For the year ended December 31, 2007, production of 20,501 boe/d (19,037 boe/d excluding Seneca) exceeded production in the comparable period of 2006, of 19,444 boe/d, by five percent. During 2007, NAL did not experience any shut-in due to Enbridge capacity constraints although trucking volume has increased.

Average Daily Production Volumes

	2007	2006
Oil (bbl/d)	9,305	9,367
Natural gas (Mcf/d)	54,773	48,804
NGLs (bbl/d)	2,067	1,944
Oil equivalent (boe/d)	20,501	19,444

Oil and natural gas liquids totaled 55 percent of production in 2007 with natural gas increasing to 45 percent due to the Seneca acquisition.

Production Weighting

	2007	2006
Oil	45%	48%
Natural gas	45%	42%
NGLs	10%	10%

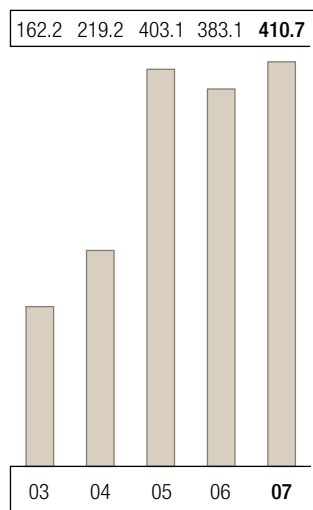
Revenue

Gross revenue from oil, natural gas and natural gas liquids, after transportation costs, totaled \$410.6 million for 2007, an increase of seven percent from 2006. This increase is attributable to a five percent increase in production and a two percent increase in the average price per boe. Compared to 2006, average commodity prices increased by two percent due to higher crude oil and natural gas liquids prices.

Revenue	2007	2006
Revenue ⁽¹⁾ (\$000s)	410,647	383,077
\$/boe	54.88	53.97

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

Revenue (\$ millions)



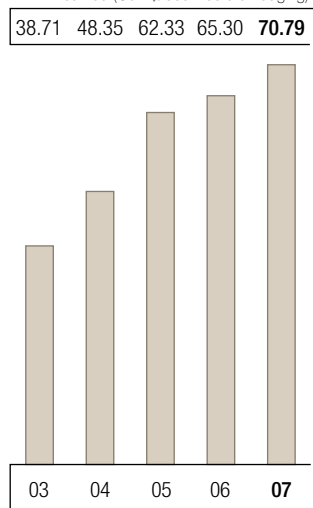
Oil Marketing

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

NAL’s average Canadian crude oil price per barrel, net of transportation costs, was \$70.79/bbl for 2007 compared to \$65.30/bbl for 2006. The eight percent increase in realized price, year over year, was driven by a nine percent increase in WTI (US\$72.30 versus US\$66.22), a four percent increase in differentials, offset by a five percent decrease in the exchange rate. In addition, NAL’s crude differentials compared to WTI priced in Canadian dollars increased realized prices.

For the year ended December 31, 2007 NAL’s realized oil price was 91 percent of WTI in Canadian dollars as compared to 87 percent in 2006. The increase in 2007 resulted from a narrower differential between WTI and Edmonton and Cromer posted prices, due to greater demand for light crude in Western Canada in that time frame.

Average Oil Price
Realized (Cdn \$/boe - before hedging)



Natural gas liquids pricing averaged \$50.82/bbl, four percent higher than the \$48.70 realized in 2006.

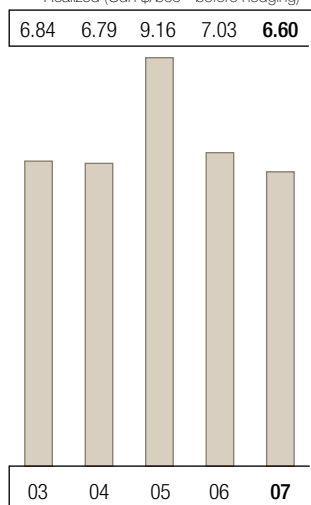
Natural Gas Marketing

Approximately 77 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 23 percent tied to NYMEX or other indexed referenced prices.

Lake Erie production accounted for seven percent of the Trust's natural gas production in 2007, compared to eight percent in 2006. The decrease was attributable to the gas weighted Seneca acquisition.

For the year ended December 31, 2007, the Trust's natural gas sales averaged \$6.60/Mcf compared to \$7.03/Mcf in 2006, a decrease of six percent. The decrease is attributable to a two percent decrease in the benchmark AECO prices and to marketing a portion of gas based on the monthly AECO, which decreased five percent year over year. During 2007, the spread between the spot and monthly AECO prices was \$0.17/Mcf compared to \$0.42/Mcf for 2006.

Average Natural Gas Price
Realized (Cdn \$/boe - before hedging)



Average Pricing (net of transportation charges)

	2007	2006
Liquids		
WTI (US\$/bbl)	72.30	66.22
NAL average oil (Cdn\$/bbl)	70.79	65.30
NAL natural gas liquids (Cdn\$/bbl)	50.82	48.70
Natural Gas (Cdn\$/Mcf)		
AECO - daily spot	6.44	6.56
AECO - monthly	6.61	6.98
NAL Western Canada natural gas	6.47	6.98
NAL Lake Erie natural gas	7.90	8.09
NAL average natural gas	6.60	7.03
NAL Oil Equivalent before hedging (Cdn\$/boe - 6:1)	54.88	53.97
Average Foreign Exchange Rate (Cdn\$/US\$)	1.0738	1.134

Risk Management

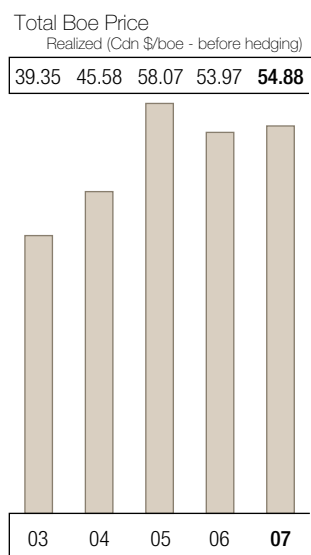
NAL employs risk management practices to assist in managing cash flows and to support capital programs and distributions. NAL's management is authorized to hedge up to 50 percent of its annual net of royalty production. NAL's risk management programs are scaled in over time using a combination of swaps and collars. During 2007, NAL had several financial WTI oil contracts and AECO natural gas contracts in place.

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

	2007	2006
Average crude volumes hedged (bbl/d)	3,106	3,244
Crude oil realized gain (loss) (\$000s)	(7,132)	1,158
Gain (loss) per bbl hedged	(6.29)	0.98
Average natural gas volumes hedged (GJ/d)	16,633	3,337
Natural gas realized gain (\$000s)	4,697	2,217
Gain per GJ hedged	0.77	1.82
Average boe hedged (boe/d)	5,733	3,771
Total realized gain (loss) (\$000s)	(2,435)	3,375
Gain (loss) per boe hedged	(116)	2.45
Gain (loss) per boe	(0.33)	0.48

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 statement of income 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 was reclassified to net income over the term of the respective contracts. During 2007, the full amount of \$4.5 million has been reclassified to net income.



Fair value is calculated at a point in time based on an approximation of the amounts that would be received or paid to settle these instruments, with reference to forward prices. Accordingly, the magnitude of the unrealized gain or loss will continue to fluctuate with changes in commodity prices.

The fair value of the derivatives at December 31, 2007 was a liability of \$9.6 million. The fair value of the liability of \$9.6 million at December 31, 2007 was comprised of a \$13.0 million liability on oil contracts offset by a \$3.4 million asset on gas contracts.

For the year ended December 31, 2007, income includes a \$14.1 million unrealized loss resulting from the change in the fair value of the derivative contracts during the year. The unrealized loss was comprised of a \$15.7 million loss on oil contracts, offset by a \$1.6 million gain on gas contracts.

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

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

	2007	2006
Unrealized gain (loss)		
Crude oil contracts	(15,709)	-
Natural gas contracts	1,604	-
Unrealized loss	(14,105)	-
Realized gain (loss)	(2,435)	3,375
Reclassification from other comprehensive income	4,521	-
Gain (loss) on derivative contracts	(12,019)	3,375

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

CRUDE OIL	US\$	CDN\$
Swap (bbls)	418,800	668,000
Swap (bbl/d)	1,144	1,825
\$/bbl	\$87.40	\$87.10
Collars (bbls)	407,800	122,000
Collars (bbl/d)	1,114	333
\$/bbl	\$74.93 - \$83.58	\$80.53 - \$88.73
Total (bbls)	826,600	790,000
Total (bbl/d)	2,258	2,158

NATURAL GAS	CDN\$
Swap (GJ)	7,434,500
Swap (GJ/d)	20,313
\$/GJ	7.38
Collars (GJ)	882,000
Collars (GJ/d)	2,410
\$/GJ	\$7.98 - \$9.57
Total (GJ)	8,316,500
Total (GJ/d)	22,723

For 2009, NAL currently has AECO natural gas swap contracts in place for 810,000 GJ or 2,219 GJ/d at an average price of \$7.36, and collars for 630,000 GJ or 1,726 GJ/d at average prices of \$7.61 - \$9.01. In addition, WTI oil swap contracts are in place for 127,600 bbls or 350 bbls/d at Cdn\$96.89 and 54,600 bbls or 150 bbls/d at US\$96.92. In addition, the Trust has WTI crude oil collar contracts in place for 54,600 bbls or 150 bbls/d at average prices of US\$92.66 - \$101.17.

Royalty Expenses

Crown, freehold and overriding royalties were \$89.1 million in 2007, up from \$83.7 million in 2006. Expressed as a percentage of gross sales, net of transportation costs, before gain/loss on derivative contracts, the royalty rate is consistent year over year at 21.7 percent for 2007 as compared to 21.8 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 minimal to the Trust, given the low level of crude oil production in Alberta and a significant weighting towards low producing gas wells. For the year ended December 31, 2007, 24 percent of crude oil and 80 percent of natural gas production is from Alberta.

Royalty Expenses

	2007	2006
Net royalties (\$000s)	89,139	83,668
As % of revenue	21.7	21.8
\$/boe	11.91	11.79

Operating Costs

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 sales process. These activities include turnarounds, pipeline replacements, pump changes and corrosion inhibition programs.

Full year 2007 operating costs increased 12 percent to \$9.34/boe from \$8.31/boe in 2006. The Seneca properties contributed an incremental \$0.08/boe in overall operating costs for 2007. In addition, approximately \$0.17/boe is attributed to third party processing fees relating to prior periods. The remaining cost increase was a direct result of significant labour, third party processing fees and property tax increases which had been included in our forecasts. For 2008, operating costs are expected to average \$9.50 to \$9.80/boe.

Operating Costs

	2007	2006
Operating costs (\$000s)	69,916	58,964
As a % of revenue	17.0	15.4
\$/boe	9.34	8.31

Operating Netback

For the year ended December 31, 2007, the operating netback before hedging gains (losses) was \$34.57/ boe, comparable with 2006. The increase in realized prices, year over year, of \$0.91/boe was offset by a \$1.03/boe increase in operating costs.

Operating Netback (\$/boe)

	2007	2006
Revenue	54.88	53.97
Royalties, net	(11.91)	(11.79)
Operating expenses	(9.34)	(8.31)
Other income	0.94	0.72
Operating netback, before hedging	34.57	34.59
Hedging gains (losses)	(0.33)	0.48
Operating netback, after hedging	34.24	35.07

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.

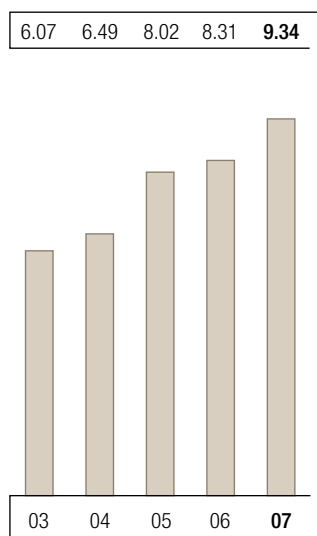
For the year ended December 31, 2007, total G&A has increased 24 percent to \$18.9 million from \$15.2 million. In 2007, \$4.5 million of G&A costs relating to exploitation and development activities were capitalized, compared with \$4.3 million in 2006. G&A expenses increased to \$14.4 million in 2007 compared with \$10.9 million in 2006.

