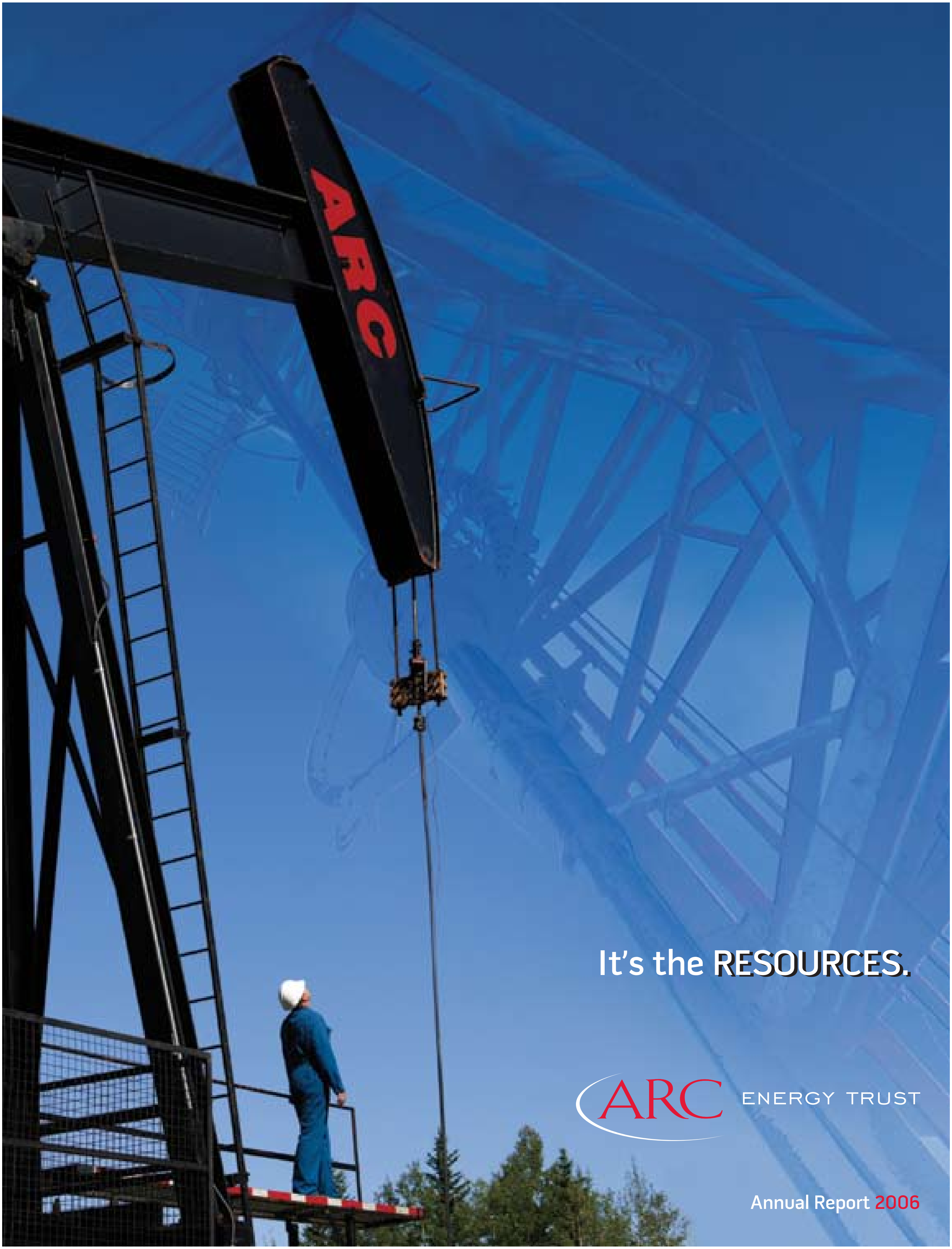


It's the RESOURCES.

ARC ENERGY TRUST

Annual Report 2006

Since inception our message and our mission have been consistent: utilize our excellent managerial and technical expertise to maximize value to our unitholders. We have done this through the acquisition and development of a portfolio of high quality, long-life assets. We have built a team that has the skills required to manage and exploit our asset base for the benefit of our unitholders.

ARC Energy Trust ("ARC" or "the Trust"), located in Calgary, Alberta, is one of Canada's largest conventional oil and gas royalty trusts. As an operating oil and gas company structured as a royalty trust, we acquire and develop long-life, lower declining oil and gas properties in western Canada. Our unitholders receive a monthly cash distribution from the Trust's producing oil and gas assets owned by ARC Resources Ltd.

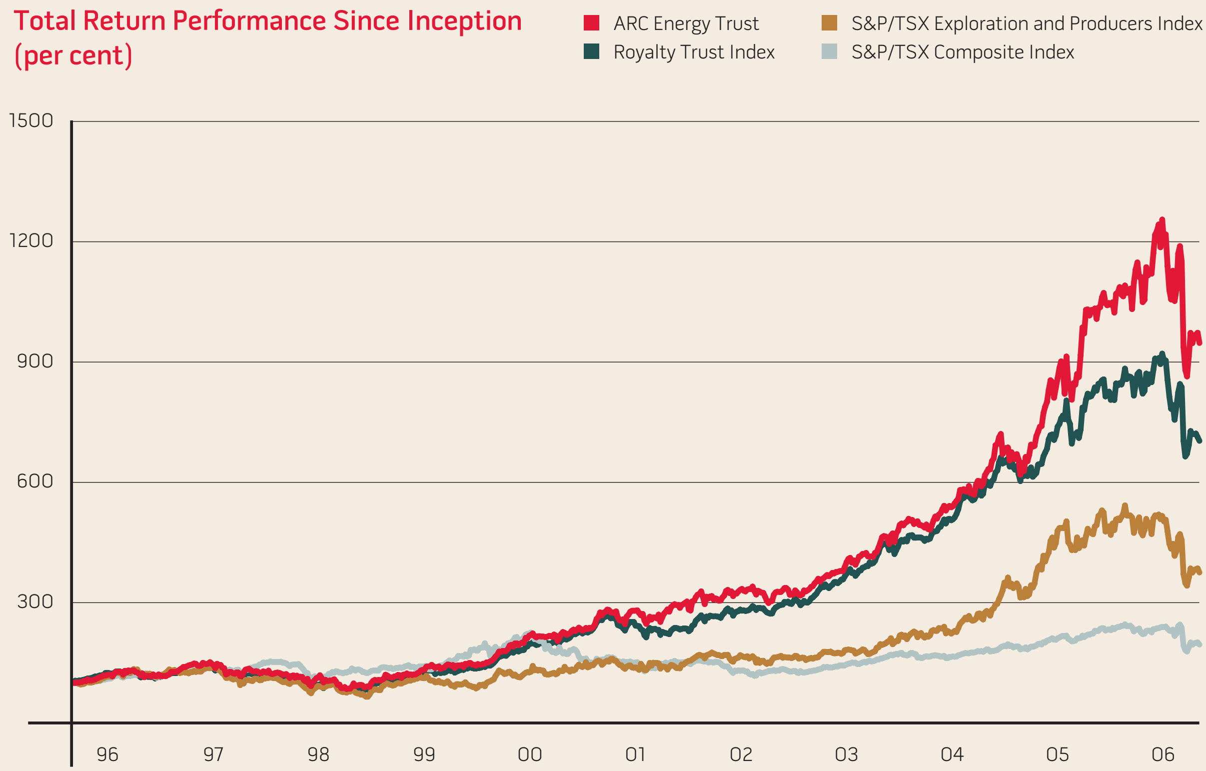
Front cover:
Gord Hallgren, Superintendent, Pembina NPCU.
This page:
Left to right:
Susan Healy, Senior Vice-President, Corporate Services; and
Yvan Chretien, Vice-President Land.

STRENGTH & STABILITY

ARC Energy Trust ("ARC" or "the Trust") has consistently outperformed the Royalty Trust Index, the S&P/TSX Composite Index, and the S&P/TSX Exploration and Producers Index. As of October 30, 2006, ARC's annual return was 11.84 per cent. On October 31, 2006, the Canadian Federal Government announced a proposal that would see trusts pay tax at 31.5 per cent on distributions commencing in 2011. After the Federal Government's announcement, ARC's annual return as of December 31, 2006 was minus 8.0 per cent, reflecting the drop in unit price. ARC's annual total returns since inception have averaged 24 per cent. ARC remains committed to generating superior returns and long-term value.

ARC Energy Trust units trade on the Toronto Stock Exchange under the symbol AET.UN along with its exchangeable shares under the symbol ARX. ARC Energy Trust options trade on the Montreal Exchange under the symbol AET.

Total Return Performance Since Inception (per cent)



This 2006 Annual Report contains forward-looking statements that may be identified by words like "outlook," "estimates" and similar expressions. These forward-looking statements are based on certain assumptions that involve a number of risks and uncertainties and are not guarantees of future performance. Actual results could differ materially as a result of changes to ARC's plans, the impact of changes in commodity prices, general economic, market and business conditions as well as production development and operating performance and other risks associated with oil and gas operations.

Financial Highlights

Twelve Months Ended December 31	2006	2005
FINANCIAL ($CDN millions, except per unit and per boe amounts)		
Revenue before royalties	**1,230.5**	1,165.2
Per unit [1]	**6.02**	6.10
Per boe [11]	**53.46**	56.75
Cash flow [2]	**760.6**	639.5
Per unit [1]	**3.72**	3.35
Per boe [11]	**33.05**	31.15
Net income	**460.1**	356.9
Per unit [3]	**2.28**	1.90
Cash distributions	**484.2**	376.6
Per unit [12]	**2.40**	1.99
Payout ratio [4]	**64%**	59%
Net debt outstanding [5]	**739.1**	578.1
Total capital expenditures and net acquisitions [8]	**496.3**	865.1
OPERATING		
Production		
Crude oil (bbl/d)	**29,042**	23,282
Natural gas (mmcf/d)	**179.1**	173.8
Natural gas liquids (bbl/d)	**4,170**	4,005
Total (boe per day)[11]	**63,056**	56,254
Average prices		
Crude oil ($/bbl)	**65.26**	61.11
Natural gas ($/mcf)	**6.97**	8.96
Natural gas liquids ($/bbl)	**52.63**	49.91
Oil equivalent ($/boe) [6] [11]	**53.46**	56.75
Operating netback ($/boe) [11]		
Commodity and other revenue (before hedging)	**53.46**	56.75
Transportation costs	**(0.63)**	(0.70)
Royalties	**(9.66)**	(11.46)
Operating costs	**(8.49)**	(6.93)
Netback (before hedging)	**34.68**	37.66

	2006 Gross Reserves	2006 Company Interest Reserves	2005 Company Interest Reserves
RESERVES [9]			
Proved reserves			
Crude oil and NGLs (mbbl)	**126,744**	**127,321**	129,745
Natural gas (bcf)	**581.6**	**593.7**	595.7
Total oil equivalent (mboe) [11]	**223,681**	**226,264**	229,033
Proved plus probable reserves			
Crude oil and NGLs (mbbl)	**161,481**	**162,193**	163,385
Natural gas (bcf)	**729.2**	**743.6**	741.7
Total oil equivalent (mboe) [11]	**283,015**	**286,125**	286,997
FINDING, DEVELOPMENT AND ACQUISITION COSTS ($/boe) [10] [11]			
Including Future Development Capital			
Current year		**27.20**	16.09
Three year average		**18.99**	13.50
Excluding Future Development Capital			
Current year		**22.41**	13.64
Three year average		**15.59**	11.00
TRUST UNITS (thousands)			
Units outstanding, end of period		**204,289**	199,105
Units issuable for exchangeable shares		**2,884**	2,934
Total units outstanding and issuable for exchangeable shares, end of period		**207,173**	202,039
Weighted average units [7]		**201,554**	188,237
TRUST UNIT TRADING STATISTICS ($CDN, except volumes) based on intra-day trading			
High		**30.74**	27.58
Low		**19.20**	16.55
Close		**22.30**	26.49
Average daily volume (thousands)		**706**	656

(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 65 per cent for the twelve months ended December 31, 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.

(8) Includes total consideration for the corporate acquisition including fees but prior to working capital, asset retirement obligation and future income tax liability assumed on acquisition.

(9) Gross reserves include the company working interest before deduction of royalty obligation and do not include royalty interests. Company interest reserves are the company interest plus the royalty interest prior to the deduction of royalty.

(10) Based on proved plus probable company interest reserves before royalties. Additional information on reserves is available in our Annual Information Form.

(11) Barrels of oil equivalent (boes) may be misleading, particularly if used in isolation. In accordance with NI-51-101, a boe conversion ratio for natural gas of 6 mcf:1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. References to boes throughout this annual report are based on a conversion ratio of 6:1.

(12) Based on the number of units outstanding at each cash distribution date.

ARC ENERGY TRUST

Message To The Unitholders

During 2006, ARC celebrated its 10th anniversary and took time to reflect on its many accomplishments over the last 10 years. ARC has been a leader in the sector in many ways – we were the first to move to a lower payout model thereby preserving more cash for re-investment, the first to incorporate an "exploreco" as a spin out from an acquisition, the first conventional trust to internalize management and one of the first trusts to look solely to internal development to sustain production. One of the things we are the most proud of is our contribution to the communities that we live and work in and to the Canadian economy. To the end of 2006, our cumulative distributions now exceed $2 billion – a significant accomplishment for a trust whose initial public offering was just $180 million.

John Dielwart, President and Chief Executive Officer

"We believe the energy trust sector is a major contributor to INCREASED productivity, as productivity is not measured by how much you spend, but how well you spend it."

ARC is proud of its investment in the local economies in western Canada. Since inception, ARC's cumulative capital spending in western Canada is $1.3 billion. ARC has distributed a total of $2.2 billion in cumulative distributions to its unitholders since 1996 out of $3.1 billion of cash flow. ARC has paid out $1.1 billion in royalties to the provinces it operates in since 1996 and contributed $932 million in operating costs to the economy. All of these contributions add positively to the Canadian economy at large through job creation both in small and large communities, money re-invested by unitholders into the purchase of goods and services and directed to other investments, and monies distributed to people across Canada in the form of distributions, which they in turn use to stimulate the economy in their provinces and communities.

Operationally and financially, 2006 was a record year. We successfully executed a $365 million capital program, drilled 294 gross wells (220 net wells) on our properties and brought 10,000 boes of production on stream. The success of the program was demonstrated by ARC raising its production guidance three times during 2006, with production averaging a record 63,056 boe per day. Continued high commodity prices in 2006 were reflected on ARC's financial performance with revenue before hedging of $1.2 billion, cash flow of $760 million, distributions of $484 million and net income of $460 million – all new highs for the Trust. Despite all of this, 2006 was one of the most challenging years of our existence. While our business fundamentals remain strong, the Government's decision to impose a punitive tax on trusts destroyed a billion dollars of value in the hands of our investors. Despite our strong operating results and record cash flow, total unitholder return for the year was a loss of eight per cent as our unit price plunged following the Government's announcement.

The Government's decision was made without an in-depth understanding of the role that energy trusts play in the Canadian economy. When you look at the October 31st announcement and examine the reasons the Finance Minister provided for his actions, they do not apply to energy trusts:

- There is no firm evidence that tax leakage is occurring from energy trusts and in fact there is strong evidence that Federal and Provincial Government tax revenues are being enhanced by energy trusts. Oil and gas companies have historically paid little tax, but all trust investors pay tax (either now, or in the future in the case of units held in tax deferred accounts) on the distributions they receive.

- There is irrefutable evidence that the energy trust sector has demonstrated enhanced productivity when managing mature assets. We believe that the energy trust sector is a major contributor to INCREASED productivity, as productivity is not measured by how much you spend, but how well you spend it.

- The Federal Government stated that "Canada stands alone in its treatment of income trusts" – this is simply not true. The United States eliminated "flow-through entities" in 1987, but provided a ten year transition period and exempted resource industries from the measures. Today, there is a strong and growing energy MLP ("Master Limited Partnership") sector in the United States that controls much of the United States' energy infrastructure. Over the past two years, we have seen the birth in the United States of Energy LLC's ("Limited Liability Corporations"), which have been designed to replicate the Canadian energy trust model and conform to United States tax law.

- Trusts have played a significant role in bringing Canadian oil and gas reserves under Canadian management and ownership

"ARC's strategy of maintaining a balanced production portfolio between oil and natural gas again proved advantageous as strong summer oil prices offset the pain of weak natural gas prices."

through the repatriation of $10 billion in previously foreign controlled assets.

ARC will continue its support for the Canadian Association of Income Funds and the Coalition of Canadian Energy Trusts as both organizations work to lobby for changes to the new legislation. We are also a founding member of the Canadian Association of Income Trust Investors ("CAITI"), which is an income trust investor advocacy group. We strongly encourage all of our unitholders to join this organization (www.caiti.info) so your voice on this issue can be heard.

Commodity prices remained volatile throughout 2006; reaching record highs on geopolitical instability but declining toward the end of 2006 and into January 2007, because of warm weather, elevated storage levels and an apparent abundance of spare capacity. AECO natural gas, in particular, started off strongly in 2006 and plunged to a low of $3.45 in September before recovering to end the year at $5.69. WTI oil prices were just as volatile, with oil reaching all time highs of $77.03 U.S. per barrel in July before falling off dramatically by year-end. ARC's strategy of maintaining a balanced production portfolio between oil and natural gas again proved advantageous as strong summer oil prices offset the pain of weak natural gas prices. While commodity prices remain strong, the growth in prices experienced in 2005 and 2006 has dissipated so that many institutional investors have been pulling their money out of energy equities so as to invest in other areas where they believe the prospects may be more attractive for short-term growth. Activity levels in the western Canadian oil and gas sector continue to be high with 22,000 wells drilled. With the high activity levels, utilization rates were high for most of 2006 throughout the oil and gas industry, putting upward pressure on the cost of services and supplies. ARC's operating costs rose to $8.49 per boe, a 23 per cent increase over 2005 with approximately half of the increase due to the acquisition of high operating cost properties in December 2005. Although operating costs for Redwater and NPCU averaged over $20 per boe in 2006, lower royalties and strong sales prices for the high-quality oil recovered on these properties offset the higher operating costs so that the netbacks from these properties were among our highest.

The continued increases in the cost of services and supplies are creating significant challenges for the industry as it struggles to ensure that returns from investing in western Canada remain competitive with opportunities elsewhere. The area where increased costs have had the most impact on ARC is in finding, development and acquisition ["FD&A"] costs. In 2006 ARC's FD&A costs increased to $22.41 per boe ($27.20 including future development costs) bringing our three year average up to $15.59 ($18.99 including future development costs). While a portion of the cost increases can be attributed to a significant increase in non-reserve adding activities – such as buying land and the initial funding for several significant enhanced oil recovery projects – the increase in the costs of services and supplies to execute the development program was significant. For western Canada to remain a competitive place to deploy capital, the double digit cost increases need to stop. We are starting to see indications that costs have reached a peak and are heading back down. Rig utilization rates were 75 per cent at the beginning of 2007, sharply down from the 95 per cent utilization rates at the same time last year and we are starting to see a roll back of prices from many of our service providers.

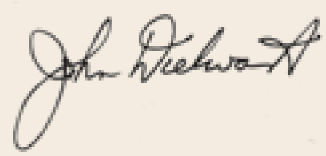
Looking forward, I believe that 2007 will be seen as the start of a new era for ARC as we begin to deploy capital towards the utilization of CO_2 for enhanced oil recovery ("EOR").

"ARC is a disciplined oil and gas company, with high quality assets, a low cost structure and an organization that has consistently delivered results. We believe the combination of these three things will allow ARC to continue to provide strong returns to its investors now and in the future."

ARC began preliminary work in 2006 on its CO_2 program by evaluating the Redwater reservoir to better understand it geologically, and to identify areas best suited for CO_2 flooding within the reservoir. ARC has performed detailed technical analysis of the Redwater reservoir and fluids and is developing preliminary designs for a CO_2 pilot plan for the Redwater area. In the Pembina area, ARC began miscibility testing of the reservoir fluids to determine their response to CO_2. While enhanced oil recovery utilizing CO_2 shows great promise to increase the oil ultimately recovered from the reservoir and to increase production, there are significant technical risks and uncertainty. Successful CO_2 projects in Canada are dependent on various factors including: a source of commercially viable CO_2, government legislation on CO_2 emissions, and the construction of infrastructure to transport the CO_2. Over the long-term, I believe that these reservoirs will play an important role in helping Canada achieve its objectives of lowering CO_2 emissions. We remain very optimistic about future value creation for our CO_2 EOR activities, despite the significant capital required to make this a reality.

ARC views itself as being an oil and gas entity that is structured as a trust. While there are challenges ahead of us, we believe the oil and gas industry is fundamentally sound and that the companies or trusts that have the best assets and the best people will continue to outperform. ARC's focus will continue to be on developing and acquiring high quality assets. What has changed as a result of the government announcement? Our cost of capital has gone up and our access to capital has gone down. Therefore we will have to carefully review any project that is particularly capital intensive and / or has a lower rate of return to ensure that they are still economic under the new regime.

The most important fact to keep in mind is that ARC is a disciplined oil and gas company, with high quality assets, a low cost structure and an organization that has consistently delivered results. We believe the combination of these three things will allow ARC to continue to provide strong returns to its investors now and in the future. ARC has a robust $360 million capital program planned for 2007 that is intended to maintain ARC's production at 63,000 boe per day. It remains business-as-usual at ARC.



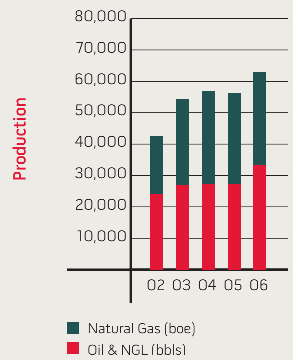
John P. Dielwart
President & Chief Executive Officer

ARC ENERGY TRUST

Review of Operations

2006 was a record year for ARC in many areas with activity levels, wells drilled, production brought on stream and capital spent all at or near record highs. Despite the record activity we are very pleased that we were able to execute our program with zero lost time accidents for our employees. During 2006 ARC successfully completed our first commercial natural gas from coal (NGC) development as well as beginning our journey to use CO_2 for enhanced oil recovery (EOR) on ARC operated properties. CO_2 has been used effectively in EOR projects in the United States for over 30 years, but has seen extremely limited use in Canada due to the lack of a cheap and plentiful supply of CO_2. This method of recovery could give ARC substantial ability to maintain stable production volumes for the longer-term.

Left to right:
Ingram Gillmore, Vice-President Engineering; **Myron Stadnyk**, Chief Operating Officer; and **Terry Anderson**, Vice-President, Operations



Production

For 2006, ARC averaged 63,056 boe per day – well ahead of the 61,000 we had budgeted for the year due to the success of our development program and some minor property acquisitions. This was a 12 per cent increase over 2005 production of 56,254 boe per day. The increase in production in 2006 was largely due to the NPCU and Redwater acquisitions completed late in 2005. These two fields contributed approximately 5,500 boe per day of production during 2006, with most of the remaining 1,300 boe increase resulting from a successful drilling program that offsets natural declines. The success of the drilling program is evidenced by a seven per cent increase in ARC's production per unit to 0.31 boe per day per thousand units in 2006 from 0.29 boe per day per thousand units in 2005. With a 2006 exit rate of 64,000 boe per day and approximately 1,000 boe per day of production associated with 2006 capital spending waiting on tie-in, ARC is well positioned to sustain its production in 2007.

Capital Expenditures

ARC invested a record $365 million on capital development activities in 2006, in line with our mid-year forecast of $370 million. The $365 million program delivered approximately 10,000 boe per day of production, more than offsetting the natural production decline of our properties. This ability to sustain production is a clear indication of the quality and depth of our asset base as we replaced production volumes in all of our five core areas in western Canada. Approximately $246 million was spent on drilling and optimization activities including our NGC projects. ARC drilled 294 gross wells (220 net) on operated properties with a 99 per cent success rate. In addition, ARC participated in 441 gross (44 net) wells drilled by other operators.

Approximately $58 million was spent on undeveloped land, seismic and growth oriented exploration activities. The $32 million spent on land was the largest land expenditure in our history and led to a nine per cent increase in our net undeveloped land to 521,000 acres. Significant funds were also devoted to early investment in enhanced oil recovery projects at Midale and Instow, Saskatchewan. While these expenditures did not contribute to production and reserves in 2006, they are expected to add reserves and value in the future.

In 2007, ARC is budgeting for a $360 million capital development program that will include the drilling of approximately 275 gross wells (225 net wells) on operated properties and participation in an estimated 150 gross wells to be drilled on non-operated properties. ARC's 2007 drilling program is expected to add approximately 11,000 boe per day to offset the natural production decline and maintaining production volumes stable at 2006 levels. The capital budget is slightly lower than the 2006 expenditures primarily due to anticipated decreases in service costs in 2007. Though ARC is drilling fewer wells in 2007, the average well cost will be higher as we are drilling fewer shallow gas wells and more wells in some of ARC's northern fields where deeper wells and more complex drilling and completion techniques are required. ARC is also budgeting $7 million for EOR activities, primarily on preliminary studies for potential CO_2 pilot projects.

Finding, Development and Acquisition Costs ("FD&A")

During 2006, ARC's exploitation and development activities replaced approximately 16 mmboe of proved plus probable reserves (including revisions) while 6 mmboe were added through acquisitions (net of minor property dispositions), bringing the total additions to 22 mmboe. This represents 96 per cent of the 23 mmboe produced during 2006. As a result, year-end 2006 reserves of 286 mmboe are effectively unchanged from the 287 mmboe of proved plus probable reserves recorded at year-end 2005.

Excluding future development capital ("FDC"), ARC's proved plus probable FD&A costs for 2006 were $22.41 per boe. On a proved basis, ARC's FD&A costs were $24.51 per boe. ARC's finding and development costs ("F&D") excluding FDC on a proved basis were $22.69 per boe and on a proved plus probable basis were $22.36 per boe. Higher FD&A costs for 2006 reflect the continued increases in the cost of services in 2006 across the oil and gas sector and also include the significant increase by ARC in pre-investing for future reserves adding activities such as buying land and initial funding of ARC's EOR projects. FD&A costs are high across the sector in 2006 and are expected to come down in 2007 as we have seen a decrease in service costs as industry utilization rates decrease.

Recycle Ratio

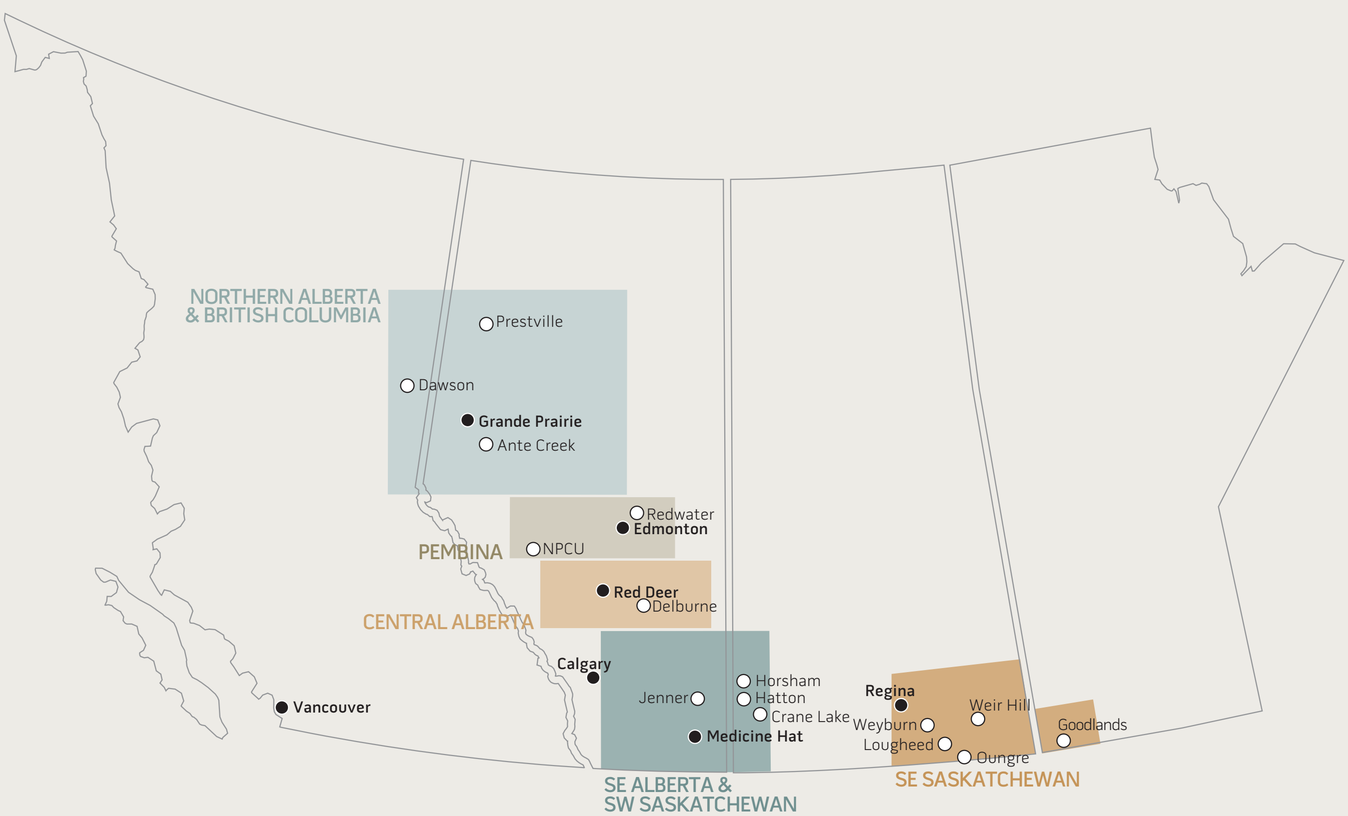
A measure of capital efficiency is the recycle ratio. The recycle ratio is determined by dividing the netback per boe by the FD&A costs per boe. It is a measure of how effectively an oil and gas company is investing its cash by calculating the dollars received for a barrel sold compared to the cost incurred to find and develop that barrel. Generally a recycle ratio of two or more is considered to be indicative of efficient capital allocation. The proved plus probable recycle ratio for 2006 using ARC's three year average FD&A of $15.59 per boe and the 2006 netback of $34.68 (prior to hedging gains) was 2.2 times. This recycle ratio is an indication of ARC's ability to maintain its profitability amidst rising costs.

Northern Alberta/British Columbia

Since the Ante Creek property acquisition in 2000, Northern Alberta and British Columbia has been a key focus area for ARC. With $59 million spent at Dawson alone, the Northern Alberta and British Columbia area accounted for 46 per cent of ARC's capital development expenditures in 2006. ARC drilled four horizontal wells at Dawson to follow-up on a successful 2005 horizontal well that tested new completion technology. The horizontal wells are expected to deliver four times the natural gas for three times the cost of a vertical well, thereby improving the drilling economics. To date, the initial horizontal well continues to exceed expectations. Three of the four 2006 horizontal wells have been tied-in but unfortunately production is restricted due to facility constraints; however, we believe that the current program will meet or exceed our expectations. ARC also drilled and tied-in six vertical wells in Dawson, which when combined with the success of the horizontal program, enabled ARC to increase production by 20 per cent at Dawson to 24 mmcf per day in the fourth quarter. With an additional four horizontal wells and four vertical wells planned for 2007, ARC is expecting to increase production to 40 mmcf per day in the fourth quarter of 2007. This increase does have risk associated with it as processing the additional volumes is dependent upon the construction and completion of a new gas plant by a third party.

Another property which saw substantial activity in 2006 was Ante Creek where $35 million was spent to drill 14 wells and construct a 16 km gas gathering system. The gathering system will tie-in production from the north half of the property to an ARC operated gas plant that was acquired as part of a small acquisition in early 2006. The completion of the gathering system in early 2007 will be critical to ARC's efforts to increase production in this core area as the existing facility is full and there are still eight wells from the 2006 drilling program that are awaiting tie-in. ARC has plans to drill up to ten additional wells at Ante Creek in 2007 and complete the facility optimization.

ARC's 2007 capital budget for Northern Alberta and British Columbia is $154 million, the largest budget of all of ARC's core areas. In 2006, production from Northern Alberta and British Columbia was 18,895 boe per day, a slight increase over 2005 production of 18,286 boe per day as facility constraints at Dawson and Ante Creek limited our production increases.



Pembina

Since inception in 1996, Pembina has been a key area for ARC, with its long-life, low decline oil fields. Although operating costs tend to be high they are more than offset by the above average netbacks that ARC receives on the high-quality oil produced from these fields. Pembina assets are also widely recognized as being some of the most suitable assets for CO_2 EOR recovery in Canada. With the late 2005 acquisition of NPCU, ARC has significantly increased its asset base in this area. Since taking over operatorship of NPCU, ARC has reactivated 65 oil wells, increasing field production by 400 boe per day (180 boe net to ARC's working interest). ARC also initiated a five well drilling program at NPCU in 2006 with production expected to be on stream at the end of the first quarter of 2007. Elsewhere in Pembina, ARC drilled 21 wells, which along with the acquisition of NPCU, helped increase production by 30 per cent to 10,179 boe per day in 2006. In 2007 ARC plans to spend $44 million in Pembina and expects to drill up to 46 gross wells and undertake numerous waterflood optimization activities.

