ARC

Second Quarter Interim Report

For The Three Months Ended June 30, 2006

	Three Months Ended June 30		Six Months Ended June 30	
	2006	2005	**2006**	2005
FINANCIAL				
($CDN thousands, except per unit and per boe amounts)				
Revenue before royalties	**306,749**	251,596	**625,680**	489,650
Per unit [1]	**1.51**	1.32	**3.09**	2.58
Per boe	**54.54**	50.40	**54.70**	49.07
Cash flow [2]	**194,653**	121,808	**385,852**	263,774
Per unit [1]	**0.96**	0.64	**1.90**	1.39
Per boe	**34.61**	24.40	**33.73**	26.43
Net income	**182,499**	73,215	**286,570**	111,861
Per unit [3]	**0.91**	0.39	**1.43**	0.60
Cash distributions	**120,620**	84,468	**240,487**	168,335
Per unit [1]	**0.60**	0.45	**1.20**	0.90
Payout ratio [4]	**62**	69	**62**	64
Net debt outstanding [5]	**567,442**	366,216	**567,442**	366,216
OPERATING				
Production				
Crude oil (bbl/d)	**27,805**	22,046	**28,723**	22,020
Natural gas (mcf/d)	**178,504**	173,116	**181,721**	174,586
Natural gas liquids (bbl/d)	**4,247**	3,962	**4,184**	4,016
Total (boe/d)	**61,803**	54,860	**63,194**	55,133
Average prices				
Crude oil ($/bbl)	**71.86**	58.37	**65.53**	56.02
Natural gas ($/mcf)	**6.35**	7.42	**7.39**	7.31
Natural gas liquids ($/bbl)	**54.44**	46.13	**53.69**	46.35
Oil equivalent ($/boe) [6]	**54.54**	50.40	**54.70**	49.06
Operating netback ($/boe)				
Commodity and other revenue (before hedging)	**54.54**	50.40	**54.70**	49.06
Transportation costs	**(0.66)**	(0.76)	**(0.64)**	(0.74)
Royalties	**(9.78)**	(10.34)	**(10.25)**	(9.67)
Operating costs	**(8.20)**	(7.35)	**(8.00)**	(6.73)
Netback (before hedging)	**35.90**	31.95	**35.81**	31.92
TRUST UNITS				
(thousands)				
Units outstanding, end of period	**201,495**	188,402	**201,495**	188,402
Units issuable for exchangeable shares	**2,895**	2,927	**2,895**	2,927
Total units outstanding and issuable for exchangeable shares, end of period	**204,441**	191,329	**204,390**	191,329
Weighted average units [7]	**200,814**	187,388	**200,202**	186,810
TRUST UNIT TRADING STATISTICS				
($CDN, except volumes) based on intra-day trading				
High	**28.61**	20.30	**28.61**	20.40
Low	**24.35**	16.88	**24.35**	16.55
Close	**28.00**	19.94	**28.00**	19.94
Average daily volume	**547,926**	604,981	**546,347**	685,964

(1) Per unit amounts (with the exception of per unit distributions) are based on weighted average units plus units issuable for exchangeable shares.

(2) Management uses cash flow to analyze operating performance and leverage. Cash flow as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Cash flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to cash flow throughout this report are based on cash flow from operating activities before changes in non-cash working capital and expenditures on site restoration and reclamation.

(3) Net income per unit is based on net income after non-controlling interest divided by weighted average units (excluding units issuable for exchangeable shares).

(4) Cash distributions divided by cash flow from operations. This ratio would have increased to 63 per cent for the three and six months ended June 30, 2006 if the exchangeable shares had been converted to trust units at the beginning of the period.

(5) Net debt excludes unrealized commodity and foreign exchange contracts asset and liability.

(6) Includes other revenue.

(7) Excludes trust units issuable for outstanding exchangeable shares at period end.

PROVEN PAST. PROMISING FUTURE.

ARC Energy Trust Seconnd Quarter Report 2006

MESSAGE TO UNITHOLDERS

ARC's unitholders are realizing the benefits of ARC's long held strategy of striving for a balanced portfolio of assets. Despite a 25 per cent drop in natural gas prices from the first quarter of 2006, cash flow increased by two per cent to $0.96 per unit as ARC's balanced portfolio benefited from record high oil prices. The decline in natural gas prices was predominantly due to high storage levels brought on by very mild winter weather. Oil prices increased based on unstable geopolitical factors, which resulted in concerns about oil supplies in several regions of the world. ARC was able to mitigate the drop in natural gas prices through higher realized revenues on the oil side and, $11 million in cash hedging gains. ARC has traditionally maintained a balanced production and reserves portfolio so as not to be overexposed to price volatility which, as we are now experiencing, sometimes occurs on just one of the commodities.

Production increased by 13 per cent to 61,803 from 54,860 in the second quarter of 2005. On a per unit basis, production increased by seven per cent to 0.31 boe per day per thousand units from 0.29 a year earlier. Historically, second quarter production drops slightly in comparison to the first quarter, due to the cessation of most development operations for spring break-up and maintenance activities traditionally conducted during May, June and July by ARC, and other operators, on oil and gas processing facilities. Approximately 1,400 boe per day of production was shut-in due to maintenance during the quarter. ARC's asset base is highly diversified with no property accounting for more than eight per cent of overall production. This split in production volumes mitigates losses in production when facilities are shut-in for scheduled maintenance, demonstrating the benefits of ARC's balanced and diversified production base.

As a result of strong cash flow, ARC has been able to fund 100 per cent of its capital program for the year-to-date out of cash flow, and maintain stable distributions while maintaining a payout ratio of just 62.2 per cent, slightly lower than the first quarter payout ratio of 63 per cent.

ARC expects a busy third quarter as it continues to execute a record capital development program with drilling activities taking place in all of ARC's core areas. ARC's board of directors has approved an increase in the capital budget to $370 million, up $30 million as a result of a $15 million increase for land purchases, new projects and increased costs. As a result of our strong production performance to date and with continued success on our development program, ARC has once again increased its production forecast for 2006 to 62,800 boes per day. This is up 1,800 boes per day from our initial guidance of 61,000 boes per day at the start of the year.

On July 11, 2006, ARC celebrated its 10 year anniversary. ARC is proud of what we have accomplished over our first 10 years, particularly the 27 per cent annualized return we have delivered to our unitholders. Since inception, our strategy has been clear and consistent: to utilize our unique managerial and technical expertise to acquire and develop quality assets to maximize long-term value to our unitholders. We have accomplished much over the past 10 years, but we still have much more we believe we can achieve with the hard work and dedication of our employees and the continued support of our investors.

John P. Dielwart
Director, President and
Chief Executive Officer

ACCOMPLISHMENTS / FINANCIAL UPDATE

- Production averaged 61,803 boe per day in the second quarter of 2006, 13 per cent higher than the 54,860 boe per day achieved in the second quarter of 2005. The increase in production is due to the Redwater and NPCU acquisitions made in late 2005, other smaller acquisitions and from the successful results of an active drilling program. Well reactivations and optimization at Redwater also contributed to increased production. Second quarter production was reduced, as expected, by approximately 1,400 boe per day due to downtime for spring breakup and turnaround activities. The Trust has increased its guidance for 2006 production to 62,800 boe per day from 62,000 boe per day as a result of the strong performance in the first half of 2006.

- The Trust spent $58.6 million on capital development and drilled 13 net wells on operated properties in the second quarter. The most significant activity was focused in northern and central Alberta during the second quarter as the Trust drilled nine net wells in these areas. In addition, the Trust was active in southeast Saskatchewan in the second quarter with the drilling of four net wells. The Trust has increased its 2006 capital expenditure budget to $370 million from $340 million.

- During the first half of 2006, the Trust acquired $30.4 million of oil and natural gas properties, net of minor property dispositions, which were financed in total with proceeds from the Trust's Distribution Reinvestment Plan and from the issuance of trust units pursuant to the Trust Unit Incentive Rights Plan.

- Production per unit increased by seven per cent to 0.31 boe per day per thousand units in the second quarter of 2006, from 0.29 boe per day per thousand units in the second quarter of 2005.

- ARC realized cash flow of $194.7 million ($0.96 per unit) in the second quarter of 2006 compared to $121.8 million ($0.64 per unit) in the second quarter of 2005. The 60 per cent increase in second quarter 2006 cash flow was due to higher oil prices and increased production volumes, which offset the impact of lower natural gas prices.

- Net income for the second quarter increased to $182.5 million from $73.2 million in the second quarter of 2005. This increase was primarily due to higher production, higher commodity prices and a future income tax recovery of $70.9 million in the second quarter of 2006 as a result of legislated federal and provincial corporate income tax rate reductions.

- ARC's second quarter average oil price increased 23 per cent to $71.86 per boe from $58.37 per boe in the second quarter of 2005. West Texas Intermediate ("WTI") increased 33 per cent in the second quarter of 2006 to US$70.70 per barrel compared to US$53.13 per barrel in the second quarter of 2005. Oil differentials contributed to the higher realized oil price as differentials narrowed significantly during the second quarter. A stronger Canadian dollar partially offset the effect of higher WTI prices and narrowing oil differentials. ARC's average natural gas price decreased by 14 per cent to $6.35 per mcf from $7.42 per mcf in the second quarter of 2005.

ACCOMPLISHMENTS / FINANCIAL UPDATE (cont'd)

- The Trust realized an operating netback, before hedging, of $35.90 per boe in the second quarter of 2006 compared to $31.95 per boe in the second quarter of 2005.

- Operating costs increased to $8.20 per boe in the second quarter of 2006 compared to $7.35 per boe in the second quarter of 2005. This increase in operating costs was primarily attributable to the acquisition of higher cost properties at Redwater and NPCU late in 2005 and overall industry operating cost increases. The Trust has decreased its guidance for 2006 operating costs to $8.40 per boe from $8.60 per boe as a result of strong performance in the first half of 2006 and increased production guidance for 2006.

- The Trust declared cash distributions of $120.6 million ($0.60 per unit) in the second quarter of 2006, resulting in a payout ratio of 62 per cent. The remaining 38 per cent of cash flow ($74.1 million) was used to fund 100 per cent of ARC's second quarter capital development program and to contribute $4.5 million to the reclamation fund. To date in 2006, the Trust has funded 100 per cent of the capital development program with cash flow after having funded distributions.

- The Trust celebrated its ten year anniversary on July 11, 2006 and has reflected on the multitude of accomplishments during that time. The Trust has provided superior financial returns to its unitholders and is recognized as an industry leader both financially and with respect to industry and community initiatives. The Trust's emphasis on long-term planning, risk management and adherence to diligent acquisition criteria have been key contributors to the Trust's success over its first 10 years of operations. Following are just a few of the Trust's many significant accomplishments in its first ten years:

  - On July 11, 1996 the Trust acquired existing oil and gas properties in Central Alberta with production of 9,600 boe per day. Since then, the Trust has increased production by 544 per cent to 61,803 boe per day.
  - The Trust has spent $1.1 billion on capital development and $2.5 billion on acquisitions since inception. As a result, the Trust has grown proved plus probable reserves by 714 per cent from 35 mmboe to 287 mmboe.
  - The Trust completed its initial public offering ("IPO") of 18 million trust units at $10 per unit on July 11, 1996. Since then, the Trust has provided unitholders with an annualized 27.3 per cent total return, consisting of total capital appreciation of $18.00 per unit and distributions of $17.43 per unit.
  - The Trust has generated cash flow from operations of $2.7 billion and paid out $1.9 billion to unitholders for a total payout ratio since inception of 71 per cent. The remaining cash flow was used to finance a portion of the Trust's capital development program and to provide funding for the Trust's reclamation fund for ongoing and future reclamation activities.
  - The Trust has diversified its asset base from one operating area in Central Alberta with an interest in 195 net wells to five core operating areas throughout Alberta, British Columbia and Saskatchewan and an interest in 4,833 net wells.

ACCOMPLISHMENTS / FINANCIAL UPDATE (cont'd)

- The Trust has continually emphasized safety as its number one priority in conducting its day-to-day operations. This is evident as the Trust has recorded only one lost time incident for Trust employees and contract operators throughout the entire 10 year history.
- The Trust has increased its unitholder base from 18 million trust units with a market capitalization of $180 million to 204 million trust units and exchangeable shares with a market capitalization of $5.7 billion. The Trust's unitholder base has evolved from primarily Canadian retail investors at inception to a diverse unitholder base of retail, institutional, and international investors.
- The Trust has strongly supported a number of community initiatives and philanthropic causes throughout its ten year history. The Calgary and Area United Way, the Alberta Children's Hospital, the Alberta Cancer Foundation, and the Canadian Sport Centre Calgary are just a few of the many organizations that the Trust has supported throughout the years. In addition to financial support, the Trust has provided such organizations with business expertise, employee volunteers, and tangible assets as needed.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2005.

This MD&A was written on July 28, 2006.

Management uses cash flow to analyze operating performance and leverage. Cash flow as presented does not have any standardized meaning prescribed by Canadian generally accepted accounting principles, ("GAAP") and therefore it may not be comparable with the calculation of similar measures for other entities. Cash flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP.

The following table reconciles the cash flow from operating activities to cash flow from operations, which is a term used frequently in this MD&A:

	Three Months Ended June 30		Six Months Ended June 30	
($ millions)	2006	2005	2006	2005
Cash flow from operating activities	182,110	127,917	371,204	256,653
Changes in non-cash working capital	10,574	(7,150)	11,414	5,033
Expenditures on site restoration and reclamation	1,969	1,041	3,234	2,088
Cash flow from operations	194,653	121,808	385,852	263,774

Management uses certain key performance indicators ("KPI's") and industry benchmarks such as operating netbacks ("netbacks"), total capitalization and payout ratios to analyze financial and operating performance. These KPI's and benchmarks as presented do not have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures for other entities.