Total G&A increased \$3.7 million year over year due to increased compensation costs associated with hiring, compensating and retaining staff. Included in G&A expenses in 2007 is a retention bonus of \$1.0 million associated with an employee retention program established at year end 2006. This represents a \$0.13/boe charge in 2007. G&A excluding the retention bonus and unit-based compensation was \$1.79/boe, on the lower end of our full year guidance of \$1.75 - \$1.95/boe.

General and Administrative Expenses

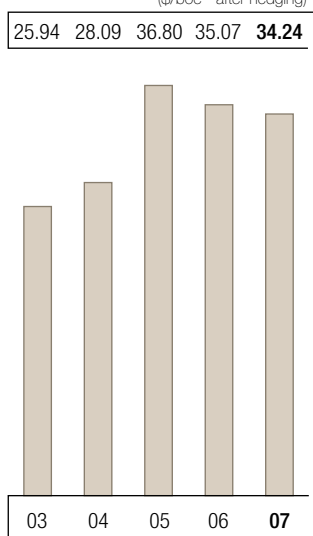
	2007	2006
G&A expenses (\$000s)		
G&A	13,435	10,946
Retention bonus	969	-
Expensed G&A (\$000s)	14,404	10,946
Capitalized G&A (\$000s)	4,486	4,275
Total G&A (\$000s)	18,890	15,221
Expensed G&A costs:		
G&A, excluding retention bonus (\$/boe)	1.79	1.54
Retention bonus (\$/boe)	0.13	-
Total G&A expenses (\$/boe)	1.92	1.54
As % of revenue	3.5	2.8
Per trust unit (\$)	0.17	0.14

Operating Costs (\$/boe)

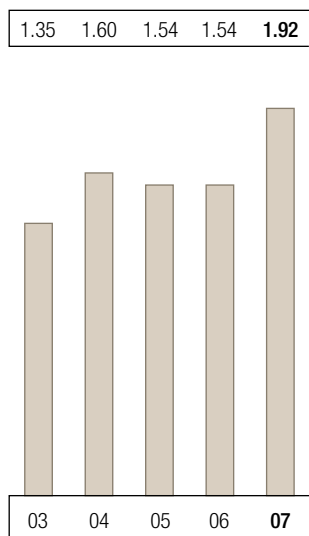


Operating Netback

(\$/boe - after hedging)



G&A Expenses (\$/boe)



Unit-based Incentive Compensation Plan

The employees of NAL Resources Management Limited (the "Manager") are all members of a unit-based incentive plan (the "Plan"). The Plan results in employees receiving cash compensation based upon the value and overall return of a specified number of notional trust units. The Plan consists of Restricted Trust Units ("RTUs") and Performance Trust Units ("PTUs"). RTUs vest one third on November 30 in each of three years after grant date. PTUs vest on November 30, three years after grant. Distributions paid on the Trust's outstanding trust units during the vesting period are assumed to be paid on the awarded notional trust units and reinvested in additional notional trust units on the date of distribution. Upon vesting, the employee is entitled to a cash payout based on the trust unit price at date of vesting of the units held. In addition, the PTUs have a performance multiplier which is based on the Trust's performance relative to its peers and may range from zero to two times the market value of the notional trust units held at vesting.

During 2007, the Trust accrued \$3.0 million of unit-based incentive compensation charges as compared to \$4.2 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 end trust unit price and performance factors. The compensation charges relating to the units granted are recognized over the vesting period based on the trust unit price, number of RTUs and PTUs outstanding, and the expected performance multiplier. As a result, the expense recorded in the accounts will fluctuate over time.

At December 31, 2007, the Trust has recorded a liability for unit-based incentive compensation in the amount of \$5.0 million, of which \$1.7 million was paid in January 2008. The remaining balance represents the Trust's estimated liability for the unit-based incentive plan as at December 31, 2007, of which \$1.6 million is recorded as current as it is payable by December 2008, and \$1.7 million is long-term as it is payable by December 2009.

Unit-Based Compensation

	2007	2006
Unit-based compensation:		
Expensed (\$000s)	2,152	2,495
Capitalized (\$000s)	875	1,659
Total unit-based compensation (\$000s)	3,027	4,154
Expensed unit-based compensation:		
As % of revenue	0.5	0.6
\$/boe	0.29	0.35
Per trust unit (\$)	0.03	0.03

Management Contract And Fees

The Trust is managed by 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 are based on joint amounts from NAL Resources. These transactions are in the normal course of joint operations and are measured using the fair value established through the original transactions with third parties.

The Manager provides certain services pursuant to a management contract. This agreement requires the Trust to reimburse the Manager at cost for general and administrative and unit based compensation expenses incurred by the Manager on behalf of the Trust.

The Trust paid \$11.6 million (2006 - \$6.6 million) for the reimbursement of G&A expenses during 2007. 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. The management contract was restructured effective May 31, 2006, after which no further management fees are payable. Prior to this date the Trust was required to pay a monthly management fee, of which \$1.4 million was paid during 2006. Under the restructuring, the Trust agreed to pay a one-time \$30 million restructuring fee in exchange for the elimination of any management fees and for the acquisition of a 50 percent ownership in the Manager's administrative capital assets. Of the \$30 million restructuring fee \$2.8 million was allocated to administrative assets and capitalized as property, plant, and equipment. The balance of \$27.2 million, representing the elimination of future management fees, was recorded as a non-cash charge in income. In payment of the restructuring fee, the Trust issued, to an affiliate of the Manager, 1,592,357 units of the Trust at a price of \$18.84 per unit. The subscription price was based on the weighted average trading price of the trust units over the five consecutive trading days ending on the third trading day preceding March 1, 2006, the date of the agreement.

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 2007 was \$242.9 million, as compared to \$203.2 million for 2006. NAL's effective interest rate averaged 5.38 percent in 2007, compared with 4.83 percent in 2006. NAL's interest is at a floating rate. The increase in the rate from 2006 is attributable to rate increases in the market.

Interest on convertible debentures represents interest charges, since the issuance of the debentures on August 28, 2007 at 6.75 percent, of \$2.3 million and accretion of the debt discount of \$0.6 million.

Interest and Debt (\$000s)

	2007	2006
Interest on bank debt	13,356	9,963
Interest on convertible debentures	2,965	-
Total interest	16,321	9,963
Bank debt outstanding at period end	275,630	220,785
Convertible debentures at period end	90,876	-

Cash Flow Netback

For the year ended December 31, 2007, NAL's cash flow netback decreased five percent to \$29.93 compared to \$31.59 in 2006. The decrease is primarily attributable to lower operating netbacks after hedging, higher G&A and interest expenses, offset partially by lower unit based compensation and management fees.

Cash Flow Netback (\$/boe)

	2007	2006
Operating netback, after hedging	34.24	35.07
Management fees	-	(0.19)
G&A expenses, excluding retention bonus	(1.79)	(1.54)
Retention bonus	(0.13)	-
Unit-based incentive compensation	(0.29)	(0.35)
Interest and fees on bank debt	(1.78)	(1.40)
Interest on convertible debentures ⁽¹⁾	(0.32)	-
Cash flow netback	29.93	31.59

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

Depletion, Depreciation and Accretion of Asset Retirement Obligations ("DDA")

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

For the year ended December 31, 2007, depletion and accretion increased by 17 percent over the comparable period due to a five percent increase in production and an 11 percent increase in the DDA rate per boe of production.

The increase in the DDA rate per boe is largely attributable to the Seneca acquisition. The DDA rate will fluctuate period over period depending on the amount and type of capital expenditures and the amount of reserves added.

Under Canadian GAAP, a ceiling test is applied to the carrying value of the property, plant and equipment. The carrying value is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves plus the lower of cost and market of undeveloped land exceeds the carrying value. When the carrying value is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value of assets exceeds the sum of the discounted cash flows expected from the production of P+P reserves plus the lower of cost and market of undeveloped land. The cash flows are estimated using expected future commodity prices and costs and are discounted using a risk-free interest rate. There was a significant surplus in the ceiling test at the year end 2007.

Depletion, Depreciation and Accretion Expenses

	2007	2006
Depletion and depreciation (\$000s)	155,392	133,079
Accretion of asset retirement obligation (\$000s)	5,533	4,984
Total DDA (\$000s)	160,925	138,063
DDA rate per boe (\$)	21.51	19.45

Taxes

For the year, NAL had a future income tax reduction of \$3.4 million in 2007 compared to \$1.2 million in 2006.

The Trust is a taxable entity and files a trust income tax return annually. The Trust's taxable income consists of royalty income, distributions from a subsidiary trust and interest and dividends from other subsidiaries, less deductions for the Trust's G&A expenses, Canadian Oil and Gas Property Expense ("COGPE"), and issue costs. In addition, Canadian Exploration Expense ("CEE"), Canadian Development Expense ("CDE") and Undepreciated Capital Cost ("UCC") are incurred and deducted by the Trust's subsidiaries. The Trust is taxable only on remaining income, if any, that is not distributed to unitholders. The Trust does not expect to incur any cash taxes in 2008.

The following tax pools are available to the Trust and subsidiaries (subject to assessment by income tax authorities) for future use as deductions from taxable income:

(\$000s)	2007	2006
Intangible resource pools	\$ 463,715	\$ 323,818
Undepreciated capital cost	202,632	149,383
Unit issue costs	13,815	9,437
Non-capital losses	17,661	11,495
Total tax pools	\$ 697,823	\$ 494,133

On June 22, 2007, the Budget Implementation Act 2007 (Canada) was enacted to, among other things, implement the October 31, 2006 announcement of the changes to taxability of Income Trusts, made by the Department of Finance. Under this legislation, distributions to unitholders will not be deductible by publicly traded income trusts and, as a result, the Trust will be taxed on its income similar to corporations. Although further clarifications are expected, these measures are now considered substantively enacted for purposes of Canadian Generally Accepted Accounting Principles. Accordingly, the Trust has measured future income tax assets and liabilities associated with this new tax. 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 year ended December 31, 2007 of \$56.5 million was \$3.7 million lower than 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 year over year by \$31.0 million, primarily due to a \$22.3 million increase in depletion, increased interest expense of \$6.4 million, an \$11.0 million increase in operating costs, partially offset by an \$8.9 million increase in revenues, net of royalties and gain/loss on derivative contracts.

Net Income (\$000s)

	2007	2006
Net income	56,457	60,198

Capital Resources And Liquidity

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

As at December 31, 2007, NAL had 90,494,151 trust units outstanding, compared with 77,971,268 trust units at December 31, 2006. The increase from December 31, 2006 is attributable to 10,246,000 trust units issued on close of the equity offering on August 31, 2007, and 2,276,883 trust units issued under the distribution reinvestment program ("DRIP").

Under the equity offering, 10.2 million trust units were issued at a price of \$12.20 per trust unit for net proceeds, after issue costs, of \$117.9 million.

For the year ended December 31, 2007, the distribution reinvestment plan resulted in 2.3 million trust units being issued at an average price of \$11.74 per trust unit for total proceeds of \$26.7 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 plan ("Premium DRIP") allows unitholders to exchange such units for a cash payment, from the plan broker, equal to 102 percent of the monthly distribution.

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

The participation rate in the regular DRIP averaged 16 percent over the three months ended December 31, 2007 and 17 percent for full year 2007, consistent with recent experience. The Trust continues to monitor the participation in this plan in conjunction with its capital requirements.

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As at December 31, 2007 the Trust had total debt of \$391.1 million, including convertible debentures at face value of \$100 million and a working capital deficit of \$15.4 million (excluding derivative contracts and future income tax asset). Excluding the convertible debentures, net debt was \$291.1 million, compared with \$223.1 million at December 31, 2006, and \$274.5 million as at September 30, 2007.

As at December 31, 2007, the Trust had a net debt to equity ratio of 0.77 compared to 0.49 at December 31, 2006. In addition, as at December 31, 2007, the Trust had a net debt (excluding convertible debentures) to 12 months trailing cash flow of 1.33 and a total net debt to 12 months trailing cash flow of 1.79.

The Trust maintains a \$400 million fully secured, extendible, revolving credit facility. The credit facility revolves 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, and in the absence of refinancing arrangements, the Trust would be required to repay the facility in four equal quarterly installments commencing May 2009.