Central Alberta

The most significant activity in ARC's Central Alberta area was the completion of ARC's first commercial NGC project at Delburne. The characteristics of NGC wells – low pressure, low rate stable production with low declines, is similar to shallow gas and ARC believes that it can use the expertise gained in operating shallow gas production to its benefit as it begins the development of its NGC resources. ARC drilled, completed and tied-in 23 NGC wells in 2006 as well as built a new low pressure gas gathering system and compressor station for this project. A second phase of this project is underway with seven wells drilled in early 2007 and nine more wells to be drilled. With this activity, our NGC production has increased to 1.5 mmcf per day. While this is still a small component of ARC's total production, it has great potential to become a more meaningful component in the future.

ARC will pursue other drilling and re-completion opportunities throughout the Central Alberta area in 2007 and has allocated a budget of $31 million with $10 million of that being targeted specifically at NGC projects. Production for Central Alberta averaged 8,206 boe per day in 2006, a small increase from 8,041 boe per day in 2005.

SE Alberta/SW Saskatchewan

ARC's production in the SE Alberta/SW Saskatchewan area is dominated by shallow natural gas. Shallow gas is an excellent trust asset as it provides large scale development opportunities with low risk and stable production. As most of the production comes from depths of between 375 and 675 metres, these are low cost wells with predictable production characteristics. Success in this area is dependent upon the successful execution of a large scale drilling, completion and tie-in program. ARC drilled 104 wells in the Crane Lake area of Saskatchewan and 57 wells in the Jenner area of Alberta. 2006 marked the third consecutive year that ARC has drilled greater than 100 shallow gas wells. With a $28 million budget for 2007, ARC expects to make it four years in a row. Importantly, ARC has at least a five year inventory of shallow gas wells to be drilled to take our lands to an eight well per section drilling density at a time when many of the offsetting lands have been drilled at 12 or even 16 wells per section. Through drilling and acquisitions, ARC's shallow gas production in this area has grown from just 35 mmcf per day in 2001 to 57 mmcf per day in 2006.

SE Saskatchewan

The light oil producing region of SE Saskatchewan continues to be an area of growth and a source of opportunities. Largely through development drilling, the continued success of the Weyburn CO_2 flood and minor acquisitions, ARC was able to increase production five per cent to 11,260 boe per day in 2006. In addition to ARC's operated activities on fields such as Lougheed, Weir Hill and Oungre, ARC is involved in the two commercial CO_2 EOR projects in Saskatchewan – Midale and Weyburn. ARC has a 6.93 per cent interest in the EnCana operated Weyburn Unit where the CO_2 flood was implemented in 2000 and a 15.5 per cent interest in the Apache operated Midale Unit where the CO_2 flood was implemented in October 2005. The knowledge gained in partnering on these projects will allow ARC to transfer the science to pilot projects it is planning on some of its other CO_2 amenable fields such as Pembina and Redwater.

ARC purchased assets in Manitoba in the Goodlands area late in 2006, which are incorporated into SE Saskatchewan for operating purposes. ARC added approximately 785 boe per day of production in the fourth quarter of 2006 through this acquisition. ARC has allocated $4 million for development opportunities on these assets in 2007. ARC plans to spend approximately $67 million in southeast Saskatchewan with drilling programs planned for Lougheed, Oungre, Weir Hill and other areas. With continued strong commodity prices, the drilling of these high productivity horizontal wells provides exceptional returns.

Non-operated Properties

On ARC's non-operated properties, ARC participated in the drilling of 441 gross (44 net) wells in 2006. One of the key properties is the Weyburn Unit (ARC working interest ("WI") of 6.93 per cent), where ARC participated in the drilling of 55 infill wells in 2006 with a further 50 planned for 2007. This Unit continues to have great results and is one of the most significant non-operated properties in ARC's portfolio.

Other key development areas include:

- Instow Unit (ARC WI at 18.55 per cent) – implementation of an Alkaline Surfactant Polymer (ASP) flood that should be fully operational in early 2007.
- Midale Unit (ARC WI at 15.54 per cent) – initiated CO_2 flood
- Bigstick-Hatton Area (ARC WI at 54 per cent) – participation in a multi-well shallow gas infill program.

Enhanced Oil Recovery ("EOR")

One of the greatest opportunities for producers in the western Canadian sedimentary basis is EOR through CO_2 injection. ARC has two properties that are prime candidates for CO_2 injection – Redwater and Pembina. Conventional recovery techniques and secondary recovery techniques such as waterfloods, only recover a small amount of the original oil-in-place in reservoirs. While EOR through CO_2 flooding is an accepted technology in the United States, use of CO_2 injection for enhanced recovery on a commercial basis in Canada is in its infancy. Success in creating commercially viable projects using CO_2 is dependent on several factors: a supportive government and regulatory environment, availability of large quantities of low cost CO_2, and construction of CO_2 infrastructure. It will take a great deal of cooperation between different stakeholders to achieve the required environment for large scale CO_2 injection to become a significant EOR option for Alberta.

In 2006, ARC launched several initiatives to better understand the CO_2 EOR potential of some of our key properties. In Redwater, ARC has begun a reservoir evaluation to better understand the geological features and to identify areas best suited for CO_2 flooding in that particular field. ARC conducted preliminary miscibility testing of the reservoir fluids to determine how they are affected by CO_2, which will help ARC design a CO_2 pilot plan for Redwater. Similar preliminary projects have taken place in the Pembina area as ARC completed an economic evaluation of a potential commercial CO_2 project for Pembina and began a reservoir evaluation so as to be able to predict the reservoir response to CO_2 injection and to identify areas best suited for a CO_2 flood.

Number of Wells Drilled by District

	Operated		Non- Operated		Total	
	Gross	Net	Gross	Net	Gross	Net
Drayton	22	14.4	19	3.5	41	18.0
Estevan	21	18.6	74	8.6	95	27.2
Grande Prairie	40	36.4	49	4.4	89	40.8
Medicine Hat	164	124.5	215	19.0	379	143.5
Red Water	2	2.0	0	0.0	2	2.0
Sundre	45	23.9	84	7.9	129	31.9
	294	219.8	441	43.6	735	263.4

2007 Outlook

ARC will continue to execute a disciplined capital program in 2007. To better execute its capital program opportunities, ARC reorganized the Operations Team by appointing Mr. Myron Stadnyk to the role of Chief Operating Officer and creating three new vice-president positions. Mr. Yvan Chretien is Vice-President Land, Mr. Terry Anderson is Vice-President Operations and Mr. Ingram Gillmore takes on the role of Vice-President Engineering. These new leadership positions will enable ARC to capitalize on the opportunities provided by its diverse asset base.

In 2007, ARC expects to focus on several key operating challenges:

- **Volumes** – Ensuring that all projects are managed effectively to meet ARC's forecast volumes of 63,000 boe per day.
- **Capital and Operating Cost Controls** – Focus on reducing capital costs ensuring that all costs are controlled to achieve forecast operating costs of $8.95 per boe.
- **Reserve Additions** – Pursue reserve additions at competitive F&D costs by focusing on core properties such as Dawson, Ante Creek, Weyburn and Jenner.

ARC ENERGY TRUST

Left to right:
Jeff Wickens, Environment and Regulatory Supervisor; **Julia McElroy**, Health and Safety Supervisor; and **Marty Welden**, Asset Integrity Supervisor.

Health, Safety & Environment

ARC has a long-standing tradition of leadership in all of its business and operations activities. ARC has consistently maintained a disciplined approach in environmental, health and safety issues and remains committed to operating in a socially responsible manner.

ARC participates and contributes to the Canadian Association of Petroleum Producers ("CAPP") Stewardship Program and is committed to reporting at the platinum level, which is the highest reporting level. CAPP defines stewardship as "analysis, planning, implementation, measurement and review of social, environmental and economic performance".

ARC continues efforts to reduce its greenhouse gas ("GHG") inventory as measured by production carbon intensity ("PCI") and production emissions index ("PEI"). This is accomplished through facility maintenance improvements and production efficiencies. ARC is also registered with, and reports to, the National Pollutant Release Inventory ("NPRI"). This federal initiative captures information on the release and transfer of key pollutants in communities across Canada. NPRI has matured to a reputable source of information available to the public on corporate environmental performance.

ARC effectively manages its liabilities through the controlled abandonment and reclamation of facilities, wells and leases. ARC maintains a reclamation fund to ensure that required funds are available for future reclamation of wells and facilities once they have reached the end of their economic life. ARC currently makes an annual contribution of $12 million to support this effort.

ARC conducts emergency response training on a regular basis in all of its operating fields to ensure a high level of response capability when placed in challenging situations.

ARC held its third annual consultant health and safety workshop in the spring of 2006. This annual workshop reinforces to contractors ARC's expectations for a safe work environment and takes the opportunity to review safe work practices and procedures, changes to regulatory requirements, and modifications to ARC programs.

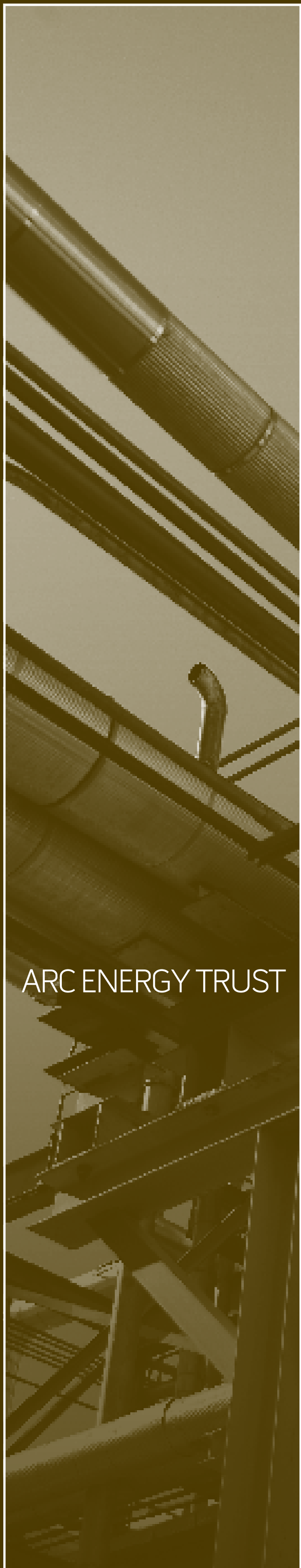
ARC performed safety audits on operated facilities and lease sites in 2006. ARC aims to conduct safety audits on a minimum of 10 per cent of its primary contracted companies. It is critical to ARC that contractors have a safety management system in place and all their employees are trained on the proper procedures to follow. The audit program provides an opportunity to evaluate contractor performance and ensure ARC safety standards are employed consistently and effectively at all sites.

ARC has consistently supported the communities it operates in by sponsoring and donating to community initiatives. In 2006, ARC contributed $1.3 million to not-for-profit groups both in Calgary and in its field communities. ARC has been pleased to partner with The United Way since 1996 and in 2006 ARC contributed over $169,000 to the Calgary and area United Way. In recognition of ARC's support, ARC received the Spirit of Gold Leadership Giving Award. ARC often partners with organizations for several years committing to yearly donations so that a non-profit organization can better budget to provide its services to the community. ARC has formed partnerships with many organizations some of which are:

- The Progressive Alternatives Society of Calgary that supports people with developmental disabilities to find employment;
- The Alberta Cancer Foundation supporting the Molecular Cancer Epidemiology Research Chair;
- The Alberta Mentor Foundation for Youth, which helps junior and senior high schools students achieve full potential through supporting in-school mentoring relationships;
- STARS – Alberta Shock Trauma Air Rescue Service Foundation, which is dedicated to the provision of a safe rapid, highly specialized emergency medical transport system for the critically ill and injured;
- Ronald McDonald House that provides accommodation to families who are accessing the Alberta Children's Hospital;
- Enviros Wilderness School, which provides support and assistance to troubled youth;
- Calgary Philarmonic Orchestra;
- Calgary Glenbow Museum; and
- Canadian Sport Centre Calgary.

ARC also donates extensively in the communities it operates in with each field office deciding where community support monies are to be directed. Through its field offices ARC supports community centres, aboriginal programs, youth sports programs, food banks, seniors outreach groups and many other community organizations across Alberta, Saskatchewan and British Columbia.

ARC's environment, health and safety program and community involvement initiatives are explained in more detail on its website at www.arcenergytrust.com.



ARC ENERGY TRUST

Reserves

Acquisitions and Dispositions

During 2006, ARC spent $132 million (net of minor dispositions) to purchase 5.8 mmboe of proved plus probable reserves. ARC's acquisitions were primarily focused on adding to our core northern properties with the purchase of additional Ante Creek and Dawson assets. These two acquisitions helped ARC to consolidate infrastructure and build upon the existing inventory of future development potential in these core areas.

ARC also acquired high netback, light oil producing properties in the Goodlands and Virden areas of southern Manitoba. These are the first properties ARC has owned in Manitoba.

As part of its active asset management program, ARC took advantage of the strong demand for producing assets by disposing of a few minor properties that no longer met the long-term needs of the Trust. The properties were sold to consolidate ARC's asset base, reduce future abandonment obligations, decrease corporate operating costs and exit an area with limited future development opportunities.

2006 Acquisition/Disposition Summary

	Purchase Price ($ millions)	Proved plus Probable Reserves (mmboe)	Reserve Purchase Price ($/boe)	Production Rate (boe/d)	Production Purchase Price ($/boe) /d)	Reserve Life Index (years)
Net Acquisitions	131.8	5.8	$22.55	1609	$81,914	9.9

Finding Development and Acquisition Costs ("FD&A")

Incorporating the net acquisitions during the year, ARC's proved FD&A costs excluding FDC were $24.51 per boe while proved plus probable FD&A costs were $22.41 per boe. The following table outlines the impacts of the significant capital devoted towards future growth opportunities

FD&A Costs – Impacts due to growth oriented spending

	Base	Undeveloped Land Acquisitions	EOR [1] Pre-investment	Seismic	Total
Expenditures ($ millions)	$ 420.8	$ 55.9	$ 13.2	$ 6.1	$ 496.3
Total Proved ($/boe)	$ 20.80	$ 2.76	$ 0.65	$ 0.30	$ 24.51
Proved Plus Probable ($/boe)	$ 19.03	$ 2.52	$ 0.59	$ 0.27	$ 22.41

[1] Enhanced oil recovery (EOR) Pre-investment relates to capital expended in 2006 on projects where the expected reserve uplift has not yet been booked.

FD&A Costs – Company Interest Reserves [1]

	Proved	Proved plus Probable
FD&A Costs Excluding Future Development Capital		
Exploration and Development Capital Expenditures ($ thousands)	$ 364,482	$ 364,482
Exploration and Development Reserve Additions Including Revisions (mboe)	16,062	16,298
Finding and Development Cost ($/boe)	$ 22.69	$ 22.36
Three Year Average F&D Cost ($/boe)	$ 18.06	$ 16.72
Net Acquisition Capital ($ thousands)	$ 131,820	$ 131,820
Net Acquisition Reserve Additions (mboe)	4,184	5,845
Net Acquisition Cost ($/boe)	$ 31.51	$ 22.55
Three Year Average Net Acquisition Cost ($/boe)	$ 17.47	$ 14.49
Total Capital Expenditures including Net Acquisitions ($ thousands)	$ 496,302	$ 496,302
Reserve Additions including Net Acquisitions (mboe)	20,246	22,143
Finding Development and Acquisition Cost ($/boe)	$ 24.51	$ 22.41
Three Year Average FD&A Cost ($/boe)	$ 17.77	$ 15.59

[1] In all cases, the F&D, or FD&A number is calculated by dividing the identified capital expenditures by the applicable reserves additions. Boes may be misleading, particularly if used in isolation. In accordance with NI 51-101, a Boe conversion ratio for natural gas of 6 mcf: 1 bbl has been used which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Future Development Capital ("FDC")

NI 51-101 requires that FD&A costs be calculated including changes in FDC. Changes in forecast FDC occur annually as a result of development activities, acquisition and disposition activities and capital cost estimates that reflect the independent evaluator's best estimate of what it will cost to bring the proved undeveloped and probable reserves on production. The current high level of activity has resulted in increased capital costs throughout the industry that are now reflected in the estimates of future development costs effective December 31, 2006.

FD&A Costs Including Future Development Capital

	Proved	Proved plus Probable
Exploration and Development Capital Expenditures ($ thousands)	$ 364,482	$ 364,482
Exploration and Development Change in FDC ($ thousands)	$ 51,780	$ 90,370
Exploration and Development Capital Including Change In FDC ($ thousands)	$ 416,262	$ 454,852
Exploration and Development Reserve Additions Including Revisions (mboe)	16,062	16,298
Finding and Development Cost ($/boe)	$ 25.92	$ 27.91
Three Year Average F&D Cost ($/boe)	$ 21.03	$ 21.64
Net Acquisition Capital ($ thousands)	$ 131,820	$ 131,820
Net Acquisition FDC ($ thousands)	$ 9,221	$ 15,630
Net Acquisition Capital Including FDC ($ thousands)	$ 141,041	$ 147,450
Net Acquisition Reserve Additions (mboe)	4,184	5,845
Net Acquisition Cost ($/boe)	$ 33.71	$ 25.22
Three Year Average Net Acquisition Cost ($/boe)	$ 19.53	$ 16.43
Total Capital Expenditures including Net Acquisitions ($ thousands)	$ 496,302	$ 496,302
Total Change in FDC ($ thousands)	$ 61,000	$ 106,000
Total Capital Including Change in FDC ($ thousands)	$ 557,302	$ 602,302
Reserve Additions including Net Acquisitions (mboe)	20,246	22,143
Finding Development and Acquisition Cost Including FDC ($/boe)	$ 27.53	$ 27.20
Three Year Average FD&A Cost Including FDC ($/boe)	$ 20.31	$ 18.99

Historic Company Interest Proved FD&A Costs

	2006	2005	2004	2003	2002	2001	2000
Annual FD&A excluding FDC	**$ 24.51**	$ 15.60	$ 16.53	$ 10.78	$ 8.87	$ 11.35	$ 5.73
Three year average FD&A excluding FDC	**$ 17.77**	$ 13.30	$ 11.05	$ 10.69	$ 9.07	$ 8.06	$ 5.68
Annual FD&A including FDC	**$ 27.53**	$ 17.64	$ 20.46	$ 12.66	$ 10.03	$ 11.93	$ 7.56
Three year average FD&A including FDC	**$ 20.31**	$ 15.45	$ 13.02	$ 11.96	$ 10.16	$ 9.09	$ 7.15

Historic Company Interest Proved Plus Probable FD&A Costs

	2006	2005	2004	2003	2002	2001	2000
Annual FD&A excluding FDC	**$ 22.41**	$ 13.64	$ 13.76	$ 8.50	$ 9.27	$ 9.75	$ 5.16
Three Year Average FD&A excluding FDC	**$ 15.59**	$ 11.00	$ 9.30	$ 9.07	$ 8.21	$ 6.94	$ 4.95
Annual FD&A including FDC	**$ 27.20**	$ 16.09	$ 19.14	$ 10.54	$ 10.79	$ 10.41	$ 7.21
Three Year Average FD&A including FDC	**$ 18.99**	$ 13.50	$ 11.65	$ 10.52	$ 9.46	$ 8.04	$ 6.54

Reserves

Reserves included herein are stated on a company interest basis (before royalty burdens and including royalty interests) unless noted otherwise. All reserves information has been prepared in accordance with National Instrument ("NI") 51-101. This report contains several cautionary statements that are specifically required by NI 51-101. In addition to the detailed information disclosed in this report more detailed information on a net basis (working interest share after deduction of royalty obligations, plus royalty interests) and on a gross basis (working interest before deduction of royalties without including any royalty interests) will be included in ARC's Annual Information Form ("AIF").

Based on an independent reserves evaluation conducted by GLJ Petroleum Consultants Ltd. ("GLJ") effective December 31, 2006 and prepared in accordance with definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("COGEH") and NI 51-101, ARC had proved plus probable reserves of 286 mmboe. Reserve additions from exploration and development activities (including revisions) were 16 mmboe while 6 mmboe were added through acquisitions (net of minor dispositions), bringing the total additions to 22 mmboe. This represents 96 per cent of the 23 mmboe produced during 2006. As a result, year-end 2006 reserves are one per cent lower than the 287 mmboe of proved plus probable reserves recorded at year-end 2005.

Proved developed producing reserves represent 66 per cent of proved plus probable reserves, while total proved reserves account for 79 per cent of proved plus probable reserves. Approximately 57 per cent of ARC's proven plus probable reserves are crude oil and natural gas liquids and 43 per cent are natural gas on a 6:1 boe conversion basis.

Net Present Value ("NPV") Summary 2006

ARC's crude oil, natural gas and natural gas liquids reserves were evaluated using GLJ's product price forecasts effective January 1, 2007 prior to provision for income taxes, interest, debt service charges and general and administrative expenses. Note that this presentation is on a before tax basis, if the tax measures announced on October 31st are substantially enacted then the after tax values could be different than the pre-tax number presented. **It should not be assumed that the discounted future net production revenues estimated by GLJ represent the fair market value of the reserves.**

NPV of Cash Flow Using GLJ January 1, 2007 Forecast Prices and Costs

NI 51-101 Net interest	Undiscounted ($ millions)	Discounted at 5% ($ millions)	Discounted at 10% ($ millions)	Discounted at 15% ($ millions)	Discounted at 20% ($ millions)
Proved Producing	5,609	3,900	3,037	2,517	2,169
Proved Developed Non-Producing	152	107	82	67	57
Proved Undeveloped	841	509	332	224	153
Total Proved	6,603	4,516	3,451	2,809	2,379
Probable	2,112	1,018	605	407	295
Proved plus Probable	8,715	5,534	4,056	3,215	2,674

At a 10 per cent discount factor, the proved producing reserves make up 75 per cent of the proved plus probable value while total proved reserves account for 85 per cent of the proved plus probable value. GLJ's price forecast utilized in the evaluation is summarized below.

GLJ January 1, 2007 Price Forecast

Year	West Texas Intermediate Crude Oil ($US/bbl)	Edmonton Light Crude Oil ($Cdn/bbl)	Natural Gas at AECO ($Cdn/mmbtu)	Foreign Exchange ($US/$Cdn)
2007	62.00	70.25	7.20	0.87
2008	60.00	68.00	7.45	0.87
2009	58.00	65.75	7.75	0.87
2010	57.00	64.50	7.80	0.87
2011	57.00	64.50	7.85	0.87
2012	57.50	65.00	8.15	0.87
2013	58.50	66.25	8.30	0.87
2014	59.75	67.75	8.50	0.87
2015	61.00	69.00	8.70	0.87
2016	62.25	70.50	8.90	0.87
2017	63.50	71.75	9.10	0.87
Escalate thereafter at	+2.0%/yr	+2.0%/yr	+2.0%/yr	0.87

Net Asset Value ("NAV")

The following NAV table shows what is normally referred to as a "produce-out" NAV calculation under which the current value of the Trust's reserves would be produced at forecast future prices and costs. The value is a snapshot in time and is based on various assumptions including commodity prices and foreign exchange rates that vary over time.

In the absence of adding reserves to the Trust, the NAV per unit will decline as the reserves are produced out. The cash flow generated by the production relates directly to the cash distributions paid to unitholders. The evaluation includes future capital expenditure expectations required to bring undeveloped reserves on production. ARC works continuously to add value, improve profitability and increase reserves which enhances the Trust's NAV.

In order to determine the "going concern" value of the Trust, a more detailed assessment would be required of the upside potential of specific properties and the ability of the ARC team to continue to make value-adding capital expenditures. At inception of the Trust on July 16, 1996, the NAV was determined to be $11.42 per unit based on a 10 per cent discount rate; since that time, including the January 15, 2007 distribution, the Trust has distributed $18.63 per unit. Despite having distributed more cash than the initial NAV, the NAV as at December 31, 2006 was $16.34 per unit using GLJ prices and $13.64 per unit using constant prices and costs. NAV per unit using GLJ prices decreased $0.28 per unit during 2006 after distributing $2.40 per unit to unitholders. Following is a summary of historical NAVs calculated at each of the Trust's year-ends utilizing the then current GLJ price forecasts and other assumptions and values utilized at such times.

Historical NAV – Discounted at 10 Per Cent

$Millions, except per unit amounts	**2006**	2005	2004	2003	2002	2001	2000
Value of NI 51-101 Net interest Proved plus Probable reserves [(1)]	**$ 4,056**	$ 3,891	$ 2,389	$ 1,689	$ 1,302	$ 1,216	$ 945
Undeveloped lands	**109**	59	48	50	20	22	6
Reclamation fund	**31**	23	21	17	13	10	10
Commodity and Foreign Currency Contracts [(2)]	**(9)**	(2)	(12)	–	–	–	–
Long term-debt, net of working capital	**(739)**	(578)	(265)	(262)	(348)	(289)	(109)
Asset retirement obligation	**(62)**	(35)	(23)	(27)	–	–	–
Net asset value	**$ 3,386**	$ 3,358	$ 2,158	$ 1,467	$ 987	$ 959	$ 852
Units outstanding (000's)	**207,173**	202,039	188,804	182,777	126,444	111,692	72,524
NAV per unit	**$ 16.34**	$ 16.62	$ 11.43	$ 8.03	$ 7.81	$ 8.59	$ 11.74

(1) Proved plus Probable from 2003 and on is estimated in accordance with NI 51-101 while in prior years it represents Established reserves (which represents Proved plus Risked Probables).

(2) Commodity and foreign currency contracts were included in the value of Proved plus Probable reserves prior to 2004.

Reserve Life Index ("RLI")

ARC's proved plus probable RLI was 12.4 years at year-end 2006 while the proved RLI was 9.8 years based upon the GLJ reserves and ARC's 2007 production guidance of 63,000 boe per day. The following table summarizes ARC's historical RLI.

Reserve Life Index

	2006	2005	2004	2003	2002	2001	2000	1999
Total Proved	**9.8**	10.3	9.7	10.1	10.1	9.8	10.4	10.1
Proved Plus Probable (Established reserves for 2002 and prior years)	**12.4**	12.9	12.2	12.4	11.8	11.5	12.1	12.0

Reserves Summary 2006 Using GLJ January 1, 2007 Forecast Prices and Costs

Company (Gross + Royalties Receivable)

	Light and Medium Crude Oil (mbbl)	Heavy Crude Oil (mbbl)	Total Crude Oil (mbbl)	NGLs (mbbl)	Natural Gas (bcf)	Oil Equivalent 2006 (mboe)	Oil Equivalent 2005 (mboe)
Proved Producing	99,543	2,759	102,302	9,627	453.4	187,501	189,179
Proved Developed Non-Producing	1,370	14	1,384	313	18.1	4,707	4,818
Proved Undeveloped	11,867	0	11,867	1,827	122.2	34,055	35,036
Total Proved	112,780	2,773	115,553	11,768	593.7	226,264	229,033
Proved plus Probable	143,746	3,677	147,423	14,770	743.6	286,125	286,997

Gross

	Light and Medium Crude Oil (mbbl)	Heavy Crude Oil (mbbl)	Total Crude Oil (mbbl)	NGLs (mbbl)	Natural Gas (bcf)	Oil Equivalent 2006 (mboe)	Oil Equivalent 2005 (mboe)
Proved Producing	99,418	2,503	101,921	9,440	441.6	184,959	186,435
Proved Developed Non-Producing	1,369	14	1,383	313	18.1	4,706	4,816
Proved Undeveloped	11,861	0	11,861	1,827	122.0	34,017	35,023
Total Proved	112,647	2,517	115,164	11,580	581.6	223,681	226,273
Proved plus Probable	143,583	3,361	146,944	14,537	729.2	283,015	283,795

Net

	Light and Medium Crude Oil (mbbl)	Heavy Crude Oil (mbbl)	Total Crude Oil (mbbl)	NGLs (mbbl)	Natural Gas (bcf)	Oil Equivalent 2006 (mboe)	Oil Equivalent 2005 (mboe)
Proved Producing	89,460	2,540	92,000	6,811	376.1	161,498	161,509
Proved Developed Non-Producing	1,226	13	1,239	218	14.0	3,790	3,944
Proved Undeveloped	10,393	0	10,393	1,282	97.8	27,975	29,183
Total Proved	101,079	2,554	103,633	8,310	487.9	193,263	194,637
Proved plus Probable	128,402	3,369	131,771	10,480	610.5	243,994	243,482

Reserves Reconciliation

	Crude Oil (mbbl)		Natural Gas (bcf)		Natural Gas Liquids (mbbl)		Total (mboe)	
Company Interest Reserves [1]	Proved [2]	Probable [3][4]	Proved	Probable [3]	Proved	Probable [3]	Proved	Probable [3]
Reserves at December 31, 1997	**18,948**	**5,207**	**127.7**	**20.5**	**7,459**	**759**	**47,690**	**9,383**
Acquisitions and divestments	2,465	648	(15.1)	(2.7)	(195)	(36)	(247)	162
Drilling and development	981	844	4.0	1.2	7	(104)	1,655	940
Production	(1,620)	0	(13.8)	0.0	(737)	–	(4,657)	0
Revisions	1,993	(1,570)	0.8	(0.6)	8	(23)	2,134	(1,693)
Reserves at December 31, 1998	**22,767**	**5,129**	**103.6**	**18.4**	**6,542**	**596**	**46,576**	**8,792**
Acquisitions and divestments	17,769	4,286	118.0	15.4	3,375	476	40,817	7,320
Drilling and development	1,992	631	5.8	1.7	204	1	3,168	912
Production	(3,069)	–	(24.3)	–	(981)	–	(8,100)	0
Revisions	536	204	0.7	1.7	(977)	232	(320)	713
Reserves at December 31, 1999	**39,995**	**10,250**	**203.9**	**37.1**	**8,163**	**1,304**	**82,141**	**17,737**
Acquisitions and divestments	18,650	3,860	47.7	8.0	1,911	328	28,517	5,527
Drilling and development	2,283	(693)	12.9	1.3	119	(25)	4,554	(497)
Production	(4,219)	–	(28.2)	–	(1,085)	–	(10,012)	0
Revisions	1,805	(268)	7.4	(3.8)	203	(166)	3,235	(1,057)
Reserves at December 31, 2000	**58,513**	**13,149**	**243.7**	**42.7**	**9,311**	**1,442**	**108,437**	**21,710**

Reserves Reconciliation (continued)

Company Interest Reserves [1]	Crude Oil (mbbl) Proved [2]	Crude Oil (mbbl) Probable [3][4]	Natural Gas (bcf) Proved	Natural Gas (bcf) Probable [3]	Natural Gas Liquids (mbbl) Proved	Natural Gas Liquids (mbbl) Probable [3]	Total (mboe) Proved	Total (mboe) Probable [3]
Acquisitions and divestments	27,932	7,124	101.9	11.1	1,643	241	46,551	9,211
Drilling and development	2,641	275	12.7	3.1	437	81	5,191	865
Production	(7,449)	–	(42.0)	–	(1,282)	–	(15,736)	0
Revisions	1,057	(610)	14.3	(1.8)	(148)	(117)	3,295	(1,029)
Reserves at December 31, 2001	**82,695**	**19,937**	**330.5**	**55.0**	**9,962**	**1,649**	**147,739**	**30,757**
Acquisitions and divestments	5,270	729	36.6	2.0	574	(32)	11,944	1,027
Driling and development	1,574	224	8.4	1.8	129	28	3,097	545
Production	(7,539)	–	(40.1)	–	(1,270)	–	(15,485)	–
Revisions	3,764	(1,513)	20.8	(6.2)	1,108	(48)	8,345	(2,598)
Reserves at December 31, 2002	**85,764**	**19,377**	**356.2**	**52.6**	**10,503**	**1,597**	**155,640**	**29,731**
Exploration discoveries	–	–	1.1	0.3	2	–	182	45
Drilling extensions	2,108	(1,460)	4.3	(1.5)	103	(28)	2,935	(1,734)
Improved recovery	510	(495)	1.5	(0.2)	61	(18)	817	(546)
Technical revisions	3,136	3,872	29.2	14.0	143	306	8,145	6,511
Economic factors	(854)	4	(1.1)	–	(35)	1	(1,076)	5
Acquisitions	17,642	5,720	307.6	59.7	3,713	702	72,614	16,380
Dispositions	(9,852)	(2,043)	(38.8)	(4.7)	(874)	(98)	(17,196)	(2,917)
Production	(8,353)	–	(59.9)	–	(1,491)	–	(19,832)	–
Reserves at December 31, 2003	**90,101**	**24,975**	**600.0**	**120.2**	**12,125**	**2,462**	**202,229**	**47,475**
Exploration discoveries	235	59	1.9	0.8	9	2	565	202
Drilling extensions	941	428	6.3	2.1	198	64	2,194	842
Improved recovery	1,522	180	16.4	13.3	374	149	4,629	2,542
Technical revisions	833	(1,042)	10.4	(4.0)	795	72	3,362	(1,643)
Acquisitions	2,000	986	19.5	2.8	23	5	5,280	1,460
Dispositions	(4,843)	(945)	(12.8)	(3.8)	(598)	(102)	(7,570)	(1,674)
Economic factors	1,816	154	12.8	3.6	142	45	4,098	796
Production	(8,404)	–	(65.3)	–	(1,534)	–	(20,814)	–
Reserves at December 31, 2004	**84,200**	**24,794**	**589.4**	**135.1**	**11,534**	**2,697**	**193,973**	**50,000**
Exploration discoveries	–	–	5	1	60	15	828	257
Drilling extensions	493	54	15	11	325	151	3,308	1,995
Improved recovery	772	(5)	5	1	251	31	1,815	127
Infill Drilling	2,471	819	16	3	275	107	5,484	1,344
Technical revisions	139	(1,220)	7	(8)	(311)	(345)	962	(2,858)
Acquisitions	36,797	6,626	18	3	1,506	257	41,380	7,406
Dispositions	(397)	(63)	(1)	–	(68)	(15)	(679)	(125)
Economic factors	1,597	(263)	5	–	63	–	2,495	(184)
Production	(8,498)	–	(63)	–	(1,462)	–	(20,533)	–
Reserves at December 31, 2005	**117,573**	**30,742**	**595.7**	**145.9**	**12,172**	**2,898**	**229,033**	**57,964**
Exploration discoveries	9	4	1	0	16	7	120	51
Drilling extensions	236	493	11	4	130	33	2,179	1,131
Improved recovery	1,202	1,572	1	0	13	4	1,335	1,607
Infill Drilling	2,181	657	29	(2)	655	115	7,721	438
Technical revisions	95	(1,871)	12	(3)	146	(171)	2,255	(2,568)
Acquisitions	3,599	1,227	6	5	112	132	4,757	2,236
Dispositions	(334)	(311)	(1)	(2)	(11)	(13)	(574)	(574)
Economic factors	1,593	(644)	5	1	58	(2)	2,452	(424)
Production	(10,600)	–	(65)	–	(1,522)	–	(23,015)	–
Reserves at December 31, 2006	**115,553**	**31,870**	**593.7**	**149.9**	**11,768**	**3,003**	**226,264**	**59,861**

[1] Company Interest reserves include working interests and royalties receivable

[2] Heavy oil reserves reconciliation as a component of crude oil on a proved basis started with reserves at December 31, 2005 of 3,011 mbbl, drilling extensions of 30 mbbl, improved recovery of 9 mbbl, infill drilling of 21 mbbl, technical revisions of 78 mbbl, economic factors of 124 mbbl and production of (499) mbbl, leaving a closing balance of 2,773 mbbl.

