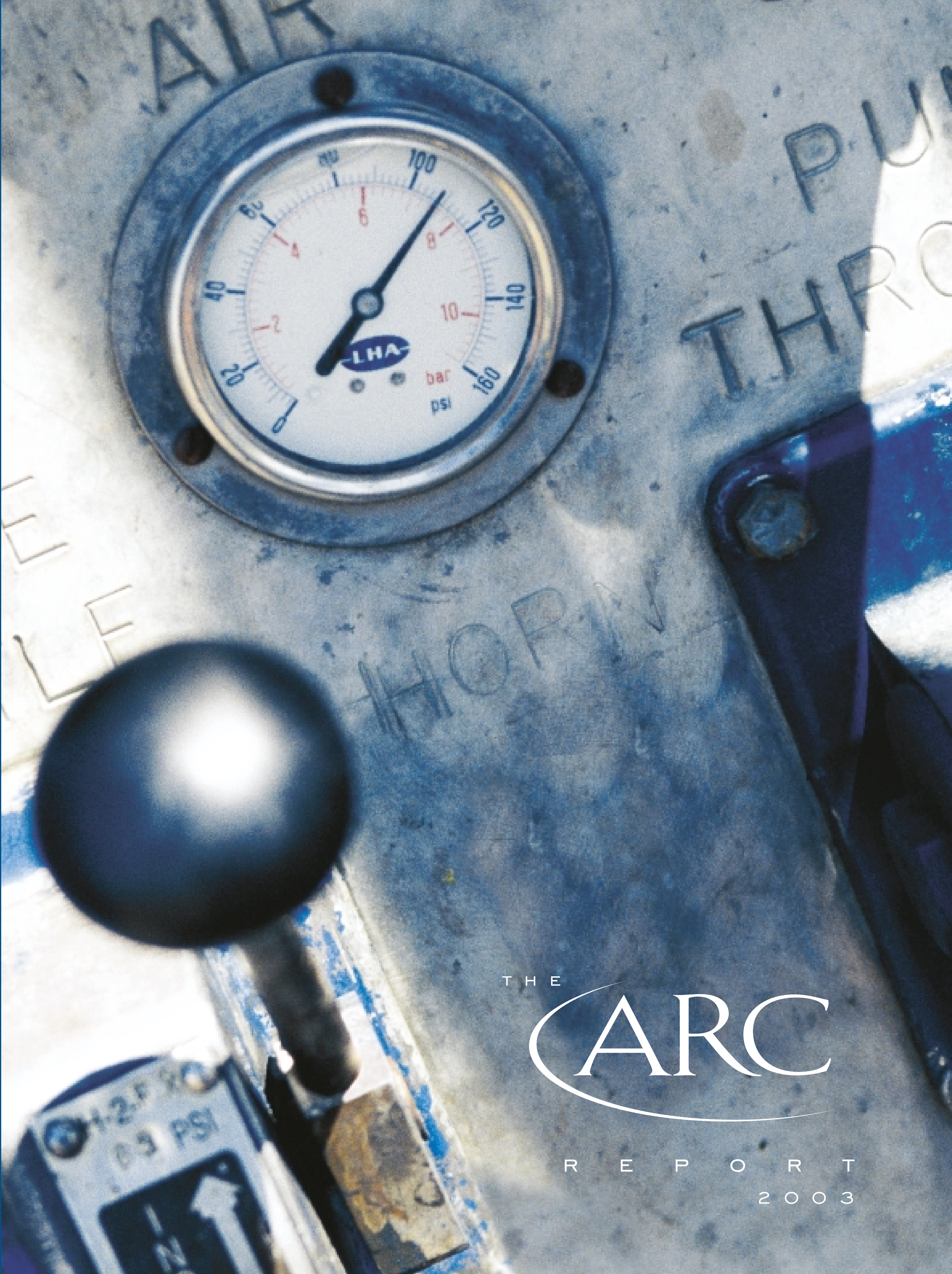
ARC ENERGY TRUST ANNUAL REPORT 2003



THE ARC REPORT 2003

ARC Energy Trust ("the Trust" or "ARC") is an actively managed royalty trust that acquires and develops long-life, lower-declining oil and gas properties. Our unitholders receive a monthly cash distribution through the Trust's royalty interest in cash generating oil and gas assets owned by ARC Resources Ltd.