This discussion and analysis contains forward-looking statements as to the Trust's internal projections, expectations or beliefs relating to future events or future performance, including the Trust's 2006 Guidance set forth herein, within the meaning of the "safe harbour" provisions of the United States Private Securities Litigation Reform Act of 1995 and the Securities Act (Ontario). In some cases, forward-looking statements can be identified by terminology such as "may", "will", "should", "expects", "projects", "plans", "anticipates" and similar expressions. These statements represent management's expectations or beliefs concerning, among other things, future operating results and various components thereof or the economic performance of ARC Energy Trust ("ARC" or "the Trust"). The projections, estimates and beliefs contained in such forward-looking statements are based on management's assumptions relating to the production performance of ARC's oil and gas assets, the cost and competition for services throughout the oil and gas industry in 2006 and the continuation of the current regulatory and tax regime in Canada, and necessarily involve known and unknown risks and uncertainties, including the business risks discussed in the MD&A, which may cause actual performance and financial results in future periods to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. Accordingly, readers are cautioned that events or circumstances could cause results to differ materially from those predicted. The Trust does not undertake to update any forward looking information in this document whether as to new information, future events or otherwise except as required by securities rules and regulations.

Highlights

	Three Months Ended June 30			Six Months Ended June 30		
(CDN$ millions, except per unit and volume data)	**2006**	2005	% Change	**2006**	2005	% Change
Cash flow from operations	**194.7**	121.8	60	**385.9**	263.8	46
Cash flow from operations per unit	**0.96**	0.64	50	**1.90**	1.39	37
Net income before taxes [(1)]	**111.6**	78.8	42	**205.4**	88.0	133
Net income	**182.5**	73.2	149	**286.6**	111.9	156
Distributions per unit	**0.60**	0.45	33	**1.20**	0.90	33
Payout ratio per cent [(2)]	**62**	69	(10)	**62**	64	(3)
Daily production (boe/d) [(3)]	**61,803**	54,860	13	**63,194**	55,133	15

(1) Represents net income after non-controlling interest and before the future income tax recovery.
(2) Based on cash distributions divided by cash flow from operations.
(3) Reported production amount is based on company interest before royalty burdens.

Net Income

Net income in the second quarter of 2006 was $182.5 million, an increase of $109.3 million from $73.2 million in the second quarter of 2005 primarily as a result of higher production and higher commodity prices in the second quarter. A significant future income tax recovery attributed to reductions in future federal and provincial corporate income tax rates was recorded in the second quarter of 2006. The second quarter future income tax recovery of $70.9 million included a $57.5 million recovery solely due to the reduction in future corporate income tax rates.

Cash Flow from Operations

Cash flow from operations increased by 60 per cent in the second quarter of 2006 to $194.7 million from $121.8 million in the second quarter of 2005. The increase in 2006 cash flow was the result of a 13 per cent increase in production volumes, higher commodity prices, partially offset by higher operating costs and royalties. Per unit cash flow from operations increased 50 per cent to $0.96 per unit from $0.64 per unit in the second quarter of 2005.

Following is a summary of variances in cash flow from operations for the second quarter and first six months of 2006 relative to the same periods of 2005:

	Three Months Ended June 30			Six Months Ended June 30		
	$ Millions	$ Per Unit	%Variance (2)	$ Millions	$ Per Unit	%Variance (2)
2005 Cash Flow	**121.8**	**0.64**	**-**	**263.8**	**1.39**	**-**
Volume variance	31.8	0.17	26	71.6	0.38	27
Price variance	23.3	0.12	19	64.4	0.34	24
Cash gains on commodity and foreign currency contracts (1)	38.5	0.21	32	44.4	0.24	17
Royalties	(3.4)	(0.02)	(3)	(20.8)	(0.11)	(8)
Expenses:						
Operating	(9.4)	(0.05)	(8)	(24.3)	(0.13)	(9)
Cash G&A	(4.2)	(0.02)	(3)	(5.7)	(0.03)	(2)
Interest and cash taxes	(3.7)	(0.02)	(3)	(8.0)	(0.05)	(3)
Other	-	-	-	0.5	(0.01)	-
Weighted average trust units	-	(0.07)	-	-	(0.12)	-
2006 Cash Flow	**194.7**	**0.96**	**60**	**385.9**	**1.90**	**46**

(1) Represents change in cash losses on commodity and foreign currency contracts including cash settlements on termination of commodity and foreign currency contracts.
(2) Variance is calculated based on $ millions column.

Production

Production volumes averaged 61,803 boe per day in the second quarter of 2006 compared to 54,860 boe per day in the second quarter of 2005. Production from the Redwater and NPCU properties purchased late in December 2005 contributed over 5,300 boe per day in the second quarter, while other 2005 acquisitions including additional interest at Berrymoor, Buckcreek and the Romulus acquisition, added approximately 1,200 boe per day. Second quarter 2006 production was four per cent lower than first quarter 2006 production largely as a result of spring breakup and turnaround activity that contributed to an approximate 1,400 boe per day reduction in second quarter production.

The Trust's annual objective is to maintain production through the drilling of wells and other development activities. In fulfilling this objective, there may be fluctuations in production depending on the timing of new wells coming on-stream. The Trust expects that 2006 full year production will be approximately 62,800 boe per day.

	Three Months Ended June 30			Six Months Ended June 30		
Production (1)	**2006**	2005	% Change	**2006**	2005	% Change
Crude oil (bbl/d)	**27,805**	22,046	26	**28,723**	22,020	30
Natural gas (mcf/d)	**178,504**	173,116	3	**181,721**	174,586	4
NGL (bbl/d)	**4,247**	3,962	7	**4,184**	4,016	4
Total production (boe/d)	**61,803**	54,860	13	**63,194**	55,133	15
% Natural gas production	**48**	53	(5)	**48**	53	(5)
% Crude oil and liquids production	**52**	47	5	**52**	47	5

(1) Reported production for a period may include minor adjustments from previous production periods.

Oil production increased by 26 per cent to 27,805 boe per day in the second quarter of 2006 from 22,046 boe per day in the second quarter of 2005. The increase in oil production was largely attributed to the Redwater and NPCU acquisition in the fourth quarter of 2005. The Trust's weighting of oil and liquids production increased to 52 per cent in the second quarter of 2006 from 47 per cent in 2005 as a result of the incremental Redwater and NPCU oil volumes.

Natural gas production increased to 178.5 mmcf per day in the second quarter of 2006, a three per cent increase compared to second quarter 2005 natural gas production of 173.1 mmcf per day. The majority of this increase was as a result of ARC's active internal drilling program, particularly three wells in the Pembina area and a very successful horizontal well drilled at Dawson in northern British Columbia.

During the second quarter of 2006, the Trust drilled 20 gross wells (13 net wells) on operated properties; nine gross oil wells and 11 gross natural gas wells with a 100 per cent success rate.

The following table summarizes the Trust's production by core area:

	Q2 2006				Q2 2005			
Core Areas [(1)]	**Total (boe/d)**	**Oil (bbls/d)**	**Gas (mmcf/d)**	**NGL (bbls/d)**	Total (boe/d)	Oil (bbls/d)	Gas (mmcf/d)	NGL (bbls/d)
Central AB	**8,082**	**1,501**	**30.7**	**1,464**	7,881	1,311	29.3	1,683
Northern AB & BC	**18,345**	**5,596**	**67.2**	**1,554**	18,064	5,905	65.0	1,331
Pembina & Redwater	**13,712**	**9,293**	**20.0**	**1,093**	7,422	3,705	17.5	800
S.E. AB & S.W. Sask.	**10,798**	**1,043**	**58.4**	**9**	11,426	1,486	59.6	10
S.E. Sask.	**10,866**	**10,372**	**2.2**	**127**	10,067	9,639	1.7	138
Total	**61,803**	**27,805**	**178.5**	**4,247**	54,860	22,046	173.1	3,962

(1) Provincial references: AB is Alberta, BC is British Columbia, Sask. Is Saskatchewan, S.E. is Southeast, S.W. is Southwest.

Commodity Prices Prior to Hedging

	Three Months Ended June 30			Six Months ended June 3E		
Benchmark Prices	**2006**	2005	% Change	**2006**	2005	% Change
AECO gas (CDN$/mcf) [(1)]	**6.28**	7.38	(15)	**7.78**	7.04	11
WTI oil (US$/bbl) [(2)]	**70.70**	53.13	33	**67.14**	51.53	30
USD/CAD foreign exchange rate	**0.89**	0.80	11	**0.88**	0.81	9
WTI oil (CDN$/bbl)	**79.08**	66.10	20	**76.28**	63.65	20

(1) Represents the AECO monthly posting.
(2) WTI represents West Texas Intermediate posting as denominated in US$.

While crude oil prices averaged US$70.70 per barrel in the second quarter of 2006, the Canadian dollar also remained strong and closed the quarter at $0.90. Despite the 33 per cent increase in the US$ WTI oil price in the second quarter 2006 relative to 2005, the Canadian denominated oil price increased by only 20 per cent to $79.08 per barrel in the second quarter of 2006 compared to $66.10 per barrel in the second quarter of 2005 as a result of the continued strengthening of the Canadian dollar. The Trust's realized oil price, before hedging, increased by 23 per cent to $71.86 per barrel in the second quarter of 2006 compared to $58.37 per barrel in 2005 in part due to the acquired Redwater and NPCU production that is a high quality light crude oil that receives a premium price. The higher realized oil price was also attributed to narrowing of the differential between the Edmonton posted price and medium and heavy oil posted prices. The Trust recorded a differential of $7.22 per barrel in the second quarter of 2006 compared to $7.73 per barrel in 2005 and $13.83 per barrel in the first quarter of 2006 from the Canadian dominated WTI to the Trust's realized price. The Trust's oil production consists predominantly of light and medium crude oil with heavy oil accounting for approximately five per cent of the Trust's liquids production.

Alberta AECO monthly Hub prices, which are commonly used as an industry reference for natural gas prices, averaged $6.28 per mcf in the second quarter of 2006 compared to $7.38 per mcf in the second quarter of 2005. ARC's realized gas price, before hedging, decreased by 14 per cent in the second quarter of 2006 to $6.35 per mcf compared to $7.42 per mcf in 2005. ARC's realized gas price is based on prices received at the various markets where the Trust sells its natural gas. ARC's natural gas sales portfolio consists of gas sales priced at the AECO monthly index, the AECO daily spot market, eastern and mid-west United States markets and a portion is sold through aggregators.

Prior to hedging activities, ARC realized commodity revenue of $54.54 per boe in the second quarter of 2006, an eight per cent increase over the $50.40 per boe received prior to hedging in the second quarter of 2005.

The following is a summary of realized prices:

	Three Months Ended June 30			Six Months Ended June 30		
ARC Realized Prices [1]	**2006**	2005	% Change	**2006**	2005	% Change
Oil ($/bbl)	**71.86**	58.37	23	**65.63**	56.02	17
Natural gas ($/mcf)	**6.35**	7.42	(14)	**7.39**	7.31	1
NGL's ($/bbl)	**54.44**	46.13	18	**53.70**	46.35	16
Total commodity revenue before hedging ($/boe)	**54.42**	50.22	8	**54.58**	48.91	12
Other revenue ($/boe)	**0.12**	0.18	(33)	**0.12**	0.16	(25)
Total revenue before hedging ($/boe)	**54.54**	50.40	8	**54.70**	49.07	11

(1) Prices as reported above are prior to gains and losses on commodity and foreign currency contracts and are prior to transportation charges. All gains and losses on commodity and foreign currency contracts are included in "gain (loss) on commodity and foreign currency contracts" in the statement of income.

Revenue

Revenue increased 22 per cent to $306.7 million in the second quarter of 2006 from second quarter 2005 revenue of $251.6 million. The increase in revenue was primarily attributable to higher volumes and higher commodity prices.

A breakdown of revenue is as follows:

	Three Months Ended June 30			Six Months Ended June 30		
Revenue ($ thousands)	**2006**	2005	% Change	**2006**	2005	% Change
Oil revenue	**181,827**	117,108	55	**340,687**	223,270	53
Natural gas revenue	**103,186**	116,964	(12)	**242,951**	231,057	5
NGL's revenue	**21,040**	16,631	27	**40,665**	33,694	21
Total commodity revenue	**306,053**	250,703	22	**624,303**	488,021	28
Other revenue	**696**	893	(22)	**1,377**	1,629	(15)
Total revenue before hedging (1)	**306,749**	251,596	22	**625,680**	489,650	28

(1) Revenue as reported above is prior to gains and losses on commodity and foreign currency contracts and prior to transportation charges. All gains and losses on commodity and foreign currency contracts are included in "gain (loss) on commodity and foreign currency contracts" in the statement of income.

Risk Management and Hedging Activities

ARC recognizes that effective risk management is a function of having a specific mandate, being adaptive to market conditions, and being disciplined in the execution of its risk management strategies.

The Trust's risk management activities are conducted by an internal Risk Management Committee, based upon guidelines approved by the Board. The Risk Management Committee has the following mandate:

- protect unitholder return on investment;
- provide protection for minimum monthly cash distributions to unitholders;
- employ a portfolio approach to risk management by entering into a number of small positions that build upon each other;
- participate in commodity price upturns to the greatest extent possible while limiting exposure to price downturns; and,
- ensure profitability of specific oil and gas properties that are more sensitive to changes in market conditions.

ARC continues to maintain upside participation on all produced volumes, with the exception of acquired volumes, but also recognizes the importance of protecting distributions with adequate price floors in a cost effective manner. ARC will continue in a disciplined manner to protect oil and natural gas price exposure.

The Trust realized cash hedging gains of $11.3 million and $9.9 million, respectively, for the second quarter and first six months of 2006 primarily due to gains on natural gas floors and the energy equivalent swap entered into by ARC in the first quarter of 2006.

As of the end of the second quarter ARC had upside participation for 2006 on all produced volumes, with the exception of the acquired volumes from Redwater and NPCU, with downside price protection for the remainder of the year on 39 per cent of liquids production and 17 per cent natural gas production (28 per cent of total production).