[3] Probable reserves risked at 50 per cent for 1998 through 2002.

[4] Heavy oil reserves reconciliation as a component of crude oil on a probable basis started with reserves at December 31, 2005 of 776 mbbl, drilling extensions of 56 mbbl, improved recovery of 2 mbbl, infill drilling of 10 mbbl, technical revisions of 36 mbbl, economic factors of 24 mbbl, leaving a closing balance of 904 mbbl.

Net Interest (Working Interest + Royalties Receivable – Royalties Payable) Reserves Reconciliation

	Crude Oil (mbbl)		Natural Gas (bcf)		Natural Gas Liquids (mbbl)		Total (mboe)	
	Proved [1]	Probable [2]	Proved	Probable	Proved	Probable	Proved	Probable
Reserves at December 31, 2005	104,432	26,838	489.5	119.5	8,621	2,092	194,637	48,845
Exploration discoveries	8	3	0.3	0.1	10	4	75	32
Drilling extensions	209	420	8.5	2.9	88	21	1,706	928
Improved recovery	1,029	1,395	0.6	0.2	11	3	1,143	1,424
Infill drilling	1,321	1,141	23.5	(1.7)	455	78	5,692	941
Technical revisions	1,563	(1,771)	10.7	(2.2)	155	(106)	3,507	(2,242)
Acquisitions	3,153	1,070	4.9	4.0	80	93	4,051	1,828
Dispositions	(332)	(309)	(1.3)	(1.5)	(11)	(13)	(568)	(573)
Economic factors	1,371	(649)	4.3	1.2	27	(3)	2,108	(451)
Production	(9,121)	–	(53.1)	–	(1,125)	–	(19,089)	–
Reserves at December 31, 2006	103,632	28,139	487.9	122.5	8,310	2,170	193,262	50,732

(1) Heavy oil reserves reconciliation as a component of crude oil on a proved basis started with reserves at December 31, 2005 of 2,758 mbbl, drilling extensions of 28 mbbl, improved recovery of 9 mbbl, infill drilling of 20 mbbl, technical revisions of 73 mbbl, economic factors of 115 mbbl and production of (450) mbbl, leaving a closing balance of 2,554 mbbl.

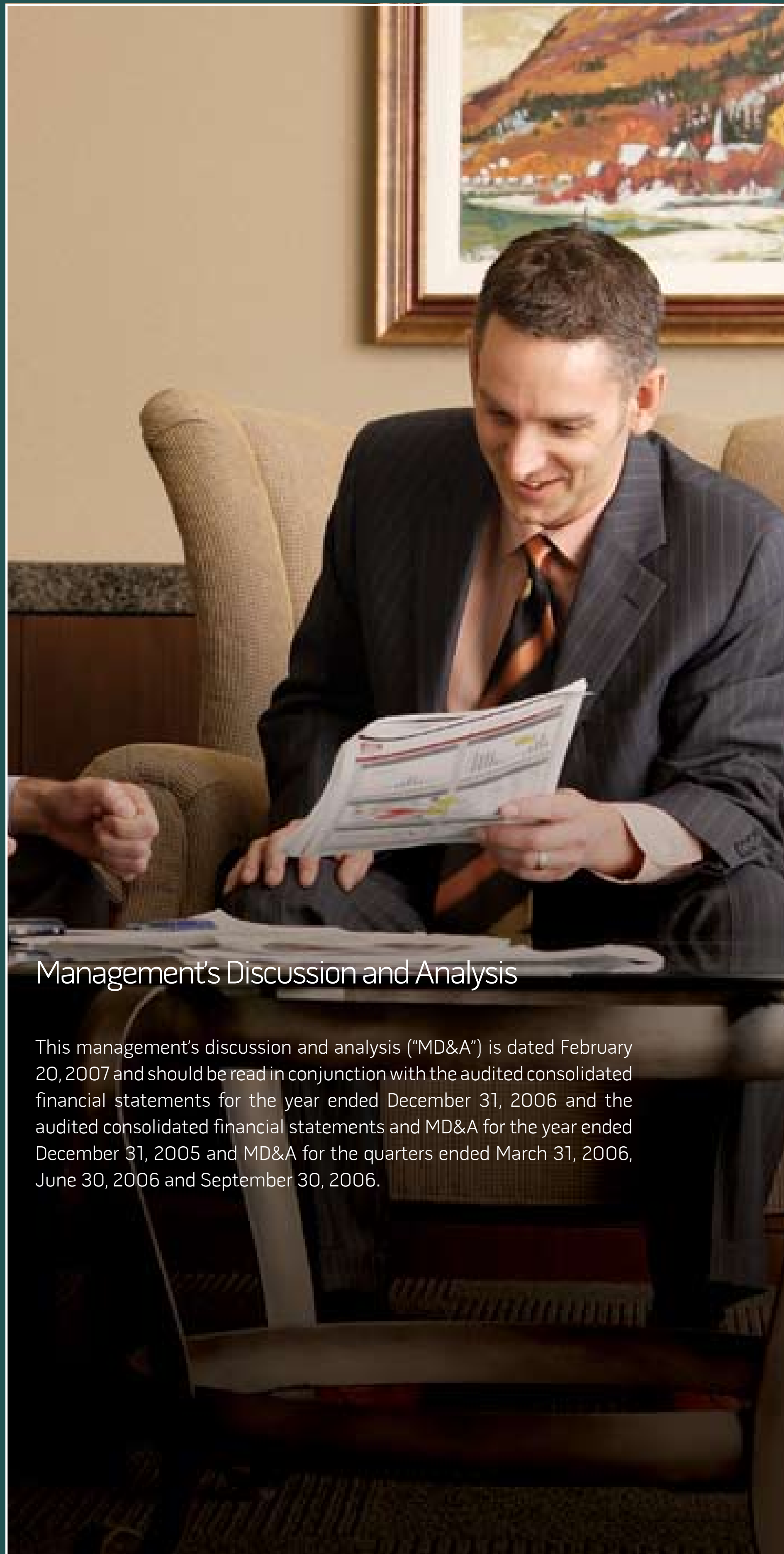
(2) Heavy oil reserves reconciliation as a component of crude oil on a probable basis started with reserves at December 31, 2005 of 699 mbbl, drilling extensions of 54 mbbl, improved recovery of 2 mbbl, infill drilling of 9 mbbl, technical revisions of 28 mbbl, economic factors of 23 mbbl, leaving a closing balance of 816 mbbl.

Additional Oil and Gas Disclosure

For more information in relation to gross reserves, net resources, F&D costs and other items of oil and gas disclosure mandated by NI 51-101, reference is made to the Annual Information Form of the Trust, which will be filed on SEDAR (www.sedar.com) by March 31, 2007 and will also be available on ARC's website at www.arcenergytrust.com. More information in relation to oil and gas matters including FD&A is available in the news release where ARC announced its year-end reserve numbers and related matters, dated February 22, 2007.

ARC ENERGY TRUST™

Left to right:
Steve Sinclair, Senior Vice-President Finance and Chief Financial Officer; and **Van Dafoe**, Treasurer



Management's Discussion and Analysis

This management's discussion and analysis ("MD&A") is dated February 20, 2007 and should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2006 and the audited consolidated financial statements and MD&A for the year ended December 31, 2005 and MD&A for the quarters ended March 31, 2006, June 30, 2006 and September 30, 2006.

NON-GAAP MEASURES

Management uses cash flow, cash flow from operations and cash flow from operations per unit derived from cash flow from operating activities (before changes in non-cash working capital and expenditures on site reclamation and restoration) 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 used frequently in this MD&A:

($ millions)	**2006**	2005
Cash flow from operating activities	**734.0**	616.7
Changes in non-cash working capital	**16.0**	17.9
Expenditures on site reclamation and restoration	**10.6**	4.9
Cash flow from operations	**760.6**	639.5

Management uses certain key performance indicators ("KPI's") and industry benchmarks such as payout ratio, operating netbacks ("netbacks"), total capitalization, finding, development and acquisition costs, recycle ratio, reserve life index, reserves per unit and production per unit to analyze financial and operating performance. Management feels that these KPI's and benchmarks are a key measure of profitability and overall sustainability for the Trust. 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.

FOURTH QUARTER FINANCIAL AND OPERATIONAL RESULTS

The Trust had an active fourth quarter with the closing of $93 million of acquisitions and $121.9 million spent on capital development activities which contributed to quarterly average production of 63,663 boe per day. The Trust had a payout ratio of 70 per cent and funded $48.8 million of its fourth quarter capital development program with cash flow. The fourth quarter was an active one for the Trust with the drilling of 59 gross wells on operated properties and new production coming on-stream.

Late in the fourth quarter, natural gas prices started to recover to levels not seen since the first quarter of 2006, however, oil prices declined. Due to increasing electricity prices, the Trust's fourth quarter operating costs were higher than previous quarters of 2006. Late in the quarter, electricity prices declined so as to be more in line with historical levels.

The Government's proposed Trust taxation announcement on October 31, 2006 was an unforeseen event in the fourth quarter of 2006 and it had a significant impact throughout the trust sector. With the government announcement, there was a significant devaluation in trust unit prices and a mass "sell off" of trust units whereby the Trust incurred an approximate 20 per cent decrease in the trust unit price and a resulting negative total return to unitholders in the fourth quarter and 2006 as a whole. Despite this event, ARC's core business is unchanged and the Trust's financial results are strong as indicated by record levels of production, revenue, capital spending, net income, cash flow, and distributions to unitholders in 2006.

Refer to "Quarterly Historical Review" in this MD&A for key quarterly financial and operational results.

- The Trust's fourth quarter production was 63,663 boe per day, an increase of eight per cent from the fourth quarter of 2005 due to acquisitions in late 2005 and during 2006.
- Cash flow decreased to $174.4 million ($0.85 per unit) from $207.6 million ($1.07 per unit) in the fourth quarter of 2005. Despite eight per cent higher volumes in the fourth quarter of 2006, significantly lower commodity prices and higher operating costs were the key contributors to the lower cash flow. Fourth quarter cash hedging gains of $9.8 million partially offset the lower commodity prices (cash hedging losses were $26.4 million in the fourth quarter of 2005).
- Net income decreased to $56.6 million ($0.28 per unit) from $130.5 million ($0.68 per unit) in the fourth quarter of 2005. In addition to the cash flow items listed above, 2006 net income decreased due to a $19.8 million increase in foreign exchange losses, a $22.5 million increase in depletion, a $24.2 million decrease in non-cash gains on commodity and foreign currency contracts offset by a $16.1 million decrease in future income tax expense and an $7.9 million decrease in the non-cash portion of general and administrative ("G&A") expenses as compared to 2005.
- The Trust maintained fourth quarter distributions at $0.20 per unit per month and paid out $122.3 million for a payout ratio of 70 per cent (56 per cent in the fourth quarter of 2005). The remaining $52.1 million of fourth quarter cash flow was used to fund $48.8 million (40 per cent) of the capital expenditure program and contribute $3.4 million to the Trust's reclamation funds, including interest.

- Both oil and natural gas prices recovered slightly late in the fourth quarter, however the total realized price for the quarter was 26 per cent lower than in 2005 due primarily to significantly lower natural gas prices and a stronger Canadian dollar which resulted in lower Canadian denominated commodity prices. The WTI oil price averaged US$60.22 per barrel in the fourth quarter, effectively unchanged from US$60.05 barrel in 2005. The stronger Canadian dollar resulted in a lower Canadian denominated oil price of $68.60 per barrel relative to $70.45 per barrel in 2005. The AECO monthly natural gas price was $6.36 per mcf, a 46 per cent decrease compared to the fourth quarter of 2005. The total realized price was $49.94 per boe, a 26 per cent decrease compared to $67.16 per boe in the fourth quarter of 2005.
- The fourth quarter netback before hedging decreased to $31.37 per boe compared to $45.84 per boe in 2005 due to a 26 per cent decrease in the realized price per boe. In addition, operating costs increased to $9.13 per boe in 2006 due to the higher cost Redwater and NPCU properties acquired in late 2005. Alberta electricity prices were significantly higher in the fourth quarter of 2006 relative to 2005 and service and labour costs increased throughout the industry in 2006 relative to 2005 levels.
- The Trust spent $121.9 million on capital development activities and undeveloped land in the fourth quarter compared to $87.8 million in 2005. The Trust had a very active fourth quarter with the drilling of 59 gross wells (45 net wells) on operated properties with a 100 per cent success rate. The Trust expanded its inventory of undeveloped land acreage with the purchase of $11.9 million of land in the fourth quarter. The land acquired was in core areas where the Trust has identified strategic development opportunities.
- Net debt levels increased to $739.1 million in the fourth quarter as a result of $93 million of acquisitions and debt funded capital expenditures of $44.4 million. A devaluation of the Canadian dollar relative to the U.S. dollar also impacted the Trust's net debt levels as 71 per cent of the Trust's debt is denominated in U.S. dollars. With the higher debt levels, interest expense increased to $8.7 million ($1.48 per boe) in the fourth quarter compared to $6 million ($1.11 per boe) in 2005.
- Cash G&A expenses increased to $1.74 per boe from $1.39 per boe in the fourth quarter of 2005. The increased G&A expenses were due to higher compensation costs in 2006. In addition, the Trust made a $0.7 million cash payout under the Whole Unit Plan for units vesting in the fourth quarter while no units vested in the fourth quarter of 2005. Non-cash G&A per boe decreased significantly in the fourth quarter of 2006, with a recovery of $0.02 per boe compared to an expense of $1.43 per boe in 2005 due to the devaluation of the trust unit price following the proposed Trust taxation announcement on October 31, 2006, which resulted in a lower value of the Whole Unit Plan and resultant non-cash expense. In addition, the Trust recorded lower non-cash rights expense in the fourth quarter of 2006 due to majority of the rights having vested and thus been fully expensed early in 2006.

FOURTH QUARTER FINANCIAL AND OPERATIONAL HIGHLIGHTS

(CDN$ millions except per unit and per cent)	**Q4 2006**	Q4 2005	% Change
Production (boe/d)	**63,663**	59,120	8
Cash flow from operations	**174.4**	207.6	(16)
Per unit	**$ 0.85**	$ 1.07	(21)
Cash distributions	**122.3**	115.7	6
Per unit	**$ 0.60**	$ 0.60	–
Payout ratio (per cent)	**70**	56	26
Net income	**56.6**	130.5	(57)
Per unit	**$ 0.28**	$ 0.68	(59)
Prices			
WTI (US$/bbl)	**60.22**	60.05	–
USD/CAD exchange rate	**0.87**	0.85	3
Realized oil price (CDN $/bbl)	**58.26**	62.12	(6)
AECO gas monthly index (CDN $/mcf)	**6.36**	11.68	(46)
Realized gas price (CDN $/mcf)	**6.99**	12.05	(42)
Operating netback ($/boe)			
Revenue, before hedging	**49.94**	67.16	(26)
Royalties	**(8.80)**	(13.51)	(35)
Transportation	**(0.64)**	(0.65)	(1)
Operating costs	**(9.13)**	(7.16)	28
Netback (before hedging)	**31.37**	45.84	(32)
Cash hedging gain (loss)	**1.68**	(4.86)	(135)
Netback (after hedging)	**$ 33.05**	$ 40.98	(20)
Capital expenditures	**121.9**	87.8	39
Capital funded with cash flow (per cent)	**40**	106	–

2006 ANNUAL FINANCIAL AND OPERATIONAL RESULTS

Following is a discussion of ARC's 2006 annual financial and operating results.

Financial Highlights

(CDN$ millions, except per unit and volume data)	**2006**	2005	% Change
Cash flow from operations	**760.6**	639.5	19
Cash flow from operations per unit [1]	**3.72**	3.35	11
Net income before future income tax and non-controlling interest	**379.6**	364.1	4
Net income	**460.1**	356.9	29
Net income per unit [2]	**2.28**	1.90	20
Distributions per unit [3]	**2.40**	1.99	21
Payout ratio per cent [4]	**64**	59	8
Average daily production (boe/d) [5]	**63,056**	56,254	12

[1] Per unit amounts are based on weighted average units plus units issuable for exhangeable shares at year-end.

[2] Based on net income after non-controlling interest divided by weighted average trust units excluding trust units issuable for exchangeable shares.

[3] Based on number of trust units outstanding at each cash distribution date.

[4] Based on cash distributions divided by cash flow from operations.

[5] Reported production amount is based on company interest before royalty burdens. Where applicable in this MD&A natural gas has been converted to barrels of oil equivalent ("boe") based on 6 mcf:1 bbl. The boe rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the well head. Use of boe in isolation may be misleading.

NET INCOME

Net income in 2006 was $460.1 million ($2.28 per unit), an increase of $103 million from $356.9 million ($1.90 per unit) in 2005 as a result of higher production volumes, strong oil prices throughout 2006 and total hedging gains on the commodity hedging program of $24.7 million compared to losses of $87.6 million in 2005. A significant future income tax recovery of $87.1 million in 2006, attributed to the reduction in legislated future corporate income tax rates, also resulted in higher net income in 2006 relative to 2005.

CASH FLOW FROM OPERATIONS

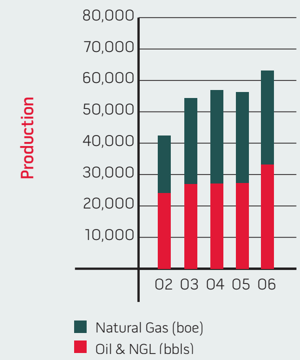
Cash flow from operations increased by 19 per cent in 2006 to $761 million from $640 million in 2005. The increase in 2006 cash flow was the result of a 12 per cent increase in production volumes, partially offset by lower natural gas prices. Cash flow was further increased by cash hedging gains of $29.3 million in 2006 compared to a cash hedging loss of $87.6 million in 2005. A change in the Trust's product mix and the acquisition of properties with lower effective royalty rates resulted in lower royalty expense in 2006. The increases in 2006 cash flow were somewhat offset by higher operating costs, higher cash G&A expenses and higher interest expense attributed to increased debt levels. Per unit cash flow from operations increased 11 per cent to $3.72 per unit from $3.35 per unit in 2005.

Following is a summary of variances in cash flow from operations from 2005 to 2006:

	($ millions)	($ per trust unit)	(% variance)
2005 Cash flow from Operations	**639.5**	**3.35**	
Volume variance	$ 140.9	$ 0.74	22
Price variance	(75.6)	(0.40)	(12)
Cash gains on commodity and foreign currency contracts [1]	116.8	0.61	18
Royalties	13.0	0.07	2
Expenses:			
Transportation	(0.2)	(0.00)	–
Operating [2]	(54.0)	(0.28)	(8)
Cash G&A	(8.9)	(0.05)	(1)
Interest	(14.8)	(0.08)	(2)
Taxes	3.6	0.02	1
Realized foreign exchange gain	0.3	0.00	–
Weighted average trust units	–	(0.26)	–
2006 Cash flow from Operations	**$ 760.6**	**$ 3.72**	**19**

[1] Represents cash gains (losses) on commodity and foreign currency contracts including cash settlements on termination of commodity and foreign currency contracts.

[2] Excludes non-cash portion of LTIP expense recorded in operating costs.



PRODUCTION

Production volume averaged 63,056 boe per day in 2006 compared to 56,254 boe per day in 2005. The Redwater and North Pembina Cardium Unit ("NPCU") acquisitions contributed approximately 5,500 boe per day (net) in 2006 including 580 boe per day (net) of incremental production on wells reactivated during the year. With the acquisition of producing properties in Manitoba, an incremental 785 boe per day of production came on-stream in the fourth quarter of 2006.

The Trust's objective is to maintain annual 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. During 2006, the Trust drilled 294 gross wells (220 net wells) on operated properties; 72 gross oil wells and 222 gross natural gas wells with a 99 per cent success rate.

The Trust expects that 2007 full year production will be approximately 63,000 boe per day and that 275 gross wells (225 net wells) will be drilled by ARC on operated properties with participation in an additional 150 gross wells to be drilled on the Trust's non-operated properties. The Trust estimates that the 2007 drilling program will add 11,000 boe per day of production which will offset production declines at existing properties.

Production	**2006**	2005	% Change
Crude oil (bbl/d)	**27,674**	22,032	26
Heavy oil (bbl/d)	**1,368**	1,250	9
Natural gas (mcf/d)	**179,067**	173,800	3
NGL (bbl/d)	**4,170**	4,005	4
Total production (boe/d) [1]	**63,056**	56,254	12
% Natural gas production	**47**	51	–
% Crude oil and liquids production	**53**	49	–

[1] Reported production for a period may include minor adjustments from previous production periods.

Oil production increased by 25 per cent to 29,042 boe per day in 2006 from 23,282 boe per day in 2005. The increase in oil production was largely attributed to the Redwater and NPCU acquisitions late in 2005. The Trust's weighting of oil and liquids production increased to 53 per cent in 2006 from 49 per cent in 2005 as the new volumes from Redwater and NPCU were primarily liquids.

Natural gas production increased to 179.1 mmcf per day in 2006, a three per cent increase from the 173.8 mmcf per day produced in 2005. The majority of this increase was as a result of ARC's active 2006 internal drilling program particularly in Northern and Central Alberta. In addition, the Trust drilled 125 net operated natural gas wells in Southeastern Alberta and Southwestern Saskatchewan during 2006, the majority of which were drilled in the third quarter and came on production during the fourth quarter.

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

	2006				2005			
Production Core Area [1]	**Total** (boe/d)	**Oil** (bbl/d)	**Gas** (mmcf/d)	**NGL** (bbl/d)	Total (boe/d)	Oil (bbl/d)	Gas (mmcf/d)	NGL (bbl/d)
Central AB	**8,206**	**1,553**	**31.3**	**1,433**	8,041	1,364	30.2	1,641
Northern AB & BC	**18,897**	**6,194**	**67.6**	**1,452**	18,286	6,026	65.3	1,381
Pembina & Redwater	**13,950**	**9,453**	**20.0**	**1,157**	7,953	4,166	17.7	832
S.E. AB & S.W. Sask.	**10,743**	**1,071**	**58.0**	**9**	11,298	1,499	58.7	15
S.E. Sask.	**11,260**	**10,771**	**2.2**	**119**	10,676	10,227	1.9	136
Total	**63,056**	**29,042**	**179.1**	**4,170**	56,254	23,282	173.8	4,005

[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

Average Benchmark Prices	2006	2005	% Change
AECO gas ($/mcf) (1)	**6.98**	8.45	(17)
WTI oil (US$/bbl) (2)	**66.25**	56.61	17
USD/CAD foreign exchange rate	**0.88**	0.83	6
WTI oil (CDN $/bbl)	**75.00**	68.52	9

(1) Represents the AECO monthly posting.

(2) WTI represents West Texas Intermediate posting as denominated in US$.

Oil prices reached historic highs in 2006 peaking at US$77.03 per barrel averaging US$66.25 per barrel for the full year of 2006. The strength of the Canadian dollar served to partially offset the impact of higher U.S. denominated oil prices. The Trust's oil production consists predominantly of light and medium crude oil while heavy oil accounts for less than three per cent of the Trust's liquids production. Overall the price of WTI oil in Canadian dollars increased by nine per cent over the prior year to $75.00 versus $68.52 in 2005.

Alberta AECO Hub natural gas prices, which are commonly used as an industry reference, averaged $6.98 per mcf in 2006 compared to $8.45 per mcf in 2005. Natural gas prices started the year at an historic high point of $12.11 per mcf but declined dramatically throughout the second and third quarters. ARC's realized gas price, before hedging, decreased by 22 per cent to $6.97 per mcf compared to $8.96 per mcf in 2005. ARC's realized gas price is based on prices received at the various markets in which 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 to aggregators.

Prior to hedging activities, ARC's total realized commodity price was $53.33 per boe in 2006, a six per cent decrease from the $56.54 per boe received prior to hedging in 2005.

The following is a summary of realized prices:

ARC Realized Prices Prior to Hedging	2006	2005	% Change
Oil ($/bbl)	**65.26**	61.11	7
Natural gas ($/mcf)	**6.97**	8.96	(22)
NGL ($/bbl)	**52.63**	49.92	5
Total commodity revenue before hedging ($/boe)	**53.33**	56.54	(6)
Other revenue ($/boe)	**0.13**	0.21	(38)
Total revenue before hedging ($/boe)	**53.46**	56.75	(6)

REVENUE

Revenue increased to a historical high of $1.2 billion in 2006. The increase in revenue was attributable to higher volumes and higher oil prices which were partially offset by lower natural gas prices.

A breakdown of revenue is as follows:

Revenue ($ millions)	2006	2005	% Change
Oil revenue	**691.8**	519.3	33
Natural gas revenue	**455.7**	568.7	(20)
NGL revenue	**80.1**	73.0	10
Total commodity revenue	**1,227.6**	1,161.0	6
Other revenue	**2.9**	4.2	(31)
Total revenue	**1,230.5**	1,165.2	6

RISK MANAGEMENT AND HEDGING ACTIVITIES

The Trust continues to maintain a strong hedging mandate with an emphasis on protecting cash flow and distributions to unitholders.

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

To satisfy this mandate, the board of directors has approved that up to three per cent of forecast revenues may be spent on option premiums on a go-forward basis to achieve price protection and satisfy the risk management mandate while limiting the risk exposure of hedged positions.

In 2006 ARC implemented the following strategies to protect distributions and provide upside commodity price participation to the unitholder:

- Protected power consumption with electricity swaps;
- Protected natural gas prices with an energy equivalent swap to crude oil;
- Protected the 2005 Redwater acquisitions volume with US$55 floors via a 3-way collar;
- Protected price conversion of US$ denominated WTI crude oil with foreign exchange swaps;
- Protected on average 44 per cent of natural gas production and 35 per cent of crude oil production for the year;
- Protected as much as 62 per cent of natural gas production volumes during the most vulnerable fall months; and,
- Protected natural gas and crude oil production with a portfolio of floor and ceiling option contracts.

ARC uses a combination of puts and call options otherwise known as floors and ceilings to protect budgeted commodity prices. A floor or put option ensures a minimum selling price and a ceiling or call option establishes a maximum selling price. ARC employs a strategy of buying floors and offsetting the cost of those floors by selling ceilings at higher prices or selling additional floors at lower prices. The net cost or premiums associated with the protection that is put in place is viewed as an insurance premium to ensure cash flow and stability of distributions, while maintaining strong upside price participation.

By implementing these strategies ARC realized total cash hedging gains of $29.3 million in 2006 as illustrated in detail in the "Gain or Loss on Commodity and Foreign Currency Contracts" section of this MD&A. In addition, cash hedging gains of $3.4 million on electricity hedges have been recorded as a reduction of 2006 operating costs.

On a forward-looking basis ARC continues to put layers of protection in place on both crude oil and natural gas. ARC has protection on approximately 40 per cent of oil production and 25 per cent of natural gas production for 2007 as shown in the following table which represents ARC's positions in place as at January 31, 2007.

2007 Hedge Positions

as at January 31, 2007 (1) (2)	Q1		Q2		Q3		Q4	
Crude Oil	US$/bbl	bbl/day	US$/bbl	bbl/day	US$/bbl	bbl/day	US$/bbl	bbl/day
Sold Call	89.05	7,500	89.05	7,500	87.65	7,500	87.65	7,500
Bought Put	**63.42**	**13,656**	**63.46**	**13,000**	**61.67**	**12,000**	**61.67**	**12,000**
Sold Put	50.02	10,000	50.02	13,000	48.13	12,000	48.13	12,000
Natural Gas	CDN$/GJ	GJ/day	CDN$/GJ	GJ/day	CDN$/GJ	GJ/day	CDN$/GJ	GJ/day
Sold Call	10.89	93,566	8.39	113,028	8.89	50,000	10.58	30,839
Bought Put	**7.97**	**93,566**	**7.05**	**113,028**	**7.15**	**50,000**	**7.62**	**30,839**
Sold Put	5.50	10,000	5.15	50,000	5.15	50,000	5.15	16,848
FX	CAD/USD	$M/month	CAD/USD	$M/month	CAD/USD	$M/month	CAD/USD	$M/month
Bought Put	**1.1321**	**2.4**	**1.1321**	**2.4**	**1.1321**	**2.4**	**1.1321**	**2.4**
Sold Put	1.0990	2.0	1.0990	2.0	1.0990	2.0	1.0990	2.0
Swap	1.1387	16.6	1.1387	16.6	1.1387	16.6	1.1387	16.6

(1) Note that the prices and volumes noted above represents averages for several contracts and the average price for the portfolio of options listed above does not have the same payoff profile as the individual option contracts. Viewing the average price of a group of options is purely for indicative purposes. The natural gas price shown translates all NYMEX positions to an AECO equivalent price. In addition to positions shown here, ARC has entered into additional basis positions.

(2) Please refer to the Trust's website at www.arcenergytrust.com under "Hedging Program" within the "Investor Relations" section for details on the Trust's hedging positions as of January 31, 2007.

The above table should be interpreted as follows using the 2007 Q1 Crude Oil Hedges as an example. For oil, the Trust has hedged 13,656 barrels per day at a minimum average price of US$63.42 and participates in prices up to a maximum average of US$89.05 on 7,500 barrels per day with no limit on the remaining 6,156 barrels per day hedged. Finally, ARC's average protected price of $63.42 reduces penny for penny at an average price below $50.02 on 10,000 barrels per day.

During 2006 ARC entered into "basis" natural gas contracts to lock in the difference between the Henry Hub index and the AECO monthly index. This set of transactions diversifies ARC's price exposure from the AECO basin to the broader North American market, thus reducing ARC's sensitivity to regional market events. Basis swaps are negotiated in terms of a fixed price in US$ per mmbtu that is deducted from the NYMEX natural gas price. For the period January 1, 2007 through March 2007, the Trust locked in the basis at US$1.31 per mmbtu on an average volume of 40,000 mcf per day and ARC has an average basis price of US$1.08 per mmbtu on an average volume of 50 mmcf per day of natural gas for the period of April 2007 through October 2010.

In addition to these positions the Trust has fixed the price of electricity for a portion of its power consumption at average prices between $59.33 and $64.63 through 2010 to mitigate the risk associated with fluctuating electricity prices which have a large impact on operating costs. A significant portion of the Trust's power usage is subject to the deregulated Alberta Power Pool price which was extremely volatile during 2006 and ranged from a record high monthly average price of $174.09 mw/h to a low of $42.87 mw/h. The electricity hedge represents approximately 69 per cent of the Trust's Alberta power consumption at operated properties.

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.

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

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 accounting definition of the requirements of an effective 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 category in the statement of income.