The Trust has consistently outperformed the Royalty Trust Index, the TSE Composite Index and the TSE Producers Index. We have provided our unitholders with a 22.9 per cent compound annual return since our inception in 1996. Our total annual return in 2003 was 42.6 per cent. We remain committed to generating superior returns and long-term value.

Since inception, we have been consistent in our message and our mission: combine 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 company of individuals who have the skills required to manage and exploit our asset base for the benefit of our unitholders. The realization of our mission statement has resulted in the Trust being the second largest conventional oil and gas royalty trust as at December 31, 2003 and Canada's 13th largest publicly traded oil and gas producer.

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

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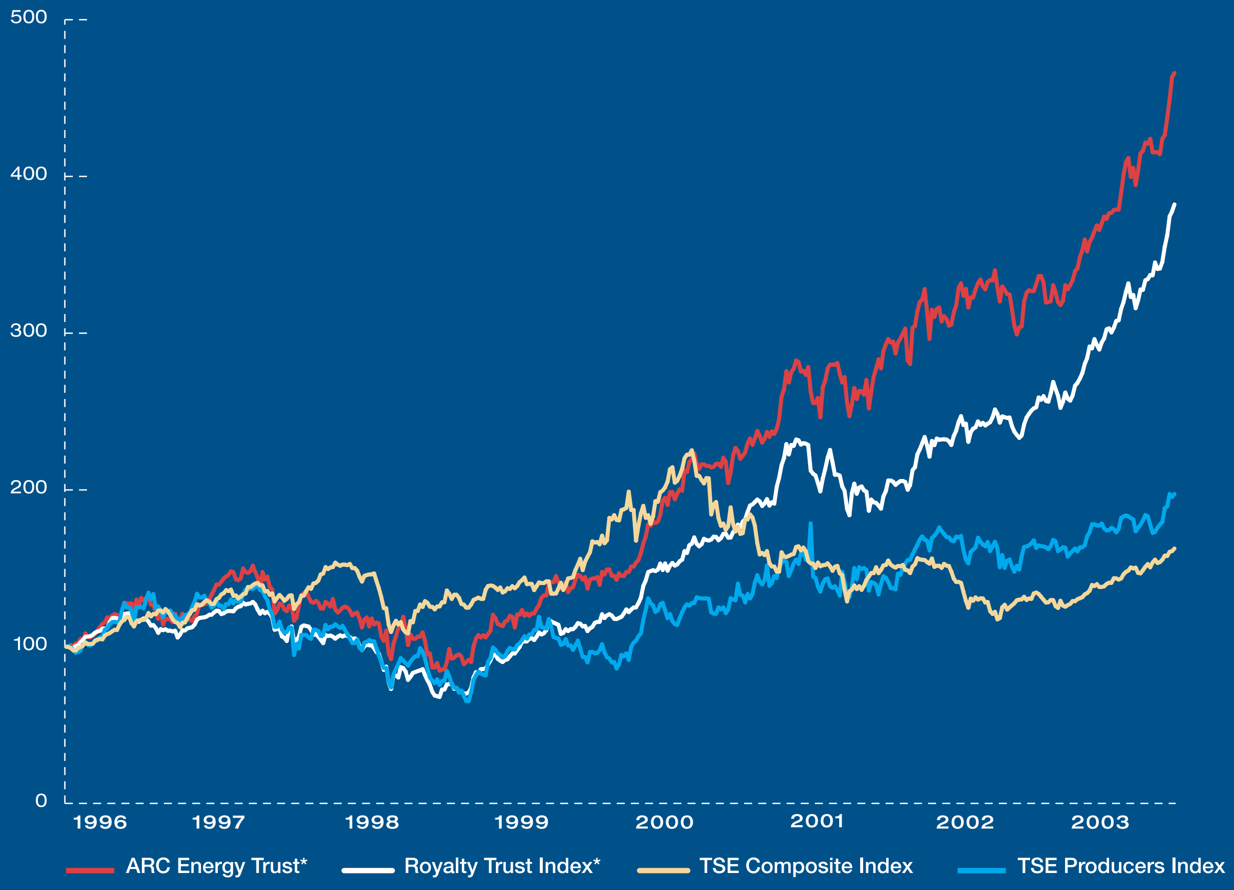
Total Return Performance Since Inception
(per cent)



* Source: ARC Energy Trust

• Total return performance includes the reinvesting of distributions.