For these volumes, ARC has an average floor on crude of US$55.69 per barrel and natural gas of CDN$7.56 per GJ (which includes the energy equivalent swap wherein ARC receives a fixed price of CDN$7.09 per GJ until August and receives upside on an additional 3,839 barrels per day of oil above US$64.52 per barrel during the month of July).

ARC has also re-allocated 22 per cent of its natural gas production to receive NYMEX pricing by entering into basis swaps which fix the differential between NYMEX and AECO natural gas prices. This strategy reduces the Trust's exposure to price specific risks at AECO by financially tying prices to the NYMEX market. The NYMEX basis swap transactions, with the fixed price representing the differential from NYMEX, are as follows:

- US$1.1925 on 40,000 mmbtu/d from July 2006 - Oct 2006
- US$1.525 on 20,000 mmbtu/d Nov 2006 - March 2007
- US$1.116 on 50,000 mmbtu/d from April 2007 - Oct 2007
- US$1.043 on 50,000 mmbtu/d from Nov 2008 - Oct 2010

For a complete summary of the Trust's oil and natural gas hedges, please refer to "Hedging Program" under the "Investor Relations" section of the Trust's website at www.arcenergytrust.com.

The Trust considers its risk management contracts to be effective economic hedges as they meet the objectives of the Trust's risk management mandate. In order to mitigate credit risk, the Trust executes commodity and foreign currency hedging risk management with financially sound, credit worthy counterparties. All contracts require approval of the Trust's Risk Management Committee prior to execution. Deferred premiums payable will be recorded as a realized cash hedging loss when payment is made in a future period. These premiums may be partially offset if ARC sells any short-term options. The Trust's oil contracts are based on the WTI index and the majority of the Trust's natural gas contracts are based on the AECO monthly index.

Gain or Loss on Commodity and Foreign Currency Contracts

Gain or loss on commodity and foreign currency contracts comprise realized and unrealized gains or losses on commodity and foreign currency contracts that do not meet the requirements of an effective accounting hedge, even though the Trust considers all commodity and foreign currency contracts to be effective economic hedges. Accordingly, gains and losses on such contracts are shown as a separate expense in the statement of income.

The Trust recorded a cash gain of $11.3 million in the second quarter, which when combined with an unrealized fair value loss of $14.2 million resulted in a loss on commodity and foreign currency contracts of $3 million in the second quarter.

The following is a summary of the gain (loss) on commodity and foreign currency contracts:

Commodity and Foreign Currency Contracts ($ thousands)	Crude Oil & Liquids	Natural Gas	Foreign Currency	Q2 2006 Total	Q2 2005 Total
Realized cash gain (loss) on contracts [1]	**(2,634)**	**9,216**	**4,681**	**11,263**	(27,232)
Unrealized gain (loss) on contracts [2]	**(10,290)**	**(3,899)**	**(28)**	**(14,217)**	26,314
Total gain (loss) on commodity and foreign currency contracts	**(12,924)**	**5,317**	**4,653**	**(2,954)**	(918)

Commodity and foreign currency contracts ($ thousands)	Crude Oil & Liquids	Natural Gas	Foreign Currency	YTD 2006 Total	YTD 2005 Total
Realized cash gain (loss) on contracts [1]	**(6,386)**	**10,083**	**6,182**	**9,879**	(34,546)
Unrealized gain (loss) on contracts [2]	**(18,083)**	**10,409**	**(1,453)**	**(9,127)**	(40,373)
Total gain (loss) on commodity and foreign currency contracts	**(24,469)**	**20,492**	**4,729**	**752**	(74,919)

(1) Realized cash gains and losses represent actual cash settlements or receipts under the respective contracts.
(2) The unrealized loss on contracts represents the change in fair value of the contracts during the period.

Operating Netbacks

The Trust's operating netback, after realized hedging gains or losses, increased 43 per cent to $37.90 per boe in the second quarter of 2006 compared to $26.49 per boe in the second quarter of 2005. The increase in netbacks in 2006 is primarily due to higher commodity prices and hedging gains offset by increases in operating costs.

The netbacks incorporate realized cash gains on commodity and foreign currency contracts of $2.00 per boe for the second quarter of 2006, compared to losses of $5.46 per boe in the second quarter of 2005.

The components of operating netbacks are shown below:

	Q2 2006				Q2 2005
Netback	Oil ($/bbl)	Gas ($/mcf)	NGL ($/bbl)	**Total ($/boe)**	Total ($/boe)
Weighted average sales price	71.86	6.35	54.44	**54.42**	50.22
Other revenue	-	-	-	**0.12**	0.18
Total revenue	71.86	6.35	54.44	**54.54**	50.40
Royalties	(11.55)	(1.21)	(15.74)	**(9.78)**	(10.34)
Transportation	(0.21)	(0.20)	-	**(0.66)**	(0.76)
Operating costs [1]	(11.13)	(0.94)	(7.22)	**(8.20)**	(7.35)
Netback prior to hedging	48.97	4.00	31.48	**35.90**	31.95
Realized gain (loss) on commodity and foreign currency contracts	0.81	0.57	-	**2.00**	(5.46)
Netback after hedging	49.78	4.57	31.48	**37.90**	26.49

(1) Operating expenses are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions have been made in allocating these costs between oil, natural gas and natural gas liquids production.

Netback	Oil ($/bbl)	Gas ($/mcf)	NGL ($/bbl)	**Total ($/boe)**	YTD 2005 Total ($/boe)
	YTD 2006				
Weighted average sales price	65.53	7.39	53.69	**54.58**	48.90
Other revenue	-	-	-	**0.12**	0.16
Total revenue	65.53	7.39	53.69	**54.70**	49.06
Royalties	(10.47)	(1.58)	(14.53)	**(10.25)**	(9.67)
Transportation	(0.15)	(0.20)	-	**(0.64)**	(0.74)
Operating costs (1)	(10.64)	(0.95)	(6.62)	**(8.00)**	(6.73)
Netback prior to hedging	44.27	4.66	32.54	**35.81**	31.92
Realized gain (loss) on commodity and foreign currency contracts	(0.04)	0.31	-	**0.86**	(3.46)
Netback after hedging	44.23	4.97	32.54	**36.67**	28.46

(1) Operating expenses are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions have been made in allocating these costs between oil, natural gas and natural gas liquids production.

Royalties decreased to $9.78 per boe in the second quarter of 2006 compared to $10.34 per boe in the second quarter of 2005. Royalties as a percentage of pre-hedged commodity revenue net of transportation costs decreased to 18 per cent compared to 21 per cent in the second quarter of 2005. The decrease in royalties is due to a lower effective royalty rate in 2006 as a result of the increased oil weighting of the Trust's production following the 2005 acquisitions and to certain royalty concessions received on certain British Columbia natural gas properties. In addition, the Redwater and NPCU properties acquired in 2005 carried a lower effective royalty rate than the Trust's existing properties due to the royalty structure of the properties.

Operating costs increased to $8.20 per boe compared to $7.35 per boe in the second quarter of 2005. The acquisition of the Redwater and NPCU properties, with operating costs of approximately $20 per boe, contributed to a large portion of the 12 per cent increase in operating costs. Higher costs for supplies, materials, electricity and labour accounted for the remainder of the cost increase.

Transportation costs decreased 13 per cent to $0.66 per boe in the second quarter of 2006 compared to $0.76 per boe in the second quarter of 2005. This is a result of the increased percentage of oil in the Trust's production mix as oil has a relatively lower transportation cost than gas.

General and Administrative Expenses and Trust Unit Incentive Compensation

Cash general and administrative expenses ("G&A"), net of overhead recoveries on operated properties increased to $8.8 million ($1.56 per boe) in the second quarter of 2006 from $6.4 million ($1.28 per boe) in 2005. Increases in cash G&A expenses in total and per boe for 2006 were due to increased staff levels and higher compensation costs. As a result of the unprecedented levels of activity for ARC and for the industry as a whole, the costs associated with hiring, compensating and retaining employees and consultants have risen.

The Trust paid out $4.2 million under the whole unit plan in April 2006 compared to $1.4 million in April 2005 ($2.7 million and $1 million of the payouts were allocated to G&A in 2006 and 2005, respectively, and the remainder to operating costs and capital projects). The higher cash payment in April 2006 is attributed to a higher unit price upon vesting, higher distributions and having two years of vesting in 2006 compared to one year in 2005.

The following is a breakdown of G&A and trust unit incentive compensation expense:

G&A and Trust Unit Compensation Expense ($ thousands)	Three Months Ended June 30 **2006**	2005	% Change	Six Months Ended June 30 **2006**	2005	% Change
G&A expenses	**11,361**	8,432	35	**21,623**	16,473	31
Operating recoveries	**(2,563)**	(2,040)	30	**(5,171)**	(3,915)	32
Cash G&A expenses before Whole Unit Plan	**8,798**	6,392	38	**16,452**	12,558	31
Cash expense – Whole Unit Plan	**2,720**	955	185	**2,722**	955	185
Cash G&A expenses including Whole Unit Plan	**11,518**	7,347	57	**19,174**	13,513	42
Accrued compensation – Rights Plan	**749**	1,807	(59)	**2,523**	3,482	(28)
Accrued compensation – Whole Unit Plan	**1,149**	99	1,061	**4,959**	406	1,121
Total G&A and trust unit compensation expense	**13,416**	9,253	45	**26,656**	17,401	53

G&A and Trust Unit Compensation Expense ($ per boe)	Three Months Ended June 30 **2006**	2005	% Change	Six Months Ended June 30 **2006**	2005	% Change
Cash G&A expenses before Whole Unit Plan	**1.56**	1.28	22	**1.45**	1.26	15
Cash G&A expenses including Whole Unit Plan	**2.05**	1.47	39	**1.68**	1.35	24
Total G&A and trust unit compensation expense	**2.39**	1.85	29	**2.33**	1.74	34

A non-cash trust unit incentive compensation expense (“non-cash compensation expense”) of $1.9 million ($0.34 per boe) was recorded in the second quarter of 2006 compared to $1.9 million ($0.38 per boe) in the second quarter of 2005. This non-cash amount relates to both the Trust Unit Incentive Rights Plan (“Rights Plan”) and the Whole Trust Unit Incentive Plan (“Whole Unit Plan”).

For the second quarter, the compensation expense for the rights plan based on the fair value calculation resulted in an expense of $0.7 million, down significantly from the $1.8 million expense recorded in the second quarter of 2005. The reduction in the rights compensation expense is due to the vesting of the majority of the rights early in the second quarter of 2006. The Rights Plan was discontinued with respect to any further issuance of rights and has been replaced with the Whole Unit Plan.

Under the Whole Unit Plan, the Trust recorded a non-cash expense of $1.1 million in the second quarter of 2006 versus $0.1 million in the second quarter of 2005 for the estimated expense attributed to the Whole Unit Plan. The increase in the accrued value of the Whole Unit Plan is attributed to the increase in the Trust’s unit value in the market, increased distributions and a higher performance multiplier reflecting ARC’s top quartile returns as compared to other midsized oil and gas producers (the “peer group”). Refer to the Trust’s 2005 Annual Report for a detailed description of the Whole Unit Plan.

Following is a summary of changes in the Whole Unit Plan during the first six months of 2006:

Whole Unit Plan (units in thousands and $ thousands)	Number of RTUs	Number of PTUs	Total RTUs and PTUs
Balance, beginning of period	479	390	869
Granted in the period	174	178	352
Vested in the period	(134)	-	(134)
Forfeited in the period	(10)	-	(10)
Balance, end of period (1)	509	568	1,077
Estimated distributions to vesting date (2)	130	192	322
Estimated units upon vesting after distributions	638	760	1,399
Performance multiplier (3)	-	2.0	-
Estimated total units upon vesting	638	1,520	2,158
Trust unit price at June 30, 2006	28.00	28.00	28.00
Estimated total value upon vesting	17,864	42,560	60,424

(1) Based on underlying units before performance multiplier and accrued distributions.
(2) Represents estimated additional units to be issued equivalent to distributions accruing to whole units to vesting date based on current distribution levels of $0.20 per unit per month.
(3) The performance multiplier only applies to PTUs. The performance multiplier was 2.0 at June 30, 2006 and the Trust estimates that the performance multiplier will remain at 2.0 upon vesting of the PTUs in future periods.

The value associated with the RTUs and PTUs is expensed in the statement of income over the vesting period with the expense amount being determined by the unit price, the estimated number of units to vest, and distributions. Therefore, the expense recorded fluctuates over time.

The Whole Unit Plan value and thus the Trust's obligation for future payments under the plan is subject to variability depending upon the trust unit price, distributions, and the performance multiplier. The performance multiplier is based on the percentile rank of the Trust's Total Unitholder Return relative to returns on the trust units or common shares of members of a selected peer comparison group over the term of the PTUs. If the percentile rank is less than 25, the performance multiplier is zero and if the percentile rank is equal to or greater than 75, the performance multiplier is two. As at June 30, 2006, all PTU grants were assessed to have a percentile rank equal or greater than 75 and thus were valued with a performance multiplier of 2.0. Below is a summary of the range of future expected payments under the Whole Unit Plan based on variability of the performance multiplier:

	Performance Multiplier		
Value of Whole Unit Plan as at June 30, 2006 (units thousands and $ thousands except per unit)	**0.0**	**1.0**	**2.0**
Estimated trust units to vest			
RTUs	638	638	638
PTUs	-	761	1,520
Total units	**638**	**1,399**	**2,158**
Trust unit price [(1)]	28.00	28.00	28.00
Trust unit distributions per month [(1)]	0.20	0.20	0.20
Value of Whole Unit Plan upon vesting	**17,871**	**39,176**	**60,424**
Officers	2,256	12,368	22,422
Directors	961	961	961
Staff	14,654	25,847	37,041
Total payments under Whole Unit Plan [(2)]	**17,871**	**39,176**	**60,424**
2006	1,403	1,403	1,403
2007	8,109	12,355	16,601
2008	6,225	16,735	27,189
2009	2,134	8,683	15,231

(1) Values will fluctuate over the vesting period based on the volatility of the underlying trust unit price and distribution levels. Assumed future trust unit price of $28 per trust unit and distributions of $0.20 per unit per month based on current levels.
(2) Upon vesting, a cash payment is made equivalent to the value of the underlying trust units. The payment is made on an annual basis and at that time is reflected as a reduction of cash flow from operations.