Bank debt amounted to \$275.6 million at December 31, 2007 compared with \$220.8 million as at December 31, 2006. Of the debt outstanding at December 31, 2007, \$273.5 million was outstanding under the production facility and \$2.1 million under the working capital facility.

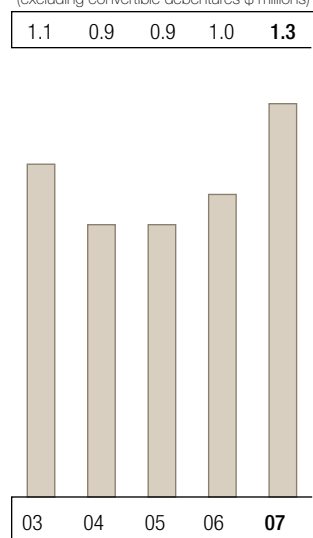
Bank debt increased from \$220.8 million as at December 31, 2006 to \$275.6 million as at December 31, 2007 primarily due to \$31.8 million required for the acquisition of Seneca.

On August 28, 2007, in connection with the acquisition of Seneca, the Trust issued \$100 million principal amount of 6.75 percent 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. Assuming conversion of all outstanding debentures 7.1 million trust units would be issued.

The convertible debentures are classified as debt on the balance sheet with a portion of the proceeds allocated to equity, representing the value of the conversion feature. As the debentures are converted to trust units, a portion of the debt and equity amounts 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 \$0.6 million of accretion of the debt discount in 2007.

Net Debt to Cash Flow
(excluding convertible debentures \$ millions)



As at February 28, 2008 the Trust had 93,331,575 trust units and \$100 million in convertible debentures outstanding.

Year-end Capitalization

	December 31, 2007	December 31, 2006
Trust unit equity (\$000s)	504,717	456,500
Bank debt (\$000s)	275,630	220,785
Working capital deficit (\$000s) ⁽¹⁾	15,429	2,276
Net debt excluding convertible debentures (\$000s)	291,059	223,061
Convertible debentures (\$000s) ⁽³⁾	100,000	-
Net debt (\$000s)	391,059	223,061
Net debt to equity	0.77	0.49
Net debt excluding convertible debentures to trailing 12-month cash flow ⁽²⁾	1.33	1.01
Net debt to trailing 12-month cash flow ⁽²⁾	1.79	1.01
Trust units outstanding (000s)	90,494	77,971

(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.

(3) Convertible debentures included at face value.

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

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

Under the tax legislation regarding the change in the taxability of the trusts, the Trust has a grandfathering period to 2011 until the rules come into effect. The grandfathering period restricts “undue expansion” of the Trust by placing growth limits for equity and convertible debt based on the market capitalization of the Trust on October 31, 2006, the date of the announcement. For 2008, the Trust has approximately \$597 million of room and for each of 2009 and 2010 an additional \$280 million each year.

Asset Retirement Obligation

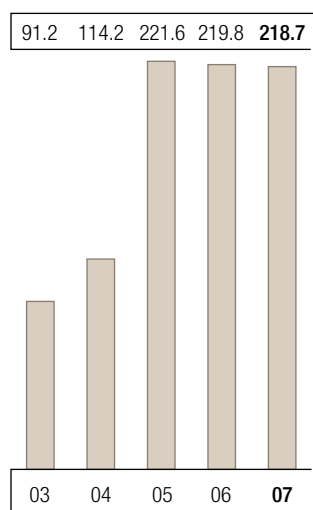
At December 31, 2007, the Trust reported an asset retirement obligation (“ARO”) balance of \$89.6 million (2006 - \$65.6 million) for future abandonment and reclamation of the Trust’s oil and gas properties and facilities. The ARO balance was increased by \$12.6 million due to the Seneca acquisition, \$11.4 million due to liabilities incurred and revisions to estimates (2006 - \$3.1 million), \$5.5 million from accretion expense (2006 - \$5.0 million) and was reduced by \$5.5 million for actual abandonment and environmental expenditures incurred in 2007 (2006 - \$4.4 million).

Distributions To Unitholders

For 2007 the Trust distributed 74 percent of its cash flow from operating activities, as compared to 71 percent in 2006. The payout associated with cash flow from operating activities will fluctuate significantly period over period as cash flow from operating activities includes changes in non-cash working capital associated with operating activities. The Trust has distributed in excess of its net income 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.

Funds from Operations (\$ millions)



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 while retaining cash to execute planned capital programs. As a result of the depleting nature of oil and gas assets some capital expenditure is required in order to minimize production declines as well as to invest in facilities and infrastructure. NAL's 2008 capital program is not expected 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 DRIP and debt. Over the medium term, fluctuations in commodity prices, other market factors, or development opportunities may make it necessary to fund the excess of distributions and capital expenditures over cash, from the credit facility. The credit facility and other sources of cash are expected to be sufficient to meet NAL's near term capital requirements, sustain distributions and provide for the resources to pursue potential growth opportunities.

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

Distributions

	2007	2006
Cash flow from operating activities	215,364	238,445
Net income	56,457	60,198
Actual cash distributions paid or payable	158,601	169,589
Excess (shortfall) of cash flow from operating activities over cash distribution paid	56,763	68,856
Percentage of cash flow from operations distributed	74%	71%
Excess (shortfall) of net income over cash distributions paid	(102,144)	(109,391)

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 year ended December 31, 2007, funds from operations was comparable with 2006 though decreased eight percent on a per unit basis from \$2.88 to \$2.65 in 2007. The decrease of eight percent on a per unit basis is due to the equity offering and units issued under the DRIP.

Funds from Operations

	2007	2006
Funds from operations (\$000s)	218,745	219,776
Funds from operations per trust unit	2.65	2.88
Payout ratio based on funds from operations	73%	77%

Variable Interest Entities

NAL has no variable interest entities.

Contractual Obligations

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

(\$000s)	2008	2009	2010	2011	2012	Thereafter
Office lease ⁽¹⁾	3,672	3,672	3,366	-	-	-
Transportation agreement	1,123	1,123	84	-	-	-
Processing agreement ⁽²⁾	469	446	428	414	401	384
Drilling rigs ⁽³⁾	494	-	-	-	-	-
Retention bonus ⁽⁴⁾	578	-	-	-	-	-
Total	6,336	5,241	3,878	414	401	384

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

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

(3) Represents the Trust's share of the 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.

Acquisition Of Tiberius Exploration Inc. ("Tiberius") And Spear Exploration Inc. ("Spear")

On February 27, 2008, the Trust completed the acquisition of all the issued and outstanding shares of Tiberius and Spear.

Total consideration is approximately \$115 million, before closing adjustments, consisting of approximately 2.4 million trust units and \$86.25 million in cash.

Concurrently, the Trust entered into an agreement with a wholly owned subsidiary of Manulife Financial Corporation ("MFC"), to contribute the assets and liabilities of Tiberius and Spear to a limited partnership owned 50 percent by the Trust and 50 percent by MFC. MFC will acquire its 50 percent interest in the limited partnership by payment of one half of the purchase price, being approximately \$57.5 million.

Consequently, the total acquisition cost to the Trust for its 50 percent interest in the acquired companies will be approximately \$57.5 million, comprising 2.4 million trust units and \$28.75 million in cash.

MFC is a related party to the Trust. See Management Contract and Fees.

The new properties will contribute primarily light oil production from the Tilston formation, along with associated natural gas and natural gas liquids.

Selected Annual Information

Years ended December 31

(\$000s) except per unit amounts	2007	2006	2005
Oil, natural gas and liquid sales ⁽¹⁾	413,426	385,624	406,007
Net income	56,457	60,198	98,538
Net income per trust unit	0.68	0.79	1.41
Net income per trust unit – diluted	0.68	0.79	1.41
Distributions paid and declared	158,601	169,589	142,050
Distributions paid or declared per trust unit	1.92	2.22	2.01
Total assets	1,063,160	796,902	834,883
Total liabilities	558,443	340,402	340,393
Long term debt ⁽²⁾	366,506	220,785	220,519
Unitholders' equity	504,717	456,500	494,490
Number of trust units outstanding at year end	90,494	77,971	73,977

(1) 2005 restated as a result of a change in presentation.

(2) Includes bank debt and convertible debentures.

Quarterly Information

(\$000s, except per unit and production amounts)	2007				2006			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue, net of royalties	86,262	78,573	83,268	71,231	75,358	75,798	77,988	81,272
Per unit	0.96	0.95	1.06	0.91	0.97	0.98	1.03	1.08
Funds from operations ⁽¹⁾	59,537	50,817	54,156	54,235	55,795	54,107	52,210	57,664
Per unit	0.66	0.61	0.69	0.69	0.72	0.70	0.69	0.77
Net income (loss)	10,556	7,801	21,390	16,710	20,472	20,473	(5,357) ⁽²⁾	24,610
Per unit – basic and diluted	0.12	0.09	0.27	0.21	0.26	0.27	(0.07)	0.33
Average oil equivalent production (boe/d – 6:1)	23,413	20,182	18,946	19,422	19,517	19,079	19,012	20,181

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

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

Fourth Quarter 2007 Review

Capital Expenditures and Exploration & Development Activities

The Trust spent \$31.0 million on drilling operations during the fourth quarter of 2007, versus \$25.6 million a year earlier, plus another \$3.3 million on plant and facilities construction (2006 - \$4.7 million) and \$2.7 million on land and seismic data acquisition (2006 - \$2.6 million).

The Trust participated in the drilling of 45 gross (18.06 net) wells during the fourth quarter of 2007.

Fourth Quarter Drilling Activity

	Crude Oil		Natural Gas		Service Wells		Dry & Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Operated wells	21	9.43	8	6.15	-	-	-	-	29	15.58
Non-operated wells	7	0.09	9	2.39	-	-	-	-	16	2.48
Total wells drilled	28	9.52	17	8.54	-	-	-	-	45	18.06

Production

Fourth quarter 2007 production of 23,413 boe/d (19,023 boe/d excluding Seneca) exceeded production of 19,517 boe/d in the comparable period of 2006 by 20 percent. The increase is mainly attributable to Seneca production of 4,390 boe/d. The average production for December was 23,365 boe/d, which includes 4,246 boe/d related to Seneca.

Revenue

Gross revenue from oil, natural gas and natural gas liquids sales, after transportation costs, totaled \$121.7 million for the three months ended December 31, 2007, 36 percent higher than the fourth quarter of 2006. The increase in revenue is attributable to a 20 percent increase in production and a 13 percent increase in the average price per boe. Compared to the fourth quarter of 2006, average commodity prices increased by 13 percent due to higher crude oil and natural gas liquids prices.

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Pricing

NAL's fourth quarter average Canadian crude oil price per barrel, net of transportation costs, was \$79.43 as compared to \$58.53 for the comparable period of 2006. The increase in realized price quarter over quarter of 36 percent, or \$20.90/bbl, was primarily driven by a 51 percent increase in WTI (US\$/bbl), over the comparable period (US\$90.62 versus US\$60.21), offset by a strengthening Canadian dollar. In addition, NAL's crude oil differentials compared to WTI priced in Canadian dollars increased realized prices. For the fourth quarter of 2007, NAL's realized oil price was 89 percent of WTI in Canadian dollars, an increase of four percent from the 85 percent for the corresponding period in 2006. The increase in the fourth 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 in that time frame.

Natural gas liquids averaged \$58.52/bbl in the fourth quarter of 2007, a 35 percent increase from \$43.24/bbl realized in 2006.

For the three months ended December 31, 2007, the Trust's natural gas sales averaged \$6.20/mcf, compared to \$6.96/mcf in the comparable period of 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 prices from the Lake Erie property averaged \$7.37/mcf in the fourth quarter of 2007 compared to \$8.16/mcf in 2006, a decrease of 10 percent.

Risk Management

During the fourth quarter of 2007, an average of 3,966 bbl/d of crude were hedged, resulting in a realized loss of \$7.7 million. In addition, 19,978 GJ/d of natural gas were hedged resulting in a realized gain of \$2.2 million. In total, for the fourth quarter of 2007, the realized loss on risk management contracts was \$5.5 million, or \$2.56/boe. Risk management contracts in place during the fourth quarter of 2006 positively affected realized prices by \$1.00/boe or \$1.8 million in aggregate.