FINANCIAL HIGHLIGHTS

Year ended December 31 ($ thousands, except per unit and volume amounts)		2003		2002
INCOME STATEMENT				
Revenue before royalties		**731,233**		444,835
Per unit (1)	**$**	**4.73**	$	3.72
Cash flow (7)		**396,180**		223,969
Per unit (1)	**$**	**2.56**	$	1.87
Net income (4)		**290,201**		71,047
Per unit (1)	**$**	**1.85**	$	0.59
Payout ratio (per cent) (6)		**71**		82
Cash distributions		**279,328**		183,617
Per unit (2)	**$**	**1.80**	$	1.56
Weighted average trust units and exchangeable shares (3)		**154,695**		119,613
Trust units outstanding and units issuable for exchangeable shares at end of period (3)		**182,777**		126,444
BALANCE SHEET				
Property, plant and equipment		**2,015,539**		1,424,291
Net debt outstanding		**262,071**		347,795
Unitholders' equity		**1,551,736**		880,751
NET DEBT AS A RATIO OF CASH FLOW		**0.7**		1.6
MARKET CAPITALIZATION AS AT DECEMBER 31		**2,694,133**		1,504,684
TOTAL CAPITALIZATION AS AT DECEMBER 31 (5)		**2,956,204**		1,852,479
TRUST UNIT TRADING				
Unit Prices ($)				
High	**$**	**14.87**	$	13.44
Low	**$**	**10.89**	$	11.04
Close	**$**	**14.74**	$	11.90
Daily average trading volume (thousands)		**430**		305

(1) Based on weighted average trust units and exchangeable shares.

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

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

(4) 2002 net income and net income per unit have been restated for the retroactive change in accounting policy for asset retirement obligations.

(5) Equity market capitalization plus net debt.

(6) Payout ratio is calculated as cash distributions divided by cash flow.

(7) Cash flow as presented throughout this report represents cash flow before changes in non-cash working capital. Cash flow does not have any standardized meaning under Canadian Generally Accepted Accounting Principles ("GAAP") and therefore may not be comparable with the calculation of similar measures or other entities.

OPERATIONAL HIGHLIGHTS

Year ended December 31		2003	2002
PRODUCTION			
Crude oil (bbl/d)		**22,886**	20,655
Natural gas (mmcf/d)		**164.2**	109.8
Natural gas liquids (bbl/d)		**4,086**	3,479
Total production (boe/d) (1)		**54,335**	42,425
TOTAL ANNUAL PRODUCTION (mboe) (1)		**19,832**	15,485
AS A PERCENTAGE OF TOTAL PRODUCTION			
Crude oil		**42%**	49%
Natural gas		**50%**	43%
Natural gas liquids		**8%**	8%
AVERAGE PRICES			
Crude oil ($/bbl)		**34.48**	31.63
Natural gas ($/mcf)		**6.21**	4.41
Natural gas liquids ($/bbl)		**32.19**	24.01
Oil equivalent ($/boe) (1)		**36.87**	28.73
RESERVES	**2003 Gross Reserves(2)**	**Company Interest Reserves(3)**	
PROVED			
Crude oil and natural gas liquids (mbbl)	**101,546**	**102,226**	96,267
Natural gas (bcf)	**587.0**	**600.0**	356.2
TOTAL OIL EQUIVALENT (mboe) (1)	**199,382**	**202,229**	155,634
PROVED PLUS PROBABLE (4)			
Crude oil and natural gas liquids (mbbl)	**128,871**	**129,663**	117,241
Natural gas (bcf)	**705.6**	**720.2**	408.8
TOTAL OIL EQUIVALENT (mboe) (1)	**246,468**	**249,704**	185,371
OPERATING COSTS			
Total		**140,734**	99,876
Per boe ($)		**7.10**	6.45
GENERAL & ADMINISTRATIVE COSTS			
Total		**22,566**	15,365
Per boe ($)		**1.14**	0.99
FINDING, DEVELOPMENT & ACQUISITION COSTS ($/boe) (5)			
Including Future Development Capital (6)			
Current year		**10.54**	10.79
Three-year average		**10.52**	9.46
Excluding Future Development Capital (7)			
Current year		**8.50**	9.27
Three-year average		**9.07**	8.21

(1) Natural gas is converted to barrels of oil at 6 mcf gas to 1 bbl oil throughout this report. BOEs may be misleading, particularly if used in isolation. A BOE conversion of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head.