Due to the variability in the future payments under the plan, the Trust estimates that $17.9 to $60.4 million will be paid out in future periods based on the current trust unit price, distribution levels and a performance multiplier ranging from 0 to 2.0.

Interest Expense

Interest expense increased to $7.6 million in the second quarter of 2006 from $3.3 million in the second quarter of 2005 due to an increase in short-term interest rates and higher debt balances as a result of the 2005 acquisitions. As at June 30, 2006, 90 per cent of the Trust's debt was denominated in U.S. dollars. At June 30, 2006, the Trust had $527.6 million of debt outstanding, of which $256.4 million was fixed at a rate of 5.2 per cent and $271.2 million was floating at a rate of 5.7 per cent.

The following is a summary of the debt balance and interest expense for the second quarters of 2006 and 2005:

Interest Expense	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2006**	2005	% Change	**2006**	2005	% Change
Period end debt balance [(1)]	**527,637**	319,628	65	**527,637**	319,628	65
Fixed rate debt	**256,439**	224,285	14	**256,439**	224,285	14
Floating rate debt	**271,198**	95,343	184	**271,198**	95,343	184
Interest expense before interest rate swaps [(2)]	**7,626**	3,579	113	**15,270**	7,048	117
Gain on interest rate hedge	**(27)**	(244)	(89)	**(69)**	(574)	(88)
Net interest expense	**7,599**	3,335	128	**15,201**	6,474	135

(1) Includes both long-term and current portions of debt.
(2) The interest rate swap was designated as an effective hedge for accounting purposes whereby actual realized gains and losses are netted against interest expense.

Foreign Exchange Gains and Losses

The Trust recorded a gain of $22.8 million ($4.05 per boe) on foreign exchange transactions in the second quarter of 2006 compared to a loss of $3.1 million ($0.62 per boe) in the second quarter of 2005. These amounts include both realized and unrealized foreign exchange gains and losses. Unrealized foreign exchange gains and losses are due to revaluation of U.S. denominated debt balances. The volatility of the Canadian dollar during the reporting period has a direct impact on the unrealized component of the foreign exchange gain or loss. The unrealized gain/loss impacts net income but does not impact cash flow as it is a non-cash amount. Realized foreign exchange gains or losses arise from U.S. denominated transactions such as interest payments, debt repayments and hedging settlements and a portion of natural gas sales.

Taxes

During the second quarter, Bill C-13, which included certain provisions of the Federal budget of May 2, 2006, received royal assent and the Alberta government legislated changes to its corporate income taxes. Following is a summary of the changes to federal and provincial corporate income tax rates that will directly impact the trust:

Enacted Tax Change	Previous	Current	Effective
Federal corporate income tax rate	23% (2006), 21% (2007 and thereafter)	23% (2006), 21% (2007), 20.5% (2008), 20% (2009), 19% (2010)	Immediate
Federal corporate surtax rate	1.12%	Eliminated	January 1, 2008
Federal large corporations tax rate	0.125% (2006), 0.0625% (2007), 0% (2008 and thereafter)	Eliminated	January 1, 2006
Federal non-capital loss carry forward	10 years	20 years	Immediate
Alberta corporate income tax rate	11.5%	10%	April 1, 2006

As a result of the above noted changes to corporate income taxes, the Trust's expected future income tax rate is expected to be 29.7 per cent, a reduction from the previous rate of 33.7 per cent. The corporate income tax rate applicable to 2006 is 34.5 per cent, however ARC does not anticipate any material cash income taxes will be paid in fiscal 2006. Due to the Trust's structure, both income tax and future tax liabilities are passed on to the unitholders by means of payments made between ARC Resources and the Trust.

The Trust recorded a capital tax recovery of $0.3 million in the second quarter of 2006 compared to an expense of $0.3 million in 2005. The recovery of capital taxes was attributed to the elimination of capital taxes effective January 1, 2006 pursuant to the federal government budget of May 2, 2006. Previously, the Trust made monthly installments of capital taxes, therefore the recovery is attributed to installments made for fiscal 2006 prior to the budget amendment.

In the second quarter of 2006, a future income tax recovery of $70.9 million was included in income compared to a $5.6 million expense in the second quarter of 2005. The future income tax recovery in the second quarter included a recovery of $57.5 million due to the significant reduction in the future corporate income tax rates from 33.7 per cent to 29.7 per cent and a recovery of $3.7 million as a result of the unrealized loss on commodity and foreign currency contracts (expense of $9 million in the second quarter of 2005 based on the unrealized gain of $26.3 million).

Depletion, Depreciation and Accretion of Asset Retirement Obligation

The depletion, depreciation and accretion ("DD&A") expense increased to $15.43 per boe in the second quarter of 2006 from $12.53 per boe in 2005. The higher DD&A expense is due to the Redwater and NPCU acquisitions in late 2005 for which the Trust recorded a higher proportionate cost per barrel of proved reserves, after adjustments for low tax pools, for the acquired properties compared to the existing ARC properties. In addition, the higher asset retirement obligation recorded in 2005 has resulted in higher accretion expense in 2006.

A breakdown of the DD&A expense is a follows:

DD&A Expense	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except per boe amounts)	**2006**	2005	% Change	**2006**	2005	% Change
Depletion of oil & gas assets [1]	**84,168**	61,300	37	**170,716**	122,515	39
Accretion of asset retirement obligation [2]	**2,613**	1,266	106	**5,225**	2,512	108
Total DD&A	**86,781**	62,566	39	**175,941**	125,027	41
DD&A expense per boe	**15.43**	12.53	23	**15.38**	12.53	23

(1) Includes depletion of the capitalized portion of the asset retirement obligation that was capitalized to the property, plant and equipment ("PP&E") balance and is being depleted over the life of the reserves.

(2) Represents the accretion expense on the asset retirement obligation during the period.

Goodwill

The goodwill balance of $157.6 million arose as a result of the acquisition of Star Oil & Gas Ltd. ("Star") in 2003. The Trust has determined that there was no goodwill impairment as of June 30, 2006.

Capital Expenditures and Net Acquisitions

Total capital expenditures, excluding acquisitions and dispositions, totaled $58.6 million in the second quarter of 2006 compared to $45.4 million in the second quarter of 2005. This amount was incurred on drilling and completions, land, geological, geophysical and facilities expenditures, as ARC continues to develop its asset base. Due to favorable conditions in the field, capital projects are ahead of schedule.

In addition to the capital expenditures, the Trust completed minor property acquisitions and property swaps of $5.2 million and $2.4 million of dispositions for $2.8 million of net acquisitions, net of post closing adjustments, in the second quarter of 2006. The execution of minor property acquisitions and dispositions is part of the Trust's strategy to continually high-grade its asset base by acquiring additional interests in properties where ARC sees future upside potential and disposing of properties with limited potential.

A breakdown of capital expenditures and net acquisitions is shown below:

	Three Months Ended June 30		Six Months Ended June 30	
Capital Expenditures ($ thousands)	**2006**	2005	**2006**	2005
Geological and geophysical	**2,825**	2,659	**5,542**	3,921
Land	**14,295**	815	**19,164**	1,627
Drilling and completions	**29,754**	32,650	**85,137**	67,880
Plant and facilities	**10,931**	8,703	**26,472**	23,198
Other capital	**836**	652	**1,372**	1,373
Total capital expenditures	**58,641**	45,479	**137,687**	97,999
Producing property acquisitions (1)	**5,191**	81,526	**39,017**	85,370
Producing property dispositions (1)	**(2,392)**	(2,805)	**(8,603)**	(2,981)
Corporate acquisition (1) (2)	**-**	62,456	**-**	62,456
Total capital expenditures and net acquisitions	**61,440**	186,656	**168,101**	242,844
Capital expenditures and net acquisitions financed with cash flow	**61,440**	33,613	**137,687**	86,133
Capital expenditures and net acquisitions financed with debt and equity	**-**	153,043	**30,414**	156,711

(1) Value is net of post-closing adjustments.
(2) Represents total consideration for the transaction including fees and prior to the future income tax liability assumed on acquisition.

The Trust's strategy is to fully exploit its asset base and to increase the recoverable portion of total oil and natural gas reserves in place on land owned by the Trust. ARC expects to undertake significant development projects in 2006 to fully execute the capital program of approximately $370 million.

Long-Term Investment

During the second quarter of 2006, the Trust made a $20 million investment in the shares of a private company that is involved in the acquisition of oil sands leases with development potential. The Trust holds a minor interest in the company and has the intent of holding the shares for investment purposes.

The investment in the shares of the private company has been considered to be a related party transaction due to common directorships of the Trust, the private company and the manager of a private equity fund that holds shares in the private company. The $20 million investment was part of a $325 million private placement of the private company. In addition, certain directors and officers of the Trust have minor direct and indirect shareholdings in the private company. All of the interested directors declared their interest and the investment was approved unanimously by the directors of the Trust not including the interested directors.

Asset Retirement Obligation and Reclamation Fund

At June 30, 2006, the Trust has recorded an Asset Retirement Obligation ("ARO") of $167.7 million ($81.1 million at June 30, 2005) for future abandonment and reclamation of the Trust's properties. During the second quarter of 2006, the ARO increased by $2.6 million for accretion expense, $0.1 million for development activities, and was reduced by $2 million for actual abandonment expenditures incurred in the second quarter of 2006. The Trust did not record a gain or loss on actual abandonment expenditures incurred to date in 2006 as the costs closely approximated the liability value included in the ARO.

ARC contributed $4.5 million cash to its reclamation fund in the second quarter of 2006 ($1.5 million in the second quarter of 2005) and earned interest of $0.2 million ($0.2 million in 2005) on the fund balance. The increase in funding is attributed to the higher obligation following the Redwater and NPCU acquisitions in 2005. The fund balance was reduced by $2.2 million for cash-funded abandonment expenditures in the second quarter of 2006 ($1.3 million in the second quarter of 2005). This fund, invested in money market instruments, is established to provide for future abandonment and reclamation liabilities. Future contributions are currently set at approximately $12 million per year and will vary over time in order to provide for the total estimated future abandonment and reclamation costs that are to be incurred upon the eventual abandonment of the Trust's properties.

Capital Structure

A breakdown of the Trust's capital structure is as follows:

Capitalization, Financial Resources and Liquidity ($ thousands except per unit and per cent amounts)	**June 30, 2006**	December 31, 2005
Revolving credit facilities	**271,198**	258,480
Senior secured notes	**256,439**	268,156
Working capital deficit (1)	**39,805**	51,450
Net debt obligations	**567,442**	578,086
Units outstanding and issuable for exchangeable shares (thousands)	**204,390**	202,039
Market price per unit at end of period	**28.00**	26.49
Market value of units and exchangeable shares	**5,722,920**	5,352,013
Total capitalization (2)	**6,290,362**	5,930,099
Net debt as a percentage of total capitalization	**9.0%**	9.7%
Net debt obligations	**567,442**	578,086
Cash flow from operations	**385,852**	639,511
Net debt to annualized cash flow	**0.7**	0.9

(1) The working capital deficit excludes the balances for commodity and foreign currency contracts.
(2) Total capitalization as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Total capitalization is not intended to represent the total funds from equity and debt received by the Trust.

The Trust has a syndicated three year credit facility allowing for maximum borrowing of up to $572 million. The debt is secured by all the Trust's oil and gas properties and is secured by the following major covenants:

Covenant	**Position as at June 30, 2006**
Long-term debt and letters of credit not to exceed three times annualized net income before non-cash items and interest expense	Long-term debt and letters of credit of 0.63 times annualized net income before non-cash items and interest expense
Long-term debt, letters of credit and subordinated debt not to exceed four times annualized net income before non-cash items and interest expense	Long-term debt, letters of credit and subordinated debt of 0.63 times annualized net income before non-cash items and interest expense
Long-term debt and letters of credit not to exceed 50 per cent of the sum of unitholders' equity, long-term debt, letters of credit, and subordinated debt	Long-term debt and letters of credit of 21.9 per cent of the sum of unitholders' equity, long-term debt, letters of credit, and subordinated debt

In the event that the Trust enters into a material acquisition whereby the purchase price exceeds 10 per cent of the book value of the Trust's assets, the ratios in the first two covenants above are increased to 3.5 and 5.5 times, respectively. As at June 30, 2006, the Trust was in compliance with all covenants, and had $4.4 million in letters of credit and no subordinated debt.

The Trust funded 100 per cent of its second quarter capital development program of $58.6 million with cash flow. The Trust intends to finance the majority of the remaining $232 million portion of the $370 million 2006 capital development program with cash flow and proceeds from the distribution reinvestment program ("DRIP") with any additional capital requirement funded with debt.

Unitholders' Equity

At June 30, 2006, there were 204.4 million units issued and issuable for exchangeable shares, an increase of 2.4 million units from December 31, 2005. The increase in number of units outstanding is mainly attributable to the 1.7 million units issued pursuant to the DRIP during the first six months of 2006 at an average price of $25.25 per unit (0.9 million units issued in the second quarter at an average price of $25.50 per unit).

The Trust had 0.8 million rights outstanding as of June 30, 2006 under an employee plan where further rights issuances were discontinued in 2004. The rights have a five-year term and vest equally over three years from the date of grant. The majority of rights vested on May 6, 2006. The remaining rights may be purchased at an average adjusted exercise price of $9.18 per unit as at June 30, 2006. Contractual life of the rights varies by series but all series will expire on or before March 22, 2009.

Unitholders electing to reinvest distributions or make optional cash payments to acquire units from treasury under the DRIP may do so at a five per cent discount to the prevailing market price with no additional fees or commissions.