In addition, fourth quarter income of 2007 includes an \$8.2 million unrealized loss on derivatives resulting from the change in the fair value of the derivative contracts during the quarter from a liability of \$1.4 million at September 30, 2007 to a liability of \$9.6 million at December 31, 2007. The \$8.2 million unrealized loss was comprised of a \$2.4 million unrealized loss on natural gas contracts, and a \$5.8 million unrealized loss on crude oil contracts. The unrealized loss in the fourth quarter is primarily attributable to stronger crude oil forward prices compared to September 30, 2007 and an increase in derivative instruments held.

Royalty Expenses

Crown, freehold and overriding royalties were \$26.0 million for the three months ended December 31, 2007, compared to \$18.6 million in the comparable period of 2006. Expressed as a percentage of gross sales, net of transportation costs, before gain/loss on derivative contracts, the net royalty rate was 21.4 percent, up slightly from 20.8 percent experienced in the comparable period of 2006.

Operating Costs

For the quarter ended December 31, 2007, operating costs averaged \$10.00/boe a 40 percent increase from the \$7.13/boe for the quarter ended December 31, 2006. On a comparative basis, the fourth quarter of 2006 was lower than expected as it includes several downward adjustments for the activity from earlier in 2006 where actual costs were less than estimated.

Operating Netback

For the quarter ended December 31, 2007, NAL's operating netback, before hedging gains (losses), was \$35.60/boe, an increase of six percent from \$33.49 for the quarter ended December 31, 2006. A 13 percent increase in average realized prices was offset by increased royalties and operating costs in the fourth quarter of 2007.

General & Administrative Expenses

For the three months ended December 31, 2007, G&A expenses were \$4.1 million, compared with \$2.4 million in the comparable quarter of 2006. In addition, \$1.0 million of G&A costs relating to exploitation and development activities were capitalized in the fourth quarter of 2007 compared with \$1.3 million in the fourth quarter of 2006.

Total G&A increased by \$1.4 million due to increased compensation costs associated with hiring, compensating and retaining staff.

Unit-based Incentive Compensation Plan

During the fourth quarter of 2007, the Trust accrued \$1.5 million of unit-based incentive compensation charges as compared to a \$0.4 million recovery in the comparable quarter of 2006. The fourth quarter recovery of unit-based compensation in 2006 is a reflection of a significant drop in unit price that occurred following the Federal government's announcement, on October 31, 2006, of their intentions to tax income trusts.

Management Contract and Fees

The Trust paid \$31 million (2006 - \$1.3 million) for the reimbursement of G&A expenses during the fourth quarter. The increase in charges from the Manager is due to increased compensation charges.

Interest

Interest expense for the quarter ended December 31, 2007 amounted to \$6.0 million, compared to \$2.8 million in 2006. Included in 2007 is interest on convertible debentures of \$2.2 million, representing interest charges at 6.75 percent of \$1.7 million and accretion of the debt discount of \$0.5 million. Interest on bank debt increased from \$2.8 million in 2006 to \$3.8 million in 2007, due to increased average debt levels (\$266.6 million versus \$213.9 million) and increased interest rates (5.61 percent versus 5.06 percent). The increase in the rate from the fourth quarter of 2006 is attributable to rate increases in the market.

Cash Flow Netback

For the quarter ended December 31, 2007, NAL's cash flow netback was \$28.08/boe, an 11 percent decrease from \$31.69 for the comparable period in 2006. The decrease is due to lower operating netbacks after hedging in 2007 and higher expenses.

Depletion, Depreciation and Accretion

For the quarter ended December 31, 2007, depletion on property, plant and equipment and accretion on the asset retirement obligations increased by 20 percent over the comparable period in 2006, due to a 20 percent increase in production volumes.

Net Income

Net income for the fourth quarter of 2007 was \$10.6 million compared to \$20.5 million for the comparable period in 2006. The decrease in net income of \$9.9 million was primarily due to a \$7.2 million increase in depletion, increased operating costs of \$8.7 million, increased G&A and unit-based compensation of \$2.9 million, and increased interest expense of \$3.2 million, partially offset by higher revenues, net of royalties and gain/loss on derivative contracts, of \$11.0 million and an increase in the future income tax reduction of \$1.7 million.

Distributions

For the three months ended December 31, 2007, the Trust distributed 96 percent of its cash flow from operating activities compared to 81 percent in 2006. The payout associated with cash flow from operating activities will fluctuate significantly period over period as cash flow from operating activities includes changes in non-cash working capital associated with operating activities.

For the three months ended December 31, 2007, funds from operations amounted to \$59.5 million compared with \$55.8 million for the three months ended December 31, 2006. The increase is due to increased revenue driven by higher production and pricing offset partially by higher costs. On a per trust unit basis funds from operations decreased eight percent from \$0.72 in 2006 to \$0.66 in 2007 due to the increase in trust units from the equity offering associated with the acquisition of Seneca.

Business Risks

The Trust is exposed to a number of risks and uncertainties inherent in the oil and gas industry, which can have a material impact on its operating results and on distributions to unitholders.

Oil and gas production activities include the uncertainties of developing or acquiring sufficient quantities of crude oil and natural gas to replace declining production levels from existing wells. Day-to-day field operations may not be able to access equipment to drill, complete or service wells, may encounter production or drilling difficulties and are faced with the safety risks of field personnel and risks of environmental damage.

Commodity prices received by the Trust are influenced by North American and international markets and events, which in turn impact the level of its funds generated from operations and its capacity to sustain distributions to unitholders.

Oil prices are influenced by global supply and demand conditions as well as worldwide political events. In addition, as a result of the US benchmark price for oil, fluctuations in the US/Canadian exchange rate further affect the price the Trust receives for its oil sales.

Natural gas prices are influenced by North American supply and demand as well as transportation costs and constraints. In addition, seasonal changes and weather patterns can significantly affect demand and natural gas prices.

The Trust's access to oil and gas sales markets may be restricted, at times, by pipeline proximity and capacity, as well as the availability of processing equipment.

The oil and natural gas industry is subject to extensive controls and regulatory policies governing royalties, income and resource taxes and other levies and fees imposed by various levels of government. These regulations, controls and taxation policies are amended from time to time. The Trust has no control over the level of government intervention or taxation in the oil and natural gas industry. Changes to regulations and policies governing royalties, taxes and other levies and fees could have a material impact on the Trust's financial results and the value of NAL's trust units.

The oil and gas industry is also subject to environmental regulations and an increasing awareness of the environmental impact of oil and gas activities, which could impact future results of the Trust.

The Trust is subject to changes in interest rates, and the general market conditions affecting financial markets in the event of a need to raise capital.

With the recent unprecedented levels of activity in the oil and gas industry as a whole, the Trust is also faced with human resource challenges, which may affect the availability of people and services.

The Trust strives to mitigate these risks by:

- Attracting and retaining highly qualified professional personnel.
- Employing experienced staff and utilizing appropriate technology in field operations.
- Using prudent work practices, training and procedures with an ongoing focus on safety programs.
- Ensuring compliance with all regulations applicable to its oil and gas operations.
- Maintaining appropriate insurance coverage in order to minimize the impact of events that may cause financial damage.
- Employing a proactive environmental program, ensuring compliance with specific environmental legislation.
- Effectively controlling processing, transportation and marketing of its products with delivery to a variety of markets.
- Hedging commodity prices when considered appropriate to manage risk.
- Continuous monitoring of debt levels in conjunction with cash flow levels and capital requirements.
- Continuous monitoring of foreign exchange and interest rates.
- Efficient operation and active development of its existing properties.
- Continuous review of acquisition opportunities, adhering to strict evaluation criteria.

Financial Reporting Disclosure Controls

Management has designed and evaluated the effectiveness of the Trust's financial reporting disclosure controls and procedures as at December 31, 2007 and has concluded that such controls and procedures were effective as at that date.

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

Changes To Internal Controls Over Financial Reporting

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

There were no changes to the Trust's internal controls over financial reporting since December 31, 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, 2007 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 following discusses such accounting policies and is included in this MD&A to assist investors in assessing the critical accounting policies and practices of NAL and the likelihood of materially different results being reported. The Manager reviews the estimates regularly. The emergence of new information and changed circumstances may result in actual results or changes in estimated amounts that differ materially from current estimates. The following assessment of significant accounting estimates is not meant to be exhaustive. NAL might realize different results from the application of new accounting standards published, from time to time, by various regulatory bodies.

Proved Oil and Gas Reserves

Under National Instrument 51-101 ("NI 51-101"), "proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable (it is possible that the actual remaining quantities recovered will exceed the estimated proved reserves). In accordance with this definition, the level of certainty targeted by the reporting company should result in at least a 90 percent probability at a company aggregate level that the quantities actually recovered will equal or exceed the estimated reserves. There was no such consideration of probability under previous reporting rules. In the case of "probable" reserves, which are less certain to be recovered than proved reserves, NI 51-101 states that it must be equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable ("P+P") reserves. As for certainty, in order to report reserves as P+P, the reporting company must believe that there is at least a 50 percent probability at a company aggregate level that the quantities actually recovered will equal or exceed the sum of the estimated P+P reserves. The implementation of NI 51-101 has resulted in a more rigorous and uniform standardization of reserve evaluation.

The oil and gas reserve estimates are made using all available geological and reservoir data as well as historical production data. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in NAL's plans. The effect of changes in proved oil and gas reserves on the financial results and position of NAL is described under the heading "Impairment of Property, Plant and Equipment".

Depletion Expense

NAL uses the full cost method of accounting for exploration and development activities. In accordance with this method of accounting, all costs associated with exploration and development are capitalized whether or not the activities funded were successful. The aggregate of net capitalized costs and estimated future development costs is amortized using the unit of production method on estimated proved oil and gas reserves.

An increase in estimated proved oil and gas reserves would result in a corresponding reduction in depletion expense. A decrease in estimated future development costs would result in a corresponding reduction in depletion expense.

Impairment of Property, Plant & Equipment

NAL is required to review the carrying value of all property, plant and equipment, including the carrying value of oil and gas assets, for potential impairment. Impairment is indicated if the carrying value of the long-lived oil and gas asset is not recoverable by the future undiscounted cash flows. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the property, plant and equipment is charged to net income.

The cash flows used in the impairment assessment require management to make assumptions and estimates about recoverable reserves (see Proved Oil and Gas Reserves), future commodity prices and operating costs. Changes in any of the assumptions, such as downward revision in reserves, a decrease in future commodity prices, or an increase in operating costs could result in an impairment of an asset's carrying value.

Fair Value of Derivative Instruments

NAL utilizes financial derivatives to manage market risk. The purpose of the hedge is to provide an element of stability to NAL's cash flow in a volatile environment. NAL recognizes the fair value of derivative contracts on its balance sheet with the change in fair value recognized in net income of the period. The fair value of the derivative contracts is based on forward commodity prices. Any change in commodity prices will impact the fair value of the contracts and therefore net income of the period.

Asset Retirement Obligations

NAL is required to recognize and measure liabilities associated with capital assets. A liability is recognized equal to the discounted fair value of the obligations in the period in which the asset is recorded with an equal offset to the carrying amount of the asset. The liability then accretes to its fair value with the passage of time. Management is required to estimate the timing and future costs to settle liabilities. Changes in the estimated future costs, the timing of these costs, and the discount rate will impact the liability, related asset and expense.

Legal, Environmental Remediation and Other Contingent Matters

NAL is required to determine whether a loss is probable based on judgment and interpretation of laws and regulations whether the loss can reasonably be estimated. When the loss is determined, it is charged to net income. NAL's management must continually monitor known and potential contingent matters and make appropriate provisions by charges to earnings when warranted by circumstances.

Income Tax Accounting

The determination of NAL's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessments after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

Future income taxes are recognized for temporary differences arising in the Trust's subsidiaries and also those arising in the Trust that reverse after 2011. No future taxes have been recognized for the Trust based on management's estimates that the reversal of all temporary differences will occur prior to 2011. Should the assumptions underlying the estimate of the reversal of temporary differences change, including future commodity prices, payout ratio, capital expenditures and reserves, future taxes may be recorded for the Trust.

New Accounting Policy

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 five categories, and 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 3 to the consolidated financial statements.

Future Accounting Changes

The CICA issued new accounting standards: Section 1535 “Capital Disclosures”, Section 3862 “Financial Instruments - Disclosures”, and Section 3863 “Financial Instruments – Presentation”. 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.