The Trust recorded a realized cash gain on commodity and foreign currency contracts of $29.3 million in 2006 as compared to a loss of $87.6 million recorded in 2005. The majority of the 2006 cash gains were attributed to the natural gas hedges whereby the Trust utilized a variety of contracts to lock in the minimum price on natural gas. As gas prices declined subsequent to the first quarter, the Trust realized significant gains on the contracts.

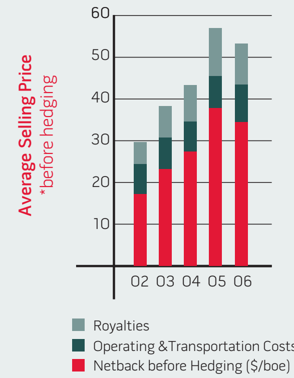
The following is a summary of the total gain (loss) on commodity and foreign currency contracts for 2006:

Commodity and Foreign Currency Contracts

($ millions)	Crude Oil & Liquids	Natural Gas	Foreign Currency	**2006 Total**	2005 Total
Realized cash gain (loss) on contracts [1]	(7.7)	29.7	7.3	**29.3**	(87.6)
Unrealized gain (loss) on contracts [2]	6.2	(4.1)	(6.7)	**(4.6)**	–
Total gain (loss) on commodity and foreign currency contracts	(1.5)	25.6	0.6	**24.7**	(87.6)

(1) Realized cash gains and losses represent actual cash settlements or receipts under the respective contracts.

(2) The unrealized (loss) gain 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 eight per cent to $35.95 per boe in 2006 compared to $33.40 per boe in 2005. The increase in netbacks in 2006 is primarily due to higher oil prices in 2006, a decrease in royalties, and cash hedging gains of $1.27 per boe compared to losses of $4.26 per boe in 2005. A decline in natural gas prices and higher operating costs partially offset the higher revenue and lower royalties.

The components of operating netbacks are shown below:

Netbacks

($ per boe)	Crude Oil ($/bbl)	Heavy Oil ($/bbl)	Gas ($/mcf)	NGL ($/bbl)	**2006 Total ($/boe)**	2005 Total ($/boe)
Weighted average sales price	66.16	46.90	6.97	52.63	**53.33**	56.54
Other revenue	–	–	–	–	**0.13**	0.21
Total revenue	66.16	46.90	6.97	52.63	**53.46**	56.75
Royalties	(10.80)	(4.86)	(1.37)	(14.08)	**(9.66)**	(11.46)
Transportation	(0.14)	(0.86)	(0.19)	–	**(0.63)**	(0.70)
Operating costs [1]	(11.51)	(10.63)	(0.96)	(7.49)	**(8.49)**	(6.93)
Netback prior to hedging	43.71	30.55	4.45	31.06	**34.68**	37.66
Realized gain (loss) on commodity and foreign currency contracts	(0.05)	–	0.45	–	**1.27**	(4.26)
Netback after hedging	43.66	30.55	4.90	31.06	**35.95**	33.40

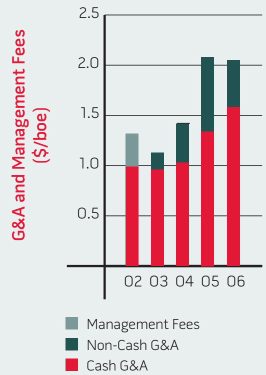
(1) Operating expenses are composed of direct costs incurred to operate oil and gas wells. A number of assumptions have been made in allocating these costs between oil, heavy oil, natural gas and natural gas liquids production.

Royalties decreased to $9.66 per boe in 2006 compared to $11.46 per boe in 2005. Royalties as a percentage of pre-hedged commodity revenue net of transportation costs decreased to 18 per cent compared to 20 per cent in 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 royalty concessions received on certain British Columbia natural gas properties. In addition, the Redwater and NPCU properties acquired in 2005 carried a significantly lower effective royalty rate than the Trust's existing properties due to the royalty structure of the properties.

Operating costs increased to $8.49 per boe compared to $6.93 per boe in 2005. The acquisition of the Redwater and NPCU properties, with operating costs of approximately $22 per boe in 2006, contributed to a large portion of the 23 per cent increase in operating costs. However, the Redwater and NPCU properties also contribute high netbacks of $40.60 per boe and $40.19 per boe, respectively, due to the premium oil quality and low royalty regime. Despite reductions in natural gas prices during 2006, the industry was still experiencing increasing costs for services, supplies, materials, electricity and labour throughout 2006. In particular, areas in northern Alberta experienced significant cost increases for services, materials and labour. In addition, the cost of electricity in Alberta was extremely volatile during the second half of 2006 with daily average prices ranging from $16.49 mw/h to $576.10 mw/h. Approximately 69 per cent of the Trust's electricity usage on Alberta operated properties was hedged at approximately $63 mw/h whereby the Trust was partially protected from the increases in electricity costs. The electricity hedge resulted in a $0.15 per boe reduction in operating costs in 2006.

Transportation costs decreased 10 per cent to $0.63 per boe in 2006 compared to $0.70 per boe in 2005. This is a result of the increased percentage of oil in the Trust's production mix as oil generally has a lower transportation cost than natural gas as a majority of the Trust's oil production is sold at the plantgate.

In 2007 it is expected that operating costs will increase by approximately five per cent to $8.95 per boe primarily due to costs associated with our newly acquired properties and the additional 11,000 boe per day of 2007 development production volumes. The Trust expects that the industry cost pressures will ease slightly in 2007 due to the moderation in industry activity levels experienced late in 2006.



GENERAL AND ADMINISTRATIVE EXPENSES AND TRUST UNIT INCENTIVE COMPENSATION

Cash G&A net of overhead recoveries on operated properties increased 32 per cent to $36.3 million in 2006 from $27.4 million in 2005. Increases in cash G&A expenses for 2006 were due to increased staff levels, higher compensation costs and the nature of ARC's long-term incentive program. 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 increase in G&A costs was partially offset by higher overhead recoveries attributed to high levels of capital and operating activity throughout 2006 and as a result of incremental overhead charged on new and existing operated properties. On a per boe basis, cash G&A costs increased 18 per cent to $1.58 per boe from $1.34 per boe as a result of higher cash G&A costs partially offset by increased production volume.

The Trust paid out $5.2 million under the whole unit plan in 2006 compared to $1.6 million in 2005 ($3.5 million and $1.1 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 2006 is attributed to a higher unit price upon vesting in April and October of each year, higher distributions and having two years of awards vesting in 2006 compared to one year of awards in 2005. The next cash payment under the Whole Unit Plan is scheduled to occur in April 2007.

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

G&A and Trust Unit Incentive Compensation Expense

($ millions except per boe)	**2006**	2005	% Change
G&A expenses	**45.8**	35.0	31
Operating recoveries	**(12.9)**	(8.7)	48
Cash G&A expenses before Whole Unit Plan	**32.9**	26.3	25
Cash Expense – Whole Unit Plan	**3.5**	1.1	218
Cash G&A expenses including Whole Unit Plan	**36.4**	27.4	32
Accrued compensation – Rights Plan	**2.5**	6.5	(62)
Accrued compensation – Whole Unit Plan	**8.2**	8.8	(7)
Total G&A and trust unit incentive compensation expense	**47.1**	42.7	10
Cash G&A expenses per boe	**1.58**	1.34	18
Total G&A and trust unit incentive compensation expense per boe	**2.05**	2.08	(1)

A non-cash trust unit incentive compensation expense ("non-cash compensation expense") of $10.7 million ($0.47 per boe) was recorded in 2006 compared to $15.3 million ($0.74 per boe) in 2005. This non-cash amount relates to estimated costs of the Trust Unit Incentive Rights Plan ("Rights Plan") and the Whole Trust Unit Incentive Plan ("Whole Unit Plan") to December 31, 2006. Despite a higher number of units outstanding under the plan in 2006, there was a decrease in the value of the Whole Unit Plan and a reduction in the non-cash expense due to the decline in trust unit prices following the Federal Government's proposed Trust taxation announcement in the fourth quarter of 2006.

RIGHTS PLAN

The Rights Plan provides employees, officers and independent directors the right to purchase units at a specified price. The rights have a five year term and vest equally over three years. The exercise price of the rights is adjusted downwards from time-to-time by the amount that distributions to unitholders, in any calendar quarter exceeds 2.5 per cent of the Trust's net book value of property, plant and equipment. The rights plan was replaced by a Whole Unit Plan during 2004 after which no further rights under the rights plan were issued. During 2006, one million rights were exercised or cancelled and 0.4 million rights remained outstanding as at December 31, 2006. Of the remaining rights outstanding, 6,000 will vest in March 2007 and compensation expense will be recorded until that time. All other rights were fully vested and expensed as of December 31, 2006.

The decrease in compensation expense for the rights plan in 2006 is due to the majority of rights having vested early in 2006 and compensation expense is only recorded up to vesting date.

WHOLE TRUST UNIT INCENTIVE PLAN ("WHOLE UNIT PLAN")

In March 2004, the Board of Directors approved a new Whole Unit Plan to replace the Rights Plan for new awards granted subsequent to the first quarter of 2004. The new Whole Unit Plan results in employees, officers and directors (the "plan participants") receiving cash compensation in relation to the value of a specified number of underlying units. The Whole Unit Plan consists of Restricted Trust Units ("RTUs") for which the number of units is fixed and will vest over a period of three years and Performance Trust Units ("PTUs") for which the number of units is variable and will vest at the end of three years.

Upon vesting, the plan participant is entitled to receive a cash payment based on the fair value of the underlying trust units plus accrued distributions. The cash compensation issued upon vesting of the PTUs is dependent upon the performance of the Trust compared to its peers and indicated by the performance multiplier. The performance multiplier is based on the percentile rank of the Trust's total unitholder return compared to its peers. Total return is calculated as the sum of the change in the market price of the units in the period plus the amount of distributions in the period. The performance multiplier ranges from zero, if ARC's performance ranks in the bottom quartile, to two for top quartile performance.

The following table shows the changes during the year of RTUs and PTUs outstanding:

Whole Unit Plan

(units in thousands and $ millions except per unit)	Number of RTUs	Number of PTUs	Total RTUs and PTUs
Balance, beginning of period	479	391	870
Granted in the period	373	303	676
Vested in the period	(180)	–	(180)
Forfeited in the period	(24)	(11)	(35)
Balance, end of period [1]	648	683	1,331
Estimated distributions to vesting date [2]	168	222	390
Estimated units upon vesting after distributions	816	905	1,721
Performance multiplier [3]	–	2.0	
Estimated total units upon vesting	816	1,810	2,626
Trust unit price at December 31, 2006	$ 22.30	$ 22.30	$ 22.30
Estimated total value upon vesting	$ 18.2	$ 40.4	$ 58.6

(1) Based on underlying units before performance multiplier and accrued distributions.

(2) Represents estimated additional units to be issued equivalent to estimated distributions accruing to vesting date.

(3) The performance multiplier only applies to PTUs and approximated 2.0 at December 31, 2006. The performance multiplier is assessed each period end based on actual results of the Trust relative to its peers.

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 number of PTUs to be issued on vesting, and distributions. Therefore, the expense recorded in the statement of income fluctuates over time.

As at December 31, 2006, the PTUs outstanding 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:

Value of Whole Unit Plan as at December 31, 2006

	Performance Multiplier		
(units thousands and $ millions except per unit)	**–**	**1.0**	**2.0**
Estimated trust units to vest			
RTUs	816	816	816
PTUs	–	905	1,810
Total units (1)	**816**	**1,721**	**2,626**
Trust unit price (2)	22.30	22.30	22.30
Trust unit distributions per month (2)	0.20	0.20	0.20
Value of Whole Unit Plan upon vesting	**18.2**	**38.8**	**58.6**
Officers	2.1	11.6	20.9
Directors	1.4	1.4	1.4
Staff	14.7	25.8	36.3
Total payments under Whole Unit Plan (3)	**18.2**	**38.8**	**58.6**
2007	7.8	11.2	14.6
2008	6.7	14.9	23.1
2009	3.7	12.7	20.9

(1) Includes additional estimated units to be issued for accrued distributions to vesting date.

(2) 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 $22.30 per trust unit and distributions of $0.20 per unit per month based on current levels.

(3) Upon vesting, a cash payment is made equivalent to the value of the underlying trust units. The payment is made on vesting dates in April and October of each year 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 $18.2 million to $58.6 million will be paid out from 2007 through 2009 based on the current trust unit price, distribution levels and a performance multiplier ranging from zero to two.

INTEREST EXPENSE

Interest expense increased to $31.8 million in 2006 from $16.9 million in 2005 due to an increase in short-term interest rates, and higher debt balances as a result of the Trust's acquisitions activity which was funded $125 million with debt. As at December 31, 2006, the Trust had $687.1 million of debt outstanding, of which $261 million was fixed at a weighted average rate of 5.056 per cent and $426.1 million was floating at current market rates plus a credit spread of 65 basis points. Seventy-one per cent of the Trust's debt is denominated in U.S. dollars.

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

Interest Expense

($ millions)	**2006**	2005	% Change
Year end debt balance (1)	**687.1**	526.6	30
Fixed rate debt	**261.0**	268.2	(3)
Floating rate debt	**426.1**	258.4	65
Interest expense before interest rate swaps (2)	**31.4**	17.4	80
Loss (gain) on interest rate hedge	**0.4**	(0.5)	180
Net interest expense	**31.8**	16.9	88

(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 loss of $4.2 million ($0.18 per boe) on foreign exchange transactions compared to a gain of $6.4 million ($0.31 per boe) in 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.

Included in the 2006 realized foreign exchange gain was a gain of $2.6 million realized upon repayment of US$6 million of debt in 2006. The debt was issued in 2002 when the USD/CAD foreign exchange rate was approximately 0.64 and strengthened considerably to 0.88 on repayment in 2006. The 2006 unrealized foreign exchange loss of $7.1 million was due to the revaluation of U.S. denominated debt balances associated with the weakening of the Canadian dollar relative to the U.S. dollar in 2006.

TAXES

In 2006, a future income tax recovery of $87.1 million was included in income compared to a $1.6 million expense in 2005. The significant increase in the future income tax recovery in 2006 was due to the legislated reduction in the future corporate income tax rates in the second quarter of 2006 whereby the Trust's expected future income tax rate decreased to 29.4 per cent from 33.7 per cent prior to the rate reductions.

Acquisitions completed in 2006 resulted in the Trust recording a future income tax liability of $5.4 million due to the difference between the tax basis and the fair value assigned to the acquired assets. The amount of tax pools versus asset value is one of the parameters that impacts the Trust's acquisition bid levels.

At December 31, 2006 the Trust's subsidiaries had tax pools of approximately $1 billion. The tax pools consist of $903 million of tangible and intangible capital assets, $18.2 million of non-capital loss carryforwards which expire at various periods to 2026, and $110 million for other tax pools. In addition to the above tax basis for the Trust's subsidiaries, the Trust itself had an approximate tax basis of $545.1 million as at December 31, 2006.

On October 31, 2006, the Federal Government announced the Trust taxation. Currently, distributions paid to unitholders, other than returns of capital, are claimed as a deduction by the Trust in arriving at taxable income whereby tax is eliminated at the Trust level and is paid by the unitholders. The proposals would result in a two-tiered tax structure whereby distributions would first be subject to a 31.5 per cent tax at the Trust level commencing in 2011, and then unitholders would be subject to tax on the distribution as if it were a taxable dividend paid by a taxable Canadian corporation. If enacted, the proposals would apply to the Trust effective January 1, 2011. The Trust is currently assessing various alternatives with respect to the potential implications of the tax proposals, however until the legislation is enacted in final form, the Trust will not arrive at a final conclusion with respect to future Trust structure and implications to the Trust. As the tax proposals had not yet been substantively enacted as of December 31, 2006, the consolidated financial statements do not reflect the impact of the proposed taxation.

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 for fiscal 2006. Due to the Trust's structure, currently, both income tax and future tax liabilities are passed on to the unitholders by means of royalty payments made between ARC Resources and the Trust.

Capital taxes were eliminated effective January 1, 2006 pursuant to the Federal Government budget of May 2, 2006.

DEPLETION, DEPRECIATION AND ACCRETION OF ASSET RETIREMENT OBLIGATION

The depletion, depreciation and accretion ("DD&A") rate increased to $15.64 per boe in 2006 from $12.88 per boe in 2005. The higher DD&A rate is due to the Redwater and NPCU acquisitions in the fourth quarter of 2005 for which the Trust recorded a higher proportionate cost per barrel of proved reserves of the acquired operations compared to the existing ARC properties. In addition, the Trust completed net acquisitions in 2006 for $131.8 million plus an additional $5.4 future income tax liability recorded on acquisition, both acquisitions were at a higher proportionate cost per barrel of proved reserves than existing ARC properties. Accretion expense was also higher in 2006 as a result of the higher asset retirement obligation recorded late in 2005 primarily attributed to the acquired Redwater and NPCU properties.

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

DD&A Rate

($ millions except per boe amounts)	**2006**	2005	% Change
Depletion of oil & gas assets [1]	**348.9**	259.3	35
Accretion of asset retirement obligation [2]	**11.1**	5.2	113
Total DD&A	**360.0**	264.5	36
DD&A rate per boe	**15.64**	12.88	21

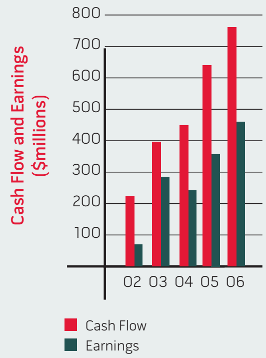
(1) Includes depletion of the capitalized portion of the asset retirement obligation that was capitalized to the property, plant and equipment ("PP&E") balance and is being depleted over the life of the reserves.

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

The costs subject to depletion included $61.3 million relating to the capitalized portion of the asset retirement obligation as at December 31, 2006 ($61.9 million as at December 31, 2005), net of accumulated depletion.

GOODWILL

The goodwill balance of $157.6 million arose as a result of the acquisition of Star in 2003. The goodwill balance was determined based on the excess of total consideration paid plus the future income tax liability less the fair value of the assets for accounting purposes acquired in the transaction.



Accounting standards require that the goodwill balance be assessed for impairment at least annually or more frequently if events or changes in circumstances indicate that the balance might be impaired. If such an impairment exists, it would be charged to income in the period in which the impairment occurs. The Trust has determined that there was no goodwill impairment as of December 31, 2006.

CAPITAL EXPENDITURES AND NET ACQUISITIONS

Total capital expenditures, excluding acquisitions and dispositions, totaled $364.5 million in 2006 compared to $268.8 million in 2005. This amount was incurred on drilling and completions, geological, geophysical and facilities expenditures, and the purchase of undeveloped acreage. The significant increase in 2006 capital expenditures is reflective of the Trust's higher production, larger asset base and the higher cost to replace production as well as increased spending on undeveloped land.

In addition to capital expenditures on development activities, the Trust completed net property acquisitions of $115.2 million in 2006. The most significant property acquisition was the purchase of Manitoba properties accounting for 785 boe per day of oil production and 3.4 mmboe of proved plus probable reserves for cash consideration of $74 million. The Trust also completed one minor corporate acquisition for consideration of $16.6 million in 2006.

During the year, the Trust drilled 294 gross wells (220 net wells) on operated properties; consisting of 72 gross oil wells and 222 gross natural gas wells most of which were shallow gas wells with a success rate of 99 per cent. In addition, the Trust participated in 441 gross wells (44 net wells) drilled by other operators.

Proved plus probable oil and gas reserves were effectively maintained at 286.1 mmboe at year end 2006 as a result of the Trust's 2006 capital expenditure program and property and corporate acquisitions.

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

Capital Expenditures

($ millions)	**2006**	2005	% Change
Geological and geophysical	**11.4**	9.2	24
Drilling and completions	**240.5**	191.8	25
Plant and facilities	**77.6**	55.0	41
Undeveloped land	**32.4**	9.1	256
Other capital	**2.6**	3.7	(30)
Total capital expenditures	**364.5**	268.8	36
Producing property acquisitions [1]	**124.0**	111.3	11
Producing property dispositions [1]	**(8.8)**	(20.0)	(57)
Corporate acquisitions [2]	**16.6**	505.0	(967)
Total capital expenditures and net acquisitions	**496.3**	865.1	(426)

[1] Value is net of post-closing adjustments.

[2] Represents total consideration for the transactions, including fees but is prior to the related future income tax liability, asset retirement obligation and working capital assumed on acquisition.

Approximately 72 per cent of the $364.5 million capital program was financed with cash flow from operations in 2006 compared to 95 per cent in 2005. Property and corporate acquisitions were financed through a combination of debt and proceeds from the 2006 distribution reinvestment program and employee rights plan.

Source of Funding of Capital Expenditures and Net Acquisitions

($ millions)	2006 Development Capital	2006 Net Acquisitions	2006 Total Expenditures	2005 Development Capital	2005 Net Acquisitions	2005 Total Expenditures
Expenditures	**364.5**	**131.8**	**496.3**	268.8	596.3	865.1
Per cent funded by:						
Cash flow	**72%**	**–**	**53%**	95%	–	30%
Proceeds from DRIP and Rights Plan	**28%**	**5%**	**22%**	5%	9%	8%
Proceeds from equity offering	**–**	**–**	**–**	–	40%	28%
Debt	**–**	**95%**	**25%**	–	51%	34%
	100%	**100%**	**100%**	100%	100%	100%

ARC expects to undertake significant development activities again in 2007 resulting in a $360 million capital budget. The Trust plans to drill 275 gross wells (225 net wells) on operated properties in 2007, allocate $6.5 million to Enhanced Oil Recovery initiatives such as carbon dioxide ("CO_2") injection, continue to research Natural Gas from Coal ("NGC") opportunities and develop the recently acquired Manitoba properties.

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. At year end, the Trust holds less than a two per cent interest in the company and has the intent of holding the shares for investment purposes.

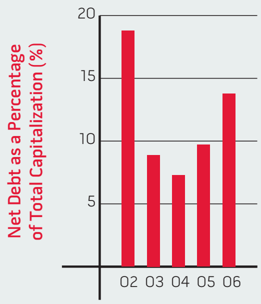
The investment in the shares of the private company has been considered to be a related party transaction due to common directorships of the Trust, the private company and the manager of a private equity fund that holds shares in the private company. In addition, certain directors and officers of the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

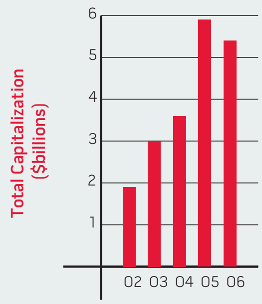
ASSET RETIREMENT OBLIGATION AND RECLAMATION FUND

At December 31, 2006, the Trust has recorded an Asset Retirement Obligation ("ARO") of $177.3 million ($165.1 million at December 31, 2005) for future abandonment and reclamation of the Trust's properties. The ARO increased slightly in 2006 as a result of wells drilled in the year and property and corporate acquisitions completed in 2006. The ARO further increased by $11.1 million for accretion expense in 2006 ($5.2 million in 2005) and was reduced by $10.6 million ($4.9 million in 2005) for actual abandonment expenditures incurred in 2005. The Trust did not record a gain or loss on actual abandonment expenditures incurred as the costs closely approximated the liability value included in the ARO.

As a result of the Redwater acquisition in December 2005, the Trust set up a new restricted reclamation fund (the "Redwater Fund") in 2006 to fund future abandonment obligations attributed to the Redwater properties. The Trust makes annual contributions to the Redwater fund and may utilize the funds only for abandonment activities for the Redwater property. With the addition of the Redwater Fund, the Trust now maintains two reclamation funds which together held $30.9 million of money market instruments at December 31, 2006. Future contributions for the two funds will vary over time in order to provide for the total estimated future abandonment and reclamation costs that are to be incurred upon abandonment of the Trust's properties. The Trust currently estimates that $230 million will be contributed to the funds over the next 50 years to provide for future abandonment and reclamation costs.

In total, ARC contributed $12.1 million cash to its reclamation funds in 2006 ($6 million in 2005) and earned interest of $1 million ($0.8 million in 2005) on the fund balances. The increase in funding is attributed to the Redwater fund. The fund balances were reduced by $5.7 million for cash-funded abandonment expenditures 2006 ($4.6 million in 2005).





CAPITALIZATION, FINANCIAL RESOURCES AND LIQUIDITY

A breakdown of the Trust's capital structure is as follows as at December 31, 2006 and 2005:

Capital Structure and Liquidity ($ millions except per unit and per cent amounts)	**2006**	2005
Revolving credit facilities	**426.1**	258.5
Senior secured notes	**261.0**	268.2
Working capital deficit excluding short-term debt (1)	**52.0**	51.4
Net debt obligations	**739.1**	578.1
Units outstanding and issuable for exchangeable shares (thousands)	**207.2**	202.0
Market price per unit at end of year	**22.30**	26.49
Market value of units and exchangeable shares	**4,620.0**	5,352.0
Total capitalization (2)	**5,359.1**	5,930.1
Net debt as a percentage of total capitalization	**13.8%**	9.7%
Net debt obligations	**739.1**	578.1
Cash flow from operations	**760.6**	639.5
Net debt to cash flow	**1.0**	0.9

(1) The working capital deficit excludes the balances for commodity and foreign currency contracts.

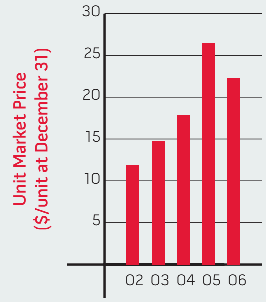
(2) Total capitalization as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Total capitalization is not intended to represent the total funds from equity and debt received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

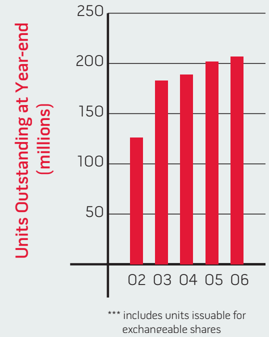
The increase in net debt to total capitalization in 2006 is attributed to the devaluation of the trust unit price following the Federal Government's proposed Trust taxation announcement and an increase in debt. Prior to the announcement, the trust unit price was $27.56 per unit and total capitalization approximated $6.3 billion. The devaluation of the unit price resulted in an approximate 20 per cent decline in market capitalization resulting in a higher net debt to total capitalization ratio.

The Federal Government's proposed Trust taxation announcement also caused increased market uncertainty pertaining to the future of the trust sector. This market uncertainty is diminishing over time, however it is our assessment that the Trust's ability to raise equity by issuing new trust units in the market has been diminished. The Government released guidelines regarding trust growth that limits expansion via acquisitions in 2007 to 40 per cent of the Trust's market capitalization as at October 31, 2006. We believe the 40 per cent limit is in excess of what the Trust could raise in the equity markets on a prudent basis. Management's assessment is that the Trust's ability to raise new equity would be dependant on financial market conditions at the time and the nature of the use of proceeds.

The Trust has a syndicated three year revolving 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 has the following major covenants:

Covenant	Position as of December 31, 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 0.9 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 0.9 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 the book value of unitholders' equity, long-term debt, letters of credit, and subordinated debt	Long-term debt and letters of credit of 26.8 per cent of the sum of unitholders' equity, long-term debt, letters of credit, and subordinated debt





As indicated by the above covenants, the Trust has additional potential borrowing capacity above the $572 credit facility, however the Trust's objective is to limit debt to under 2.0 times cash flow from operations and 20 per cent of total capitalization.

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. The Trust had $4.7 million of letters of credit outstanding at December 31, 2006 and no subordinated debt. As at December 31, 2006, the Trust was in compliance with all covenants.

In addition to the $572 million credit facility, the Trust has issued senior secured notes which do not reduce the available borrowings under the credit facility.

Net debt obligations increased by $161 million in 2006 to $739.1 million as a result of significant capital and acquisition activity in the year that resulted in a working capital deficit and the majority of acquisitions having been funded with debt. The Trust funded 72 per cent of its 2006 capital development program of $364.5 million with cash flow and the remaining $101.2 million was funded with proceeds from the DRIP and employee rights plan. The Trust funded $125 million of the 2006 acquisitions with debt and the remaining $6.8 million was funded with proceeds from the DRIP and Employee Rights program.

The Trust intends to finance its $360 million 2007 capital program with cash flow and the proceeds of the distribution reinvestment program with any remainder being financed with debt.

UNITHOLDERS' EQUITY

At December 31, 2006, there were 207.2 million units issued and issuable for exchangeable shares, an increase of 5.2 million units from December 31, 2005. The increase in number of units outstanding is mainly attributable to the 3.9 million units issued pursuant to the DRIP during 2006 at an average price of $24.67 per unit.

The Trust had 0.4 million rights outstanding as of December 31, 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 $9.47 per unit as at December 31, 2006. All but 6,000 of the rights were fully vested at December 31, 2006 and the remainder will vest on March 22, 2007. The contractual life of the rights varies by series but all will expire on or before March 22, 2009.

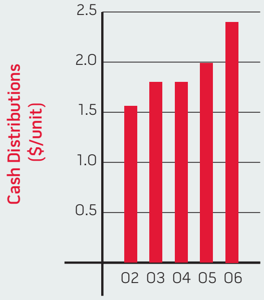
The Whole Unit Plan introduced in 2004 is a cash compensation plan for employees, officers and directors of the Trust and does not involve any units being issued from treasury. The Trust has made provisions whereby employees may elect to have units purchased for them on the market with the cash received upon vesting.

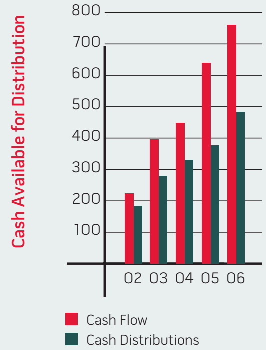
Unitholders electing to reinvest distributions or make optional cash payments to acquire units from treasury under the DRIP may do so at a five per cent discount to the prevailing market price with no additional fees or commissions. During 2006, the Trust raised proceeds of $96.1 million and issued 3.9 million trust units pursuant to the DRIP.

CASH DISTRIBUTIONS

ARC declared cash distributions of $484.2 million ($2.40 per unit), representing 64 per cent of 2006 cash flow from operations compared to cash distributions of $376.6 million ($1.99 per unit), representing 59 per cent of cash flow from operations in 2005. The remaining 36 per cent of 2006 cash flow ($276.4 million) was used to fund 72 per cent of ARC's 2006 capital expenditures and make contributions, including interest, to the reclamation fund ($13.2 million).

Monthly cash distributions for 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 contribution to the reclamation funds and interest earned on the 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, an estimated return based on current interest rates and a future funding period approximating 50 years. 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 was $12.1 million in 2006 or two per cent of cash flow and will vary 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 most significant annual contributions to the reclamation funds are expected to occur in years 2007 through 2015. The 2007 contribution is currently estimated to be $12 million.
- 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 2006, the Trust withheld 34 per cent of 2006 cash flow to fund 72 per cent of the 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 covenants specified in the debt agreements and, accordingly, there are no current mandatory requirements for repayment. Refer to the "Capital Structure and Liquidity" 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 currently 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 and if proposed changes in Trust taxation are enacted. Taxability of the Trust is currently passed on to unitholders in the form of taxable distributions whereby corporate income taxes are eliminated at the Trust level. If the proposed Trust taxation legislation is enacted, the Trust anticipates that the resulting tax commencing in 2011 at the Trust level would decrease cash flow and thus reduce cash distributions to unitholders.
- 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 $18.2 million to $58.6 million will be paid out pursuant to such commitments in 2007 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 were as follows:

Cash Flow and Distributions

	($ million)			($ per unit)		
($ millions and $ per unit)	**2006**	2005	% Change	**2006**	2005	% Change
Cash flow from operations	**760.6**	639.5	19	**3.72**	3.35	11
Reclamation fund contributions [1]	**(13.2)**	(6.8)	94	**(0.06)**	(0.04)	50
Capital expenditures funded with cash flow	**(263.2)**	(256.1)	3	**(1.28)**	(1.34)	(4)
Other [2]	**–**	–		**0.02**	0.02	–
Cash distributions	**484.2**	376.6	29	**2.40**	1.99	21

(1) Includes interest income earned on the reclamation fund balances that is retained in the reclamation funds.

(2) Other represents 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 trust units in the year plus units issuable for exchangeable shares at year-end.

The Trust continually assesses distribution levels, in light of commodity prices and production volumes, 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 effect of 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 a portion 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. The use of cash flow to fund capital development activities reduces the requirements of the Trust to use debt and equity to finance these expenditures. In 2006 the Trust funded 72 per cent of capital development activities with 34 per cent of cash flow. 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 per cent, a minimum of 20 per cent of annual cash flow to fund capital expenditures, and a minimum annual contribution to the reclamation funds. 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 there is a reasonable probability that the revised distribution may be maintained for a minimum six-month period. 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 financial and operating results.

Monthly cash distributions for the first quarter of 2007 have been set at $0.20 per unit subject to monthly review based on commodity price fluctuations. 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.

Historical Cash Distributions by Calendar Year

The following table presents cash distributions paid and payable for each calendar period.