Cash Distributions

ARC declared cash distributions of $120.6 million ($0.60 per unit), representing 62 per cent of second quarter 2006 cash flow compared to cash distributions of $84.5 million ($0.45 per unit), representing 69 per cent of cash flow in the second quarter of 2005. The remaining 38 per cent of second quarter 2006 cash flow ($74.1 million) was used to fund 100 per cent of ARC's second quarter 2006 capital and contribute $4.5 million to the reclamation fund.

Monthly cash distributions for the second quarter of 2006 were $0.20 per unit. Revisions, if any, to the monthly distribution are normally announced on a quarterly basis in the context of prevailing and anticipated commodity prices at that time.

The following items may be deducted from cash flow to arrive at cash distributions to unitholders:

- An annual $12 million contribution to reclamation funds and interest earned on the reclamation fund balances. The reclamation funds are segregated bank accounts or subsidiary trusts and the balances will be drawn on in future periods as the Trust incurs abandonment and reclamation costs over the life of its properties. The contribution level is reviewed annually based on a detailed assessment of the Trust's total future abandonment obligation, a 20-year funding schedule, an estimated return based on current interest rates and the funding amount is approved by the Health, Safety and Environment committee. As future abandonment and reclamation obligations will be settled with reclamation fund balances over the life of the properties, the Trust does not anticipate any separate deductions from cash flow for abandonment and reclamation costs. The annual contribution may be higher than $12 million in future periods depending on acquisition and capital development activity and abandonment cost estimates to reclaim the Trust's oil and natural gas properties.

- The portion of capital expenditures that are funded with cash flow. The Trust's distribution policy guideline is to withhold at least 20 per cent of cash flow to fund a portion of capital expenditures. In the first half of 2006, the Trust withheld 36 per cent of its cash flow to fund 100 per cent of its capital program excluding acquisitions. The objective of the Trust's capital expenditure program is to replace natural production declines resulting in stable production. This level of capital expenditures may not replace the Trust's reserves produced out during the period, but rather bring non-producing reserves on stream.

- Debt principal repayments to the extent that required principal repayment cannot be refinanced by other means. The Trust's current debt level is well within the covenant specified in the debt agreements and, accordingly, there are no current mandatory requirements for repayment. Refer to the "Capital Structure" section of this MD&A for a detailed review of the debt covenants.

- Income taxes that are not passed on to unitholders. The Trust has a liability for future income taxes due to the excess of book value over the tax basis of the assets of the Trust and its corporate subsidiaries. The Trust minimizes or eliminates cash income taxes in corporate subsidiaries by maximizing deductions, however in future periods there may be cash income taxes if deductions are not sufficient to eliminate taxable income. Taxability of the Trust is passed on to unitholders in the form of taxable distributions. The Trust does not anticipate having to pay any significant amount of cash income taxes in the future and thus does not expect any material deductions from cash flow for income taxes.

- Working capital requirements as determined by the Trust. Certain working capital amounts may be deducted from cash flow, however such amounts would be minimal and the Trust does not anticipate any such deductions in the foreseeable future.

- The Trust has certain obligations for future payments relative to employee long-term incentive compensation. Presently, the Trust estimates that $17.8 million to $60.4 million will be paid out pursuant to such commitments in 2006 through 2009 subject to vesting provisions and future performance of the Trust. These amounts will reduce cash flow and in turn cash distributions in future periods.

Cash flow and cash distributions in total and per unit for 2006 and 2005 were as follows:

Cash Flow and Distributions	Three Months Ended June 30			Three Months Ended June 30		
	2006	2005 ($ millions)	% Change	**2006**	2005 ($ per unit)	% Change
Cash flow from operations	**194.7**	121.8	60	0.96	0.64	50
Reclamation fund contributions (1)	**(4.7)**	(1.7)	176	(0.02)	(0.01)	100
Capital expenditures funded with cash flow	**(68.0)**	(35.6)	91	(0.33)	(0.19)	74
Discretionary debt repayments	**(1.4)**	-	-	-	-	-
Other (2)	**-**	-	-	(0.01)	0.01	-
Cash distributions	**120.6**	84.5	43	0.60	0.45	33

Cash Flow and Distributions	Six Months Ended June 30			Six Months Ended June 30		
	2006	2005 ($ millions)	% Change	**2006**	2005 ($ per unit)	% Change
Cash flow from operations	**385.9**	263.8	46	**1.90**	1.39	37
Reclamation fund contributions (1)	**(6.4)**	(3.4)	88	**(0.03)**	(0.02)	50
Capital expenditures funded with cash flow	**(137.7)**	(88.2)	56	**(0.68)**	(0.47)	45
Discretionary debt repayments	**(1.4)**	(3.9)	(64)	**-**	(0.02)	-
Other (2)	**-**	-	-	**0.01**	0.02	(50)
Cash distributions	**240.4**	168.3	43	**1.20**	0.90	33

(1) Includes interest income earned on the reclamation fund balance that is retained in the reclamation fund.
(2) Other total dollars represents working capital adjustments. Other per unit includes the difference due to cash distributions paid being based on actual units at each distribution date whereas per unit cash flow, reclamation fund contributions and capital expenditures funded with cash flow are based on weighted average units in the year.

The Trust continually assesses distribution levels, in light of commodity prices, to ensure that distributions are in line with the long-term strategy and objectives of the Trust as per the following guidelines:

- To maintain a level of distributions that, in the opinion of Management and the Board of Directors, are sustainable for a minimum period of six months. The Trust's objective is to normalize the volatility of commodity prices rather than to pass on that volatility to unitholders in the form of fluctuating monthly distributions.
- To ensure that the Trust's payout ratio does not exceed 80 per cent on an annual basis. The Trust believes that at least 20 per cent of cash flow should be reinvested in capital development activities in order to offset, in part, the natural production declines of the Trust's assets over the long term. Using a minimum 20 per cent of cash flow to fund capital development activities reduces the requirements of the Trust to use debt and equity to finance these expenditures. This may result in 100 per cent of capital development activities being funded with cash flow in a given period depending on the levels of cash flow and capital expenditures. The actual amount of cash flow withheld to fund the Trust's capital expenditure program is dependent on the commodity price environment and is at the discretion of the Board of Directors.

In order to set distributions to meet the above noted objectives, the Trust maintains an annual cash flow forecast that incorporates actual results of the Trust and market conditions. An annual distribution is determined based on the Trust's objectives of a maximum annual payout ratio of 80 percent, a minimum of 20 per cent of annual cash flow to fund capital expenditures, and a minimum annual contribution to the reclamation funds of $12 million. As market conditions change, the forecast is updated to assess whether there should be a change in distribution levels. A change to distributions is proposed only if it is determined that the revised distribution can be maintained for the long-term. If distribution levels remain the same, the difference in cash flow between estimated and actual results is reflected in the level of cash funded capital expenditures.

The actual amount of future monthly cash distributions are proposed by management and are subject to the approval and discretion of the Board of Directors. The Board reviews future cash distributions in conjunction with their review of quarterly operating and financial results.

Historical Cash Distributions by Calendar Year

The following table presents cash distributions paid in each calendar period. Cash distributions for 2006 include distributions paid up to and including June 15, 2006:

Calendar Year	Distributions (1)	Taxable Portion	Return of Capital
2006 YTD (2)	1.40 (2)	1.37 (2)	0.03 (2)
2005	1.94	1.90	0.04
2004	1.80	1.69	0.11
2003	1.78	1.51	0.27
2002	1.58	1.07	0.51
2001	2.41	1.64	0.77
2000	1.86	0.84	1.02
1999	1.25	0.26	0.99
1998	1.20	0.12	1.08
1997	1.40	0.31	1.09
1996	0.81	-	0.81
Cumulative	**$17.43**	**$10.71**	**$6.72**

(1) Based on cash distributions paid in the calendar year.
(2) Based on cash distributions paid in 2006 up to and including June 15, 2006 and estimated taxable portion of 2006 distributions of 98 per cent.

__2006 Monthly Cash Distributions__

Actual cash distributions paid for 2006 along with relevant payment dates are as follows:

Ex-distribution Date	Record Date	Distribution Payment Date	Total Distribution
December 28, 2005	December 31, 2005	January 16, 2006	0.20
January 27, 2006	January 31, 2006	February 15, 2006	0.20
February 24, 2006	February 28, 2006	March 15, 2006	0.20
March 29, 2006	March 31, 2006	April 17, 2006	0.20
April 26, 2006	April 30, 2006	May 15, 2006	0.20
May 29, 2006	May 31, 2006	June 15, 2006	0.20
June 28, 2006	June 30, 2006	July 17, 2006	0.20
July 27, 2006	July 31, 2006	August 15, 2006	0.20
August 29, 2006	August 31, 2006	September 15, 2006	*0.20
September 27, 2006	September 30, 2006	October 16, 2006	*0.20
October 27, 2006	October 31, 2006	November 15, 2006	
November 28, 2006	November 30, 2006	December 15, 2006	
December 27, 2006	December 31, 2006	January 15, 2007	

* Estimated

__Taxation of Cash Distributions__

Cash distributions comprise a return of capital portion (tax deferred) and a return on capital portion (taxable). The return of capital component reduces the cost basis of the trust units held. For a more detailed breakdown, please visit our website at www.arcenergytrust.com.

For 2006, it is estimated that cash distributions paid in the calendar year will be approximately 98 per cent return on capital (taxable) and two per cent return of capital (tax deferred). Actual taxable amounts may differ from the estimated amount as they are dependent on commodity prices experienced throughout the year. Changes in the estimated taxable and deferred portion of the distributions will be announced quarterly.

The ARC Resources Ltd. (ARL) exchangeable shares are traded on the TSX under the symbol "ARX" and are convertible into units, at the option of the shareholder, based on the then current exchange ratio. Exchangeable shareholders are not eligible to receive monthly cash distributions, however the exchange ratio increases on a monthly basis by an amount equal to the current month's unit distribution multiplied by the then current exchange ratio and divided by the 10 day weighted average trading price of the units at the end of each month. The gain realized as a result of the monthly increase in the exchange ratio is taxed, in most circumstances, as a capital gain rather than income and is therefore subject to a lower effective tax rate. Tax on the exchangeable shares is deferred until the exchangeable share is sold or converted into a trust unit.

__Deficit__

During the quarter, presentation changes were made to combine the previously reported Accumulated Earnings and Accumulated Cash Distribution figures on the balance sheet into a single Deficit balance. The Trust has historically paid cash distributions in excess of accumulated earnings as cash distributions are based on cash flow generated in the current period while accumulated earnings are based on cash flow generated in the current period less a depletion and depreciation expense recorded on the original property, plant, and equipment investment.

Contractual Obligations and Commitments

The Trust has contractual obligations in the normal course of operations including purchase of assets and services, operating agreements, transportation commitments, sales commitments, royalty obligations, and lease rental obligations. These obligations are of a recurring and consistent nature and impact cash flow in an ongoing manner. The following is a summary of the Trust's contractual obligations and commitments as at June 30, 2006:

	Payments Due by Period				
($ millions)	**2006**	**2007 - 2008**	**2009 - 2010**	**Thereafter**	**Total**
Debt repayments	-	20.0	318.1	189.5	527.6
Reclamation fund contributions (1)	6.1	11.8	10.2	80.9	109.0
Purchase commitments	7.3	18.4	3.0	7.6	36.3
Operating leases	2.4	8.3	8.4	-	19.1
Derivative contract premiums (2)	12.6	3.6	1.8	-	18.0
Retention bonuses	1.0	1.0	-	-	2.0
Total contractual obligations	29.4	63.1	341.5	278.0	712.0

(1) Contribution commitments to a restricted reclamation fund associated with the Redwater property acquired in the Redwater and NPCU acquisition.
(2) Fixed premiums to be paid in future periods on certain commodity derivative contracts.

In addition to the above, the Trust has commitments related to its risk management program.

The Trust is involved in litigation and claims arising in the normal course of operations. Management is of the opinion that pending litigation will not have a material adverse impact on the Trust's financial position or results of operations.

The Trust enters into commitments for capital expenditures in advance of the expenditures being made. At a given point in time, it is estimated that the Trust has committed to capital expenditures equal to approximately one quarter of its capital budget by means of giving the necessary authorizations to incur the capital in a future period. The Trust's 2006 capital budget has been approved by the Board at $370 million. This commitment has not been disclosed in the commitment table as it is of a routine nature and is part of normal course of operations for active oil and gas companies and trusts.

Off Balance Sheet Arrangements

The Trust has certain lease agreements that are entered into in the normal course of operations. All leases are treated as operating leases whereby the lease payments are included in operating expenses or G&A expenses depending on the nature of the lease. No asset or liability value has been assigned to these leases in the balance sheet as of June 30, 2006.

The Trust entered into agreements to pay premiums pursuant to certain crude oil derivative put contracts. Premiums of approximately $18 million will be paid in 2006 to 2009 for the put contracts in place at June 30, 2006. As the premiums are part of the underlying derivative contract, they have been recorded at fair market value at June 30, 2006 on the balance sheet.

Critical Accounting Estimates

The Trust has continuously evolved and documented its management and internal reporting systems to provide assurance that accurate, timely internal and external information is gathered and disseminated.

The Trust's financial and operating results incorporate certain estimates including:

- estimated revenues, royalties and operating costs on production as at a specific reporting date but for which actual revenues and costs have not yet been received;
- estimated capital expenditures on projects that are in progress;
- estimated depletion, depreciation and accretion that are based on estimates of oil and gas reserves, which the Trust expects to recover in the future;
- estimated fair values of derivative contracts that are subject to fluctuation depending upon the underlying commodity prices and foreign exchange rates;
- estimated value of asset retirement obligations that are dependent upon estimates of future costs and timing of expenditures; and
- estimated future recoverable value of property, plant and equipment and goodwill.

The Trust has hired individuals and consultants who have the skill set to make such estimates and ensures individuals or departments with the most knowledge of the activity are responsible for the estimates. Further, past estimates are reviewed and compared to actual results, and actual results are compared to budgets in order to make more informed decisions on future estimates.