Sections 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 is currently assessing the impact of these standards on its financial statements. However, it is not anticipated that the adoption of these new standards will impact the amounts reported in the Trust’s financial statements as they primarily relate to disclosure.

Consolidated Financial Statements

Management's Report

NAL Resources Management Limited, as manager of NAL Oil & Gas Trust and NAL Energy Inc., is responsible for the preparation of the accompanying consolidated financial statements of the Trust. The consolidated financial statements have been prepared in accordance with Canadian Generally Accepted Accounting Principles, and where applicable, amounts based on management's best estimates and judgement.

Management has established procedures and systems of internal control designed to provide reasonable assurance that assets are safeguarded and that accurate financial information is produced in a timely manner.

The Board of Directors is responsible for reviewing and approving the consolidated financial statements, and through its Audit Committee, ensuring that management fulfills its responsibilities for financial reporting. The Audit Committee, which is comprised of four independent directors, meets regularly with management, the internal auditor and the external auditors to satisfy itself that each party is properly discharging its responsibilities. The Audit Committee reviews the consolidated financial statements and recommends their approval to the Board of Directors.

KPMG LLP, an independent firm of Chartered Accountants, appointed by the unitholders of NAL Oil & Gas Trust, have audited the consolidated financial statements in accordance with Canadian generally accepted auditing standards. KPMG LLP have full and free access to the Audit Committee.



Andrew B. Wiswell
President and CEO
February 28, 2008




Keith Steeves
Chief Financial Officer

Auditors' Report to the Unitholders

We have audited the consolidated balance sheets of NAL Oil & Gas Trust as at December 31, 2007 and 2006 and the consolidated statements of income, comprehensive income and deficit and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2007 and 2006 and the results of its operations and its cash flows for the years then ended in accordance with Canadian Generally Accepted Accounting Principles.



Chartered Accountants
Calgary, Canada – February 28, 2008

Consolidated Balance Sheets

As at December 31 (thousands of dollars)

	2007	2006
Assets		
Current assets		
Cash and cash equivalents	\$ 1,394	\$ 6,295
Accounts receivable and other	70,791	44,467
Derivative contracts (Note 13)	3,389	-
Future income tax asset (Note 12)	2,602	-
	78,176	50,762
Future income tax asset (Note 12)	4,096	3,345
Property, plant and equipment (Notes 4 and 6)	980,888	742,795
	\$ 1,063,160	\$ 796,902
Liabilities and Unitholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	\$ 73,135	\$ 40,563
Distributions payable to unitholders	14,479	12,475
Derivative contracts (Note 13)	12,973	-
	100,587	53,038
Bank debt (Note 7)	275,630	220,785
Convertible debentures (Note 8)	90,876	-
Unit-based incentive compensation (Note 9)	1,748	1,005
Asset retirement obligations (Note 10)	89,602	65,574
	558,443	340,402
Unitholders' equity		
Unitholders' capital (Note 11)	969,588	824,986
Equity component of convertible debentures (Note 8)	5,759	-
Deficit (Note 11)	(470,630)	(368,486)
	504,717	456,500
	\$ 1,063,160	\$ 796,902
Commitments (Note 14)		
Subsequent event (Note 15)		
Trust units outstanding (000s)	90,494	77,971

See accompanying notes.



J. Charles Caty
Director and Chairman of the Board



Irvine J. Koop
Director and Chairman of the Audit Committee

Consolidated Statements of Income, Comprehensive Income and Deficit

Years ended December 31 (thousands of dollars, except per unit amounts)

	2007	2006
Revenue		
Oil, natural gas and liquid sales	\$ 413,426	\$ 385,624
Crown royalties	(64,798)	(61,570)
Freehold and other royalties	(24,341)	(22,098)
	324,287	301,956
Gain (loss) on derivative contracts (Note 13):		
Realized gain (loss)	(2,435)	3,375
Unrealized loss	(14,105)	-
Reclassification from other comprehensive income	4,521	-
	(12,019)	3,375
Royalty and other income	7,066	5,085
	319,334	310,416
Expenses		
Operating	69,916	58,964
Transportation	2,779	2,547
General and administrative	14,404	10,946
Unit-based incentive compensation (Note 9)	2,152	2,495
Management fees (Note 5)	-	1,350
Restructuring fee (Note 5)	-	27,299
Interest on bank debt	13,356	9,963
Interest and accretion on convertible debentures	2,965	-
Depletion, depreciation and amortization	155,392	133,079
Accretion on asset retirement obligations	5,533	4,984
	266,497	251,627
Income before taxes	52,837	58,789
Income tax recovery	267	200
Future income tax reduction	3,353	1,209
Total income taxes (Note 12)	3,620	1,409
Net income	56,457	60,198
Other comprehensive income:		
Reclassification to net income, net of tax of \$1,349 (Notes 3 and 13)	(3,172)	-
Comprehensive income	53,285	60,198
Deficit, beginning of period	(368,486)	(259,095)
Net income	56,457	60,198
Distributions declared (Note 11)	(158,601)	(169,589)
Deficit, end of period	\$ (470,630)	\$ (368,486)
Net income per trust unit – basic and diluted (Note 11)	\$ 0.68	\$ 0.79
Weighted average trust units outstanding (000s)	82,556	76,350

See accompanying notes.

Consolidated Statements of Cash Flows

Years ended December 31 (thousands of dollars)

	2007	2006
Operating Activities		
Net income	\$ 56,457	\$ 60,198
Items not involving cash:		
Depletion, depreciation and amortization	155,392	133,079
Accretion on asset retirement obligations	5,533	4,984
Unrealized loss on derivative contracts	14,105	-
Reclassification from other comprehensive income	(4,521)	-
Future income tax reduction	(3,353)	(1,209)
Non-cash accretion expense on convertible debentures	635	-
Restructuring fee	-	27,159
Abandonment and environmental expenditures	(5,503)	(4,435)
Change in non-cash working capital	(3,381)	18,669
	215,364	238,445
Financing Activities		
Distributions paid to unitholders	(129,862)	(129,769)
Issue of trust units, net of issue costs	117,867	-
Increase in bank debt	54,127	266
Issue of convertible debentures, net of issue costs	96,000	-
Change in non-cash working capital	1,341	2,241
	139,473	(127,262)
Investing Activities		
Acquisition of Seneca Energy Canada Inc. (Note 4)	(245,687)	-
Additions to property, plant and equipment	(118,011)	(120,030)
Property acquisitions	(1,449)	(1,267)
Proceeds from dispositions	26	96
Reclamation reserve	-	3,898
Change in non-cash working capital	5,383	11,291
	(359,738)	(106,012)
Increase (decrease) in cash and cash equivalents	(4,901)	5,171
Cash and cash equivalents, beginning of period	6,295	1,124
Cash and cash equivalents, end of period	\$ 1,394	\$ 6,295
Supplementary disclosure of cash flow information:		
Cash paid during the period for:		
Interest	\$ 16,913	\$ 9,816
Tax recovery	\$ (267)	\$ 136
Cash and cash equivalents is comprised of:		
Cash	\$ 1,394	\$ 303
Short term investments	-	5,992
	\$ 1,394	\$ 6,295

See accompanying notes.



J. Charles Caty
Director and Chairman of the Board



Irvine J. Koop
Director and Chairman of the Audit Committee

Notes to the Consolidated Financial Statements

Years ended December 31, 2007 and 2006
(Tabular amounts in thousands of dollars, except per unit amounts)

1. STRUCTURE OF THE TRUST

The Trust is an open-ended investment trust formed under the laws of the Province of Alberta. Operations commenced on May 9, 1996. The principal undertakings of the Trust are to indirectly acquire and hold, through its direct and indirect wholly owned subsidiaries and partnerships, interests in oil and natural gas properties and to distribute the net cash proceeds to its unitholders.

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 operator. As a result, a significant portion of the net operating revenues and capital expenditures represent joint operations amounts from NAL Resources. These transactions are in the normal course of joint operations and are based on the original exchange amounts established through transactions with third parties.

2. SUMMARY OF ACCOUNTING POLICIES

Basis of Presentation

The Trust's financial statements have been prepared in accordance with Generally Accepted Accounting Principles ("GAAP") in Canada and they include the accounts of the Trust, its subsidiaries and partnerships, which are wholly owned. All inter-entity transactions and balances have been eliminated.

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimated. In particular, the amounts recorded for depletion and depreciation of property, plant and equipment and for the accretion of asset retirement obligations are based on estimates of reserves and future costs. The amounts recorded for unit-based compensation are based on estimates of trust unit price and performance factors, while the fair value estimates for derivatives are based on expected future oil and natural gas prices and volatility in these prices. The ceiling test calculation is based on estimates of reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. Future income taxes are based on estimates as to the timing of the reversal of temporary differences, and tax rates currently substantively enacted. By their nature, these estimates are subject to measurement uncertainty and may impact the consolidated financial statements of future periods.

Property, Plant and Equipment

The Trust follows the full cost method of accounting for petroleum and natural gas properties, whereby all costs of acquiring petroleum and natural gas properties and related development costs are capitalized and accumulated in one cost centre. Such costs include land acquisition, geological and geophysical expenditures, costs of drilling both productive and non-productive wells, related plant and production equipment costs and related overhead charges.

Proceeds from the sale of petroleum and natural gas properties are applied against capitalized costs, with no gain or loss recognized, unless such sale would alter the depletion rate by 20 percent or more.

Depletion of petroleum and natural gas properties and depreciation of equipment is calculated using the unit of production method based on total proved reserves before royalties, as determined by independent petroleum engineers. Natural gas reserves are converted to barrels of oil equivalent based on relative energy content (6:1). The depletion base includes capitalized costs, plus future costs to be incurred in developing proved reserves and excludes the unimpaired cost of undeveloped land. Costs associated with undeveloped land are not subject to depletion and are assessed periodically to assess whether impairment has occurred. When proved reserves are assigned or the value of the unproved property is considered to be impaired, the cost of the undeveloped land or the amount of impairment is added to the costs subject to depletion.

Petroleum and natural gas properties are evaluated in each reporting period to determine that the carrying amount in a cost centre is recoverable and does not exceed the fair value of the properties in the cost centre.

The carrying amount of petroleum and natural gas properties is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves plus the lower of cost and market of undeveloped land, exceeds the carrying amount. When the carrying amount is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying amount of the cost centre exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, plus the lower of cost and market of undeveloped land. The cash flows are estimated using expected future commodity prices and costs and discounted using a risk-free rate.

Asset Retirement Obligations

The Trust recognizes the fair value of an asset retirement obligation in the period in which it is incurred, on a discounted basis, with a corresponding increase to the carrying amount of property, plant and equipment. The asset recorded is depleted on a unit of production basis over the life of the reserves. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to income in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost could also result in an increase or decrease to the obligation. Actual costs incurred upon settlement of the retirement obligation are charged against the obligation to the extent of the liability recorded.

Income Taxes

The Trust is a taxable entity under the Canadian Income Tax Act and until 2011 is taxable only on income that is not distributed or distributable to unitholders, provided that the Trust continues to adhere to the transition rules provided for under the Federal legislation. The Trust meets the criteria qualifying for income tax treatment permitting a tax deduction for distributions paid to the unitholders in addition to other deductions available in the Trust. In addition, the Trust is currently exempt from future income taxes because it is contractually committed to distribute all of its income to its unitholders. This tax treatment is only applicable up to 2011, at which time the distributions paid to unitholders will not be deductible for tax and the Trust will be taxed on its income similar to corporations.

The Trust follows the asset and liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the Trust's subsidiaries financial statements and their respective tax bases, using substantively enacted income tax rates. In addition, income tax liabilities and assets are recognized for the estimated tax consequences of temporary differences arising in the Trust that reverse after 2011. The effect of the change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs. A valuation allowance is recorded against any future income tax assets if it is more likely than not that the asset will not be realized.

Financial Instruments

Financial instruments are required to be classified into one of five categories: held for trading, held to maturity, loans and receivables, available for sale or other liabilities. Cash and cash equivalents have been designated as held for trading which are measured at fair value. Accounts receivable are classified as loans and receivables which are measured at amortized cost. Accounts payable and accrued liabilities, distributions payable and bank debt are classified as other liabilities which are measured at amortized cost, which is determined using the effective interest method. The convertible debentures are classified as debt on the balance sheet with a portion of the proceeds allocated to equity. The debt component has been measured at amortized cost.