Calendar Year	Distributions	Taxable Portion	Return of Capital
2007 YTD [2]	0.20	0.20 [2]	0.00 [2]
2006 [1]	2.60	2.55 [3]	0.05 [3]
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	**$ 18.83**	**$ 12.09**	**$ 6.74**

(1) Based on cash distributions paid and payable in 2006.

(2) Based on cash distributions declared at January 31, 2007 and estimated taxable portion of 2007 distributions of 98 per cent.

(3) Based on taxable portion of 2006 distributions of 98 per cent.

2006 Monthly Cash Distributions

Actual cash distributions paid and payable in 2006 along with relevant payment dates were 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	0.20
November 28, 2006	November 30, 2006	December 15, 2006	0.20
December 27, 2006	December 31, 2006	January 15, 2007	0.20
Total 2006			**2.60** [1]

(1) At the Annual and Special Meeting of Unitholders held on Monday, May 15, 2006, the Unitholders approved amendments to the Trust Indenture including a modification to the distribution language to ensure that all income of the Trust as of December 31 in each year is payable to Unitholders. As a result of this amendment, beginning in 2006 the distributions declared payable to Unitholders on the December 31st record date will be included in the Unitholder's income in that calendar year. For 2006, the Unitholders will include distributions with respect to record dates for the period December 31, 2005 to December 31, 2006, i.e. 13 distributions.

Please refer to the Trust's website at www.arcenergytrust.com for details on distributions dates for 2007.

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 units held. For 2006, cash distributions paid in the calendar year will be 98 per cent return on capital (taxable) and two per cent return of capital (tax deferred).For a more detailed breakdown, please visit our website at www.arcenergytrust.com.

The proposed Trust taxation announced by the Federal Government on October 31, 2006 and subsequent draft legislation would result in income taxes being imposed at the Trust level on distributions paid to unitholders effective January 1, 2011. The Trust is currently assessing the proposals and the potential implications to the Trust in future periods.

DEFICIT

During the second 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. Numbers presented for comparative purposes have been restated to reflect this change in presentation.

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 Trust also has contractual obligations and commitments that are of a less routine nature as disclosed in the following table.

Commitments

	Payments due by period				
($ millions)	2007	2008 – 2009	2010-1011	Thereafter	Total
Debt repayments	8.0	451.2	53.1	174.8	687.1
Interest payments (1)	11.3	21.5	18.1	20.8	71.7
Reclamation fund contributions (2)	6.0	11.1	9.5	76.2	102.8
Purchase commitments	12.6	8.4	3.4	6.8	31.2
Operating leases	5.3	9.9	5.0	–	20.2
Derivative contract premiums (3)	12.4	3.3	–	–	15.7
Retention bonuses	1.0	–	–	–	1.0
Total Contractual Obligations	**56.6**	**505.4**	**89.1**	**278.6**	**929.7**

(1) Fixed interest payments on the Senior Secured Notes.

(2) Contribution commitments to a restricted reclamation fund associated with the Redwater property acquired in 2005.

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

The above noted derivative contract premiums are part of the Trust's commitments related to its risk management program. In addition to the above premiums, the Trust has commitments related to its risk management program. As the premiums are part of the underlying derivative contract, they have been recorded at fair market value at December 31, 2006 on the balance sheet as part of commodity and foreign currency contracts.

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 2007 capital budget has been approved by the Board at $360 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.

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 and therefore the following table does not include any commitments for outstanding litigation and claims.

The Trust has certain sales contracts with aggregators whereby the price received by the Trust is dependent upon the contracts entered into by the aggregator. 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.

OFF BALANCE SHEET ARRANGEMENTS

The Trust has certain lease agreements which aggregate to less that $1 million and were entered into in the normal course of operations. All leases have been 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 December 31, 2006.

The Trust's long-term electricity hedge and interest rate hedges have not been recorded as an asset or liability on the balance sheet as they qualify as effective accounting hedges.

The Trust entered into agreements to pay premiums pursuant to certain crude oil derivative put contracts. Premiums of $15.7 million will be paid in 2007 through 2009 for the put contracts in place at December 31, 2006. As the premiums are part of the underlying derivative contract, they have been recorded at fair market value at December 31, 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 that 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 skills required to make such estimates and ensures that 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.

INTERNAL CONTROLS UPDATE

On July 31, 2002, the United States Congress enacted the Sarbanes-Oxley Act ("SOX"). SOX applies to all companies registered with the Securities and Exchange Commission ("SEC"). Although ARC is not listed on a U.S. stock exchange, the Trust is registered with the SEC as a result of having acquired Startech Energy Inc. in 2001 and therefore was required to comply with section 404 of the SOX legislation as at December 31, 2006 and each year thereafter.

There are various components to the SOX legislation, however the most comprehensive is Section 404 "Internal Controls Over Financial Reporting". Section 404 requires that management undertake the following:

- identify and document internal controls that impact financial reporting;
- assess the effectiveness of those internal controls;
- remediate any deficiencies in internal controls and/or implement any required controls that are not already in place;
- test the internal controls to ensure that they are operating effectively; and
- issue a report, to be signed by the Chief Operating Officer and the Chief Financial Officer, on management's assessment of the effectiveness of internal controls and communicate any material weaknesses.

Internal control over financial reporting is a process designed to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable and timely information. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Management has assessed the effectiveness of the company's internal control over financial reporting based on the criteria in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and concluded that the company's internal control over financial reporting was effective as of December 31, 2006. Management's assessment of the effectiveness of the company's internal control over financial reporting as of December 31, 2006 has been audited by Deloitte & Touche LLP, as reflected in their report for 2006.

As of December 31, 2006, an internal evaluation was carried out of the effectiveness of the Trust's disclosure controls and procedures as defined in Rule 13a-15 under the US Securities Exchange Act of 1934, also known as SOX 302. Based on that evaluation, the President and Chief Executive Officer and Chief Financial Officer concluded that the disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that the Trust files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the rules and forms of the SEC. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that the information required to be disclosed by the Trust in the reports that it files or submits under the Exchange Act is accumulated and communicated to the Trust's management, including the senior executive and financial officers, as appropriate to allow timely decisions regarding the required disclosure.

In addition to SOX, ARC is required to comply with Multilateral Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings", otherwise referred to as Canadian SOX ("C-Sox"). The Canadian requirements closely parallel the SEC's certification rules, however, currently there is no requirement to have the external auditor opine on the Trust's internal controls or management's assessment thereof. ARC has complied with this legislation by filing bare interim certificates and a full annual certificate with no modifications in conjunction with the December 31, 2006 year end. The 2006 certificate requires that the Trust disclose in the annual MD&A any changes in the Trust's internal control over financial reporting that occurred during the period that has materially affected, or is reasonably likely to materially affect the Trust's internal control over financial reporting. The Trust confirms that no such changes were made to the internal controls over financial reporting during 2006.

FINANCIAL REPORTING UPDATE

During 2006, the Trust commenced a review of the new CICA Handbook section 3855 "Financial Instruments – Recognition and Measurement", section 1530 "Comprehensive Income" and section 3865 "Hedges" that deal with the recognition and measurement of financial instruments at fair value and comprehensive income. The new standards are intended to harmonize Canadian standards with United States and international accounting standards. The new standards are effective for annual and interim periods in fiscal years beginning on or after October 1, 2006. These new standards will impact the Trust in 2007 and are currently being reviewed to assess their impact.

OBJECTIVES AND 2007 OUTLOOK

Sustainability

It is the Trust's objective to provide superior and sustainable long-term returns to unitholders by focusing on the key strategic objectives of the business plan. The Trust acquires, develops and optimizes oil and natural gas properties in predominantly mature areas to generate a cash flow stream. Due to natural production declines, the Trust must continually develop its reserves and/or acquire new reserves in an effort to maintain reserves, production and cash flow levels on which distributions are paid. The trust facilitates this by withholding a portion of cash flow to fund a portion of ongoing capital development activities and maintaining moderate debt levels; this is evidenced by the Trust's low payout ratio. Oil and gas royalty trusts hold assets that are depleting and unitholders should expect production, revenue, cash flow and distributions to decline over the long-term if reserves cannot be economically replaced. The Trust has an inventory of internal development prospects that will enable the Trust to maintain production and reserves for a minimum period of two years. The Trust anticipates employing a conservative payout policy to provide for cash funding of a portion of ongoing capital development programs and maintaining low debt levels to facilitate further growth. The Trust measures its sustainability and success in terms of per unit cash distributions, production, reserves, and cash flow in addition to the ability to maintain low debt levels and the annual replacement of reserves.

Following is a summary of the historical debt-adjusted production and reserves per unit and reserve life index on which the Trust assesses performance and sustainability:

Per Trust Unit Ratios	2006	2005	2004	2003	2002	5 Year Total
Production per unit: (1)						
Unadjusted	**0.31**	0.29	0.31	0.35	0.35	–
Debt-adjusted (3)	**0.27**	0.26	0.28	0.31	0.29	–
Normalized (4)	**0.31**	0.31	0.33	0.38	0.33	–
Reserves per unit: (2)						
Unadjusted	**1.38**	1.42	1.29	1.37	1.47	–
Debt-adjusted (3)	**1.19**	1.28	1.20	1.25	1.19	–
Normalized (4)	**1.38**	1.49	1.39	1.44	1.38	–
Reserve life index (5)	**12.4**	12.9	12.2	12.4	11.8	–
Cash flow per unit	**$ 3.72**	$ 3.35	$ 2.41	$ 2.56	$ 1.87	$ 13.91
Cash distributions per unit	**$ 2.40**	$ 1.99	$ 1.80	$ 1.80	$ 1.56	$ 9.55
Payout ratio per cent (6)	**64**	59	74	71	82	70
Per cent of cash flow retained	**36**	41	26	29	18	30

(1) Represents daily average production per thousand units. Calculated based on annual daily average production divided by weighted average trust units outstanding including trust units issuable for exchangeable shares.

(2) Calculated based on proved plus probable reserves divided by period end trust units outstanding including trust units issuable for exchangeable shares.

(3) Debt-adjusted indicates that all years as presented have been adjusted to reflect a nil net debt to capitalization. It is assumed that additional trust units were issued at a period end price for the reserves per unit calculation and at an annual average price for the production per unit calculation in order to reduce the net debt balance to zero in each year. The debt-adjusted amounts are presented to enable comparability of annual per unit values.

(4) Normalized indicates that all years as presented have been adjusted to reflect a net debt to capitalization of 14 per cent as per December 31, 2006. It is assumed that additional trust units were issued (or repurchased) at a period end price for the reserves per unit calculation and at an annual average price for the production per unit calculation in order to reduce the net debt balance to 14 per cent of total capitalization each year. The normalized amounts are presented to enable comparability of annual per unit values.

(5) Calculated based on proved plus probable reserves divided by annual 2007 production estimate of 63,000 boe per day for 2006 RLI.

(6) Calculated as cash distributions divided by cash flow from operations.

During the 2002 to 2006 time period the trust's normalized production per unit has decreased only slightly from 0.33 to 0.31 boe of daily average production per thousand trust units and normalized reserves per unit have remained constant during this time at 1.38 boe of proved plus probable reserves per trust unit. The maintenance of production and reserves per unit occurred even with the payout of $1.7 billion of cash distributions ($9.55 per trust unit and 70 per cent of cash flow) during the 2002 through 2006 time period. This indicates that the Trust has continually grown production levels to offset natural production declines and developed and grown its reserve base. The normalized production per unit is a key measure as it indicates the ability to generate cash flow from core operations which in turn impacts the level of cash that may be distributed to unitholders. The Trust expects to replace production in 2007 from internal development opportunities.

To compare the Trust's results with oil and gas companies that retain all of their cash flow to grow production and reserves, the Trust looks at normalized and distribution-adjusted production and reserves per unit which calculates the total reserves and production per initial investment with the assumption that distributions are reinvested through the DRIP plan. Consequently, the reserves and production per initial investment increase over time as the investor's number of trust units increase with distribution reinvestment. The Trust's normalized daily average production per initial investment has increased from 0.33 boe per thousand trust units in 2002 to 0.56 in 2006, while normalized reserves per initial investment have increased from 1.53 boe at January 1, 2002 to 2.50 boe at December 31, 2006. The increase is attributed to the DRIP factor whereby one trust unit purchased on January 1, 2002 would have grown to 1.81 trust units on December 31, 2006. A unitholder can replicate this by participating in the DRIP so that the number of units they own increases over time.

The Trust's reserve life index ("RLI") increased to 12.4 years in 2006 from 11.8 years in 2002. The RLI is a measure of the remaining average life of the reserves based on a current production estimate for 2007 of 63,000 boe per day. The Trust's high RLI is indicative of the high quality of assets and long reserve life of the properties. The acquisition of the Redwater and NPCU properties in 2005 resulted in an increase in the RLI due to the long reserve life of the properties. A high RLI is key for a royalty trust as it is indicates the potential sustainability of production levels and cash flow over a longer period of time.

The Trust's distribution policy centres around the goal of providing a consistent and sustainable level of distributions to unitholders and to provide for future growth. The low payout ratio is indicative of the Trust's commitment to fund ongoing development activities with cash flow to enable long-term sustainability. A high payout ratio indicates that ongoing capital development activities must be either debt or equity financed. The Trust's payout ratio has declined over time as the Trust has addressed the issue of long-term sustainability while setting distribution levels.

An additional measure of sustainability is the comparison of net income to cash distributions. Net income incorporates all costs including depletion expense and other non-cash expenses whereas cash flow from operations measures the cash generated in a given period before the cost of the associated reserves. Therefore, net income may be more representative of the profitability of the entity and thus a relevant measure against which to measure cash distributions to illustrate sustainability. As net income is sensitive to fluctuations in commodity prices, it is expected that there will be deviations between annual net income and cash distributions. The following table illustrates the annual excess or shortfall of cash distributions to net income as a measure of long-term sustainability.

Net Income and Cash Distributions

($ millions except per cent)	**2006**	2005	2004	2003	2002	5 Year Total
Net income	**460.1**	356.9	241.7	284.6	70.0	1,413.3
Cash distributions	**484.2**	376.6	330.0	279.3	183.6	1,653.7
Excess (shortfall)	**(24.1)**	(19.7)	(88.3)	5.3	(113.6)	(240.4)
Excess (shortfall) as per cent of net income	**(5%)**	(6%)	(37%)	2%	(62%)	(17%)
Payout of cash flow per cent	**64%**	59%	74%	71%	82%	70%

During 2002 through 2004, there was significant volatility in commodity prices and it was management's decision to maintain distributions at a consistent level during that time as it was perceived that the decline in commodity prices was temporary. Management's decision to lower payout ratios over time is illustrated in the table as cash distributions more closely approximate net income in 2005 and 2006.

Returns to Unitholders and Proposed Federal Legislation to Tax Income Trusts

The Trust has provided unitholders with the following one, three and five year returns, including reinvestment of distributions:

Total Returns

($ per unit except for per cent)		One Year		Three Year		Five Year
Distributions per unit	$	2.40	$	6.19	$	9.55
Capital appreciation per unit	$	(4.19)	$	7.56	$	10.20
Total return per unit	$	(1.79)	$	13.75	$	19.75
Annualized total return per unit	%	(8.0)	%	26.7	%	26.5

To the end of 2006, the Trust has provided cumulative cash distributions of $18.63 per unit and capital appreciation of $12.30 per unit for a total return of $30.93 per unit (23.8 per cent annualized total return) for unitholders who invested in the Trust at inception in 1996. The Trust has announced 2007 cash distributions of $0.20 per unit per month through March 2007.

During 2006, the announcement and subsequent introduction of proposed legislation regarding taxation of Trusts resulted in a significant decline in trust unit prices throughout the industry. Consequently, many trusts have reported a negative total return to unitholders in 2006 as a result of the decline in trust unit prices immediately following the announcement. ARC's return to unitholders was negative eight per cent in 2006 as a result of a 20 per cent decline in the trust unit price following the Federal Government announcement on October 31, 2006. The Trust had reached a historic high unit price of $30.74 in August 2006. Annual distributions to unitholders of $2.40 per trust unit are our highest to date.

Despite the devaluation of the trust unit price following the proposed Trust taxation announcement, the Trust's business remains unchanged and the Trust is still a prospering and sustainable entity with no change to the core operations. Subsequent to the announcement, the Trust has been actively researching alternatives regarding the structure and business strategy leading up to the implementation of the proposed tax in 2011. Under the current proposed legislation, the most viable option appears to be conversion to a corporate entity no earlier than January 1, 2011 due to the punitive financial impact that the taxation would have on the trust structure. However, given that the legislation has not been officially enacted, the Trust has not made any conclusive decisions with respect to the strategy over the next four years as we feel it is prudent to await the final legislation and fully research all alternatives before making a final decision. The Trust is working closely with legal and business advisors as to the potential future structure and direction of the Trust in an effort to maximize the value to unitholders, and to choose a direction which is in the best interest of its unitholders.

ARC plans to proceed with its full $360 million capital expenditure budget for 2007 which consists of a robust drilling and development program on its diverse asset base. The 2007 capital budget 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. The 2007 capital expenditure budget anticipates the drilling of 225 net operated wells and the addition of 11,000 boe per day of new production from the capital development program to replace declines at existing properties. The 2007 capital budget also allows for a portion of spending to further research and pursue Enhanced Recovery Initiatives such as CO_2 injection and NGC development. Despite the Trust's active fourth quarter, there was a general slow down in activity levels for the industry late in 2006. The Trust expects that with the lower activity levels and decreased demand for industry services that costs will moderate slightly in 2007. Current low debt levels and a strong working capital position provide the Trust with the financial flexibility to fund the 2007 capital expenditure program.

The Trust continually looks to execute minor property acquisitions and dispositions in order to enhance and streamline 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. The Federal Government issued guidance with respect to limitations on future growth of the Trust in conjunction with the proposed Trust taxation announcement. The Trust does not anticipate that the guidelines will impair the Trust's ability to annually replace or grow reserves in the next four years as the guidelines allow sufficient growth targets. Key attributes of the future growth constraints are as follows:

- Trusts may grow in size by 100 per cent cumulatively for the period 2007 through 2010 as measured by the value of equity based on the October 31, 2006 market capitalization. The cumulative limit starts at 40 per cent in 2007 and increases by 20 per cent per year in 2008 through 2010.
- Merger of two Trusts will not be impacted by the growth limitations.
- The growth limits are not impacted by non-convertible debt-financed growth but rather focus solely on the issuance of equity to facilitate growth.

The Trust will continue to assess accretive acquisition opportunities. Acquisitions are evaluated internally and acquisitions in excess of $25 million are subject to Board approval.

Accomplishment of 2006 Objectives

The key future objectives of the Trust's business plan, as identified below, are reviewed annually by the Board. The Trust was successful in meeting all of its objectives in 2006 as individually addressed below. They continue to be key objectives for 2007.

- **Annual reserves replacement** – The Trust's proved plus probable reserves were effectively maintained as December 31, 2006 reserves of 286.1 mmboe were within one per cent of the 287 mmboe recorded as at December 31, 2005. The reserves were maintained through a combination of the $364.5 million 2006 capital development program and corporate and property acquisitions (net of dispositions) of $131.8 million.
- **Ensuring acquisitions are strategic and enhance unitholder returns** – The Trust added producing properties in Manitoba to its asset base in 2006 and also increased its land ownership in certain core areas in 2006 in an effort to increase its inventory of future development opportunities. In addition, the Redwater property acquired in 2005 provided many opportunities to ARC due to the optimization potential of this long-life, light oil property. Since acquisition, ARC has reactivated 95 gross wells (62 net wells) at

Redwater and NPCU and increased production by approximately 580 boe per day net. ARC believes that long-life, light oil properties will provide future opportunities to enhance unitholder value through the application of tertiary recovery methods.

- **Controlling costs** – Due to the diligence of field and office operating staff, the Trust's base operating costs per boe, before the impact of higher cost acquisitions, increased by approximately five per cent over 2005 costs. Cash G&A costs in 2006 increased 18 per cent to $1.58 per boe from $1.34 per boe in 2005 as a result of both increased staff counts following acquisitions and increased compensation costs due to the extremely competitive marketplace for experienced staff with oil and gas expertise. The Trust believes the $1.58 per boe cash G&A costs will be better than average for mid-sized oil and gas producers in 2006. The Trust's three year average FD&A costs of $15.59 per boe prior to incorporating future development costs ("FDC") and $18.99 per boe with FDC are expected to approximate the industry average. The increase in FD&A costs in 2006 is considered an anomaly partly due to the large investment in strategic undeveloped land with no associated reserves. The land acquisitions provide future development opportunities and are expected to yield reserves in future periods as development occurs.
- **Conservative utilization of debt** – The Trust's net debt levels were under 14 per cent of total capitalization and debt to 2006 cash flow was slightly less than 1.0 times for the year ended 2006. With the Federal Government's proposed Trust taxation announcement, the Trust's market capitalization fell by approximately 20 per cent to $4.5 billion whereby the net debt to total capitalization increased accordingly. The Trust's debt levels are still considered to be one of the lowest in the Trust sector.
- **Continuously developing the expertise of our staff and seeking to hire and retain the best in the industry** – The Trust runs an active training and development program for its employees and encourages personal development. The Trust continues to assess compensation levels in the industry to ensure that the Trust's compensation is competitive so as to attract and retain the best employees. The Trust's long-term incentive plan's payouts are directly tied to the Trust's performance providing alignment between employees and investors.
- **Building relationships and conducting business in a way that is viewed as fair and equitable** – ARC employees, leadership team and directors work hard to build the ARC "franchise value" through honest, transparent dealings with our business partners. "Treating all people with respect" is a key message inside and outside the organization. This basic business fundamental allows us to build enduring relationships with joint venture partners, land owners, investors, banks and lending institutions, governments and the investment community.
- **Promoting the use of proven and effective technologies** – The Trust continues to research new technologies in an effort to conduct its operations in the most efficient and cost effective manner. The Trust has committed a portion of its 2007 capital expenditure budget towards continued research into tertiary recovery methods.
- **Being an industry leader in health, safety and environmental performance** – The Trust's primary focus continues to be on operating in a safe, reliable and responsible fashion. The Trust is committed to the platinum level of CAPP Stewardship reporting and continues to achieve reductions in greenhouse gas emissions under the Canada Climate Change VCR initiative. The Trust's commitment to pursue additional CO_2 injection opportunities is expected to have the two-fold benefit of enhanced recovery of reserves and the capture and containment of CO_2 emissions which will benefit the environment. The Trust's commitment to safety is evidenced by zero lost time incidents reported for employees of the Trust in 2006.
- **Continuing to actively support local initiatives in the communities in which we live and work** – The Trust is very actively involved in charitable and philanthropic causes both in Calgary and in the rural communities in which it operates. ARC continued to be a strong supporter of the United Way, Alberta Cancer Foundation, Alberta Children's Hospital and many community organizations in rural centres. In addition to the $1.3 million of cash donations made to charitable organizations in 2006 the Trust also provided business expertise, employee volunteers and tangible assets as needed.

2006 Review and 2007 Guidance

Following is a summary of the Trust's 2007 Guidance issued by way of news release on November 2, 2006 and a review of 2006 actual results compared to 2006 Guidance:

	2006 Guidance	Actual 2006	% Change	2007 Guidance
Production (boe/d)	63,000	63,056	–	63,000
Expenses ($/boe):				
Operating costs	8.40	8.49	1	8.95
Transportation	0.70	0.63	(10)	0.70
G&A expenses – cash	1.65	1.58	(4)	2.25
G&A expenses – stock compensation plans	0.60	0.47	(22)	0.20
Interest	1.35	1.38	2	1.50
Taxes	0.02	0.01	(50)	0.00
Capital expenditures ($ millions)	370	365	(1)	360
Weighted average trust units and units issuable (millions)	205	207	1	208

Actual 2006 results were in line with 2006 guidance with only minor exceptions as follows:

- Operating costs were slightly higher than guidance due to increased Alberta electricity rates in the fourth quarter of 2006.
- Transportation costs were lower than guidance due to lower than anticipated transportation costs in the fourth quarter on trucked volumes.
- Cash G&A expenses were lower than guidance due to higher operating recoveries attributed to high levels of capital and operating activity in the fourth quarter.
- Non-cash G&A expenses were lower than guidance due to the decline in the value of the Trust's whole unit plan following the Federal Government's proposed Trust taxation announcement on October 31, 2006. As the value of the whole unit plan is dependent upon the trust unit price, there was a considerable decrease in the fourth quarter non-cash whole unit plan expense.
- Interest expense was slightly higher than guidance due to increased debt levels in the fourth quarter resulting from high capital and acquisition activity which was partially funded with debt.
- Weighted average trust units were slightly higher than guidance due to the large number of units issued pursuant to the DRIP in the fourth quarter.

There have been no revisions to the 2007 Guidance estimates as originally published on November 2, 2006.

2007 CASH FLOW SENSITIVITY

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/bbl) [1]	$ 59.00	$ 1.00	$ 0.05
Natural gas price (CDN $AECO/mcf) [1]	$ 7.25	$ 0.10	$ 0.03
USD/CAD exchange rate	0.88	$ 0.01	$ 0.06
Interest rate on debt	5.2%	% 1.0	$ 0.03
Operational			
Liquids production volume (bbl/d)	32,200	% 1.0	$ 0.02
Gas production volumes (mmcf/d)	185.0	% 1.0	$ 0.02
Operating expenses per boe	$ 8.95	% 1.0	$ 0.01
Cash G&A expenses per boe	$ 2.25	% 10.0	$ 0.02

(1) Analysis does not include the effect of hedging 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 as follows:

Changes in Tax and Royalty Legislation

Income tax laws, or other laws, or provincial royalty programs relating to the oil and gas industry may in the future be changed or interpreted in a manner that adversely affects the Trust or its Unitholders. Tax authorities having jurisdiction over the Trust or Unitholders may disagree with how the Trust calculates its income for tax purposes or how we calculate payment of crown royalties or could change administrative practices to the detriment of the Trust and its Unitholders.

On October 31, 2006, the federal government announced plans to impose a tax of 31.5 per cent on all distributions paid by all income trusts with the exception of Real Estate Income Trusts. At the time of writing this MD&A the legislation has not been passed, however, if the legislation is successfully passed, the Trust will no longer be able to flow through the Trust's income to unitholders on a tax free basis. The Trust is part of the Coalition of Canadian Energy Trusts who are lobbying the government to exempt the energy trust sector from the proposed rules. In the event that the coalition is not successful in obtaining this exemption the Trust's distributions would become taxable on January 1, 2011.

In light of the proposed changes, the Trust is actively evaluating alternative strategies that could be implemented to ensure that the Trust's guiding principles are still being fulfilled. The proposed solutions could result in a change to the Trust's structure which could impact the amount of distributions being paid to unitholders.

On February 16, 2007, the Alberta government launched a review of Alberta's royalty regime for oil sands, conventional oil and gas and coalbed methane. The review is intended to assess whether the existing royalty regime is providing Albertans with a fair return on the province's natural resources while maintaining an internationally competitive system that allows the Alberta economy to continue to prosper. The review, expected to be completed by August 31, 2007, may result in recommendations which could adversely impact the current royalty structure in place for the Trust's conventional production as well as the future economics for the Trust's coalbed methane prospects.

Access To Capital Markets

To the extent that external sources of capital, including the issuance of additional trust units become limited or unavailable, ARC's ability to make the necessary capital investments to maintain or expand its oil and natural gas reserves could be impaired. To the extent that ARC is required to use cash flow to finance capital expenditures or property acquisitions, the level of distributions could be reduced.

Under the proposed changes in tax legislation, the Trust would be subject to the "undue expansion" provisions between now and 2011 which would restrict the amount of equity that ARC can issued for purposes of completing acquisitions.

Volatility of Oil and Natural Gas Prices

The Trust's operational results and financial condition, and therefore the amount of distributions paid to the unitholders will be dependent on the prices received for oil and natural gas production. Oil and gas prices have fluctuated widely during recent years and are determined by economic and in the case of oil prices, political factors. Supply and demand factors, including weather and general economic conditions as well as conditions in other oil and natural gas regions impact prices. Any movement in oil and natural gas prices could have an effect on the Trust's financial condition and therefore on the distributions to the holders of trust units. ARC may manage the risk associated with changes in commodity prices by entering into oil or natural gas price derivative contracts. If ARC engages in activities to manage its commodity price exposure, the Trust may forego the benefits it would otherwise experience if commodity prices were to increase. In addition, commodity derivative contracts activities could expose ARC to losses. To the extent that ARC engages in risk management activities related to commodity prices, it will be subject to credit risks associated with counterparties with which it contracts.

Variations in Interest Rates and Foreign Exchange Rates

Variations in interest rates could result in a significant increase in the amount the Trust pays to service debt, resulting in a decrease in distributions to unitholders. World oil prices are quoted in US dollars and the price received by Canadian producers is therefore affected by the Canadian/US dollar exchange rate that may fluctuate over time. A material increase in the value of the Canadian dollar may negatively impact the Trust's net production revenue. In addition, the exchange rate for the Canadian dollar versus the US dollar has increased significantly over the last 24 months, resulting in the receipt by the Trust of fewer Canadian dollars for its production, which may affect future distributions. ARC has initiated certain derivative contracts to attempt to mitigate these risks. To the extent that ARC engages in risk management activities related to foreign exchange rates, it will be subject to credit risk associated with counterparties with which it contracts. The increase in the exchange rate for the Canadian dollar and future Canadian/US exchange rates may impact future distributions and the future value of the Trust's reserves as determined by independent evaluators.

Reserves Estimates

The reserves and recovery information contained in ARC's independent reserves evaluation is only an estimate. The actual production and ultimate reserves from the properties may be greater or less than the estimates prepared by the independent reserves evaluator. The reserves report was prepared using certain commodity price assumptions that are described in the notes to the reserves tables. If lower prices for crude oil, natural gas liquids and natural gas are realized by the Trust and substituted for the price assumptions utilized in those reserves reports, the present value of estimated future net cash flows for the Trust's reserves would be reduced and the reduction could be significant, particularly based on the constant price case assumptions.

Depletion of Reserves and Maintenance of Distribution

ARC's future oil and natural gas reserves and production, and therefore its cash flows, will be highly dependent on ARC's success in exploiting its reserves base and acquiring additional reserves. Without reserves additions through acquisition or development activities, the Trust's reserves and production will decline over time as the oil and natural gas reserves are produced out.

There can be no assurance that the Trust will make sufficient capital expenditures to maintain production at current levels; nor as a consequence, that the amount of distributions by the Trust to unitholders can be maintained at current levels.

There can be no assurance that ARC will be successful in developing or acquiring additional reserves on terms that meet the Trust's investment objectives.

Acquisitions

The price paid for reserves acquisitions is based on engineering and economic estimates of the reserves made by independent engineers modified to reflect the technical views of management. These assessments include a number of material assumptions regarding such factors as recoverability and marketability of oil, natural gas, natural gas liquids and sulphur, future prices of oil, natural gas, natural gas liquids and sulphur and operating costs, future capital expenditures and royalties and other government levies that will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the operators of the working interests, management and the Trust. In particular, changes in the prices of and markets for oil, natural gas, natural gas liquids and sulphur from those anticipated at the time of making such assessments will affect the amount of future distributions and as such the value of the units. In addition, all such estimates involve a measure of geological and engineering uncertainty that could result in lower production and reserves than attributed to the working interests. Actual reserves could vary materially from these estimates.

Consequently, the reserves acquired may be less than expected, which could adversely impact cash flows and distributions to unitholders.

Environmental Concerns and Impact on Enhanced Oil Recovery Projects

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines or issuance of clean up orders in respect of ARC or its working interests. Such legislation may be changed to impose higher standards and potentially more costly obligations on ARC. Furthermore, management believes the federal political parties, appear to favor new programs for environmental laws and regulation, particularly in relation to the reduction of emissions, and there is no assurance that any such programs, laws or regulations, if proposed and enacted, will not contain emission reduction targets which ARC cannot meet, and financial penalties or charges could be incurred as a result of the failure to meet such targets. In particular there is uncertainty regarding the Federal Government's Clean Air Act of 2006. The Clean Air Act proposes to reduce greenhouse gas emissions, however emission targets and compliance deadlines differ from those outlined in the Kyoto Protocol which was ratified by Canada. If passed, the Clean Air Act may have adverse operational and financial implications to the Trust.

Additionally, the potential impact on the Trust's operations and business of the December 1997 Kyoto Protocol, which has been ratified by Canada, with respect to instituting reductions of greenhouse gases, is difficult to quantify at this time as specific measures for meeting Canada's commitments have not been developed. Currently, companies are permitted to emit CO2 into the atmosphere with no requirement to capture and re-inject the emissions. In order for the Trust to carry out its enhanced oil recovery program it is necessary to obtain CO2 at a cost effective rate. Given that companies are not forced to capture their emissions, the infrastructure has not been put in place to facilitate this process. Without any additional provisions from the government, the economic parameters of the Trust's enhanced oil recovery programs would be limited.

Although ARC has established a reclamation fund for the purpose of funding its currently estimated future environmental and reclamation obligations based on its current knowledge, there can be no assurance that the Trust will be able to satisfy its actual future environmental and reclamation obligations.