The ARC leadership team's mandate includes ongoing development of procedures, standards and systems to allow ARC staff to make the best decisions possible and ensuring those decisions are in compliance with the Trust's environmental, health and safety policies.

Objectives and 2006 Outlook

It is the Trust's objective to provide the highest possible long-term returns to unitholders by focusing on the key strategic objectives of the business plan.

To the end of the second quarter of 2006, the Trust has provided cumulative cash distributions of $17.43 per unit and capital appreciation of $18.00 per unit for a total return of $35.43 per unit (27.3 per cent annualized total return) for unitholders who invested in the Trust at inception in July of 1996. For the first six months of 2006, the Trust provided unitholders with a total return of 10.4 per cent.

During 2006, ARC will continue to be active with a robust drilling and development program on its diverse asset base. The $370 million capital expenditure budget for 2006 is being deployed on well tie-ins and other facility related costs, a balanced drilling program of low and moderate risk wells, and the acquisition of undeveloped land. The Trust continues to focus on major properties with significant upside, with the objective to replace production declines through internal development opportunities.

Current low debt levels and a strong working capital position provide the Trust with the financial flexibility to fund the 2006 capital expenditure program and be poised to take advantage of accretive acquisition opportunities. The Trust is continually executing minor property acquisitions and dispositions in order to enhance the Trust's portfolio of oil and natural gas assets. The Trust continually reviews potential acquisitions of both conventional oil and natural gas reserves and in the broader energy industry. Acquisitions are evaluated internally and acquisitions in excess of $25 million are subject to Board approval.

Following is a summary of the Trust's 2006 Guidance:

	2006 Revised Guidance	2006 Previous Guidance	2006 Actual YTD	% Variance
Production (boe/d)	62,800	62,000	63,194	2
Expenses ($/boe):				
Operating costs	8.40	8.65	8.00	(7)
Transportation	0.70	0.70	0.64	(9)
G&A expenses – cash (1)	1.70	1.70	1.64	(4)
G&A expenses – stock compensation plans	0.65	0.65	0.65	-
Interest	1.35	1.40	1.33	(5)
Cash taxes	0.02	-	0.03	-
Capital expenditures ($ millions)	370 over 4 quarters	340 over 4 quarters	138	19
Units (millions) (2)	205	205	204	-

(1) Includes cash portion of whole unit plan.
(2) Weighted average trust units and units issuable.

Despite production declines attributed to spring breakup and turnaround activities, second quarter 2006 production was ahead of budget. As a result, ARC has increased its production guidance for the full year 2006 to 62,800 boe per day.

The variance-to-date for operating costs on a boe basis is attributed to the seasonality of operating costs and the strong production results achieved in the first six months of 2006. As workover and maintenance activities continue into the third quarter, the Trust expects higher costs for 2006 as a whole, however due to strong performance in the first half of 2006 the Trust has decreased its guidance for operating costs to $8.40 per boe for 2006.

Overall G&A expense at $2.29 per boe closely approximates the guidance of $2.35 per boe, therefore, the Trust maintains the annual G&A guidance at $2.35 per boe for 2006.

Interest expense in the second quarter of 2006 was lower than the guidance target for 2006 as a result of strong cash flow in the quarter that resulted in the Trust funding 100 per cent of its capital program with cash rather than debt. Consequently, debt levels and the corresponding interest expense were lower than anticipated during the second quarter of 2006. The Trust has decreased its guidance for interest expense to $1.35 per boe for the full year due to lower interest in the first half of 2006 and higher production guidance of 62,800 boe per day for 2006. For the second half of 2006, the Trust will be undertaking significant capital development projects which may require debt funding.

Taxes for the second quarter of 2006 were above the guidance level as a result of $0.3 million of cash taxes paid pursuant to tax pool reclassifications for Star Oil & Gas Ltd. for pre-acquisition periods. The Trust does not anticipate any further cash taxes to the paid in the remainder of 2006 but has revised the 2006 annual guidance to $0.02 per boe for cash taxes incurred to the end of the second quarter.

To the end of the second quarter, the Trust had incurred $138 million of capital expenditures pursuant to the original $340 million capital development program. The Trust has significant capital development projects planned for the remainder of 2006 and has increased the 2006 capital expenditure guidance target to $370 million.

See "Outlook" in the Trust's Annual Report MD&A for additional discussion of the Trust's key future objectives.

2006 Cash Flow

Below is a table that illustrates sensitivities to pre-hedged cash flow with operational changes and changes to the business environment:

			Impact on Annual Cash Flow
Business Environment	**Assumption**	**Change**	**$/Unit**
Oil price (US$WTI/barrel) [1]	$ 68.00	$ 1.00	$ 0.05
Natural gas price (CDN$AECO/mcf) [1]	$ 6.75	$ 0.10	$ 0.03
USD/CAD exchange rate	$ 0.88	$ 0.01	$ 0.05
Interest rate on debt	5.4%	1.0%	$ 0.03
Operational			
Liquids production volume (bbls/d)	32,100	1.0%	$ 0.03
Gas production volumes (mmcf/d)	183.9	1.0%	$ 0.01
Operating expenses per boe	$ 8.50	1.0%	$ 0.01
Cash G&A expenses per boe	$ 1.70	10.0%	$ 0.03

(1) Analysis does not include the effect of derivative contracts.

Assessment of Business Risks

The ARC management team is focused on long-term strategic planning and has identified the key risks, uncertainties and opportunities associated with the Trust's business that can impact the financial results. See "Assessment of Business Risks" in the Trust's 2005 Annual Report MD&A for a detailed assessment.

Additional Information

Additional information relating to ARC can be found on SEDAR at www.sedar.com.

QUARTERLY REVIEW

(CDN$ thousands, except per unit amounts)	2006		2005				2004	
FINANCIAL	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Revenue before royalties	**306,749**	318,931	365,298	310,249	251,596	238,054	232,112	230,769
Per unit [1]	**1.51**	1.58	1.89	1.62	1.32	1.26	1.23	1.23
Cash flow	**194,653**	191,200	207,621	168,117	121,808	141,965	106,935	110,835
Per unit – basic [1]	**0.96**	0.94	1.07	0.88	0.64	0.75	0.57	0.59
Per unit – diluted	**0.95**	0.94	1.07	0.87	0.63	0.74	0.56	0.59
Net income	**182,499**	104,071	130,474	114,600	73,215	38,646	112,995	38,897
Per unit – basic [2]	**0.91**	0.52	0.68	0.61	0.39	0.21	0.61	0.21
Per unit – diluted	**0.91**	0.52	0.68	0.59	0.39	0.20	0.60	0.21
Cash distributions	**120,620**	119,867	115,671	92,559	84,468	83,867	83,531	83,178
Per unit [3]	**0.60**	0.60	0.60	0.49	0.45	0.45	0.45	0.45
Total assets	**3,277,849**	3,279,721	3,251,161	2,483,540	2,427,463	2,303,948	2,304,998	2,316,297
Total liabilities	**1,339,856**	1,434,090	1,415,519	912,160	895,179	785,776	755,650	804,603
Net debt outstanding [4]	**567,442**	598,911	578,086	357,560	366,216	254,252	264,842	220,500
Weighted average units (thousands) [5]	**203,708**	202,479	193,445	191,709	190,315	189,210	188,521	184,675
Units outstanding and issuable (thousands)	**204,441**	203,090	202,039	192,089	191,329	189,609	188,804	187,629
CAPITAL EXPENDITURES ($ thousands)								
Geological and geophysical	**2,825**	2,718	3,040	2,258	2,659	1,262	867	828
Land	**14,295**	4,868	5,540	2,048	815	812	2,484	798
Drilling and completions	**29,754**	55,383	60,150	63,628	32,650	35,230	36,641	41,755
Plant and facilities	**10,931**	15,540	17,031	14,803	8,703	14,495	6,183	11,668
Other capital	**836**	536	2,020	317	652	721	1,480	394
Total capital expenditures	**58,641**	79,045	87,781	83,054	45,479	52,520	47,655	55,443
Property acquisitions (dispositions) net	**2,799**	27,613	3,037	5,860	78,721	3,668	(1,036)	(5,345)
Corporate acquisitions [6]	**-**	-	462,814	-	42,182	-	41,449	-
Total capital expenditures and net acquisitions	**61,440**	106,658	553,632	88,914	166,382	56,188	88,068	50,098
OPERATING								
Production								
Crude oil (bbl/d)	**27,805**	29,651	25,534	23,513	22,046	21,993	22,969	22,496
Natural gas (mmcf/d)	**178.5**	185.0	177.9	168.2	173.1	176.1	174.7	177.4
Natural gas liquids (bbl/d)	**4,247**	4,120	3,943	4,047	3,962	4,072	4,097	4,034
Total (boe/d 6:1)	**61,803**	64,600	59,120	55,592	54,860	55,410	56,179	56,096
Average prices								
Crude oil ($/bbl)	**71.86**	59.53	62.12	69.37	58.37	53.63	49.48	51.00
Natural gas ($/mcf)	**6.35**	8.40	12.05	9.08	7.42	7.20	6.82	6.65
Natural gas liquids ($/bbl)	**54.44**	52.91	57.14	50.43	46.13	46.57	43.72	42.30
Oil equivalent ($/boe) [7]	**54.54**	54.86	67.16	60.66	50.40	47.74	44.62	44.72
TRUST UNIT TRADING (based on intra-day trading)								
Unit prices								
High	**28.61**	27.51	27.58	24.2	20.30	20.40	17.98	17.38
Low	**24.35**	25.09	20.45	19.94	16.88	16.55	14.80	15.02
Close	**28.00**	27.36	26.49	24.10	19.94	18.15	17.90	16.85
Average daily volume (thousands)	**548**	546	653	599	605	895	456	384

(1) Based on weighted average units plus units issuable for exchangeable shares.
(2) Net income in the basic per unit calculation has been reduced by interest on the convertible debentures.
(3) Based on number of units outstanding at each cash distribution date.
(4) Total current and long-term debt net of working capital. Net debt excludes commodity and foreign currency contracts, the deferred hedge loss and deferred commodity and foreign currency contracts.
(5) Includes units issuable for outstanding exchangeable shares.
(6) Represents total consideration for the corporate acquisition including fees but prior to working capital, asset retirement obligations, and future income tax liability assumed on acquisition.
(7) Includes other revenue.

CONSOLIDATED BALANCE SHEETS

As at June 30 and December 31 (unaudited)

($CDN thousands)	2006	2005
ASSETS		
Current assets		
Accounts receivable	**$ 111,342**	$ 122,956
Prepaid expenses	**18,393**	14,020
Commodity and foreign currency contracts (Note 5)	**15,333**	3,125
	145,068	140,101
Reclamation fund	**27,149**	23,491
Property, plant and equipment	**2,928,040**	2,929,977
Long-term investment (Note 2)	**20,000**	-
Goodwill	**157,592**	157,592
Total assets	**$ 3,277,849**	$ 3,251,161
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	**$ 129,205**	$ 148,587
Cash distributions payable	**40,336**	39,839
Commodity and foreign currency contracts (Note 5)	**28,502**	7,167
	198,043	195,593
Long-term debt (Note 3)	**527,637**	526,636
Other long-term liabilities (Note 4)	**11,738**	12,360
Asset retirement obligations (Note 6)	**167,725**	165,053
Future income taxes (Note 7)	**434,713**	515,877
Total liabilities	**1,339,856**	1,415,519
COMMITMENTS AND CONTINGENCIES (Note 15)		
NON-CONTROLLING INTEREST		
Exchangeable shares (Note 8)	**39,385**	37,494
UNITHOLDERS' EQUITY		
Unitholders' capital (Note 9)	**2,286,819**	2,230,842
Contributed surplus (Note 11)	**4,782**	6,382
Deficit (Note 10)	**(392,993)**	(439,076)
Total unitholders' equity	**1,898,608**	1,798,148
Total liabilities and unitholders' equity	**$ 3,277,849**	$ 3,251,161

See accompanying notes to consolidated financial statements

CONSOLIDATED STATEMENTS OF INCOME AND DEFICIT

For the three and six months ended June 30 (unaudited)

($CDN thousands, except per unit amounts)	Three Months Ended June 30 **2006**	Three Months Ended June 30 2005	Six Months Ended June 30 **2006**	Six Months Ended June 30 2005
Revenues				
Oil, natural gas and natural gas liquids	**$ 306,749**	$ 251,596	**$ 625,680**	$ 489,650
Royalties	**(55,022)**	(51,643)	**(117,263)**	(96,482)
	251,727	199,953	**508,417**	393,168
Gain (loss) on commodity and foreign currency contracts (Note 5)				
Realized	**11,263**	(27,232)	**9,879**	(34,546)
Unrealized	**(14,217)**	26,314	**(9,127)**	(40,373)
	248,773	199,035	**509,169**	318,249
Expenses				
Transportation	**3,727**	3,781	**7,266**	7,367
Operating	**46,138**	36,672	**91,514**	67,113
General and administrative	**13,416**	9,253	**26,656**	17,401
Interest on long-term debt (Note 3)	**7,599**	3,335	**15,201**	6,474
Depletion, depreciation and accretion	**86,781**	62,566	**175,941**	125,027
(Gain) loss on foreign exchange	**(22,802)**	3,082	**(17,238)**	4,108
	134,859	118,689	**299,340**	227,490
Income before taxes	**113,914**	80,346	**209,829**	90,759
Capital and other taxes	**293**	(337)	**(329)**	(987)
Future income tax recovery (expense) (Note 7)	**70,892**	(5,600)	**81,164**	23,900
Net income before non-controlling interest	**185,099**	74,409	**290,664**	113,672
Non-controlling interest (Note 8)	**(2,600)**	(1,194)	**(4,094)**	(1,811)
Net income	**$ 182,499**	$ 73,215	**$ 286,570**	$ 111,861
Deficit, beginning of period	**$ (454,872)**	$ (464,666)	**$ (439,076)**	$ (419,445)
Distributions paid or declared	**(120,620)**	(84,469)	**(240,487)**	(168,336)
Deficit, end of period	**$ (392,993)**	$ (475,920)	**$ (392,993)**	$ (475,920)
Net income per unit (Note 14)				
Basic	**$ 0.91**	$ 0.39	**$ 1.43**	$ 0.60
Diluted	**$ 0.91**	$ 0.39	**$ 1.43**	$ 0.59