All derivative contracts are classified as held for trading and 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 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. The Trust has not designated 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. Proceeds and costs realized from holding the derivative contracts are recognized in net income at the time each transaction under a contract is settled. The fair value of derivative contracts 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.

Transaction costs are frequently attributed to the issue of a financial asset or liability. The Trust has selected a policy of netting all transaction costs with the related financial assets and liabilities, and recording its bank debt net of deferred interest payments. In accordance with this policy convertible debentures are presented net of issue costs and bank debt is presented net of deferred interest payments, with interest recognized in net income on an effective interest basis.

The Trust applies trade date accounting for the recognition of a purchase or sale of short term investments and derivative contracts.

The Trust measures and recognizes embedded derivatives separately from host contracts when the economic characteristics and risks of the embedded derivative are not closely related to those of the host contract, when it meets the definition of a derivative, and when the contract is not measured at fair value. Embedded derivatives are recorded at fair value.

Joint Operations

Substantially all development and production activities are conducted jointly with others and, accordingly, these financial statements reflect only the Trust's proportionate interests in such activities.

Revenue Recognition

Revenues from the sale of petroleum and natural gas are recorded when title passes to the purchaser.

Unit-Based Incentive Compensation

The Manager has established a unit-based incentive compensation plan (the "Plan") for all employees. Under the Plan, employees receive cash compensation based upon the value and overall return of a specified number of awarded notional trust units on a fixed vesting date. The notional trust unit grants are in the form of Restricted Trust Units ("RTUs") and Performance Trust Units ("PTUs"). Distributions paid on the Trust's outstanding trust units during the vesting period are assumed to be reinvested in the awarded trust notional units on the date of distribution. The compensation incorporates the trust unit price and the number of RTUs and PTUs outstanding at each period end. In addition, for the PTUs there is a performance multiplier which is based on the Trust's performance relative to its peers and may range from zero to two times the value of the notional trust units held at vesting.

Compensation expense is recognized over the vesting period and is determined based on the market price of the notional trust units at each period end and an expected performance multiplier with a corresponding increase or decrease in liabilities. Classification between current liabilities and long-term liabilities is dependent on the expected payout date.

The Trust charges the accrued compensation amounts relating to head office employees to general and administrative expenses, the amounts relating to field staff to operating costs, and the amounts relating to exploitation and development personnel to property, plant and equipment.

The Trust has not incorporated an estimated forfeiture rate for units that will not vest and accounts for actual forfeitures as they occur.

Basic and Diluted per Trust Unit Calculation

Basic net income per trust unit is calculated by dividing net income by the weighted average number of trust units outstanding. Diluted net income per unit is calculated using the treasury stock method to determine the dilutive effects of the convertible debentures. Dilutive trust units are arrived at by taking the weighted average trust units and the trust units issuable on conversion of the convertible debentures, giving effect to the potential dilution that would occur had conversion occurred at the beginning of the period or on issuance of the convertible instrument, whichever is later.

Cash and Cash Equivalents

Cash and cash equivalents include short-term investments with a maturity of three months or less when purchased.

Comparative Information

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

3. CHANGES IN ACCOUNTING POLICIES

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 five 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. There were no changes to the measurement or presentation of these financial assets or liabilities at the date of adoption, other than bank debt as discussed below. 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 certain revenues, expenses, gains and losses not included in the determination of net income. Section 3251 provides guidance on the presentation and disclosure of the components of equity, including accumulated other comprehensive income.

These standards were applied on a prospective basis on January 1, 2007, in accordance with the relevant transitional provisions with no restatement of prior periods.

As a result of the new standards, the Trust began to fair value its derivative contracts. 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 allowed 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 has been reclassified to net income during 2007 in accordance with the terms of the derivatives.

On adoption, the Trust elected to recognize, as separate assets and liabilities, only those embedded derivatives in hybrid instruments issued, acquired or substantively modified after January 1, 2003. The Trust did not identify any material embedded derivatives which required separate recognition and measurement.

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 straight-line basis with the deferred amount included in accounts receivable. There was no impact at January 1, 2007 resulting from this change.

Future Accounting Changes

The CICA issued new accounting standards: Section 1535 "Capital Disclosures", Section 3862 "Financial Instruments - Disclosures", and Section 3863 "Financial Instruments – Presentation". These standards are effective January 1, 2008.

Sections 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 Trust is currently assessing the impact of these standards on its financial statements, however, it is not anticipated that the adoption of these new standards will impact the amounts reported in the Trust's financial statements as they primarily relate to disclosure.

4. CORPORATE 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)	\$ (4,366)
Property, plant and equipment	262,678
Asset retirement obligations	(12,625)
	\$ 245,687
Consideration:	
Cash	\$ 245,110
Acquisition costs	577
	\$ 245,687

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.

5. RELATED PARTY TRANSACTIONS

The Manager provides certain services pursuant to a management contract. This contract requires the Trust to reimburse the Manager, at cost, for general and administrative expenses ("G&A") incurred by the Manager on behalf of the Trust. In 2007 the Trust paid \$11.6 million (2006 - \$6.6 million) for the reimbursement of G&A. The Trust accrues for its share of unit based incentive compensation as units vest, but only pays the Manager its share of the expense when cash compensation is paid to employees under the terms of the unit based incentive compensation plan. During 2007 \$2.2 million was paid in the first quarter of 2007 relating to notional units that vested November 30, 2006.

On May 31, 2006 the Trust's unitholders approved the restructuring of the management contract with the Manager. Prior to this date the Trust was required to pay an interim monthly management fee, of which \$1.4 million was paid during 2006. Prior to January 1, 2006, the Trust was required to pay a monthly base management fee equal to three percent of its net production revenue and a quarterly performance fee based on the Trust's overall return compared to the S&P / TSX Capped Energy Trust Index.

Under the terms of the restructuring, the Trust agreed to pay a one-time \$30 million restructuring fee in exchange for the elimination of any further base and performance management fees payable by the Trust and the acquisition of a 50 percent ownership in the Manager's administrative capital assets, effective January 1, 2006. In payment of the restructuring fee, the Trust issued, to an affiliate of the Manager, 1,592,357 trust units of the Trust at a price of \$18.84 per trust unit. The subscription price was based on the weighted average trading price of the trust units over the five consecutive trading days ending on the third trading day preceding March 1, 2006, the date of the agreement.

Of the \$30 million restructuring fee, \$2.8 million was allocated to the administrative assets acquired and capitalized as property, plant and equipment. The balance of \$27.2 million, representing the elimination of future management and performance fees, has been recorded as a non-cash charge to income.

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

	2007	2006
Due from NAL Resources Limited	\$ 14,203	\$ 1,478
Due to NAL Resources Management Limited	\$ (2,826)	\$ (3,718)

6. PROPERTY, PLANT AND EQUIPMENT

Net book value as at December 31:	2007	2006
Petroleum and natural gas properties, at cost	\$ 1,687,331	\$ 1,293,854
Less: Accumulated depletion and depreciation	(706,443)	(551,059)
	\$ 980,888	\$ 742,795

Costs associated with undeveloped land of \$30.1 million (2006 - \$nil) have been excluded from the depletion calculation for the year ended December 31, 2007.

Future development costs for proved reserves of \$41.6 million (2006 - \$49.3 million) have been included in the depletion calculation.

During 2007, the Trust capitalized \$4.5 million (2006 - \$4.3 million) of general and administrative costs and \$0.9 million (2006 - \$1.7 million) of unit based incentive compensation that were directly related to exploitation and development programs.

The Trust performed a ceiling test calculation at December 31, 2007 to assess the recoverable value of property, plant and equipment. The oil and gas future prices are based on the January 1, 2008 commodity price forecast of our independent reserve evaluators, adjusted for commodity differentials specific to the Trust. The following table summarizes the benchmark prices used in the ceiling test calculation. Based on these assumptions, the undiscounted value of net reserves from the Trust's proved reserves exceeded the carrying value of property, plant and equipment as at December 31, 2007.

Year	WTI Oil (US\$/bbls)	US\$/Cdn\$ Exchange Rate	WTI Oil (Cdn\$/bbls)	AECO Gas (Cdn\$/GJ)
2008	90.00	1.0	90.00	6.45
2009	86.70	1.0	86.70	7.00
2010	83.20	1.0	83.20	7.00
2011	79.60	1.0	79.60	7.00
2012	78.50	1.0	78.50	7.10
Remainder ⁽¹⁾	2%	1.0	2%	3%

(1) Percentage change represents the change in each year after 2012 to the end of the reserve life.

7. BANK DEBT

	2007	2006
Production loan facility	\$ 273,528	\$ 219,000
Working capital facility	2,102	1,785
Total debt outstanding	\$ 275,630	\$ 220,785

The Trust maintains a \$400 million fully secured, extendible, 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 existing and future acquired properties and assets of the Trust and its subsidiary and affiliated entities. The facility was renewed in April 2007, and revised in conjunction with the Seneca acquisition in September 2007, and will revolve until April 30, 2008 at which time it may be extended for a further 364-day revolving period upon agreement between the Trust and the bank syndicate. If the credit facility is not extended in April 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, if any, in May 2010.

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

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 US dollars by way of US 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 US base rates plus an applicable margin or stamping fee. The applicable margin or stamping fee, if any, varies based on the consolidated debt-to-cash flow ratio of the Trust. As at December 31, 2007 and 2006 all amounts outstanding were in Canadian dollars.

On December 31, 2007 the effective interest rate on amounts outstanding under the credit facility was 5.74 percent (2006 - 5.18 percent).

8. CONVERTIBLE DEBENTURES

On August 28, 2007 the Trust issued \$100 million principal amount of 6.75 percent 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 any time into 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 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	-	635	-
Balance, December 31, 2007	\$100,000	\$90,876	\$5,759

9. UNIT-BASED INCENTIVE COMPENSATION PLAN

The Manager has a long term incentive plan under which employees receive cash compensation based upon the value and overall return of a specified number of awarded notional trust units on a fixed vesting date. The notional trust unit grants are in the form of Restricted Trust Units ("RTUs") and Performance Trust Units ("PTUs"). RTUs vest one third on November 30 in each of the three years after grant. PTUs vest on November 30, three years after grant.

The Trust recorded a total compensation expense of \$3.0 million in 2007 of which \$2.1 million was recorded as an expense and \$0.9 million as property, plant and equipment (2006 - \$2.5 million expense, \$1.7 million property, plant and equipment). The compensation expense was based on the December 31, 2007 trust unit price of \$11.60 (2006 - \$12.31), accrued distributions, performance factors, and the number of units vesting on maturity.

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

	2007	2006
Balance, beginning of year	\$ 4,153	\$ —
Increase in liability	3,027	4,153
Cash payout, relating to units vested November 30, 2006	(2,184)	—
Balance, end of year	\$ 4,996	\$ 4,153
Current portion of liability ⁽¹⁾	\$ 3,248	\$ 3,148
Long-term liability	\$ 1,748	\$ 1,005

(1) Included in accounts payable and accrued liabilities.

10. 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 \$89.6 million as at December 31, 2007 (2006 - \$65.6 million) based on a total undiscounted and inflated amount of cash flows required to settle its asset retirement obligations of \$276.0 million (2006 - \$224.7 million). These costs are expected to be made over the next 45 years with the majority of the costs incurred between 2008 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.

	2007	2006
Balance, beginning of year	\$ 65,574	\$ 61,908
Accretion expense	5,533	4,984
Revisions to estimates	10,294	39
Liabilities incurred	1,079	3,078
Liabilities acquired (Note 4)	12,625	-
Liabilities settled	(5,503)	(4,435)
Balance, end of year	\$ 89,602	\$ 65,574

11. UNITHOLDERS EQUITY

Unitholders' Capital

The Trust is authorized to issue 500 million trust units of which 90 million units were issued and outstanding as at December 31, 2007 (December 31, 2006 - 78 million). Each trust unit is transferable, carries the right to one vote and represents an equal undivided beneficial interest in any distributions from the Trust and in the assets of the Trust in the event of termination or winding up of the Trust. All trust units are of the same class with equal rights and privileges.