Operational Matters

The operation of oil and gas wells involves a number of operating and natural hazards that may result in blowouts, environmental damage and other unexpected or dangerous conditions resulting in damage to operating subsidiaries of the Trust and possible liability to third parties. ARC will maintain liability insurance, where available, in amounts consistent with industry standards. Business interruption insurance may also be purchased for selected facilities, to the extent that such insurance is available. ARC may become liable for damages arising from such events against which it cannot insure or against which it may elect not to insure because of high premium costs or other reasons. Costs incurred to repair such damage or pay such liabilities will reduce distributable cash.

Continuing production from a property, and to some extent the marketing of production there from, are largely dependent upon the ability of the operator of the property. Approximately 30% of ARC's production is operated by third parties. ARC has limited ability to influence costs on partner operated properties. Operating costs on most properties have increased steadily over recent years. To the extent the operator fails to perform these functions properly, revenue may be reduced. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent. Although satisfactory title reviews are generally conducted in accordance with industry standards, such reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat the claim of the Trust to certain properties. A reduction of the distributions could result in such circumstances.

Debt Service and Additional Financing

Amounts paid in respect of interest and principal on debt will reduce distributions. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service before payment of distributions. Certain covenants of the agreements with ARC's lenders may also limit distributions. Although ARC believes the credit facilities will be sufficient for the Trust's immediate requirements, there can be no assurance that the amount will be adequate for the future financial obligations of the Trust or that additional funds will be able to be obtained.

The lenders will be provided with security over substantially all of the assets of ARC. If ARC becomes unable to pay its debt service charges or otherwise commits an event of default such as bankruptcy, the lender may foreclose on or sell the working interests.

In the normal course of making capital investments to maintain and expand the oil and gas reserves of the Trust, additional units are issued from treasury that may result in a decline in production per unit and reserves per unit. Additionally, from time to time the Trust issues units from treasury in order to reduce debt and maintain a more optimal capital structure. Conversely, to the extent that external sources of capital, including the issuance of additional units, become limited or unavailable, the Trust's ability to make the necessary capital investments to maintain or expand its oil and gas reserves will be impaired. To the extent that ARC is required to use cash flow to finance capital expenditures or property acquisitions, to pay debt service charges or to reduce debt, the level of distributable income will be reduced.

FORWARD-LOOKING STATEMENT

This discussion and analysis contains forward-looking statements as to the Trusts internal projections, expectations or beliefs relating to future events or future performance 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 2007 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 this discussion analysis, 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.

ADDITIONAL INFORMATION

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

ANNUAL HISTORICAL REVIEW

For the year ended December 31

(CDN $ millions, except per unit amounts)	**2006**	2005	2004	2003	2002
FINANCIAL					
Revenue before royalties	**1,230.5**	1,165.2	901.8	743.2	444.8
Per unit [1]	**6.02**	6.10	4.85	4.80	3.72
Cash flow	**760.6**	639.5	448.0	396.2	224.0
Per unit – basic [1]	**3.72**	3.35	2.41	2.56	1.87
Per unit – diluted	**3.71**	3.32	2.38	2.48	1.86
Net income	**460.1**	356.9	241.7	284.6	70.0
Per unit – basic [2]	**2.28**	1.90	1.32	1.88	0.60
Per unit – diluted	**2.27**	1.88	1.31	1.82	0.59
Cash distributions	**484.2**	376.6	330.0	279.3	183.6
Per unit [3]	**2.40**	1.99	1.80	1.80	1.56
Total assets	**3,479.0**	3,251.2	2,305.0	2,281.8	1,467.9
Total liabilities	**1,550.6**	1,415.5	755.7	730.0	599.3
Net debt outstanding [4]	**739.1**	578.1	264.8	262.1	347.8
Weighted average units (millions) [5]	**204.4**	191.2	186.1	154.7	119.6
Units outstanding and issuable at period end (millions) [5]	**207.2**	202.0	188.8	182.8	126.4
CAPITAL EXPENDITURES					
Geological and geophysical	**11.4**	9.2	5.4	5.7	2.0
Land	**32.4**	9.1	4.1	4.0	–
Drilling and completions	**240.5**	191.8	140.4	106.2	70.0
Plant and facilities	**77.6**	55.0	41.1	36.5	14.4
Other capital	**2.6**	3.7	2.8	3.4	1.9
Total capital expenditures	**364.5**	268.8	193.8	155.8	88.3
Property acquisitions (dispositions), net	**115.2**	91.3	(58.2)	(161.6)	119.1
Corporate acquisitions [6]	**16.6**	505.0	72.0	721.6	–
Total capital expenditures and net acquisitions	**496.3**	865.1	207.6	715.8	207.4
OPERATING					
Production					
Crude oil (bbl/d)	**29,042**	23,282	22,961	22,886	20,655
Natural gas (mmcf/d)	**179.1**	173.8	178.3	164.2	109.8
Natural gas liquids (bbl/d)	**4,170**	4,005	4,191	4,086	3,479
Total (boe per day 6:1)	**63,056**	56,254	56,870	54,335	42,425
Average prices					
Crude oil ($/bbl)	**65.26**	61.11	47.03	36.90	31.63
Natural gas ($/mcf)	**6.97**	8.96	6.78	6.40	4.41
Natural gas liquids ($/bbl)	**52.63**	49.92	39.04	32.19	24.01
Oil equivalent ($/boe)	**53.33**	56.54	43.13	37.29	28.73
RESERVES [7] (company interest)					
Proved plus probable reserves					
Crude oil and NGL (mbbl)	**162,193**	163,385	123,226	129,663	117,241
Natural gas (bcf)	**743.6**	741.7	724.5	720.2	408.8
Total (mboe)	**286,125**	286,997	243,974	249,704	185,371
TRUST UNIT TRADING (based on intra-day trading)					
Unit prices					
High	**30.74**	27.58	17.98	14.87	13.44
Low	**19.20**	16.55	13.50	10.89	11.04
Close	**22.30**	26.49	17.90	14.74	11.90
Average daily volume (thousands)	**706**	656	420	430	305

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

(2) Net income in the basic per trust unit calculation has been reduced by interest on the convertible debentures in 2003 and is based on net income after non-controlling interest divided by weighted average units (excluding units issuable for exchangeable shares) for the years 2003-2006.

(3) Based on number of trust units outstanding at each cash distribution date.

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

(5) Includes trust units issuable for outstanding exchangeable shares based on the period end exchange ratio

(6) Represents total consideration for the corporate acquisition including fees but prior to working capital, asset retirement obligation and future income tax liability assumed on acquisition.

(7) Established reserves for 2002.

QUARTERLY HISTORICAL REVIEW

(CDN $ millions, except per unit amounts)	2006				2005			
FINANCIAL	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue before royalties	**292.5**	312.3	306.7	318.9	365.3	310.2	251.6	238.1
Per unit [(1)]	**1.42**	1.52	1.51	1.58	1.89	1.62	1.32	1.26
Cash flow	**174.4**	200.3	194.7	191.2	207.6	168.1	121.8	142.0
Per unit – basic [(1)]	**0.85**	0.98	0.96	0.94	1.07	0.88	0.64	0.75
Per unit – diluted	**0.84**	0.97	0.95	0.94	1.07	0.87	0.63	0.74
Net income	**56.6**	116.9	182.5	104.1	130.5	114.6	73.2	38.6
Per unit – basic [(2)]	**0.28**	0.58	0.91	0.52	0.68	0.61	0.39	0.21
Per unit – diluted	**0.28**	0.58	0.91	0.52	0.68	0.59	0.39	0.20
Cash distributions	**122.3**	121.4	120.6	119.9	115.7	92.6	84.5	83.9
Per unit [(3)]	**0.60**	0.60	0.60	0.60	0.60	0.49	0.45	0.45
Total assets	**3,479.0**	3,335.8	3,277.8	3,279.7	3,251.2	2,483.5	2,427.5	2,303.9
Total liabilities	**1,550.6**	1,371.3	1,339.9	1,434.1	1,415.5	912.2	895.2	785.8
Net debt outstanding [(4)]	**739.1**	579.7	567.4	598.9	578.1	357.6	366.2	254.3
Weighted average units [(5)]	**206.5**	205.1	203.7	202.5	193.4	191.7	190.3	189.2
Units outstanding and issuable [(5)]	**207.2**	205.7	204.4	203.1	202.0	192.1	191.3	189.6
CAPITAL EXPENDITURES								
Geological and geophysical	**3.7**	2.2	2.8	2.7	3.0	2.3	2.7	1.3
Land	**11.8**	1.4	14.3	4.9	5.5	2.0	0.8	0.8
Drilling and completions	**79.1**	76.2	29.8	55.4	60.3	63.6	32.7	35.2
Plant and facilities	**26.5**	24.6	10.9	15.6	17.0	14.8	8.7	14.5
Other capital	**0.8**	0.5	0.8	0.5	2.0	0.3	0.6	0.7
Total capital expenditures	**121.9**	104.9	58.6	79.1	87.8	83.0	45.5	52.5
Property acquisitions (dispositions) net	**76.4**	8.4	2.8	27.6	3.0	5.9	78.7	3.7
Corporate acquisitions [(6)]	**16.6**	–	–	–	462.8	–	42.2	–
Total capital expenditures and net acquisitions	**214.9**	113.3	61.4	106.7	553.6	88.9	166.4	56.2
OPERATING								
Production								
Crude oil (bbl/d)	**29,605**	29,108	27,805	29,651	25,534	23,513	22,046	21,993
Natural gas (mmcf/d)	**179.5**	173.4	178.5	185.0	177.9	168.2	173.1	176.1
Natural gas liquids (bbl/d)	**4,144**	4,166	4,247	4,120	3,943	4,047	3,962	4,072
Total (boe per day 6:1)	**63,663**	62,178	61,803	64,600	59,120	55,592	54,860	55,410
Average prices								
Crude oil ($/bbl)	**58.26**	71.84	71.86	59.53	62.12	69.37	58.37	53.63
Natural gas ($/mcf)	**6.99**	6.10	6.35	8.40	12.05	9.08	7.42	7.20
Natural gas liquids ($/bbl)	**46.51**	56.60	54.44	52.91	57.14	50.43	46.13	46.57
Oil equivalent ($/boe)	**49.94**	54.59	54.54	54.86	67.16	60.66	50.40	47.74
TRUST UNIT TRADING (based on intra-day trading)								
Unit prices								
High	**29.22**	30.74	28.61	27.51	27.58	24.20	20.30	20.40
Low	**19.20**	25.25	24.35	25.09	20.45	19.94	16.88	16.55
Close	**22.30**	27.21	28.00	27.36	26.49	24.10	19.94	18.15
Average daily volume (thousands)	**1,125**	614	548	546	653	599	605	895

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

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

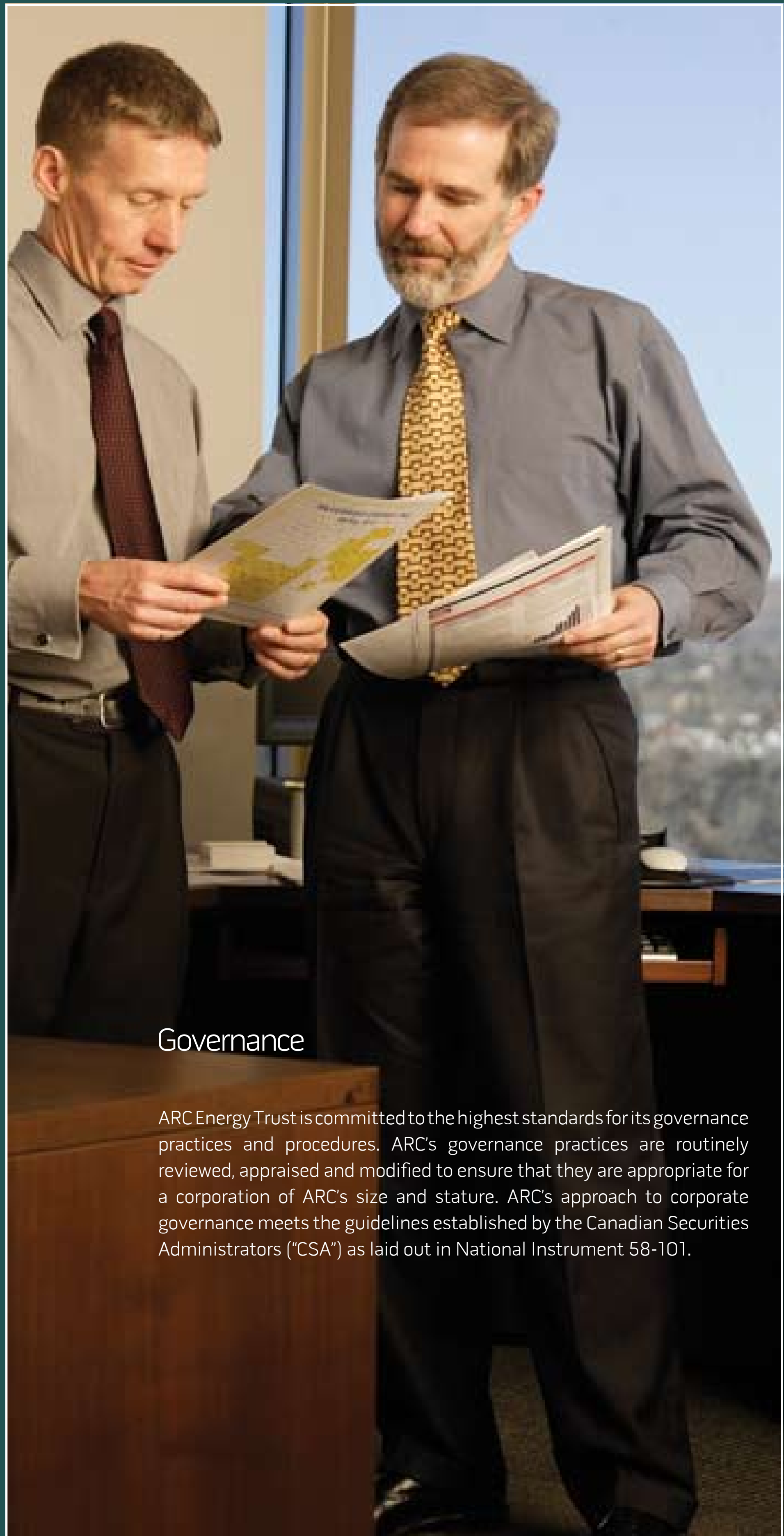
(3) Based on number of trust units outstanding at each cash distribution date.

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

(5) Includes trust units issuable for outstanding exchangeable shares based on the period end exchange ratio.

(6) Represents total consideration for the corporate acquisition including fees but prior to working capital, asset retirement obligation and future income tax liability assumed on acquisition.

ARC ENERGY TRUST



Governance

ARC Energy Trust is committed to the highest standards for its governance practices and procedures. ARC's governance practices are routinely reviewed, appraised and modified to ensure that they are appropriate for a corporation of ARC's size and stature. ARC's approach to corporate governance meets the guidelines established by the Canadian Securities Administrators ("CSA") as laid out in National Instrument 58-101.

Left to right:
Doug Bonner, Senior Vice-President, Corporate Development; and
David Carey, Senior Vice-President, Capital Markets

INDEPENDENCE OF THE BOARD

ARC's board comprises eight members, all of whom are "independent" directors, except for the Chief Executive Officer. ARC uses the definition of independence as defined in NI 58-101 which states that a director is independent if the member has no direct or indirect material relationship with the company. A material relationship means a relationship which could, in the opinion of the board of directors, reasonably interfere with the exercise of a member's independent judgement.

The Board has determined that none of the directors who serve on its committees has a material relationship with ARC that could reasonably be expected to interfere with the exercise of such director's independent judgment. The Chairman of the Board is an independent director and, in conjunction with the Vice-Chairman, is responsible for managing the affairs of the Board and its committees, including ensuring the Board is organized properly, functions effectively and independently of management and meets its obligations and responsibilities.

MANDATE OF THE BOARD

The Board of Directors of ARC sees its primary role as the stewardship of ARC Resources and for overseeing the management of the business and affairs of ARC, with the goal of achieving the Trust's fundamental objective of providing long-term superior returns to unitholders. The Board oversees the conduct of the business and management through its review and approval of strategic, operating, capital and financial plans; the identification of the principal risks of the Trust's business and oversight of the implementation of systems to manage such risks; the appointment and performance review of the Chief Executive Officer; the approval of communication policies for the Trust and the review of the integrity of the Trust's internal financial controls and management systems.

COMMITTEES OF THE BOARD

The Board has established an Audit Committee, a Reserve Committee, a Human Resources and Compensation Committee, a Policy and Board Governance Committee and a Health, Safety and Environment Committee to assist it in the discharge of its duties and responsibilities. All of the committees are comprised of independent directors and report to the Board of Directors of ARC Resources.

Audit Committee

Members: Fred Dyment (Chair), Walter DeBoni, Michael Kanovsky and Mac Van Wielingen.
The Audit Committee assists the Board in fulfilling its oversight responsibilities with respect to the integrity and completeness of the annual and quarterly financial statements and accompanying management discussion and analysis provided to Unitholders and regulatory bodies; compliance with accounting and finance based legal and regulatory requirements; and review of the independence and performance of the external auditor, internal accounting systems and procedures. The committee reviews the audit plans of the external auditors and meets with them at the time of each committee meeting, independently of management.

There were five meetings of the committee in 2006.

Reserves Committee

Members: Fred Coles (Chair), Fred Dyment and Michael Kanovsky.
The Reserves Committee assists the Board in meeting their responsibilities to review the qualifications, experience, reserve evaluation approach and costs of the independent engineering firm that performs ARC's reserve evaluation and to review the annual independent engineering report. The committee reviews and recommends for approval by the Board on an annual basis the statements of reserve data and other information specified in National Instrument 51 101. The committee also reviews any other oil and gas reserve report prior to release by ARC to the public and reviews all of the disclosure in the Annual Information Form and elsewhere, related to the oil and gas activities of ARC.

There were four meetings of the committee in 2006.

Human Resources and Compensation Committee

Members: John Stewart (Chair), Fred Coles, Herb Pinder and Mac Van Wielingen.

The Human Resources and Compensation Committee assists the Board in fulfilling its oversight responsibilities with respect to overall human resource policies and procedures; the compensation program for ARC; and in consultation with the Board, undertakes an annual performance review with the President and CEO, and reviews the CEO's appraisal of the other executive officers' performance. The committee reviews the salary, bonus and other remuneration for the executive officers of ARC and makes recommendations on such matters to the CEO. The committee also reviews and recommends for approval to the Board the principal compensation plans of ARC such as the long term incentive program and any awards under such plans.

There were six meetings of the committee in 2006.

Health, Safety and Environment Committee

Members: Fred Coles (Chair), Walter DeBoni and John Stewart.

The Health, Safety and Environmental Committee assists the Board in its responsibility for oversight and due diligence by reviewing, reporting and making recommendations to the Board on the development and implementation of the policies, standards and policies of ARC with respect to the areas of health, safety and environment. This committee meets separately with management of ARC who have responsibility for such matters and reports to the Board.

There were four meetings of the committee in 2006.

Policy and Board Governance Committee

Members: Walter DeBoni (Chair), Herb Pinder, John Stewart and Mac Van Wielingen.

The Policy and Board Governance Committee assists the Board in fulfilling its oversight responsibilities with respect to reviewing the effectiveness of the Board and its Committees; developing and reviewing ARC's approach to board governance matters; and reviewing, developing and recommending to the Board procedures designed to ensure that the Board can function independently of management. The committee annually reviews the need to recruit and recommend new members to fill Board vacancies giving consideration to the competencies, skills and personal qualities of the candidates and of the existing Board, and recommends to the Board the nominees for election at each annual meeting. The effectiveness of individual board members and the board is reviewed through a yearly self assessment and inquiry questionnaire.

There were four meetings of the committee in 2006.

Management's Report

MANAGEMENT'S RESPONSIBILITY ON FINANCIAL STATEMENTS

Management is responsible for the preparation of the accompanying consolidated financial statements and for the consistency therewith of all other financial and operating data presented in this annual report. The consolidated financial statements have been prepared in accordance with the accounting policies detailed in the notes thereto. In Management's opinion, the consolidated financial statements are in accordance with Canadian generally accepted accounting principles, have been prepared within acceptable limits of materiality, and have utilized supportable, reasonable estimates.

To ensure the integrity of our financial statements, we carefully select and train qualified personnel. We also ensure our organizational structure provides appropriate delegation of authority and division of responsibilities. Our policies and procedures are communicated throughout the organization including a written ethics and integrity policy that applies to all employees including the chief executive officer and chief financial officer.

The Board of Directors approves the consolidated financial statements. Their financial statement related responsibilities are fulfilled mainly through the Audit Committee. The Audit Committee is composed entirely of independent directors, and includes at least one director with financial expertise. The Audit Committee meets regularly with management and the external auditors to discuss reporting and control issues and ensures each party is properly discharging its responsibilities. The Audit Committee also considers the independence of the external auditors and reviews their fees.

The consolidated financial statements have been audited by Deloitte & Touche LLP, independent auditors, in accordance with generally accepted auditing standards on behalf of the shareholders.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining an adequate system of internal control over financial reporting. During the past year, we have directed efforts to improve and document our internal control over financial reporting. Internal control over financial reporting is a process designed to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable and timely information. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Management has assessed the effectiveness of the company's internal control over financial reporting based on the criteria in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and concluded that the company's internal control over financial reporting was effective as of December 31, 2006. Management's assessment of the effectiveness of the company's internal control over financial reporting as of December 31, 2006 has been audited by Deloitte & Touche LLP, as reflected in their report for 2006.

John P. Dielwart
President and Chief Executive Officer

Steven W. Sinclair
Senior Vice-President Finance and Chief Financial Officer

Calgary, Alberta
February 14, 2007

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Unitholders of ARC Energy Trust:

We have audited the accompanying consolidated balance sheets of ARC Energy Trust and subsidiaries (the "Trust") as of December 31, 2006 and 2005 and the related consolidated statements of income and deficit and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

With respect to the financial statements for the year ended December 31, 2006, we conducted our audit in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). With respect to the financial statements for the year ended December 31, 2005, we conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of ARC Energy Trust and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for the years then ended in conformity with Canadian generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Trust's internal control over financial reporting as of December 31, 2006, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 14, 2007 expressed an unqualified opinion on management's assessment of the effectiveness of the Trust's internal control over financial reporting and an unqualified opinion on the effectiveness of the Trust's internal control over financial reporting.

Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Canada
February 14, 2007

COMMENTS BY INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS ON CANADA-UNITED STATES OF AMERICA REPORTING DIFFERENCE

The standards of the Public Company Accounting Oversight Board (United States) require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the Trust's financial statements, such as the change described in Note 22 to the consolidated financial statements. Our report to the Board of Directors and Unitholders dated February 14, 2007 is expressed in accordance with Canadian reporting standards which do not require a reference to such a change in accounting principles in the auditors' report when the change is properly accounted for and adequately disclosed in the financial statements.

Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Canada
February 14, 2007

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Unitholders of ARC Energy Trust:

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that ARC Energy Trust and subsidiaries (the "Trust") maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Trust's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Trust's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Trust maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2006 of the Trust, and our report dated February 14, 2007 expressed an unqualified opinion on those financial statements and included a separate report titled Comments by Independent Registered Chartered Accountants on Canada-United States of America Reporting Difference referring to a change in accounting policy.

Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Canada
February 14, 2007

Consolidated Balance Sheets

As at December 31

(CDN$ millions)		2006		2005
ASSETS				
Current assets				
Cash and cash equivalents	$	2.8	$	–
Accounts receivable		129.8		123.0
Prepaid expenses		18.4		14.0
Commodity and foreign currency contracts (Note 11)		25.7		3.1
		176.7		140.1
Reclamation funds (Note 4)		30.9		23.5
Property, plant and equipment (Note 5)		3,093.8		2,930.0
Long-term investment (Note 6)		20.0		–
Goodwill		157.6		157.6
Total assets	$	3,479.0	$	3,251.2
LIABILITIES				
Current liabilities				
Accounts payable and accrued liabilities (Note 7)	$	162.1	$	148.6
Cash distributions payable		40.9		39.8
Commodity and foreign currency contracts (Note 11)		34.4		7.2
		237.4		195.6
Long-term debt (Note 8)		687.1		526.6
Other long-term liabilities (Note 9)		14.6		12.4
Asset retirement obligations (Note 10)		177.3		165.1
Future income taxes (Note 13)		434.2		515.9
Total liabilities		1,550.6		1,415.6
COMMITMENTS AND CONTINGENCIES (Note 21)				
NON-CONTROLLING INTEREST				
Exchangeable shares (Note 14)		40.0		37.5
UNITHOLDERS' EQUITY				
Unitholders' capital (Note 15)		2,349.2		2,230.8
Contributed surplus (Note 18)		2.4		6.4
Deficit (Note 16)		(463.2)		(439.1)
Total unitholders' equity		1,888.4		1,798.1
Total liabilities and unitholders' equity	$	3,479.0	$	3,251.2

See accompanying notes to the consolidated financial statements.

Mac H. Van Wielingen
Director

Fred Dyment
Director

Consolidated Statements of Income and Deficit

For the years ended December 31

(CDN$ millions, except per unit amounts)	2006	2005
REVENUES		
Oil, natural gas, and natural gas liquids	$ 1,230.5	$ 1,165.2
Royalties	(222.3)	(235.3)
	1,008.2	929.9
Gain (loss) on commodity and foreign currency contracts (Note 11)		
Realized	29.3	(87.6)
Unrealized	(4.6)	–
	1,032.9	842.3
EXPENSES		
Transportation	14.5	14.3
Operating	195.4	142.2
General and administrative	47.1	42.8
Interest on long-term debt (Note 8)	31.8	16.9
Depletion, depreciation and accretion (Notes 5 and 10)	360.0	264.5
Loss (gain) on foreign exchange (Note 12)	4.2	(6.4)
	653.0	474.3
Income before taxes	379.9	368.0
Capital and other taxes	(0.3)	(3.9)
Future income tax recovery (expense) (Note 13)	87.1	(1.6)
Net income before non-controlling interest	466.7	362.5
Non-controlling interest (Note 14)	(6.6)	(5.6)
Net income	460.1	356.9
Deficit, beginning of year	$ (439.1)	$ (419.4)
Distributions paid or declared (Note 17)	(484.2)	(376.6)
Deficit, end of year (Note 16)	$ (463.2)	$ (439.1)
Net income per unit (Note 20)		
Basic	$ 2.28	$ 1.90
Diluted	$ 2.27	$ 1.88

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flows

For the years ended December 31

(CDN$ millions)	2006	2005
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 460.1	$ 356.9
Add items not involving cash:		
Non-controlling interest (Note 14)	6.6	5.6
Future income tax (recovery) expense (Note 13)	(87.1)	1.6
Depletion, depreciation and accretion (Notes 5 and 10)	360.0	264.5
Non-cash loss on commodity and foreign currency contracts (Note 11)	4.6	–
Non-cash loss (gain) on foreign exchange (Note 12)	4.5	(6.3)
Non-cash trust unit incentive compensation (Notes 18 and 19)	11.9	17.2
Expenditures on site restoration and reclamation (Note 10)	(10.6)	(4.9)
Change in non-cash working capital	(16.0)	(17.9)
	734.0	616.7
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of long-term debt under revolving credit facilities, net	162.7	258.2
Issuance of senior secured notes	–	86.8
Repayment of senior secured notes	(6.8)	(32.5)
Issue of trust units	14.4	259.7
Trust unit issue costs	(0.2)	(12.2)
Cash distributions paid, net of distribution reinvestment (Note 17)	(389.6)	(318.3)
Payment of retention bonus (Note 9)	(1.0)	(1.0)
Change in non-cash working capital	–	(0.2)
	(220.5)	240.5
CASH FLOWS FROM INVESTING ACTIVITIES		
Corporate acquisitions, net of cash received (Note 3)	(16.6)	(505.0)
Acquisition of petroleum and natural gas properties	(117.4)	(93.8)
Proceeds on disposition of petroleum and natural gas properties	2.1	2.5
Capital expenditures	(362.7)	(257.9)
Long-term investment (Note 6)	(20.0)	–
Net reclamation funds contributions (Note 4)	(7.4)	(2.2)
Change in non-cash working capital	11.3	(5.2)
	(510.7)	(861.6)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	2.8	(4.4)
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	–	4.4
CASH AND CASH EQUIVALENTS, END OF YEAR	$ 2.8	$ –

See accompanying notes to the consolidated financial statements.

Notes to the Consolidated Financial Statements

December 31, 2006 and 2005 (all tabular amounts in CDN$ millions, except per unit and volume amounts)

1. STRUCTURE OF THE TRUST

ARC Energy Trust (the "Trust") was formed on May 7, 1996 pursuant to a Trust indenture (the "Trust Indenture") that has been amended from time to time, most recently on May 15, 2006. Computershare Trust Company of Canada was appointed as Trustee under the Trust Indenture. The beneficiaries of the Trust are the holders of the Trust units.

The Trust was created for the purposes of issuing Trust units to the public and investing the funds so raised to purchase a royalty in the properties of ARC Resources Ltd. ("ARC Resources") and ARC Sask Energy Trust ("ARC Sask"). The Trust Indenture was amended on June 7, 1999 to convert the Trust from a closed-end to an open-ended investment Trust. The current business of the Trust includes the investment in all types of energy business-related assets including, but not limited to, petroleum and natural gas-related assets, gathering, processing and transportation assets. The operations of the Trust consist of the acquisition, development, exploitation and disposition of these assets and the distribution of the net cash proceeds from these activities to the unitholders.

2. SUMMARY OF ACCOUNTING POLICIES

The consolidated financial statements have been prepared by management following Canadian generally accepted accounting principles ("GAAP"). These principles differ in certain respects from accounting principles generally accepted in the United States of America ("US GAAP") and to the extent that they affect the Trust, these differences are described in Note 22. The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingencies at the date of the financial statements, and revenues and expenses during the reporting year. Actual results could differ from those estimated.

In particular, the amounts recorded for depletion, depreciation and accretion of the petroleum and natural gas properties and for asset retirement obligations are based on estimates of reserves and future costs. By their nature, these estimates, and those related to future cash flows used to assess impairment, are subject to measurement uncertainty and the impact on the financial statements of future periods could be material.

Principles of Consolidation

The consolidated financial statements include the accounts of the Trust and its subsidiaries. Any reference to "the Trust" throughout these consolidated financial statements refers to the Trust and its subsidiaries. All inter-entity transactions have been eliminated.

Revenue Recognition

Revenue associated with the sale of crude oil, natural gas, and natural gas liquids ("NGLs") owned by the Trust are recognized when title passes from the Trust to its customers.

Transportation

Costs paid by the Trust for the transportation of natural gas, crude oil and NGLs from the wellhead to the point of title transfer are recognized when the transportation is provided.

Joint Venture

The Trust conducts many of its oil and gas production activities through joint ventures and the financial statements reflect only the Trust's proportionate interest in such activities.

Depletion and Depreciation

Depletion of petroleum and natural gas properties and depreciation of production equipment are calculated on the unit-of-production basis based on:

(a) total estimated proved reserves calculated in accordance with National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities;

(b) total capitalized costs, excluding undeveloped lands, plus estimated future development costs of proved undeveloped reserves, including future estimated asset retirement costs; and

(c) relative volumes of petroleum and natural gas reserves and production, before royalties, converted at the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of oil.

Unit Based Compensation

The Trust established a Trust Unit Incentive Rights Plan (the "Rights Plan") for employees, independent directors and long-term consultants who otherwise meet the definition of an employee of the Trust. The exercise price of the rights granted under the Plan may be reduced in future periods in accordance with the terms of the Plan. The Trust accounts for the rights using the fair value method, whereby the fair value of rights is determined on the date on which fair value can initially be determined. The fair value is then recorded as compensation expense over the period that the rights vest, with a corresponding increase to contributed surplus. When rights are exercised, the proceeds, together with the amount recorded in contributed surplus, are recorded to unitholders' capital.

Whole Trust Unit Incentive Plan Compensation

The Trust has established a Whole Trust Unit Incentive Plan (the "Whole Unit Plan") for employees, independent directors and long-term consultants who otherwise meet the definition of an employee of the Trust. Compensation expense associated with the Whole Unit Plan is granted in the form of Restricted Trust Units ("RTUs") and Performance Trust Units ("PTUs") and is determined based on the intrinsic value of the Whole Trust Units at each period end. The intrinsic valuation method is used as participants of the Whole Unit Plan receive a cash payment on a fixed vesting date. This valuation incorporates the period end Trust unit price, the number of RTUs and PTUs outstanding at each period end, and certain management estimates. As a result, large fluctuations, even recoveries, in compensation expense may occur due to changes in the underlying Trust unit price. In addition, compensation expense is amortized and recognized in earnings over the vesting period of the Whole Unit Plan with a corresponding increase or decrease in liabilities. Classification between accrued liabilities and other long-term liabilities is dependent on the expected payout date.

The Trust charges amounts relating to head office employees to general and administrative expense, amounts relating to field employees to operating expense and amounts relating to geologists and geophysicists to property, plant and equipment.