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the three and six months ended June 30 (unaudited)

($CDN thousands)	Three Months Ended June 30 **2006**	Three Months Ended June 30 2005	Six Months Ended June 30 **2006**	Six Months Ended June 30 2005
CASH FLOW FROM OPERATING ACTIVITIES				
Net income	**$ 182,499**	$ 73,215	**$ 286,570**	$ 111,861
Add items not involving cash:				
Non-controlling interest	**2,600**	1,194	**4,094**	1,811
Future income tax (recovery) expense	**(70,892)**	5,600	**(81,164)**	(23,900)
Depletion, depreciation and accretion	**86,781**	62,566	**175,941**	125,027
Non-cash loss (gain) on commodity and foreign currency contracts (Note 5)	**14,217**	(26,314)	**9,127**	40,373
Non-cash (gain) loss on foreign exchange	**(22,233)**	2,926	**(16,649)**	3,999
Non-cash trust unit incentive compensation (Notes 11 and 12)	**1,681**	2,621	**7,933**	4,603
Expenditures on site restoration and reclamation	**(1,969)**	(1,041)	**(3,234)**	(2,088)
Change in non-cash working capital	**(10,574)**	7,150	**(11,414)**	(5,033)
	182,110	127,917	**371,204**	256,653
CASH FLOW FROM FINANCING ACTIVITIES				
Issuance of long-term debt, net	**847**	90,129	**17,694**	95,163
Issue of trust units	**5,763**	11,842	**8,583**	14,901
Trust unit issue costs	**(6)**	(11)	**(251)**	(13)
Cash distributions paid, net of distribution reinvestment	**(98,972)**	(73,667)	**(198,671)**	(148,712)
Change in non-cash working capital	**(2,505)**	(1,811)	**1,445**	36
	(94,873)	26,482	**(171,200)**	(38,625)
CASH FLOW FROM INVESTING ACTIVITIES				
Corporate acquisition, net of cash received	**-**	(42,182)	**-**	(42,182)
Acquisition of petroleum and natural gas properties	**(3,592)**	(81,525)	**(32,417)**	(85,369)
Proceeds on disposition of petroleum and natural gas properties	**791**	2,804	**2,003**	2,980
Capital expenditures	**(57,886)**	(49,737)	**(136,489)**	(97,591)
Long-term investment (Note 2)	**(20,000)**	-	**(20,000)**	-
Net reclamation fund contributions	**(3,226)**	(412)	**(3,657)**	(986)
Changes in non-cash working capital	**(12,061)**	16,653	**(9,444)**	707
	(95,974)	(154,399)	**(200,004)**	(222,441)
DECREASE IN CASH AND CASH EQUIVALENTS	**(8,737)**	-	**-**	(4,413)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	**8,737**	-	**-**	4,413
CASH AND CASH EQUIVALENTS, END OF PERIOD	**$ -**	$ -	**$ -**	$ -

See accompanying notes to consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

June 30, 2006 and 2005 (unaudited)

(all tabular amounts in thousands, except per unit and volume amounts)

1. SUMMARY OF ACCOUNTING POLICIES

The unaudited interim consolidated financial statements follow the same accounting policies as the most recent annual audited financial statements. The interim consolidated financial statement note disclosures do not include all of those required by Canadian generally accepted accounting principles ("GAAP") applicable for annual consolidated financial statements. Accordingly, these interim consolidated financial statements should be read in conjunction with the audited consolidated financial statements included in the Trust's 2005 annual report.

2. LONG-TERM INVESTMENT

During the quarter the Trust entered into an equity investment in a private oil sands company in the amount of $20 million. This portfolio investment is carried at cost and is subject to impairment in the event of a non-temporary decline in value.

The investment in the shares of the private company has been considered to be a related party transaction due to common directorships of the Trust, the private company and the manager of a private equity fund that holds shares in the private company. The $20 million investment was part of a $325 million private placement of the private company. In addition, certain directors and officers of the Trust have minor direct and indirect shareholdings in the private company.

3. LONG-TERM DEBT

		June 30, 2006		December 31, 2005
Revolving credit facilities				
Syndicated credit facility	**$**	**263,513**	$	254,680
Working capital facility		**7,685**		3,800
Senior secured notes				
5.42% USD Note		**83,622**		87,443
4.94% USD Note		**33,449**		34,977
4.62% USD Note		**69,684**		72,868
5.10% USD Note		**69,684**		72,868
Total long-term debt outstanding	**$**	**527,637**	$	526,636

During the first quarter for 2006, the Trust entered into a $572 million secured, extendible, financial covenant-based three year syndicated credit facility that expires in March 2009 and a $25 million demand working capital facility. The credit facility is extendible annually and security is in the form of floating charges on all lands and assignments.

Various borrowing options exist under the credit facility including prime rate advances, bankers' acceptances and LIBOR-based loans denominated in either Canadian or U.S. dollars. All drawings under the facility are subject to stamping fees that vary between 65 bps and 115 bps depending on certain consolidated financial ratios.

The following represents the significant financial covenants governing the credit facility:

- Long-term debt and letters of credit not to exceed three times annualized net income before non-cash items and interest expense;
- Long-term debt, letters of credit, and subordinated debt not to exceed four times annualized net income before non-cash items and interest expense; and
- Long-term debt and letters of credit not to exceed 50 per cent of unitholders' equity and long-term debt, letters of credit, and subordinated debt.

In the event that the Trust enters into a material acquisition whereby the purchase price exceeds 10 per cent of the book value of the Trust's assets, the ratios in the first two covenants above are increased to 3.5 and 5.5 times, respectively. As at June 30, 2006, the Trust was in compliance with all covenants and had $4.4 million in letters of credit and no subordinated debt.

The weighted-average effective interest rate under the credit facility was 5.4 per cent for the three months ended June 30, 2006 (3.2 per cent in 2005) and 5.0 per cent for the six months ended June 30, 2006 (3.2 per cent in 2005).

Amounts due under the senior secured notes and working capital facility in the next 12 months have not been included in current liabilities as management has the ability and intent to refinance this amount through the syndicated credit facility.

Interest paid during the period did not differ significantly from interest expense.

4. OTHER LONG-TERM LIABILITIES

	June 30, 2006	December 31, 2005
Retention bonuses	**$ 1,000**	$ 1,000
Accrued long-term incentive compensation	**10,738**	11,360
Total other long-term liabilities	**$ 11,738**	$ 12,360

The retention bonuses arose upon internalization of the management contract in 2002. The long-term portion of retention bonuses will be paid in August 2007.

The accrued long-term incentive compensation represents the long-term portion of the Trust's estimated liability for the Whole Unit Plan as at June 30, 2006 (see Note 12). This amount is payable in 2007 through 2009.

5. FINANCIAL INSTRUMENTS

The Trust uses a variety of derivative instruments to reduce its exposure to fluctuations in commodity prices and foreign exchange rates. The Trust considers all of these transactions to be effective economic hedges, however, the majority of the Trust's contracts do not qualify as effective hedges for accounting purposes.

Following is a summary of all derivative contracts in place as at June 30, 2006:

Financial WTI Crude Oil Sales Contracts

Term	Contract	Volume bbl/d	Bought Put US$/bbl	Sold Put US$/bbl	Sold Call US$/bbl
2006					
Jul 06 – Jul 06	Bought Put	161	64.50	-	-
Jul 06 – Sep 06	Put Spread	2,000	65.00	55.00	-
Jul 06 – Dec 06	Bought Put	1,000	55.00	-	-
Jul 06 – Dec 06	Bought Put	2,000	50.00	-	-
Jul 06 – Dec 06	Put Spread	1,000	55.00	45.00	-
Jul 06 – Dec 06	Put Spread	2,000	55.00	45.00	-
Jul 06 – Dec 06	3 - Way Collar	5,000	55.00	40.00	90.00
2007					
Jan 07 – Dec 07	3 - Way Collar	5,000	55.00	40.00	90.00
2008					
Jan 08 – Dec 08	3 - Way Collar	5,000	55.00	40.00	90.00
2009					
Jan 09 – Dec 09	3 - Way Collar	5,000	55.00	40.00	90.00

Energy Equivalent Swap

Term	Contract	Volume	Swap	Bought Put
Financial Cdn$ Crude Oil Purchase Contract				
Jul 06 – Jul 06	Swap	3,839 bbl/d	73.79 CDN$/bbl	-
Financial WTI Crude Oil Sales Contract				
Jul 06 – Jul 06	Bought Put	3,839 bbl/d	-	64.50 US$/bbl
Financial AECO Natural Gas Sales Contract				
Jul 06 – Aug 06	Swap	40,000 GJ/d	7.09 CDN$/GJ	-
USD Sales Contracts				
Jul 06 – Jul 06	Swap	8.8 MM US$	1.1613 CDN$/US$	-

Financial AECO Natural Gas Sales Contracts

Term	Contract	Volume GJ/d	Bought Put CDN$/GJ	Sold Put CDN$/GJ
2006				
Jul 06 – Aug 06	Put Spread	20,000	7.15	5.65
Jul 06 – Oct 06	Put Spread	20,000	7.50	5.50
Jul 06 – Oct 06	Put Spread	10,000	9.00	7.00

Financial Natural Gas AECO to NYMEX Basis Contracts

Term	Contract	Volume mmbtu/d	Swap US$/mmbtu
Jul 06 – Oct 06	Swap	40,000	(1.1925)
Nov 06 – Mar 07	Swap	20,000	(1.5250)
Apr 07 – Oct 08	Swap	50,000	(1.1160)
Nov 08 – Oct 10	Swap	50,000	(1.0430)

Financial Natural Gas Henry Hub to NYMEX Basis Contract

Term	Contract	Volume mmbtu/d	Swap US$/mmbtu
2006			
Sep 06 – Oct 06	Swap	20,000	(1.0600)

Financial Foreign Exchange Contracts

Term	Contract	Volume MM US$	Swap CDN$/US$	Swap US$/CDN$
USD Sales Contracts				
2006				
Jul 06 – Jul 06	Swap	3.2	1.1614	0.8610
Jul 06 – Dec 06	Swap	30.0	1.1659	0.8577
USD Purchase Contracts				
2006				
Oct 06 – Dec 06	Swap	15.0	1.1685	0.8558

Financial Electricity Contracts [1]

Term	Contract	Volume MWh	Swap CDN$/MWh
Jul 06 – Dec 10	Swap	5.0	63.00
Jul 06 – Dec 06	Swap	15.0	62.42
Jan 07 – Dec 07	Swap	15.0	65.17
Jan 08 – Dec 08	Swap	10.0	58.75
Jan 09 – Dec 09	Swap	10.0	57.50

(1) Contracted volume is based on a 24/7 term.

Financial Interest Rate Contracts [2]

Term	Contract	Principal MM US$	Fixed Annual Rate (%)	Spread on 3 Mo. LIBOR
Jul 06 – Apr 14	Swap	30.5	4.62	38.5 bps
Jul 06 – Apr 14	Swap	32.0	4.62	(25.5 bps)

(2) Interest rate swap contracts have an optional termination date of April 27, 2009. The Trust has the option to extend the optional termination date by one year on the anniversary of the trade date each year until April 2009. Starting in 2009, the contract amount decreases annually until 2014. The Trust pays the floating interest rate based on the three month LIBOR plus or minus a spread and receives the fixed interest rate.

The Trust has designated all fixed price electricity contracts as effective accounting hedges on their respective contract dates. A realized loss of $0.4 million and $0.5 million for three and six months ended June 30, 2006 respectively ($0.1 million and $0.3 million, respectively, in 2005) on the electricity contracts has been included in operating costs. The fair value unrealized loss on the electricity contracts of $2.5 million has not been recorded on the consolidated balance sheet as at June 30, 2006.

The Trust has entered into interest rate swap contracts to manage the Company's interest rate exposure on debt instruments. These contracts have been designated as effective accounting hedges on the contract date. A realized loss of $0.03 million and $0.1 million for three and six months ended June 30, 2006 respectively (gain of $0.2 million and $0.6 million, respectively, in 2005) on the interest rate swap contracts has been included in interest expense. The fair value unrealized loss on the interest rate swap contracts of $3.5 million has not been recorded on the consolidated balance sheet as at June 30, 2006.

None of the Trust's commodity and foreign currency contracts have been designated as effective accounting hedges. Accordingly, all commodity and foreign currency contracts have been accounted for as assets and liabilities in the consolidated balance sheet based on their fair values.

The following table reconciles the movement in the fair value of the Trust's financial commodity and foreign currency contracts that have not been designated as effective accounting hedges for the first six months of the year:

	June 30, 2006	June 30, 2005
Fair value, beginning of period [1]	**$ (4,042)**	$ (4,042)
Fair value, end of period [1]	**(13,169)**	(44,415)
Change in fair value of contracts in the period	**(9,127)**	(40,373)
Realized gains (losses) in the period	**9,879**	(34,546)
Gain (loss) on commodity and foreign currency contracts [1]	**$ 752**	$ (74,919)
Commodity and foreign currency contracts liability	**$ (28,502)**	$ (45,718)
Commodity and foreign currency contracts asset	**$ 15,333**	$ 1,303

(1) Excludes the fixed price electricity contract and interest rate swap contracts that were accounted for as effective accounting hedges.

At June 30, 2006, the fair value of the contracts that were not designated as accounting hedges was a loss of $13.2 million. The Trust recorded a net gain on commodity and foreign currency contracts of $0.8 million in the statement of income for the first six months of 2006 ($74.9 million loss in 2005). This amount includes the realized and unrealized gains and losses on derivative contracts that do not qualify as effective accounting hedges.