Redemption

Unitholders may redeem their trust units for cash at any time, up to an aggregate maximum value of \$100,000 in any calendar month, by delivering their trust unit certificates to the Trustee, accompanied by a properly completed notice requesting redemption. The redemption amount per trust unit will be the lesser of 95 percent of the market price of the trust units on the principal market on which the trust units are quoted as trading during the ten-trading day period commencing immediately after the date on which the trust units are surrendered for redemption, and the closing market price of the trust units or the principal market on which the units are quoted for trading on the date that the trust units are tendered for redemption.

Units Issued:

	2007		2006	
	Units	Amount	Units	Amount
Balance, beginning of the year	77,971	\$ 824,986	73,977	\$ 753,585
Issued for cash	10,246	125,001	-	-
Issued under management agreement restructuring (Note 5)	-	-	1,592	30,000
Less issue expenses	-	(7,134)	-	(29)
Issued from Distribution Reinvestment Plan	2,277	26,735	2,402	41,430
Balance, end of the year	90,494	\$ 969,588	77,971	\$ 824,986

Distribution Reinvestment Plan

The Trust has in place a Distribution Reinvestment Plan ("DRIP") and a Premium Distribution Reinvestment Plan ("Premium DRIP"). The regular DRIP entitles unitholders to reinvest cash distributions in additional units of the Trust at 95 percent of the average market price with no additional fees or commissions. The average market price is the arithmetic average of the daily volume weighted average trading price of the trust units during a defined period before the distribution payment date.

The Premium DRIP component of the plan allows unitholders to exchange new trust units, acquired by reinvesting their cash distributions, for a cash payment from the plan broker equal to 102 percent of the monthly distribution on the applicable distribution payment date.

The trust units issued under the Premium DRIP component of the plan at a five percent discount to the average market price will be delivered to the plan broker in exchange for 102 percent of the cash distribution payable on the participant's existing trust units. At certain times and at the discretion of management, the Premium DRIP may be suspended.

Cash Distributions

The Trust is required to distribute all of its cash available for distribution each calendar month, in accordance with the terms of the Trust Indenture. The cash available for distribution is defined as all cash amounts received less all costs, expenses, liabilities or obligations of the Trust, plus net proceeds from the issuance of units, less any amounts the Trustee, upon recommendations of the Manager, considers it necessary to retain. The amount considered necessary to retain includes: any costs, expenses, liabilities or obligations which are reasonably expected to be incurred such as for property, plant and equipment; amounts required to be retained for repayment in order to comply with loan agreements; an allowance for contingencies, working capital, investments or acquisitions; or any amount appropriate to retain for a reserve to stabilize distributions. The Trust intends to continue to make cash distributions, however, these cash distributions cannot be guaranteed.

Distributions since the inception of the Trust are as follows:

	Total
Accumulated distributions at December 31, 2005	\$ 532,891
2006 distributions	169,589
Accumulated distributions at December 31, 2006	\$ 702,480
2007 distributions	158,601
Accumulated distributions at December 31, 2007	\$ 861,081

Per Unit Information

Basic net income per trust unit is calculated using the weighted average number of trust units outstanding. The calculation of diluted net income per trust unit excludes the convertible debentures as the trust units potentially issuable on the conversion of the convertible debentures are anti-dilutive for the year ended December 31, 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 year ended December 31, 2007 were 2,465,753. As at December 31, 2007, the total convertible debentures outstanding were immediately convertible to 7,142,857 trust units.

Deficit

The deficit is comprised of the following:

	2007	2006
Accumulated income	\$ 390,451	\$ 333,994
Accumulated cash distributions	(861,081)	(702,480)
Deficit, end of year	\$(470,630)	\$ (368,486)

The Trust has historically paid cash distributions in excess of accumulated income as cash distributions are based on cash flow generated in the period whereas accumulated income is based on net income which includes non-cash items such as depletion, depreciation, accretion, future income taxes and unrealized gains and losses on derivative contracts.

Accumulated Other Comprehensive Income

	2007	2006
Balance, beginning of year	\$ -	\$ -
Fair value of derivative instruments on transition to new accounting standards, net of tax of \$1,349 (Note 3)	3,172	-
Reclassification to net income in period, net of tax \$1,349 (Note 3)	(3,172)	-
Balance, end of year	\$ -	\$ -

12. INCOME TAXES

The provision for income taxes in the consolidated financial statements differs from the result that would have been obtained by applying the combined federal and provincial tax rate to income before income taxes as follows:

	2007	2006
Income before taxes	\$ 52,837	\$ 58,789
Statutory income tax rate	33.4%	39.0%
Expected income tax expense	17,648	22,928
Increase (decrease) resulting from:		
Non-deductible Crown charges	-	8,471
Resource allowance	-	(9,208)
Alberta Royalty Tax Credit	17	(39)
Valuation allowance	32	200
Net income of the Trust	(23,672)	(24,937)
Other	2,397	968
Effect of future tax rate reductions	(42)	208
Current and future income tax recovery	(3,620)	(1,409)

74 The future income tax asset is comprised of:

	2007	2006
Property, plant and equipment	\$ (3,768)	\$ (6,794)
Future tax liability resulting from different year ends	(2,570)	-
Non-capital tax loss carry forward	4,396	3,197
Asset retirement obligations	6,985	7,889
Other	2,921	400
	7,964	4,692
Valuation allowance	(1,266)	(1,347)
Future income tax asset	\$ 6,698	\$ 3,345
Current asset	\$ 2,602	\$ -
Long-term asset	\$ 4,096	\$ 3,345

The Trust meets the criteria qualifying it for income tax treatment permitting a tax deduction for distributions paid to the unitholders in addition to other deductions available in the Trust. At December 31, 2007, the book amounts of the Trust's assets and liabilities exceed the tax basis by \$213.5 million (2006 - \$192.2 million).

The Trust has non-capital loss carry forwards of \$17.0 million of which \$9.1 million expire between 2009, and 2015, and \$7.9 million expire between 2025 and 2027.

On June 22, 2007, the Budget Implementation Act 2007 (Canada) was enacted to, among other things, implement the October 31, 2006 announcement of the changes to taxability of Income Trusts made by the Department of Finance. Under this legislation, distributions to unitholders will not be deductible by publicly traded income trusts and, as a result, the Trust will be taxed on its income similar to corporations. These measures are considered substantively enacted for purposes of Canadian generally accepted accounting principles. Accordingly, the Trust measured future income tax assets and liabilities associated with this new tax. 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 taxable temporary differences of the Trust 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.

13. 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 percent of its estimated annual net of royalty production. NAL's risk management programs tend to be scaled-in over time using a combination of swaps and collars.

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

Term	Contract	Volume bbls/d	Total Volume bbls	Bought Put US\$/bbl	Sold Call US\$/bbl	Swap US\$/bbl
COLLARS						
January-June	2-way	100	18,200	75.00	81.00	-
January-December	2-way	100	36,600	85.00	100.00	-
January-December	2-way	100	36,600	83.00	100.00	-
July-December	2-way	100	18,400	75.00	85.50	-
January-June	2-way	100	18,200	73.00	79.00	-
January-June	2-way	100	18,200	72.00	78.00	-
January-June	2-way	100	18,200	71.00	78.50	-
January	2-way	100	3,100	70.50	75.50	-
January-June	2-way	100	18,200	70.00	76.25	-
January	2-way	100	3,100	70.00	75.00	-
April-June	2-way	100	9,100	69.00	74.25	-
January-June	2-way	100	18,200	69.00	74.00	-
January-June	2-way	200	36,400	68.50	73.00	-
January-March	2-way	100	9,100	68.00	74.35	-
January-March	2-way	100	9,100	68.00	73.60	-
January-March	2-way	100	9,100	66.00	71.90	-
January-June	2-way	200	36,400	64.00	72.26	-
January-June	2-way	100	18,200	70.00	75.05	-
January-December	2-way	100	36,600	76.00	87.00	-
July-December	2-way	100	18,400	94.00	100.50	-
July-December	2-way	100	18,400	92.00	101.50	-
Weighted Average	Collars		407,800	74.93	83.58	-

Term	Contract	Volume bbls/d	Total Volume bbls	Bought Put US\$/bbl	Sold Call US\$/bbl	Swap US\$/bbl
SWAPS						
January-December	swap	100	36,600	-	-	73.50
April-December	swap	100	27,500	-	-	94.00
January-December	swap	100	36,600	-	-	92.18
January-December	swap	100	36,600	-	-	87.10
January-December	swap	100	36,600	-	-	79.10
January-December	swap	100	36,600	-	-	71.00
January-December	swap	100	36,600	-	-	80.75
March-October	swap	100	24,500	-	-	88.10
July-December	swap	100	18,400	-	-	94.50
July-December	swap	100	18,400	-	-	94.04
July-December	swap	100	18,400	-	-	92.00
July-December	swap	100	18,400	-	-	98.50
July-December	swap	100	18,400	-	-	98.25
July-December	swap	100	18,400	-	-	98.10
July-December	swap	100	18,400	-	-	97.25
July-December	swap	100	18,400	-	-	96.75
Weighted Average	Swaps		418,800	-	-	87.40

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

Term	Contract	Volume bbls/d	Total Volume bbls	Bought Put Cdn\$/bbl	Sold Call Cdn\$/bbl	Swap Cdn\$/bbl
COLLARS						
July-December	2-way	100	18,400	85.00	94.40	-
July-December	2-way	100	18,400	85.00	96.00	-
January-December	2-way	100	36,600	87.10	97.35	-
February-June	2-way	100	15,100	71.75	76.88	-
February-December	2-way	100	33,500	72.40	77.54	-
Weighted Average	2-way		122,000	80.53	88.73	-

Term	Contract	Volume bbls/d	Total Volume bbls	Bought Put Cdn\$/bbl	Sold Call Cdn\$/bbl	Swap Cdn\$/bbl
SWAPS						
January-December	swap	100	36,600	-	-	84.90
January-December	swap	100	36,600	-	-	90.05
April-June	swap	100	9,100	-	-	71.55
February-December	swap	100	33,500	-	-	90.15
February-December	swap	100	33,500	-	-	90.05
April-December	swap	100	27,500	-	-	90.20
January-December	swap	100	36,600	-	-	89.05
January-December	swap	100	36,600	-	-	87.00
January-December	swap	100	36,600	-	-	83.80
January-June	swap	100	18,200	-	-	77.07
January-June	swap	200	36,400	-	-	75.05
January-December	swap	100	36,600	-	-	73.55
January-March	swap	200	18,200	-	-	70.00
July-December	swap	100	18,400	-	-	93.00
January-June	swap	100	18,200	-	-	73.77
July-December	swap	100	18,400	-	-	98.50
January-December	swap	100	36,600	-	-	90.70
April-December	swap	100	27,500	-	-	91.00
March-October	swap	100	24,500	-	-	87.50
January-June	swap	100	18,200	-	-	84.90
April-December	swap	100	27,500	-	-	96.50
April-December	swap	100	27,500	-	-	97.00
July-December	swap	100	18,400	-	-	94.00
July-December	swap	200	36,800	-	-	97.00
Weighted Average	Swaps		668,000	-	-	87.10

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

Term	Contract	Volume GJ/d	Total Volume GJ	Bought Put Cdn\$/GJ	Sold Call Cdn\$/GJ	Swap Cdn\$/GJ
COLLARS						
January-March	2-way	1,000	91,000	8.40	10.15	-
January-March	2-way	2,000	182,000	8.40	10.25	-
January-March	2-way	1,000	91,000	8.40	10.40	-
January-March	2-way	1,000	91,000	8.00	9.40	-
November-December	2-way	1,000	61,000	7.30	8.50	-
November-December	2-way	1,000	61,000	7.75	9.05	-
November-December	2-way	1,000	61,000	7.55	9.10	-
November-December	2-way	1,000	61,000	7.55	9.05	-
November-December	2-way	1,000	61,000	7.30	8.60	-
November-December	2-way	1,000	61,000	7.85	9.25	-
November-December	2-way	1,000	61,000	8.00	9.50	-
Weighted Average	2-ways		882,000	7.98	9.57	-