The Trust has not incorporated an estimated forfeiture rate for RTUs and PTUs that will not vest. Rather, the Trust accounts for actual forfeitures as they occur.

Cash and Cash Equivalents

Cash and cash equivalents include short-term investments, such as money market deposits or similar type instruments, with an original maturity of three months or less when purchased.

Reclamation Funds

Reclamation funds hold investment grade assets which are carried at cost and are subject to impairment in the event of a non-temporary decline in market value.

Long-Term Investment

Investments are recorded and carried at cost and are subject to impairment in the event of a non-temporary decline in market value.

Property, Plant and Equipment ("PP&E")

The Trust follows the full cost method of accounting. All costs of exploring, developing and acquiring petroleum and natural gas properties, including asset retirement costs, are capitalized and accumulated in one cost centre as all operations are in Canada. Maintenance and repairs are charged against income, and renewals and enhancements that extend the economic life of the PP&E are capitalized. Gains and losses are not recognized upon disposition of petroleum and natural gas properties unless such a disposition would alter the rate of depletion by 20 per cent or more.

Impairment

The Trust places a limit on the aggregate carrying value of PP&E, which may be amortized against revenues of future periods.

Impairment is recognized if the carrying amount of the PP&E exceeds the sum of the undiscounted cash flows expected to result from the Trust's proved reserves. Cash flows are calculated based on third party quoted forward prices, adjusted for the Trust's contract prices and quality differentials.

Upon recognition of impairment, the Trust would then measure the amount of impairment by comparing the carrying amounts of the PP&E to an amount equal to the estimated net present value of future cash flows from proved plus risked probable reserves. The Trust's risk-free interest rate is used to arrive at the net present value of the future cash flows. Any excess carrying value above the net present value of the Trust's future cash flows would be recorded as a permanent impairment and charged against net income.

The cost of unproved properties is excluded from the impairment test described above and subject to a separate impairment test. In the case of impairment, the book value of the impaired properties are moved to the petroleum and natural gas depletable base.

Goodwill

The Trust must record goodwill relating to a corporate acquisition when the total purchase price exceeds the fair value for accounting purposes of the net identifiable assets and liabilities of the acquired company. The goodwill balance is assessed for impairment annually at year-end or as events occur that could result in an impairment. Impairment is recognized based on the fair value of the reporting entity (consolidated Trust) compared to the book value of the reporting entity. If the fair value of the consolidated Trust is less than the book value, impairment is measured by allocating the fair value of the consolidated Trust to the identifiable assets and liabilities as if the Trust had been acquired in a business combination for a purchase price equal to its fair value. The excess of the fair value of the consolidated trust over the amounts assigned to the identifiable assets and liabilities is the fair value of the goodwill. Any excess of the book value of goodwill over this implied fair value of goodwill is the impairment amount. Impairment is charged to earnings in the period in which it occurs.

Goodwill is stated at cost less impairment and is not amortized.

Asset Retirement Obligations

The Trust recognizes the fair value of an Asset Retirement Obligation ("ARO") in the period in which it is incurred when a reasonable estimate of the fair value can be made. On a periodic basis, management will review these estimates and changes, if any, to the estimate will be applied on a prospective basis. The fair value of the estimated ARO is recorded as a long-term liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on a unit-of-production basis over the life of the reserves. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost would also result in an increase or decrease to the ARO. Actual costs incurred upon settlement of the ARO are charged against the ARO to the extent of the liability recorded. Any difference between the actual costs incurred upon settlement of the ARO and the recorded liability is recognized as a gain or loss in the Trust's earnings in the period in which the settlement occurs.

Income Taxes

The Trust follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements of the Trust's corporate subsidiaries and their respective tax base, using substantively enacted future income tax rates. The effect of a change in income tax rates on future tax liabilities and assets is recognized in income in the period in which the change occurs. Temporary differences arising on acquisitions result in future income tax assets and liabilities.

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the unitholders. As the Trust distributes all of its taxable income to the unitholders and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no provision for income taxes has been made in the Trust.

Basic and Diluted per Trust Unit Calculations

Basic net income per unit is computed by dividing the net income by the weighted average number of trust units outstanding during the period. Diluted net income per unit amounts are calculated based on net income before non-controlling interest divided by dilutive trust units. Dilutive trust units are arrived at by taking weighted average trust units and trust units issuable on conversion of exchangeable shares, and giving effect to the potential dilution that would occur if rights were exercised at the beginning of the period. The treasury stock method assumes that proceeds received from the exercise of in-the-money rights and any unrecognized trust unit incentive compensation are used to repurchase units at the average market price.

Derivative Financial Instruments

The Trust is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments are used by the Trust to reduce its exposure to fluctuations in commodity prices, foreign exchange rates, and interest rates. The fair values of these derivative instruments are based on an estimate of the amounts that would have been received or paid to settle these instruments prior to maturity. The Trust considers all of these transactions to be effective economic hedges, however, the majority of the Trust's contracts do not qualify or have not been designated as effective hedges for accounting purposes.

For derivative instruments that do qualify as effective accounting hedges, policies and procedures are in place to ensure that the required documentation and approvals are in place. This documentation specifically ties the derivative financial instrument to their use, and in the case of commodities, to the mitigation of market price risk associated with cash flows expected to be generated. When applicable, the Trust also identifies all relationships between hedging instruments and hedged items, as well as its risk management objective and the strategy for undertaking hedge transactions. This would include linking the particular derivative to specific assets and liabilities on the consolidated balance sheet or to specific firm commitments or forecasted transactions. Where specific hedges are executed, the Trust assesses, both at the inception of the hedge and on an ongoing basis, whether the derivative used in the particular hedging transaction is effective in offsetting changes in fair value or cash flows of the hedged item.

Realized and unrealized gains and losses associated with hedging instruments that have been terminated or cease to be effective prior to maturity, are deferred on the consolidated balance sheet and recognized in income in the period in which the underlying hedged transaction is recognized.

For transactions that do not qualify for hedge accounting, the Trust applies the fair value method of accounting by recording an asset or liability on the consolidated balance sheet and recognizing changes in the fair value of the instruments in the statement of income for the current period.

Foreign Currency Translation

Monetary assets and liabilities denominated in a foreign currency are translated at the rate of exchange in effect at the consolidated balance sheet date. Revenues and expenses are translated at the period average rates of exchange. Translation gains and losses are included in income in the period in which they arise.

Non-Controlling Interest

The Trust must record non-controlling interest when exchangeable shares issued by a subsidiary of the Trust are transferable to third parties. Non-controlling interest on the consolidated balance sheet is recognized based on the fair value of the exchangeable shares upon issuance plus the accumulated earnings attributable to the non-controlling interest. Net income is reduced for the portion of earnings attributable to the non-controlling interest. As the exchangeable shares are converted to Trust units, the non-controlling interest on the consolidated balance sheet is reduced by the cumulative book value of the exchangeable shares and Unitholders' capital is increased by the corresponding amount.

3. CORPORATE ACQUISITIONS

On December 6, 2006 the Trust completed a minor corporate acquisition for net cash consideration of $16.6 million. There was no goodwill recognized with this acquisition. Substantially all of the consideration was applied against property, plant and equipment, with a nominal amount applied against working capital items.

The following acquisitions were completed in 2005:

Redwater And North Pembina Cardium Unit

On December 16, 2005, the Trust acquired all of the issued and outstanding shares of three legal entities, 3115151 Nova Scotia Company, 3115152 Nova Scotia Company and 3115153 Nova Scotia Company which together hold the Redwater and North Pembina Cardium Unit assets (collectively "Redwater and NPCU") for total consideration of $462.8 million. The allocation of the purchase price and consideration paid were as follows:

Net Assets Acquired

Working capital deficit	$	(0.6)
Property, plant and equipment		729.5
Asset retirement obligations		(70.7)
Future income taxes		(195.4)
Total net assets acquired	**$**	**462.8**

Consideration Paid

Cash consideration and fees paid	$	462.8
Total consideration paid	**$**	**462.8**

The acquisition of Redwater and NPCU has been accounted for as an asset acquisition pursuant to EIC-124.

In addition to consideration paid, the Trust committed to making contributions to a restricted reclamation fund as detailed in Note 21.

The future income tax liability on acquisition was based on the difference between the fair value of the acquired net assets of $463.4 million and the associated tax basis of $93.3 million.

These consolidated financial statements incorporate the operations of Redwater and NPCU from December 16, 2005.

Romulus Exploration Inc.

On June 30, 2005, the Trust acquired all of the issued and outstanding shares of Romulus Exploration Inc. ("Romulus") for total consideration of $42.2 million. The allocation of the purchase price and consideration paid were as follows:

Net Assets Acquired

Working capital deficit	$ (1.4)
Property, plant and equipment	62.5
Asset retirement obligations	(0.4)
Future income taxes	(18.5)
Total net assets acquired	**$ 42.2**

Consideration Paid

Cash and fees paid	$ 42.2
Total consideration paid	**$ 42.2**

The acquisition of Romulus has been accounted for as an asset acquisition pursuant to EIC-124.

The future income tax liability on acquisition was based on the difference between the fair value of the acquired net assets of $44 million and the associated tax basis of $9 million.

These consolidated financial statements incorporate the operations of Romulus from June 30, 2005.

4. RECLAMATION FUNDS

	2006		2005	
	Unrestricted	**Restricted**	Unrestricted	Restricted
Balance, beginning of year	**$ 23.5**	**$ –**	$ 21.3	$ –
Contributions	**6.0**	**6.1**	6.0	–
Reimbursed expenditures [(1)]	**(5.7)**	**–**	(4.6)	–
Interest earned on funds	**1.0**	**–**	0.8	–
Balance, end of year	**$ 24.8**	**$ 6.1**	$ 23.5	$ –

(1) Amount differs from actual expenditures incurred by the Trust due to timing differences and discretionary reimbursements.

An unrestricted reclamation fund was established to fund future asset retirement obligation costs. In addition, the Trust has created a restricted reclamation fund associated with the Redwater property acquired in 2005. Contributions to the restricted and unrestricted reclamation funds and interest earned on the balances have been deducted from the cash distributions to the unitholders. The Board of Directors of ARC Resources has approved voluntary contributions to the unrestricted reclamation fund over a 20-year period that currently results in minimum annual contributions of $6 million ($6 million in 2005) based upon properties owned as at December 31, 2006. Contributions to the restricted reclamation fund will vary over time and have been disclosed in Note 21. Contributions for both funds are continually reassessed to ensure that the funds are sufficient to finance the majority of future abandonment obligations. Interest earned on the funds are retained within the funds.

5. PROPERTY, PLANT AND EQUIPMENT

	2006	2005
Property, plant and equipment, at cost	**$ 4,655.3**	$ 4,142.0
Accumulated depletion and depreciation	**(1,561.5)**	(1,212.0)
Property, plant and equipment, net	**$ 3,093.8**	$ 2,930.0

The calculation of 2006 depletion and depreciation included an estimated $547 million ($488 million in 2005) for future development costs associated with proved undeveloped reserves and excluded $108.9 million ($58.9 million in 2005) for the book value of unproved properties.

The Trust performed a ceiling test calculation at December 31, 2006 to assess the recoverable value of property plant and equipment (PP&E). Based on the calculation, the present value of future net revenues from the Trust's proved plus probable reserves exceeded the carrying value of the Trust's PP&E at December 31, 2006. The benchmark prices used in the calculation were as follows:

Year	WTI Oil ($US/bbl)	AECO Gas (CDN$/mmbtu)	USD/CAD Exchange Rates
2007	62.00	7.20	0.87
2008	60.00	7.45	0.87
2009	58.00	7.75	0.87
2010	57.00	7.80	0.87
2011	57.00	7.85	0.87
2012	57.50	8.15	0.87
2013	58.50	8.30	0.87
2014	59.75	8.50	0.87
2015	61.00	8.70	0.87
2016	62.25	8.90	0.87
2017	63.50	9.10	0.87
Remainder [1]	2.0%	2.0%	0.87

[1] Percentage change represents the change in each year after 2017 to the end of the reserve life.

6. LONG-TERM INVESTMENT

During the year the Trust entered into an equity investment in a private oil sands company in the amount of $20 million. 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.

7. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	2006	2005
Trades payable	**$ 39.0**	$ 33.0
Accrued liabilities	**108.8**	109.2
Current portion of accrued long-term incentive compensation	**11.5**	3.6
Interest payable	**1.8**	1.8
Retention bonuses	**1.0**	1.0
Total accounts payable and accrued liabilities	**$ 162.1**	$ 148.6

The current portion of accrued long-term incentive compensation represents the current portion of the Trust's estimated liability for the Whole Unit Plan as at December 31, 2006 (see Note 19). This amount is payable in 2007.

8. LONG-TERM DEBT

	2006	2005
Revolving credit facilities		
Syndicated credit facility	**$ 425.0**	$ 254.6
Working capital facility	**1.1**	3.8
Senior secured notes		
5.42% USD Note	**87.4**	87.4
4.94% USD Note	**28.0**	35.0
4.62% USD Note	**72.8**	72.9
5.10% USD Note	**72.8**	72.9
Total long-term debt outstanding	**$ 687.1**	$ 526.6

Revolving Credit Facilities

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

Borrowings under the facility bear interest at bank prime (6.0 per cent and 5.0 per cent at December 31, 2006 and December 31, 2005, respectively) or, at the Trust's option, Canadian or U.S. dollar bankers' acceptances plus a stamping fee. The lenders review the credit facility each year and determine whether they will extend the revolving periods for another year. In the event that the credit facility is not extended at anytime before the maturity date, the loan balance will become repayable on the maturity date. The maturity date of the current credit facility is March 24, 2009.

The working capital facility allows for maximum borrowings of $25 million and is due and payable immediately upon demand by the bank. The facility is secured and is subject to the same covenants as the syndicated credit facility.

Various borrowing options exist under the revolving 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.

5.42 Per Cent and 4.94 Per Cent Senior Secured USD Notes

These senior secured notes were issued in two separate issues pursuant to an Uncommitted Master Shelf Agreement. The US$24 million Senior secured notes were issued in 2002, bear interest at 4.94 per cent, have a remaining final term of 3.8 years (remaining average term of 2.3 years) and require equal principal payments of US$6 million over a four year period commencing in 2007. The US$75 million Senior secured notes were issued in 2005, bear interest at 5.42 per cent, have a remaining final term of 11 years (remaining weighted average term of 7.6 years) and require equal principal repayments over an eight year period commencing in 2010.

4.62 Per Cent and 5.10 Per Cent Senior Secured USD Notes

These notes were issued on April 27, 2004 via a private placement in two tranches of US$62.5 million each. The first tranche of US$62.5 million bears interest at 4.62 per cent and has a remaining final term of 7.3 years (remaining weighted average term of 4.9 years) and require equal principal repayments over a 6 year period commencing 2009. Immediately following the issuance, the Trust entered into interest rate swap contracts which effectively changed the interest rate from fixed to floating (see Note 11). The second tranche of US$62.5 million bears interest at 5.10 per cent and has a remaining final term of 9.3 years (remaining weighted average term of 7.4 years). Repayments of the notes will occur over a five year period commencing in 2012.

Debt Covenants

The following are the significant financial covenants governing the revolving credit facilities:

- 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 December 31, 2006, the Trust had $4.7 million in letters of credit ($4.4 million in 2005), no subordinated debt, and was in compliance with all covenants.

The payment of principal and interest are allowable deductions in the calculation of cash available for distribution to unitholders and rank ahead of cash distributions payable to unitholders. Should the properties securing this debt generate insufficient revenue to repay the outstanding balances, the unitholders have no direct liability.

During 2006, the weighted-average effective interest rate under the credit facility was 5.3 per cent (3.3 per cent in 2005).

Amounts due under the working capital facility and the senior secured notes 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.

9. OTHER LONG-TERM LIABILITIES

	2006	2005
Accrued long-term incentive compensation	$ **14.6**	$ 11.4
Retention bonuses	–	1.0
Total other long-term liabilities	$ **14.6**	$ 12.4

The accrued long-term incentive compensation represents the long-term portion of the Trust's estimated liability for the Whole Unit Plan as at December 31, 2006 (see Note 19). This amount is payable in 2008 through 2009.

The retention bonuses arose upon internalization of the management contract in 2002. The final retention payment will occur in August 2007 and therefore is classified as a current liability as at December 31, 2006.

10. ASSET RETIREMENT OBLIGATIONS

The total future asset retirement obligations were estimated by management based on the Trust's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. The Trust has estimated the net present value of its total asset retirement obligations to be $177.3 million as at December 31, 2006 ($165.1 million in 2005) based on a total future undiscounted liability of $1,042.6 million ($603.4 million in 2005). These payments are expected to be made over the next 61 years with the bulk of payments being made in years 2017 to 2021 and 2057 to 2067. The Trust's weighted average credit adjusted risk free rate of 6.5 per cent (5.6 per cent in 2005) and an inflation rate of 2.0 per cent (2.0 per cent in 2005) were used to calculate the present value of the asset retirement obligations. During the year, no gains or losses were recognized on settlements of asset retirement obligations.

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

	2006	2005
Balance, beginning of year	**$ 165.1**	$ 73.0
Increase in liabilities relating to corporate acquisitions	**4.9**	71.1
Increase in liabilities relating to development activities	**2.8**	5.1
Increase in liabilities relating to change in estimate	**4.0**	15.6
Settlement of liabilities during the year	**(10.6)**	(4.9)
Accretion expense	**11.1**	5.2
Balance, end of year	**$ 177.3**	$ 165.1

11. FINANCIAL INSTRUMENTS

The Trust is exposed to a number of financial risks that are part of its normal course of business. The Trust has a risk management program in place that includes financial instruments as disclosed in this note. The objective of the risk management program is to mitigate the Trust's exposure to the following financial risks:

Credit Risk
Most of the Trust's accounts receivable relate to oil and natural gas sales and are exposed to typical industry credit risks. The Trust manages this credit risk by entering into sales contracts with only highly rated entities and reviewing its exposure to individual entities on a regular basis. With respect to counterparties to financial instruments the Trust partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings.

Volatility of Oil and Natural Gas Prices
The Trust's operational results and financial condition, and therefore the amount of distributions paid to unitholders are dependent on the prices received for oil and natural gas production. Oil and gas prices have fluctuated widely during recent years and are determined by economic and in the case of oil prices, political factors. Supply and demand factors, including weather and general economic conditions as well as conditions in other oil and natural gas regions impact prices. Any movement in oil and natural gas prices could have an effect on the Trust's financial condition and therefore on the distributions to unitholders. ARC may manage the risk associated with changes in commodity prices by entering into oil or natural gas price derivative contracts. To the extent that ARC engages in risk management activities related to commodity prices, it will be subject to credit risks associated with counterparties with which it contracts.

Variations in Interest Rates and Foreign Exchange Rates
Increases in interest rates could result in a significant increase in the amount the Trust pays to service variable interest debt, resulting in a decrease in distributions to unitholders. World oil prices are quoted in U.S. dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate that may fluctuate over time. Variations in the exchange rate of the Canadian dollar could have significant positive or negative impact on future distributions. ARC has initiated certain derivative contracts to attempt to mitigate these risks. To the extent that ARC engages in risk management activities related to foreign exchange rates, it will be subject to credit risk associated with counterparties with which it contracts. The increase in the exchange rate for the Canadian dollar and future Canadian/U.S. exchange rates will impact future distributions and the future value of the Trust's reserves as determined by independent evaluators.

Financial Instruments
Financial instruments of the Trust carried on the consolidated balance sheet consist mainly of cash and cash equivalents, accounts receivable, reclamation funds, current liabilities, other long-term liabilities, commodity and foreign currency contracts and long-term

debt. Except as noted below, as at December 31, 2006 and 2005, there were no significant differences between the carrying value of these financial instruments and their estimated fair value due to their short-term nature.

The fair value of the US$224 million fixed rate senior secured notes approximated CDN$257 million as at December 31, 2006 and will vary with changes in interest rates (2005 – US$230 million outstanding approximated CDN$269 million).

Derivative Contracts

Following is a summary of all derivative contracts in place as at December 31, 2006 in order to mitigate the risks discussed above:

Financial WTI Crude Oil Contracts

Term	Contract	Volume (bbl/d)	Bought Put (US$/bbl)	Sold Put (US$/bbl)	Sold Call (US$/bbl)
Jan 07 – Feb 07	Bought Put	1,000	62.50	–	–
Jan 07 – Jun 07	Put Spread	1,000	75.00	62.70	–
Jan 07 – Jun 07	Put Spread	1,000	75.00	65.00	–
Jan 07 – Dec 07	Put Spread	1,000	75.00	60.00	–
Jan 07 – Dec 07	3 – Way Collar	2,500	65.00	52.50	80.00
Jan 07 – Dec 07	Put Spread	2,500	65.00	52.50	–
Jan 07 – Dec 09	3 – Way Collar	5,000	55.00	40.00	90.00
Jul 07 – Dec 07	Put Spread	1,000	65.00	55.00	–

Financial AECO Natural Gas Contracts

Term	Contract	Volume (GJ/d)	Bought Put (CDN$/GJ)	Sold Put (CDN$/GJ)	Sold Call (CDN$/GJ)
Jan 07 – Mar 07	Collar	10,000	7.25	–	9.00
Jan 07 – Mar 07	Collar	10,000	7.50	–	9.50
Jan 07 – Mar 07	Collar	10,000	8.00	–	12.00
Jan 07 – Mar 07	Collar	20,000	8.50	–	12.35
Jan 07 – Mar 07	3 – Way Collar	10,000	8.00	5.50	11.90
Apr 07 – Oct 07	3 – Way Collar	10,000	7.25	5.25	9.00
Apr 07 – Oct 07	3 – Way Collar	10,000	7.50	5.50	9.50
Apr 07 – Oct 07	3 – Way Collar	30,000	7.00	5.00	8.65

Financial NYMEX Natural Gas Contracts

Term	Contract	Volume (mmbtu/d)	Bought Put (US$/mmbtu)	Sold Put (US$/mmbtu)	Sold Call (US$/mmbtu)
Jan 07 – Mar 07	Collar	5,000	8.50	–	10.25
Jan 07 – Mar 07	Collar	10,000	8.25	–	10.00
Jan 07 – Mar 07	Collar	10,000	10.00	–	13.65

Financial Natural Gas AECO (monthly) to NYMEX (last 3 day) Basis Contracts

Term	Contract	Volume (mmbtu/d)	Basis Swap (US$/mmbtu)
Jan 07 – Mar 07	Swap	40,000	(1.3125)
Apr 07 – Oct 08	Swap	50,000	(1.1160)
Nov 08 – Oct 10	Swap	50,000	(1.0430)

Financial Foreign Exchange Contracts [1]

Term	Contract	Volume (MM US$)	Swap (CDN$/US$)	Swap (US$/CDN$)	Bought Put (CDN$/US$)	Sold Put (CDN$/US$)
USD Sales Contracts						
Jan 07 – Dec 07	Swap	192	1.1379	0.8788	–	–
USD Option Contracts						
Jan 07 – Dec 07	Put Spread	12	–	–	1.125	1.100
Jan 07 – Dec 07	Put Spread	12	–	–	1.128	1.098

[1] Contracted volume is a total notional volume for the entire term.

Financial Electricity Contracts [2]

Term	Contract	Volume (MWh)	Swap (CDN$/MWh)
Jan 07 – Dec 07	Swap	20.0	64.63
Jan 08 – Dec 08	Swap	15.0	60.17
Jan 09 – Dec 09	Swap	15.0	59.33
Jan 10 – Dec 10	Swap	5.0	63.00

[2] Contracted volume is based on a 24/7 term.

Financial Interest Rate Contracts [3]

Term	Contract	Principal (MM USD)	Fixed Annual Rate (%)	Spread on 3 Mo. LIBOR
Jan 07 – Apr 14	Swap	30.5	4.62	38.5 bps
Jan 07 – Apr 14	Swap	32.0	4.62	(25.5 bps)

[3] Starting in 2009, the notional amount of the contracts decreases annually until 2014. The Trust pays the floating interest rate based on the three month LIBOR plus a spread and receives the fixed interest rate.

The Trust has designated its fixed price electricity and interest rate swap contracts as effective accounting hedges as at January 1, 2004. A realized gain of $3.4 million ($0.3 million gain in 2005) on the electricity contract has been included in operating costs. The fair value unrealized gain on the electricity contract of $7.0 million has not been recorded on the consolidated balance sheet at December 31, 2006 ($0.2 million loss in 2005). A realized loss of $0.4 million for the year on the interest rate swap contracts has been included in interest expense ($0.5 million gain in 2005). The fair value unrealized loss on the two interest rate swap contracts of $1.8 million has not been recorded on the consolidated balance sheet at December 31, 2006 ($1 million loss in 2005).

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 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:

		2006		2005
Fair value, beginning of year [1]	**$**	**(4.1)**	$	(4.1)
Fair value, end of year		**(8.7)**		(4.1)
Change in fair value of contracts in the year [1]		**(4.6)**		–
Realized gains (losses) in the year		**29.3**		(87.6)
Gain (loss) on commodity and foreign currency contracts [1]	**$**	**24.7**	$	(87.6)
Commodity and foreign currency contracts asset	**$**	**25.7**	$	3.1
Commodity and foreign currency contracts liability	**$**	**(34.4)**	$	(7.2)

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

The Trust recorded a net gain on commodity and foreign currency contracts of $24.7 million in the statement of income for 2006 ($87.6 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. During the year, $4.6 million in unrealized losses ($ nil in 2005) and $29.3 million in realized cash gains ($87.6 million loss in 2005) on contracts was recognized during the year.

12. GAIN (LOSS) ON FOREIGN EXCHANGE

The following is a summary of the total gain (loss) US$ denominated transactions:

		2006		2005
Unrealized (loss) on US$ denominated debt	**$**	**(7.1)**	$	(4.2)
Realized gain on US$ denominated debt repayments		**2.6**		10.5
Total non-cash (loss) gain on US$ denominated transactions		**(4.5)**		6.3
Realized cash gain on US$ denominated transactions		**0.3**		0.1
Total foreign exchange (loss) gain	**$**	**(4.2)**	$	6.4

13. 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:

	2006	2005
Income before future income tax expense and recovery	$ 379.6	$ 364.1
Canadian statutory rate	34.5%	37.6%
Expected income tax expense at statutory rates	130.9	137.0
Effect on income tax of:		
Net income of the Trust	(138.0)	(111.7)
Effect of change in corporate tax rate	(62.2)	(4.9)
Resource allowance	(10.7)	(20.0)
Change in estimated pool balances	(10.0)	–
Unrealized loss (gain) on foreign exchange	1.2	(1.6)
Non-deductible crown charges	1.2	1.3
Other non-deductible items	0.5	1.5
Future income tax (recovery) expense	$ (87.1)	$ 1.6

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

	2006	2005
Future tax liabilities:		
Capital assets in excess of tax value	$ 509.8	$ 569.8
Long-term debt	4.0	–
Future tax assets:		
Non-capital losses	(5.3)	(1.5)
Asset retirement obligations	(52.1)	(45.7)
Accrued long-term incentive compensation	(7.7)	–
Commodity and foreign currency contracts	(2.5)	(1.4)
Attributed Canadian royalty income	(10.4)	(5.3)
Cumulative eligible capital and deductible share issue costs	(1.6)	–
Net future income tax liability	$ 434.2	$ 515.9

The petroleum and natural gas properties and facilities owned by the Trust's subsidiaries have an approximate tax basis of $1,031 million ($788.4 million in 2005) available for future use as deductions from taxable income. Included in this tax basis are estimated non-capital loss carry forwards of $18.2 million ($13.1 million in 2005) that expire in the years 2008 through 2026. The following is a summary of the estimated Trust's subsidiaries' tax basis:

	2006	2005
Canadian oil and gas property expenses	$ 200.1	$ 88.6
Canadian development expenses	285.9	201.3
Canadian exploration expenses	27.7	22.7
Undepreciated capital cost	389.0	352.2
Non-capital losses	18.2	13.1
Provincial tax pools	104.5	104.5
Other	5.6	6.0
Estimated tax basis	$ 1,031.0	$ 788.4

In addition to the above tax basis for the Trust's subsidiaries, the Trust itself has an approximate tax basis of $545.1 million as at December 31, 2006 ($555.4 million in 2005).

On October 31, 2006, the Federal Government announced tax proposals pertaining to taxation of distributions paid by publicly traded income trusts. Currently, distributions paid to unitholders, other than returns of capital, are claimed as a deduction by the Trust in arriving at taxable income whereby tax is eliminated at the Trust level and is paid by the unitholders. The proposals would result in a two-tiered tax structure whereby distributions would first be subject to a 31.5 per cent tax at the Trust level commencing in 2011 and then unitholders would be subject tax on the distribution as if it were a taxable dividend paid by a taxable Canadian corporation. If enacted, the proposals would apply to the Trust effective January 1, 2011. The Trust is currently assessing various alternatives with respect to the potential implications of the tax proposals; however, until the legislation is enacted in final form, the Trust will not arrive at a final conclusion with respect to future Trust structure and implications to the Trust. As the tax proposals had not yet been substantively enacted as of December 31, 2006, the consolidated financial statements do not reflect the impact of the proposed taxation.

No current income taxes were paid or payable in 2006.

14. EXCHANGEABLE SHARES

The ARC Resources exchangeable shares ("ARL Exchangeable Shares") were issued on January 31, 2001 at $11.36 per exchangeable share as partial consideration for the Startech Energy Inc. acquisition. The issue price of the exchangeable shares was determined based on the weighted average trading price of Trust units preceding the date of announcement of the acquisition. The ARL Exchangeable Shares had an exchange ratio of 1:1 at the time of issuance.

The Trust is authorized to issue an unlimited number of ARL Exchangeable Shares which can be converted (at the option of the holder) into Trust units at any time. The number of Trust units issuable upon conversion is based upon the exchange ratio in effect at the conversion date. The exchange ratio is calculated monthly based on the cash distribution paid divided by the ten day weighted average unit price preceding the record date and multiplied by the opening exchange ratio. The exchangeable shares are not eligible for distributions and, in the event that they are not converted, any outstanding shares are redeemable by the Trust for Trust units on August 28, 2012. The ARL Exchangeable Shares are publicly traded.

ARL EXCHANGEABLE SHARES (thousands)	**2006**	2005
Balance, beginning of year	**1,595**	1,784
Exchanged for Trust units	**(162)**	(189)
Balance, end of year	**1,433**	1,595
Exchange ratio, end of year	**2.01251**	1.83996
Trust units issuable upon conversion, end of year	**2,884**	2,935

The non-controlling interest on the consolidated balance sheet consists of the fair value of the exchangeable shares upon issuance plus the accumulated earnings attributable to the non-controlling interest. The net income attributable to the non-controlling interest on the consolidated statement of income represents the cumulative share of net income attributable to the non-controlling interest based on the Trust units issuable for exchangeable shares in proportion to total Trust units issued and issuable at each period end.

Following is a summary of the non-controlling interest for 2006 and 2005:

	2006	2005
Non-controlling interest, beginning of year	**$ 37.5**	$ 35.9
Reduction of book value for conversion to Trust units	**(4.1)**	(4.0)
Current year net income attributable to non-controlling interest	**6.6**	5.6
Non-controlling interest, end of year	**$ 40.0**	$ 37.5
Accumulated earnings attributable to non-controlling interest	**$ 27.3**	$ 20.7

15. UNITHOLDERS' CAPITAL

The Trust is authorized to issue 650 million Trust units of which 204.3 million units were issued and outstanding as at December 31, 2006 (199.1 million as at December 31, 2005).

The Trust has in place a Distribution Reinvestment and Optional Cash Payment Program ("DRIP") in conjunction with the Trusts' transfer agent to provide the option for unitholders to reinvest cash distributions into additional Trust units issued from treasury at a five per cent discount to the prevailing market price with no additional fees or commissions.

The Trust is an open ended mutual fund under which unitholders have the right to request redemption directly from the Trust. Units tendered by holders are subject to redemption under certain terms and conditions including the determination of the redemption price at the lower of the closing market price on the date units are tendered or 90 per cent of the weighted average trading price for the 10 day trading period commencing on the tender date. Cash payments for units tendered for redemption are limited to $100,000 per month with redemption requests in excess of this amount eligible to receive a note from ARC Resources Ltd. accruing interest at 4.5 per cent and repayable within 20 years.

	2006		2005	
	Number of Trust Units (thousands)	**$**	Number of Trust Units (thousands)	$
Balance, beginning of year	**199,104**	**2,230.8**	185,822	1,926.4
Issued for cash	**1**	**–**	9,000	239.8
Issued on conversion of ARL exchangeable shares (Note 14)	**310**	**4.1**	333	4.0
Issued on exercise of employee rights (Note 18)	**978**	**18.4**	1,500	24.0
Distribution reinvestment program	**3,896**	**96.1**	2,449	48.8
Trust unit issue costs	**–**	**(0.2)**	–	(12.2)
Balance, end of year	**204,289**	**2,349.2**	199,104	2,230.8

16. DEFICIT

The deficit balance is composed of the following items:

	2006	2005
Accumulated earnings	**$ 1,695.8**	$ 1,235.7
Accumulated cash distributions	**(2,159.0)**	(1,674.8)
Deficit	**$ (463.2)**	$ (439.1)

During the year, 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, depreciation, and accretion expense recorded on the original property, plant, and equipment investment and other non-cash charges.