6. ASSET RETIREMENT OBLIGATIONS

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

	June 30, 2006	December 31, 2005
Carrying amount, beginning of period	**$ 165,053**	$ 73,001
Increase in liabilities relating to corporate acquisitions	**-**	71,143
Increase in liabilities relating to development activities	**681**	5,096
Increase in liabilities relating to change in estimate	**-**	15,487
Settlement of liabilities during the period	**(3,234)**	(4,881)
Accretion expense	**5,225**	5,207
Carrying amount, end of period	**$ 167,725**	$ 165,053

7. INCOME TAXES

The tax provision differs from the amount computed by applying the combined Canadian federal and provincial statutory income tax rates to income before future income tax recovery as follows:

	June 30, 2006	June 30, 2005
Income before future income tax expense and recovery	**$ 209,500**	$ 89,772
Expected income tax expense at statutory rates	**72,257**	33,772
Effect on income tax of:		
Net income of the Trust	**(79,289)**	(52,869)
Effect of change in corporate tax rate	**(58,545)**	-
Resource allowance	**(5,485)**	(7,468)
Change in estimated pool balances	**(6,345)**	-
Non-deductible crown charges	**473**	590
Alberta Royalty Tax Credit	**(15)**	(70)
Capital Tax	**112**	371
Other	**(4,327)**	1,774
Future income tax recovery	**$ (81,164)**	$ (23,900)

The net future income tax liability is comprised of the following:

	June 30, 2006	June 30, 2005
Future tax liabilities:		
Capital assets in excess of tax value	**$ 494,006**	$ 349,635
Future tax assets:		
Non-capital losses	**(1,605)**	(11,904)
Asset retirement obligations	**(42,266)**	(21,032)
Commodity and foreign currency contracts	**(3,912)**	(15,214)
Attributed Canadian royalty income	**(11,499)**	(6,464)
Deductible share issue costs	**(11)**	(43)
Net future income tax liability	**$ 434,713**	$ 294,978

8. EXCHANGEABLE SHARES

ARL EXCHANGEABLE SHARES	June 30, 2006	December 31, 2005
Balance, beginning of period	**1,595**	1,784
Exchanged for trust units [1]	**(90)**	(189)
Balance, end of period	**1,505**	1,595
Exchange ratio, end of period	**1.92377**	1.83996
Trust units issuable upon conversion, end of period	**2,895**	2,935

(1) During the first six months of 2006, 89,792 ARL exchangeable shares were converted to units at an average exchange ratio of 1.88758.

The following is a summary of the non-controlling interest for June 30, 2006 and December 31, 2005:

	June 30, 2006	December 31, 2005
Non-controlling interest, beginning of period	**$ 37,494**	$ 35,967
Reduction of book value for conversion to trust units	**(2,203)**	(4,018)
Current period net income attributable to non-controlling interest	**4,094**	5,545
Non-controlling interest, end of period	**$ 39,385**	$ 37,494
Accumulated earnings attributable to non-controlling interest	**$ 24,778**	$ 20,684

9. UNITHOLDERS' CAPITAL

	June 30, 2006		December 31, 2005	
TRUST UNITS ISSUED	Number of trust units	$	Number of trust units	$
Balance, beginning of period	**199,104**	**2,230,842**	185,822	1,926,351
Issued for cash	**-**	**-**	9,000	239,850
Issued on conversion of ARL exchangeable shares (Note 8)	**169**	**2,203**	333	4,018
Issued on exercise of employee rights (Note 11)	**573**	**11,144**	1,500	24,052
Distribution reinvestment program	**1,700**	**42,881**	2,449	48,789
Trust unit issue costs		**(251)**		(12,218)
Balance, end of period	**201,546**	**2,286,819**	199,104	2,230,842

10. DEFICIT

The deficit balance is composed of the following items:

	June 30, 2006	December 31, 2005
Accumulated earnings	**$ 1,522,312**	$ 1,235,742
Accumulated cash distributions	**(1,915,305)**	(1,674,818)
Deficit	**$ (392,993)**	$ (439,076)

During the quarter, presentation changes were made to combine the previously reported Accumulated Earnings and Accumulated Cash Distribution figures on the balance sheet into a single Deficit balance. The Trust has historically paid cash distributions in excess of accumulated earnings as cash distributions are based on cash flow generated in the current period while accumulated earnings are based on cash flow generated in the current period less a depletion and depreciation expense recorded on the original property, plant, and equipment investment.

11. TRUST UNIT INCENTIVE RIGHTS PLAN

A summary of the changes in rights outstanding under the plan is as follows:

	Weighted Number of Rights	**Average Exercise Price ($)**
Balance, beginning of period	1,349	10.22
Exercised	(573)	12.24
Balance before reduction of exercise price	776	9.41[1]
Reduction of exercise price		(0.23)
Balance, end of period	776	9.18[1]

(1) The holder of the right has the option to exercise rights held at the original grant price or a reduced exercise price.

The Trust recorded compensation expense of $2.5 million for the first six months of 2006 ($3.5 million in 2005) for the cost associated with the rights. The compensation expense was based on the fair value of all outstanding rights in the second quarter of 2006 and is amortized over the remaining vesting period of such rights. Of the 3,013,569 rights issued on or after January 1, 2003 that were subject to recording compensation expense, 335,499 rights have been cancelled and 1,920,053 rights have been exercised to June 30, 2006.

The following table reconciles the movement in the contributed surplus balance:

CONTRIBUTED SURPLUS	**June 30, 2006**	December 31, 2005
Balance, beginning of period	**$ 6,382**	$ 6,475
Compensation expense	**2,523**	(6,617)
Balance, end of period	**$ 4,782**	$ 6,382

(1) Upon exercise, the net benefit is reflected as a reduction of contributed surplus and an increase to unitholders' capital.

12. WHOLE TRUST UNIT INCENTIVE PLAN

The Trust recorded compensation expense of $7.8 million and $1.4 million to general and administrative and operating expenses, respectively, in the six months ended June 30, 2006 ($8.8 million and $1.9 million respectively for the twelve months ended December 31, 2005) for the estimated cost of the plan. The compensation expense was based on the June 30, 2006 unit price of $28.00 ($26.49 in 2005), accrued distributions, a performance multiplier of 2.0 (2.0 in 2005), and the number of units to be issued on maturity.

The following table summarizes the RTU and PTU movement for the six months ended June 30, 2006:

	Number of RTUs	Number of PTUs
Balance, beginning of period	478,765	390,557
Granted	173,885	178,339
Vested	(133,826)	-
Forfeited	(10,418)	(189)
Balance, end of period	508,406	568,707

The following table reconciles the change in total accrued compensation liability relating to the Whole Unit Plan:

	June 30, 2006	December 31, 2005
Balance, beginning of period	**$ 14,957**	$ 2,915
Increase in liabilities in the year (net of cash payments)		
General and administrative expense	**4,959**	8,774
Operating expense	**451**	1,916
Property, plant and equipment	**1,196**	1,352
Balance, end of period	**$ 21,563**	$ 14,957
Current portion of liability	**10,825**	3,597
Long-term liability	**$ 10,738**	$ 11,360

13. RECONCILIATION OF CASH FLOW AND DISTRIBUTIONS

Cash distributions are calculated in accordance with the Trust Indenture. To arrive at cash distributions, cash flow from operations adjusted for changes in non-cash working capital and expenditures on site restoration and reclamation, is reduced by reclamation fund contributions including interest earned on the fund, a portion of capital expenditures, and debt repayments. The portion of cash flow withheld to fund capital expenditures and to make debt repayments is at the discretion of the Board of Directors.

	Three Months Ended June 30		Six Months Ended June 30	
	2006	2005	**2006**	2005
Cash flow from operating activities	**$ 182,110**	$ 127,917	**$ 371,204**	$ 256,653
Change in non-cash working capital	**10,574**	(7,150)	**11,414**	5,033
Expenditures on site restoration and reclamation	**1,969**	1,041	**3,234**	2,088
Cash flow from operating activities after the above adjustments	**194,653**	121,808	**385,852**	263,774
Deduct:				
Cash withheld to fund capital expenditures	**(68,024)**	(35,663)	**(137,687)**	(88,183)
Reclamation fund contributions and interest earned on fund	**(4,727)**	(1,677)	**(6,396)**	(3,395)
Discretionary debt repayments	**(1,282)**	-	**(1,282)**	(3,860)
Cash distributions (1)	**120,620**	84,468	**240,487**	168,336
Accumulated cash distributions, beginning of period	**1,794,685**	1,382,120	**1,674,818**	1,298,252
Accumulated cash distributions, end of period	**$1,915,305**	$1,466,588	**$1,915,305**	$ 1,466,588
Cash distributions per unit (2)	**$ 0.60**	$ 0.45	**$ 1.20**	$ 0.90
Accumulated cash distributions per unit, beginning of period	**$ 16.83**	$ 14.69	**$ 16.23**	$ 14.24
Accumulated cash distributions per unit, end of period	**$ 17.43**	$ 15.14	**$ 17.43**	$ 15.14

(1) Cash distributions include non-cash amounts of $21 million and $42 million for the three and six months ended June 30, 2006, respectively ($10 million and $19 million for the same periods in 2005, respectively). These non-cash amounts relate to the distribution reinvestment program.

(2) Cash distributions per trust unit reflect the sum of the per trust unit amounts declared monthly to unitholders.

14. BASIC AND DILUTED PER UNIT CALCULATIONS

Net income per unit has been determined based on the following:

	Three Months Ended June 30		Six Months Ended June 30	
	2006	2005	**2006**	2005
Weighted average units (1)	**200,814**	187,388	**200,202**	186,810
Trust units issuable on conversion of exchangeable shares (2)	**2,895**	2,927	**2,895**	2,927
Dilutive impact of rights (3)	**740**	1,671	**817**	1,917
Diluted trust units	**204,449**	191,986	**203,914**	191,654

(1) Weighted average trust units excludes trust units issuable for exchangeable shares.

(2) Diluted trust units include trust units issuable for outstanding exchangeable shares at the period end exchange ratio.

(3) All outstanding rights were dilutive and therefore all have been included in the diluted trust unit calculation.

Basic net income per unit has been calculated based on net income after non-controlling interest divided by weighted average units. Diluted net income per unit has been calculated based on net income before non-controlling interest divided by diluted units.

15. COMMITMENTS AND CONTINGENCIES

Following is a summary of the Trust's contractual obligations and commitments as at June 30, 2006:

			Payments Due by Period		
($ millions)	**2006**	**2007-2008**	**2009-2010**	**Thereafter**	**Total**
Debt repayments	-	20.0	318.1	189.5	527.6
Reclamation fund contributions (1)	6.1	11.8	10.2	80.9	109.0
Purchase commitments	7.3	18.4	3.0	7.6	36.3
Operating leases	2.4	8.3	8.4	-	19.1
Derivative contract premiums (2)	12.6	3.6	1.8	-	18.0
Retention bonuses	1.0	1.0	-	-	2.0
Total contractual obligations	29.4	63.1	341.5	278.0	712.0

(1) Contribution commitments to a restricted reclamation fund associated with the Redwater property acquired in the Redwater and NPCU acquisition.

(2) Fixed premiums to be paid in future periods on certain commodity derivative contracts.

In addition to the above, the Trust has commitments related to its risk management program (See Note 5).

The Trust is involved in litigation and claims arising in the normal course of operations. Management is of the opinion that pending litigation will not have a material adverse impact on the Trust's financial position or results of operations.

16. RECLASSIFICATION

Certain information provided for prior periods has been reclassified to conform to the presentation adopted in 2006.

CORPORATE AND UNITHOLDER INFORMATION

DIRECTORS

Mac H. Van Wielingen (1) (3) (4)
Chairman

Walter DeBoni (1) (4) (5)
Vice-Chairman

John P. Dielwart
President and Chief Executive Officer

Frederic C. Coles (2) (3) (5)

Fred J. Dyment (1) (2)

Michael M. Kanovsky (1) (2)

Herb Pinder (3) (4)

John M. Stewart (3) (4) (5)

(1) Member of Audit Committee
(2) Member of Reserve Audit Committee
(3) Member of Human Resources and Compensation Committee
(4) Member of Policy and Board Governance Committee
(5) Health, Safety and Environment Committee

OFFICERS

John P. Dielwart
President and Chief Executive Officer
Doug J. Bonner
Senior Vice-President, Corporate Development
David P. Carey
Senior Vice-President, Capital Markets
Susan D. Healy
Senior Vice-President, Corporate Services
Steven W. Sinclair
Senior Vice-President Finance and Chief Financial Officer
Myron M. Stadnyk
Senior Vice-President and Chief Operating Officer
Allan R. Twa
Corporate Secretary
P. Van R. Dafoe
Treasurer
Terry Anderson
Vice-President, Operations
Yvan Chretien
Vice-President, Land

EXECUTIVE OFFICE

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TRUSTEE AND TRANSFER AGENT

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600, 530 – 8th Avenue S.W.
Calgary, Alberta T2P 3S8
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AUDITORS

Deloitte & Touche LLP
Calgary, Alberta

ENGINEERING CONSULTANTS

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP
Calgary, Alberta

Canada's Climate Change Voluntary Challenge and Registry. The industry's voluntary effort to reduce greenhouse gas emissions and document the efforts year over year.

CORPORATE CALENDAR

November 2	2006 Q3 Results

STOCK EXCHANGE LISTING

The Toronto Stock Exchange

Trading Symbols:
AET.UN (Trust Units)
ARX (Exchangeable Shares)

INVESTOR INFORMATION

Visit our website at
www.arcenergytrust.com
or contact:
Investor Relations
(403) 503-8600 or
1-888-272-4900 (Toll Free)

PRIVACY OFFICER

Susan D. Healy
privacy@arcresources.com
Facsimile: (403) 509-7260

Members commit to continuous improvement in the responsible management, development and use of our natural resources; protection of our environment; and, the health and safety of our workers and the general public

NOTES

ARC ENERGY TRUST