Term	Contract	Volume GJ/d	Total Volume GJ	Bought Put Cdn\$/GJ	Sold Call Cdn\$/GJ	Swap Cdn\$/GJ
SWAPS						
January-March	swap	1,000	91,000	-	-	8.90
January-March	swap	1,000	91,000	-	-	9.13
January-December	swap	2,000	732,000	-	-	7.60
April-December	swap	1,000	275,000	-	-	7.40
January-December	swap	2,000	732,000	-	-	7.40
April-December	swap	1,000	275,000	-	-	7.31
January-December	swap	2,000	732,000	-	-	7.26
April-December	swap	1,000	275,000	-	-	7.05
February-December	swap	1,000	335,000	-	-	7.20
January-March	swap	1,500	136,500	-	-	7.20
March-December	swap	1,000	306,000	-	-	7.10
April-December	swap	1,000	275,000	-	-	7.15
April-December	swap	1,000	275,000	-	-	7.10
April-December	swap	1,000	275,000	-	-	7.05
April-December	swap	1,000	275,000	-	-	7.23
April-October	swap	1,000	214,000	-	-	7.35
April-October	swap	1,000	214,000	-	-	7.60
April-October	swap	1,000	214,000	-	-	7.85
April-December	swap	1,000	275,000	-	-	7.30
April-October	swap	1,000	214,000	-	-	7.65
April-October	swap	1,000	214,000	-	-	7.43
March-December	swap	1,000	306,000	-	-	7.10
April-October	swap	1,000	214,000	-	-	7.15
April-October	swap	1,000	214,000	-	-	7.09
April-October	swap	1,000	214,000	-	-	7.80
November-December	swap	1,000	61,000	-	-	8.66
Weighted Average	Swaps		7,434,500	-	-	7.38

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

Term	Contract	Volume bbls/d	Total Volume bbls	Bought Put US\$/bbl	Sold Call US\$/bbl	Swap US\$/bbl
COLLARS						
January-December	2-way	100	36,500	92.00	101.50	-
January-June	2-way	100	18,100	94.00	100.50	-
Weighted Average	2-ways		54,600	92.66	101.17	-

Term	Contract	Volume bbls/d	Total Volume bbls	Bought Put US\$/bbl	Sold Call US\$/bbl	Swap US\$/bbl
SWAPS						
January-June	swap	100	18,100	-	-	97.25
January-December	swap	100	36,500	-	-	96.75
Weighted Average	Swaps		54,600	-	-	96.92

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

Term	Contract	Volume bbls/d	Total Volume bbls	Bought Put Cdn\$/bbl	Sold Call Cdn\$/bbl	Swap Cdn\$/bbl
SWAPS						
January-September	swap	100	27,300	-	-	96.50
January-December	swap	200	73,000	-	-	97.00
January-September	swap	100	27,300	-	-	97.00
Weighted Average	Swaps		127,600	-	-	96.89

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

Term	Contract	Volume GJ/d	Total Volume GJ	Bought Put Cdn\$/GJ	Sold Call Cdn\$/GJ	Swap Cdn\$/GJ
COLLARS						
January-March	2-way	1,000	90,000	8.00	9.50	-
January-March	2-way	1,000	90,000	7.75	9.05	-
January-March	2-way	1,000	90,000	7.85	9.25	-
January-March	2-way	1,000	90,000	7.55	9.10	-
January-March	2-way	1,000	90,000	7.55	9.05	-
January-March	2-way	1,000	90,000	7.30	8.60	-
January-March	2-way	1,000	90,000	7.30	8.50	-
Weighted Average	2-way		630,000	7.61	9.01	-

Term	Contract	Volume GJ/d	Total Volume GJ	Bought Put Cdn\$/GJ	Sold Call Cdn\$/GJ	Swap Cdn\$/GJ
SWAPS						
January-March	swap	1,000	90,000	-	-	7.40
January-March	swap	1,000	90,000	-	-	7.05
January-March	swap	1,000	90,000	-	-	7.05
January-March	swap	1,000	90,000	-	-	7.10
January-March	swap	1,000	90,000	-	-	7.15
January-March	swap	1,000	90,000	-	-	7.23
January-March	swap	1,000	90,000	-	-	7.31
January-March	swap	1,000	90,000	-	-	7.30
January-March	swap	1,000	90,000	-	-	8.66
Weighted Average	Swaps		810,000	-	-	7.36

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 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 December 31, 2007 was \$98.0 million, based on market price.

Derivative contracts are recorded at fair value on the balance sheet as current or long-term, assets or liabilities, based on their fair values on a contract by contract basis.

	2007	2006
Current unrealized gain on derivative contracts	\$ 3,389	\$ -
Current unrealized loss on derivative contracts	(12,973)	-
Fair value of derivative contracts	\$ (9,584)	\$ -

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 was transferred to net income over the term of the respective contracts. During 2007, the full amount of \$4.5 million has been reclassified to net income and is included in the gain (loss) on derivative contracts.

As at December 31, 2007, the total fair value of derivative contracts was a liability of \$9.6 million. The change in the fair value for the year of \$14.1 million has been recognized as an unrealized loss in the statement of income.

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

	2007	2006
Unrealized loss, beginning of period	\$ -	\$ -
Unrealized gain on adoption of new accounting standards (Note 3)	4,521	-
Unrealized loss, end of period	(9,584)	-
Unrealized loss	(14,105)	-
Realized gain (loss) in the period	(2,435)	3,375
Reclassification from other comprehensive income	4,521	-
Gain (loss) on derivative contracts	\$ (12,019)	\$ 3,375

Credit Risk Management

Accounts receivable includes amounts due from NAL Resources for oil, natural gas and natural gas liquids sales. Oil and gas marketing is conducted by the Manager on behalf of the Trust and NAL Resources generally with large, creditworthy purchasers, for which the Trust views the credit risk as low. The credit risk associated with NAL Resources is also considered to be minimal as amounts owing are from actual collections of oil and gas sales.

Interest Rate Risk

The Trust is exposed to interest rate risk to the extent that bank debt is at a floating interest rate.

Foreign Exchange Risk

The Trust is exposed to foreign currency fluctuations as crude oil and natural gas prices received are referenced to US dollar denominated prices.

14.COMMITMENTS

At December 31, 2007 the Trust had the following contractual obligations and commitments:

	2008	2009	2010	2011	2012	Thereafter
Office lease ⁽¹⁾	\$ 3,672	\$ 3,672	\$ 3,366	\$ -	\$ -	\$ -
Transportation agreement	1,123	1,123	84	-	-	-
Processing agreement ⁽²⁾	469	446	428	414	401	384
Drilling rigs ⁽³⁾	494	-	-	-	-	-
Retention bonus ⁽⁴⁾	578	-	-	-	-	-
Total	\$ 6,336	\$ 5,241	\$ 3,878	\$ 414	\$ 401	\$ 384

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

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

(3) Represents the Trust's share of the 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.

15.SUBSEQUENT EVENT

On February 27, 2008 the Trust completed the acquisition of all of the issued and outstanding common shares of two private oil and gas companies ("Private Companies"). Total consideration is approximately \$115 million before closing adjustments, consisting of approximately 2.4 million trust units and \$86.25 million in cash.

The Trust closed two private company acquisitions and one asset purchase by February 27, 2008, all with interests in southeast Saskatchewan, for a total purchase price of approximately \$64.4 million net to the Trust. These transactions will add 2.1 million boe of proved plus probable reserves in close proximity to existing fields at Alida and Steelman/Elswick. For 2008, these acquisitions are expected to add approximately 700 boe/d of production on an annualized basis with an additional \$5 million in capital expenditures. NAL's strategic partner, Manulife Financial Corporation, participated equally in these acquisitions, demonstrating the value of our strategic partnership and their continued interest in adding investments in the oil and gas sector. These 'tuck-in acquisitions' add to the Trust's cornerstone presence in southeast Saskatchewan, and position NAL for further reserves additions as well as infrastructure and cost synergies.

In addition, the Trust entered into an agreement with a wholly owned subsidiary of MFC, to contribute the assets and liabilities of the Private Companies to a limited partnership owned 50 percent by the Trust and 50 percent by MFC. MFC acquired its 50 percent interest in the limited partnership by payment in cash for one half of the purchase price for the Private Companies.

Consequently, the total acquisition cost to the Trust for its 50 percent interest in the acquired companies is approximately \$57.5 million, comprising of approximately 2.4 million trust units and \$28.75 million in cash.

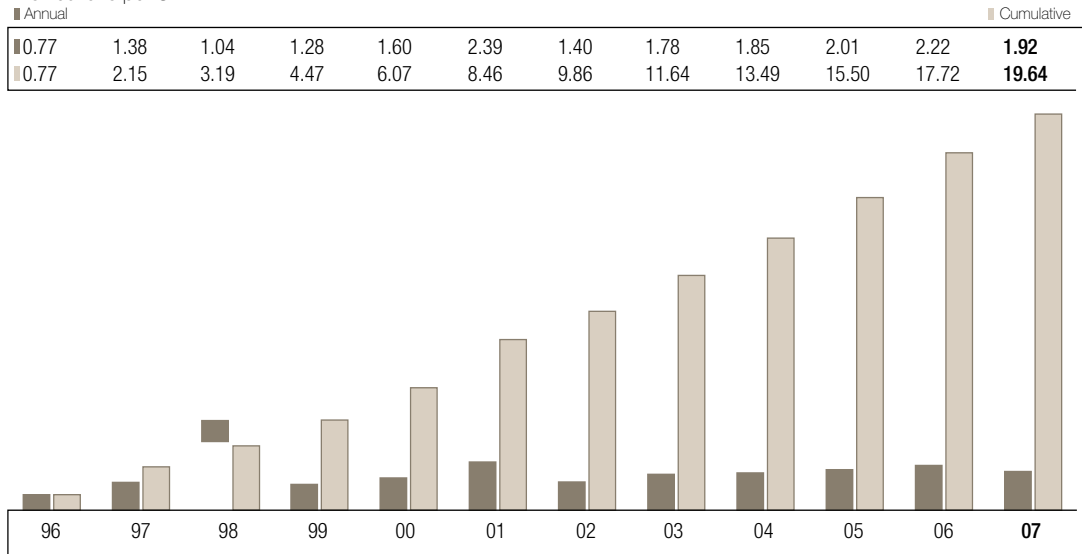
Performance

NAL's initial public offering was in May, 1996 at \$10.25 per unit. Since that time the Trust has paid out \$861 million in distributions or \$19.64 per unit. Sometime late in 2008 cumulative distributions will surpass the \$1 billion mark.

The unit price reached a peak of \$20.75 in late July, 2006 but fell sharply following the federal government's announcement of a new tax on income trusts later that year. Although the tax will not be implemented until 2011, the impact on the market value of units was felt immediately.

In 2007 an investment in NAL generated a total return (unit price appreciation plus distributions) of 14.6 percent, assuming reinvestment of distributions, which was in the top quartile among Canadian energy trusts.

Distributions per Unit



Unit Price Performance



FSC Logo Here Please

Corporate Information

Directors

J. Charles Caty, Chairman of the Board
Irvine J. Koop
Dennis G. Flanagan
Barry D. Stewart

Gordon S. Lackenbauer
Warren A. Thomson
Andrew B. Wiswell

Officers

Andrew B. Wiswell, President and Chief Executive Officer
Keith A. Steeves, Vice President, Finance and Chief Financial Officer
Marlon J. McDougall, Vice President, Operations
Ben L. Bury, Vice President, Marketing
John H. Kousinoris, Corporate Secretary

Legal Counsel

Bennett Jones LLP

Auditors

KPMG LLP

Independent Engineers

McDaniel and Associates Consultants Ltd.

Banks

Bank of Montreal
Royal Bank of Canada
CIBC
Bank of Nova Scotia

Trustee & Transfer Agent

Computershare Trust Company of Canada
Telephone: 1 (800) 564-6253
Website: www.computershare.com

Trading

Toronto Stock Exchange
Symbol: NAE.UN

Head Office

1000, 550 – 6th Avenue S.W.
Calgary, Alberta T2P 0S2
Telephone: (403) 294-3600
Facsimile: (403) 294-3601

Investor Relations

Toll-Free Telephone: 1 (888) 223-8792
In Calgary: (403) 294-3620
Facsimile: (403) 515-3407
E-mail: investor.relations@nal.ca
Website: www.nal.ca

Annual General Meeting

The Annual Meeting of the shareholders of NAL will be held at 3:00 p.m. (MDT) on Wednesday, May 21, 2008, at the Metropolitan Conference Centre, Strand/Tivoli Room, Calgary, Alberta. Shareholders are urged to attend and participate in the business of the meeting.



NAL Oil & Gas Trust
1000, 550 - 6th Avenue SW
Calgary, Alberta T2P 0S2

www.nal.ca