17. RECONCILIATION OF CASH FLOW AND DISTRIBUTIONS

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

	2006	2005
Cash flow from operating activities	**$ 734.0**	$ 616.7
Change in non-cash working capital	**16.0**	17.9
Expenditures on site reclamation and restoration	**10.6**	4.9
Cash flow from operating activities after the above adjustments	**760.6**	639.5
Deduct:		
Cash withheld to fund current period capital expenditures	**(263.2)**	(256.1)
Reclamation fund contributions and interest earned on fund balances	**(13.2)**	(6.8)
Cash distributions [1]	**484.2**	376.6
Accumulated cash distributions, beginning of year	**1,674.8**	1,298.2
Accumulated cash distributions, end of year	**$ 2,159.0**	$ 1,674.8
Cash distributions per unit [2]	**$ 2.40**	$ 1.99
Accumulated cash distributions per unit, beginning of year	**16.23**	14.24
Accumulated cash distributions per unit, end of year	**$ 18.63**	$ 16.23

[1] Cash distributions include non-cash amounts of $94.6 million ($58.3 million in 2005). These 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.

18. TRUST UNIT INCENTIVE RIGHTS PLAN

The Trust Unit Incentive Rights Plan (the "Rights Plan") was established in 1999 and authorized the Trust to grant up to 8,000,000 rights to its employees, independent directors and long-term consultants to purchase Trust units, of which 7,866,088 were granted to December 31, 2006. The initial exercise price of rights granted under the Rights Plan could not be less than the market price of the Trust units as at the date of grant and the maximum term of each right was not to exceed ten years. In general, the rights have a five year term and vest equally over three years commencing on the first anniversary date of the grant. In addition, the exercise price of the rights is to be adjusted downwards from time to time by the amount, if any, that distributions to unitholders in any calendar quarter exceeds 2.5 per cent (ten per cent annually) of the Trust's net book value of property, plant and equipment (the "Excess Distribution"), as determined by the Trust.

During the 2006 and 2005, the Trust did not grant any rights as the Rights Plan was replaced with a Whole Unit Plan during 2004 (see Note 19). The existing Rights Plan will be in place until the remaining 0.4 million rights outstanding as at December 31, 2006 are exercised or cancelled.

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

	2006		2005	
	Number of Rights (thousands)	**Weighted Average Exercise** Price ($)	Number of Rights (thousands)	Weighted Average Exercise Price ($)
Balance, beginning of year	**1,349**	**10.22**	3,009	10.92
Granted	**–**	**–**	–	–
Exercised	**(978)**	**12.19**	(1,500)	11.60
Cancelled	**(2)**	**10.07**	(160)	10.99
Balance before reduction of exercise price	**369**	**10.40**	1,349	11.10
Reduction of exercise price [1]	**–**	**(0.93)**	–	(0.88)
Balance, end of year	**369**	**9.47**	1,349	10.22

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

A summary of the plan as at December 31, 2006 is as follows:

Exercise Price At Grant Date ($)	Adjusted Exercise Price ($)	Number of Rights Outstanding (thousands)	Remaining Contractual Life of Rights (years)	Number of Rights Exercisable (thousands)
12.58	9.11	32	0.4	32
12.29	9.40	328	1.4	328
15.42	13.27	9	2.2	3
12.40	9.47	369	1.3	363

The Trust recorded compensation expense of $2.5 million for the year ($6.5 million in 2005) for the cost associated with the rights. Of the 3,013,569 rights issued on or after January 1, 2003 that were subject to recording compensation expense, 357,999 rights have been cancelled and 2,318,222 rights have been exercised to December 31, 2006.

The Trust used the Black-Scholes option-pricing model to calculate the estimated fair value of the outstanding rights issued on or after January 1, 2003. Subsequent to the initial valuation, the Trust used a binomial lattice model and observed immaterial valuation differences. The following assumptions were used to arrive at the estimate of fair value as at December 31, 2004:

	2004
Expected annual right's exercise price reduction	0.72
Expected volatility	13.2%
Risk-free interest rate	3.7%
Expected life of option (years)	1.1
Expected forfeitures	0%

Prior to 2004, the Trust recorded compensation expense on its Rights Plan using the intrinsic method. In 2004, the Trust adopted the fair value method. Use of the fair value prior to 2004 would have resulted in an immaterial impact to the Trust.

The following table reconciles the movement in the contributed surplus balance for 2006 and 2005:

	2006	2005
Balance, beginning of year	**$ 6.4**	$ 6.5
Compensation expense	**2.5**	6.5
Net benefit on rights exercised [1]	**(6.5)**	(6.6)
Balance, end of year	**$ 2.4**	$ 6.4

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

19. WHOLE TRUST UNIT INCENTIVE PLAN

In March 2004, the Board of Directors, upon recommendation of the Compensation Committee, approved a new Whole Trust Unit Incentive Plan (the "Whole Unit Plan") to replace the existing Trust Unit Incentive Rights Plan for new awards granted subsequent to March 31, 2004. The new Whole Unit Plan will result in employees, officers and directors (the "plan participants") receiving cash compensation in relation to the value of a specified number of underlying notional trust units. The Whole Unit Plan consists of Restricted Trust Units ("RTUs") for which the number of trust units is fixed and will vest over a period of three years and Performance Trust Units ("PTUs") for which the number of trust units is variable and will vest at the end of three years.

Upon vesting, the plan participant receives a cash payment based on the fair value of the underlying trust units plus notional accrued distributions. The cash compensation issued upon vesting of the PTUs is dependent upon the future performance of the Trust compared to its peers based on a performance multiplier. The performance multiplier is based on the percentile rank of the Trust's Total Unitholder Return. The cash compensation issued upon vesting of the PTUs may range from zero to two times the value of the PTUs originally granted.

The fair value associated with the RTUs and PTUs is expensed in the statement of income over the vesting period. As the value of the RTUs and PTUs is dependent upon the trust unit price, the expense recorded in the statement of income may fluctuate over time.

The Trust recorded compensation expense of $8.2 million and $1.1 million to general and administrative and operating expenses, respectively, and capitalized $1.8 million to property, plant and equipment in the twelve months ended December 31, 2006 for the estimated cost of the plan ($8.8 million, $1.9 million, and $1.4 million for the twelve months ended December 31, 2005). The compensation expense was based on the December 31, 2006 unit price of $22.30 ($26.49 in 2005), accrued distributions, a performance multiplier ranging from 1.9 to 2.0 for the various series (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 twelve months ended December 31, 2006 and 2005:

	2006		2005	
	Number of RTUs (thousands)	Number of PTUs (thousands)	Number of RTUs (thousands)	Number of PTUs (thousands)
Balance, beginning of year	**479**	**391**	224	128
Vested	**(180)**	**–**	(78)	–
Granted	**373**	**303**	367	305
Forfeited	**(24)**	**(11)**	(34)	(42)
Balance, end of year	**648**	**683**	479	391

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

	2006	2005
Balance, beginning of year	**$ 15.0**	$ 2.9
Change in liabilities in the year		
General and administrative expense	**8.2**	8.8
Operating expense	**1.1**	1.9
Property, plant and equipment	**1.8**	1.4
Balance, end of year	**$ 26.1**	$ 15.0
Current portion of liability (Note 7)	**11.5**	3.6
Long-term liability	**$ 14.6**	$ 11.4

During the year $5.2 million in cash payments were made to employees relating to the Whole Unit Plan ($1.6 million in 2005).

20. BASIC AND DILUTED PER TRUST UNIT CALCULATIONS

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

(thousands)	2006	2005
Weighted average trust units [1]	**201,554**	188,237
Trust units issuable on conversion of exchangeable shares [2]	**2,884**	2,935
Dilutive impact of rights [3]	**711**	1,372
Dilutive trust units and exchangeable shares	**205,149**	192,544

[1] Weighted average Trust units exclude 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 have been included in the diluted unit calculation for both 2006 and 2005.

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

21. COMMITMENTS AND CONTINGENCIES

Following is a summary of the Trust's contractual obligations and commitments as at December 31, 2006:

	Payments Due By Period				
	2007	2008-2009	2010-2011	Thereafter	Total
Debt repayments (1)	8.0	451.2	53.1	174.8	687.1
Interest payments (2)	11.3	21.5	18.1	20.8	71.7
Reclamation fund contributions (3)	6.0	11.1	9.5	76.2	102.8
Purchase commitments	12.6	8.4	3.4	6.8	31.2
Operating leases	5.3	9.9	5.0	–	20.2
Derivative contract premiums (4)	12.4	3.3	–	–	15.7
Retention bonuses	1.0	–	–	–	1.0
Total contractual obligations	56.6	505.4	89.1	278.6	929.7

(1) Long-term and short-term debt, excluding interest.
(2) Fixed interest payments on senior secured notes.
(3) Contribution commitments to a restricted reclamation fund associated with the Redwater property acquired in 2005.
(4) Fixed premiums to be paid in future periods on certain commodity derivative contracts.

The above noted derivative contract premiums are part of the Trust's commitments related to its risk management program. In addition to the above premiums, the Trust has commitments related to its risk management program (see Note 11). As the premiums are part of the underlying derivative contract, they have been recorded at fair market value at December 31, 2006 on the balance sheet as part of commodity and foreign currency contracts.

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 2007 capital budget has been approved by the Board at $360 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.

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 and therefore the following table does not include any commitments for outstanding litigation and claims.

The Trust has certain sales contracts with aggregators whereby the price received by the Trust is dependent upon the contracts entered into by the aggregator. 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.

22. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The consolidated financial statements have been prepared in accordance with Canadian GAAP, which differs in some respects from US GAAP. Any differences in accounting principles as they pertain to the accompanying consolidated financial statements are immaterial except as described below:

The application of US GAAP would have the following effect on net income as reported for the twelve months ended December 31, 2006 and 2005.

	2006	2005
Net income as reported for Canadian GAAP	$ 460.1	$ 356.9
Adjustments:		
Depletion and depreciation (a)	15.8	15.6
Unit based compensation (b)	(1.6)	(7.3)
Non-controlling interest (d)	6.6	5.6
Effect of applicable income taxes on the above adjustments (h)	(0.3)	(5.3)
Net income under US GAAP before cumulative catch-up adjustment related to change in accounting policy	$ 480.6	$ 365.5
Cumulative catch-up adjustment related to change in accounting policy under SFAS 123R (b)	(2.6)	–
Net income under US GAAP	478.0	365.5
Net income per Trust unit (Note 20)		
Before cumulative catch-up adjustment related to change in accounting policy		
Basic (e)	$ 2.35	$ 1.91
Diluted (e)	$ 2.34	$ 1.90
After cumulative catch-up adjustment related to change in accounting policy		
Basic (e)	$ 2.34	$ 1.91
Diluted (e)	$ 2.33	$ 1.90
Comprehensive income:		
Net income under US GAAP	$ 478.0	$ 365.5
Unrealized gain (loss) on derivative instruments, net of applicable income taxes (c)	4.5	1.6
Comprehensive income (c)	$ 482.5	$ 367.1

The application of US GAAP would have the following effect on the consolidated balance sheets as reported:

	2006		2005	
	Canadian GAAP	US GAAP	Canadian GAAP	US GAAP
Property, plant and equipment (a)	$ 3,093.8	$ 2,977.0	$ 2,930.0	$ 2,797.4
Commodity and foreign currency contracts (c)	(8.7)	(3.5)	(4.1)	(5.3)
Trust Unit Rights Liability (b)	–	(3.6)	–	–
Future income taxes (h)	(434.2)	(412.3)	(515.9)	(491.8)
Non-controlling interest (d)	(40.0)	–	(37.5)	–
Temporary equity (b), (d), (f), (g)	–	(3,822.1)	–	(5,078.0)
Unitholders' capital (g)	(2,349.2)	–	(2,230.8)	–
Contributed surplus (b), (f)	(2.4)	–	(6.4)	–
Deficit (g)	463.2	1,990.7	439.1	3,351.3
Accumulated other comprehensive loss (gain) (c)	–	(3.7)	–	0.8

The above noted differences between Canadian GAAP and US GAAP are the result of the following:

(a) The Trust performs an impairment test that limits net capitalized costs of property, plant and equipment to the discounted estimated future net revenue from proved and risked probable oil and natural gas reserves plus the cost of unproved properties less impairment, using forward prices. For Canadian GAAP the discount rate used must be equal to a risk free interest rate. Under US GAAP, companies using the full cost method of accounting for oil and gas producing activities perform a ceiling test on each cost centre using discounted estimated future net revenue from proved oil and gas reserves using a discount rate of 10 per cent. Prices used in the US GAAP ceiling tests are those in effect at year-end. The amounts recorded for depletion and depreciation have been adjusted in the periods following the additional write-downs taken under US GAAP to reflect the impact of the reduction of depletable costs.

(b) On January 1, 2006 the Trust adopted Statement of Accounting Standards ("SFAS") 123R, "Share-Based Payment" using the modified prospective application of this standard and adopted the fair value method of accounting for the Rights Plan for all rights granted under the plan.

Previously, under US GAAP, the Rights Plan was accounted for as a variable award under APB 25 and was intrinsically valued at each reporting period. Under SFAS 123R, rights granted under the Rights Plan are considered liability awards and must be fair valued at each reporting date. As a result of this change, the Trust recorded $2.6 million to cumulative effect of a change in accounting policy which represented the difference between the intrinsic value of the plan at December 31, 2005 and the fair value at January 1, 2006. The Trust also recorded a trust unit rights liability of $16.5 million and an increase to the deficit of $13.9 million, representing the fair value of all outstanding rights in proportion to the requisite service period rendered at January 1, 2006 and the previously recognized compensation expense for all outstanding rights, respectively.

Changes in fair value between periods are charged or credited to net income with a corresponding change in the trust unit rights liability.

Under Canadian GAAP, the Rights Plan is treated as an equity award with the initial fair value calculated upon grant date. The fair value is then recorded to compensation expense and credited to contributed surplus over the vesting period of the rights. Upon any rights exercises, the fair value recorded in contributed surplus is reclassified to unitholders' capital.

The Trust's Whole Unit Plan is also accounted for in accordance with FAS 123R. Under Canadian GAAP the plan is intrinsically valued. There is, however, no US GAAP difference as terms of the plan result in the fair value of the plan equaling the intrinsic value.

(c) US GAAP requires that all derivative instruments (including derivative instruments embedded in other contracts), as defined, be recorded on the consolidated balance sheet as either an asset or liability measured at fair value and requires that changes in fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Hedge accounting treatment allows unrealized gains and losses to be deferred in other comprehensive income (for the effective portion of the hedge) until such time as the forecasted transaction occurs, and requires that a company formally designate, document, and assess the effectiveness of derivative instruments that receive hedge accounting treatment. Under Canadian GAAP, derivative instruments that meet these specific hedge accounting criteria are not recorded on the consolidated balance sheet. In addition, unrealized gains and losses on effective hedges are not recorded in the financial statements. The Trust formally documented and designated all hedging relationships and verified that its hedging instruments were effective in offsetting changes in actual prices and rates received by the Trust. Hedge effectiveness is monitored and any ineffectiveness is reported in the consolidated statement of income.

US GAAP requires that financial instruments be carried at fair value in the financial statements. The Trust carries its reclamation fund assets at the lower of cost and market as described in Canadian GAAP. At December 31, 2006 the carrying value and fair value of the reclamation fund assets varied by a nominal amount.

A reconciliation of the components of accumulated other comprehensive income related to all derivative positions is as follows:

	2006		2005	
	Gross	**After Tax**	Gross	After Tax
Accumulated other comprehensive loss, beginning of year	**$ (1.2)**	**$ (0.8)**	$ (3.6)	$ (2.4)
Reclassification of net realized gains into earnings	**(2.9)**	**(2.1)**	(0.8)	(0.5)
Net change in fair value of derivative instruments	**9.3**	**6.6**	3.2	2.1
Accumulated other comprehensive gain (loss), end of year	**$ 5.2**	**$ 3.7**	$ (1.2)	$ (0.8)

(d) Under Canadian GAAP, ARL Exchangeable Shares are classified as non-controlling interest to reflect a minority ownership in one of the Trust's subsidiaries. As these exchangeable shares must ultimately be converted into Trust Units, the exchangeable shares are classified as temporary equity along with the Trust Units for US GAAP purposes using the exchange ratio.

(e) Under Canadian GAAP, basic net income per unit is calculated based on net income after non-controlling interest divided by weighted average trust units and diluted net income per unit is calculated based on net income before non-controlling interest divided by dilutive trust units. Under US GAAP, as the exchangeable shares are classified in the same manner as the trust units with no non-controlling interest treatment, basic net income per unit is calculated based on net income divided by weighted average trust units and the trust unit equivalent of the outstanding exchangeable shares. Concurrently, diluted net income per unit is calculated based on net income divided by a sum of the weighted average trust units, the trust unit equivalent of the outstanding exchangeable shares, and the dilutive impact of rights.

(f) Under Canadian GAAP, compensation expense relating to the Rights Plan is credited to contributed surplus. In the current year for US GAAP purposes all amounts credited to contributed surplus are classified as trust unit rights liability. In prior year, because the plan was accounted for as an equity award under US GAAP, contributed surplus was classified as temporary equity.

(g) Under US GAAP, as the Trust Units are redeemable at the option of the unitholder, the Trust Units must be recorded at their redemption amount and presented as temporary equity in the consolidated balance sheet. The redemption amount is determined with reference to the trading value of the Trust Units and the Trust Unit equivalent of the exchangeable shares at each balance sheet date. Under Canadian GAAP, all Trust Units are classified as permanent equity. As at December 31, 2006 and 2005, the Trust has classified $3.8 billion and $5.1 billion, respectively, as temporary equity in accordance with US GAAP. Changes in redemption value between periods are charged or credited to deficit. For the years ended 2006 and 2005, $1.4 billion was credited and $1.4 billion was charged, respectively.

(h) Relates to the future income tax effect of all US GAAP adjustments made on the income statement.

(i) In 2006 and 2005, the FASB and the CICA issued new and revised standards, all of which were assessed by Management to be not applicable to the Trust with the exception of the following:

- In June 2006, the FASB issued Interpretation No. 48, Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109 (FIN 48). This interpretation prescribes a more likely than not recognition threshold and a measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 also provides guidance on de-recognition of a tax position, classification of a liability for unrecognized tax benefits, accounting for interest and penalties, accounting in interim periods, and expanded income tax disclosures. FIN 48 is effective for fiscal years beginning after December 15, 2006. The Trust is currently evaluating the impact of this interpretation on its financial statements.

- In September 2006, the SEC staff issued Staff Accounting Bulletin No. 108 (SAB 108) in order to address the observed diversity in quantification practices with respect to annual financial statements. In SAB 108, the SEC staff establishes an approach that requires quantification of financial statement errors based on the effects of the error on each of the Trust's financial statements and the related financial statement disclosures. This model is commonly referred to as a "dual approach" because it essentially requires quantification of errors under both the "iron curtain" and the "roll-over methods". The iron curtain method focuses primarily on the effect of correcting the period-end balance sheet with less emphasis on the reversing effects of prior year errors on the income statement in the period of correction. The roll-over method focuses primarily on the impact of a misstatement on the income statement, including the reversing effect of prior year misstatements, but can lead to the accumulation of misstatements in the balance sheet. The provisions of SAB 108 are effective for the first year ending after November 15, 2006. The Trust's 2006 annual financial statements have not been impacted by this bulletin.

- In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements, to increase consistency and comparability in fair value measurements and to expand their disclosures. The new standard includes a definition of fair value as well as a framework for measuring fair value. The standard is effective for fiscal periods beginning after November 15, 2007 and should be applied prospectively, except for certain financial instruments where it must be applied retrospectively as a cumulative-effect adjustment to the balance of opening retained earnings in the year of adoption. The Trust is currently evaluating the impact of this standard on its financial statements.

- In February 2006, the FASB issued SFAS No.155, Accounting for Certain Hybrid Financial Instruments. This standard is effective for all financial instruments acquired or issued after January 1, 2007. Among other things, SFAS No. 155 simplifies the accounting for certain hybrid financial instruments by permitting fair value accounting for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation. The Trust is currently evaluating the impact of this standard on its financial statements.

- In January 2005, the CICA approved Handbook Sections 3855, 3861, 3862, 3863, "Financial Instruments", 3865, "Hedges" and 1530, "Comprehensive Income". The new standard is intended to harmonize Canadian GAAP with US GAAP. The new standard is effective for the Trust in the first quarter of 2007 and the Trust is currently evaluating the impact of this standard on its financial statements.

Officers and Senior Management

John P. Dielwart, B.Sc., P.Eng.

Mr. Dielwart is **President and Chief Executive Officer** of ARC Resources Ltd. and has overall management responsibility for the Trust. Prior to joining ARC in 1994, Mr. Dielwart spent 12 years with a major Calgary based oil and natural gas engineering consulting firm, as senior vice-president and a director, where he gained extensive technical knowledge of oil and natural gas properties in western Canada. He began his career working for five years with a major oil and natural gas company in Calgary. Mr. Dielwart is a Past-Chairman of the board of governors for the Canadian Association of Petroleum Producers (CAPP). He holds a Bachelor of Science with Distinction (Civil Engineering) degree, University of Calgary. He has also been a director of ARC since 1996.

Steven W. Sinclair, B. Comm., CA

Mr. Sinclair is **Senior Vice-President Finance and Chief Financial Officer** of ARC Resources Ltd. and oversees all of the financial and marketing affairs of ARC Energy Trust. Mr. Sinclair has a Bachelor of Commerce from the University of Calgary, obtained his Chartered Accountant's designation in 1981 and has over 20 years experience within the finance, accounting and taxation areas of the oil and gas industry. Mr. Sinclair has been with the Trust since 1996.

Myron M. Stadnyk, P.Eng.

Mr. Stadnyk is **Senior Vice-President and Chief Operating Officer** of ARC Resources Ltd. and is responsible for all aspects of ARC's ongoing operational and production management and strategies. He has 22 years experience in the oil and gas business. Prior to joining ARC Resources Ltd. in 1997, Mr. Stadnyk worked with a major oil and gas company in both domestic and international operations. He has a B.Sc. in Mechanical Engineering from the University of Saskatchewan and is a member of the Association of Professional Engineers in Alberta, British Columbia and Saskatchewan.

Doug J. Bonner, P.Eng.

Mr. Bonner is **Senior Vice-President, Corporate Development** of ARC Resources Ltd. and is responsible for the strategic development and expansion of ARC's assets. He holds a B.Sc. in Geological Engineering from the University of Manitoba. Mr. Bonner's major area of expertise is reservoir engineering and he has extensive technical knowledge of oil and natural gas fields throughout western Canada, the east coast and northern Canada. Prior to joining ARC in 1996, Mr. Bonner spent 18 years with various major oil and natural gas companies in positions of increasing responsibility.

David P. Carey, P.Eng., MBA

Mr. Carey is **Senior Vice-President, Capital Markets** of ARC Resources Ltd. and is responsible for all facets of investor relations and corporate governance. He holds both a B.Sc. in Geological Engineering and a MBA from Queen's University. Mr. Carey has over 20 years of diverse experience in the Canadian and International energy industries covering exploration, production and project evaluations in western Canada, oilsands, the Canadian frontiers and internationally. Prior to joining ARC Resources in 2001, Mr. Carey held senior positions with Athabasca Oil Sands Investments Inc. and a major Canadian oil and gas company.

Susan D. Healy, P. Land

Ms. Healy is **Senior Vice-President, Corporate Services** of ARC Resources Ltd. and oversees all human resources, information technology and office services related activities. Ms. Healy joined the Trust at inception in July 1996, bringing with her over 17 years of diverse experience gained from working with junior and senior oil and gas companies.

Terry M. Anderson, P.Eng.

Mr. Anderson is **Vice-President, Operations** of ARC Resources Ltd. and is responsible for all of ARC's operational activities. He has a B.Sc. in Petroleum Engineering and is a member of the Association of Professional Engineers in Alberta, Saskatchewan and British Columbia. Mr. Anderson has 13 years of experience in drilling, completion, pipeline, facility and production operations. Prior to joining ARC in 2000, he worked at a major oil and gas company.

Yvan Chretien, B.Comm.

Mr. Chretien is **Vice-President, Land** of ARC Resources Ltd. and is responsible for all of ARC's land related activities. He has 16 years of land related experience. Prior to joining ARC in 2001, Mr Chretien worked for both senior and intermediate oil and gas companies.

Ingram B. Gillmore, P.Eng.

Mr. Gillmore is **Vice-President, Engineering** of ARC Resources Ltd. and is responsible for all of ARC's engineering, geophysical, geological and joint venture related activities. He holds a B.Sc. in Chemical engineering (1991) and a Bachelor of Fine Arts. Mr. Gillmore has been at ARC since 2002. Prior to joining ARC, Mr. Gillmore held positions with several major oil and gas companies. His varied experience includes working on and directing multifunctional teams growing both development and exploration oriented production across western Canada.

P. Van R. Dafoe, B. Comm., CMA

Mr. Dafoe is **Treasurer** of ARC Resources Ltd. and is responsible for all of ARC's Treasury related activities. He has a Bachelor of Commerce – Honours from the University of Manitoba and obtained his Certified Management Accountant's designation in 1995. Mr. Dafoe joined ARC in 1999 after 13 years with various companies in the finance and accounting area of the oil and gas industry.

Allan R. Twa, Q.C.

Mr. Twa acts as **Corporate Secretary** of ARC Resources Ltd. A member of the Alberta Bar since 1971, Mr. Twa is a partner in the law firm Burnet, Duckworth & Palmer LLP. Mr. Twa holds a B.A. (Political Science) from the University of Calgary, a LL.B. from the University of Alberta and a LL.M. from the University of London, England. Over the last 25 years, Mr. Twa has been engaged in a legal practice involving legal administration of public companies and trusts, corporate finance, and mergers and acquisitions.

Board of Directors

Fred C. Coles, B.Sc., P.Eng.

Mr. Coles is founder and President of Menehune Resources Ltd., having previously served as the Executive Chairman of Applied Terravision Systems Inc. to March 15, 2002. In his earlier career Mr. Coles worked as a reservoir engineer for a number of oil and gas companies, prior to undertaking the role of Chairman and President of an engineering consulting firm specializing in oil and gas. Mr. Coles also sits as a Director of a number of junior oil and gas companies and is a member of the Association for Professional Engineers, Geologists and Geophysicists of Alberta and the Canadian Institute of Mining, Metallurgy and Petroleum. Mr. Coles has been a Director of ARC since 1996.

Walter DeBoni, P.Eng., MBA

Mr. DeBoni recently retired from Husky Energy Inc. where he held the position of VP, Canada Frontier & International Business. Prior to this Mr. DeBoni was CEO of Bow Valley Energy for a number of years. In addition to his time at Husky and Bow Valley he has also held numerous top executive posts in the oil and gas industry with major corporations. Mr. DeBoni holds a B.A.Sc. Chem. Eng. from the University of British Columbia, a MBA degree with a major in Finance from the University of Calgary and is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and the Society of Petroleum Engineers. He is a past Chairman of the Petroleum Society of CIM, a past Director of the Society of Petroleum Engineers and has been a Director of ARC Resources since 1996.

John P. Dielwart, B.Sc., P.Eng.

Mr. Dielwart is President and CEO of ARC Resources Ltd. and has overall management responsibility for the Trust. Prior to joining ARC in 1994, Mr. Dielwart spent 12 years with a major Calgary based oil and natural gas engineering consulting firm, as senior vice-president and a director, where he gained extensive technical knowledge of oil and natural gas properties in Western Canada. He began his career working for five years with a major oil and natural gas company in Calgary. Mr. Dielwart is a Past-Chairman of the board of governors for the Canadian Association of Petroleum Producers (CAPP). He holds a Bachelor of Science with Distinction (Civil Engineering) degree, University of Calgary. He has also been a director of ARC since 1996.

Fred Dyment

Mr. Dyment has 30 years experience in the oil and gas business and is currently an independent businessman. His past business career included positions as President and CEO for Maxx Petroleum and President and CEO of Ranger Oil Limited. Mr. Dyment received a Chartered Accountant designation from the province of Ontario in 1972. Mr. Dyment currently sits as a Director on the Boards of Tesco Corporation, Western Oil Sands and ZCL Composites Inc. He has been a Director of ARC since 2003.

Michael M. Kanovsky, B.Sc., P.Eng., MBA

Mr. Kanovsky graduated from Queen's University and the Ivey School of Business. Mr. Kanovsky's business career included the position of VP of Corporate Finance with a major Canadian investment dealer followed by co-founding Northstar Energy Corporation and PowerLink Corporation (electrical cogeneration) where he served as Senior Executive Board Chairman and Director. Mr. Kanovsky is a Director of Bonavista Petroleum Inc. and Devon Energy Corporation. He has been a Director of ARC since 1996.

Herb Pinder, B.Arts, LL.B., MBA

Mr. Pinder has gained extensive experience as a director on various public company boards over the last twenty years. As a result he brings an extensive business background to ARC covering several industries and a broad knowledge of corporate governance. Currently, Mr. Pinder is the President of the Goal Group, a private equity management firm located in Saskatoon, Saskatchewan. He is a director of the Saskatchewan Wheat Pool and C1 Energy Ltd., as well as several private companies. Mr. Pinder also serves as a director of the C.D. Howe Institute and as a Trustee of the Fraser Institute. Mr Pinder became a director of ARC in 2006.

John M. Stewart, B.Sc., MBA

Mr. Stewart is a founder and Vice-Chairman of ARC Financial Corporation where he holds senior executive responsibilities focused primarily within the area of private equity investment management. He holds a B.Sc. in Engineering from the University of Calgary and a MBA from the University of British Columbia. Prior to ARC Financial, he was a Director and Vice-President of a major national investment firm. His career and experience span nearly thirty years with a focus on oil and gas and finance. Mr. Stewart has been a Director of ARC Resources Ltd. since 1996.

Mac H. Van Wielingen

Mr. Van Wielingen has served as a Director of ARC Resources Ltd. since its formation in 1996. He is Co-Chairman and a founder of ARC Financial Corporation. Previously Mr. Van Wielingen was a Senior Vice-President and Director of a major national investment dealer responsible for all corporate finance activities in Alberta. He has managed numerous significant corporate merger and acquisition transactions, capital raising projects and equity investments relating to the energy sector. Mr. Van Wielingen holds an Honours Business Degree from the University of Western Ontario Business School and has studied post-graduate Economics at Harvard University.

Corporate 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

Fred 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

P. Van R. Dafoe
Treasurer

Terry Anderson
Vice-President, Operations

Yvan Chretien
Vice-President, Land

Ingram Gillmore
Vice-President, Engineering

Allan R. Twa
Corporate Secretary

Executive Office

ARC Resources Ltd.
2100, 440 – 2nd Avenue S.W.
Calgary, Alberta T2P 5E9
Telephone: (403) 503-8600
Toll Free: 1-888-272-4900
Facsimile: (403) 503-8609
Website: www.arcenergytrust.com
E-Mail: ir@arcresources.com

Trustee And Transfer Agent

Computershare Trust Company of Canada
600, 530 – 8th Avenue S.W.
Calgary, Alberta T2P 3S8
Telephone: (403) 267-6800

Auditors

Deloitte & Touche LLP
Calgary, Alberta

Engineering Consultants

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

Legal Counsel

Burnet, Duckworth & Palmer LLP
Calgary, Alberta

Stock Exchange Listing

The Toronto Stock Exchange
Trading Symbols:
AET.UN (Trust Units)
ARX (Exchangeable Shares)

Investor Information

Visit our website at
www.arcresources.com
or 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

Unitholder Information

Notice of Annual Meeting

The annual meeting will be held on May 23, 2007 at 3:30pm at the Metropolitan Conference Centre, 333 - 4 Avenue SW, Calgary, Alberta.

Corporate Calendar 2007

May 8	First Quarter Financial Results
May 23	Annual General Meeting

Glossary

API	American Petroleum Institute
bbls	barrels
bbls/d	barrels per day
bcf	billion cubic feet
boe*	barrels of oil equivalent
boe/d*	barrels of oil equivalent per day
Capex	capital expenditures
FD&A	costs finding, development and acquisition costs
F&D	finding and development costs
FDC	future development costs
GAAP	generally accepted accounting principles
G&A	general and administrative
GJ	gigajoule
mbbls	thousand barrels
mboe*	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmbbls	million barrels
mmboe*	million barrels of oil equivalent
mmbtu	million British Thermal Units
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NAV	net asset value
NGC	natural gas from coal
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange
RLI	reserve life index
WTI	West Texas Intermediate

* Boes may be misleading, particularly if used in isolation. In accordance with NI 51-101, a boe conversion ratio for natural gas of 6 mcf:1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head.

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.

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.

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ARC ENERGY TRUST

Suite 2100, 440 - 2 Avenue SW
Calgary, Alberta, Canada T2P 5E9
1-888-272-4900 (403) 503-8600

www.arcenergytrust.com