(2) Working interest reserves not including royalties receivable and before royalties payable.

(3) Working interest reserves including royalties receivable and before royalties payable.

(4) For 2002, reserve numbers are established reserves (proved reserves plus one-half probable reserves) before royalties.

(5) Based on proved plus probable company interest reserves before royalties for 2003 and established company interest reserves before royalties for 2002 and prior years.

(6) Includes net change in future development capital as defined in NI 51-101.

(7) Excludes net change in future development capital to permit comparisons to prior years' results.

In all cases where there is a reference to reserves in this annual report, the reference is to Company Interest Reserves (gross reserves plus royalties receivable) unless otherwise specifically stated.


John Dielwart, President and Chief Executive Officer


John Dielwart, President and Chief Executive Officer
Gayle Cosgrove, Executive Assistant to the President and Chief Executive Officer

MESSAGE TO UNITHOLDERS

ARC Energy Trust ("ARC" or "the Trust") had an extremely eventful year in 2003. A combination of strong commodity prices, the largest acquisition ever completed by ARC (Star Oil and Gas Ltd. ("Star")) and excellent drilling results contributed to a record year for the Trust. ARC attained historic highs in its unit price; record production, revenue and cash flow; and significantly strengthened its balance sheet during the year with a year-end debt to cash flow ratio of 0.7 times.

Most importantly, 2003 marked the completion of a strategic transformation of the Trust. Since 2001, the Trust has evolved from a primarily acquisition company to one with a large inventory of internal development opportunities capable of sustaining production for an extended period of time without acquisitions. When ARC acquired Startech Energy Inc. ("Startech") in 2001, our inventory of development opportunities expanded dramatically. More importantly, the staff who joined ARC from Startech significantly strengthened our technical team, especially in the areas of geology and geophysics. This allowed us to pursue new opportunities for the development of our asset base and to make larger value adding acquisitions for the Trust. As a result, 2002 was a year in which we significantly expanded our drilling activities, particularly in Ante Creek where we developed a tight Triassic Montney oil reservoir with great success. Heading into 2003, the Trust's capital budget for internal development projects was set at a record $115 million that was expected to maintain production at a level just below that achieved in 2002.

Early in 2003, Star became available for acquisition and ARC pursued this very unique opportunity. Star was a gas focused company with an intriguing combination of mature and very immature properties with significant further development potential. Given the size of Star (approximately 22,000 boe/d of production), a limited number of companies had the size and financial capacity to pursue the opportunity. As a result, competition was restricted and ARC's technical expertise in Star's two main operating areas gave us a unique advantage in evaluating the assets. A key property gained in the acquisition was Dawson in northeast British Columbia. Dawson has an estimated 800 billion cubic feet of original gas-in-place in the tight Triassic Montney formation underlying lands in which ARC now owns virtually a 100 per cent interest. ARC's knowledge and experience in Ante Creek (also a tight Montney formation) was crucial to our assessment of the potential of the Dawson property. Although it is still highly uncertain what the ultimate recovery of the large natural gas resource in Dawson will be, ARC and its independent evaluator have only recognized a 14 per cent proved reserve recovery for the property. We are confident that the ultimate recovery will significantly exceed this level following ongoing development of the field.

The other key Star property was the Hatton area (which includes Horsham and Crane Lake) in southwest Saskatchewan. Prior to the Star acquisition, ARC's main natural gas producing areas were Brooks and Jenner in southeast Alberta through which ARC had developed significant shallow gas operating expertise. Hatton is a similar operating area east of Jenner in Saskatchewan. The drilling density on the Hatton area lands is roughly half of that of other operators in the area. ARC identified up to 1,000 potential infill drilling locations on Star's Hatton area lands, only a small component of which were included in our evaluation at the time of the acquisition. It is our expectation that most, if not all, of these wells will ultimately be drilled and will add significant value over time.

A wild card in the Star acquisition is the Prestville property in northwest Alberta. Star drilled a discovery well into a new Slave Point light oil reservoir just prior to completion of the acquisition. Follow-up drilling in 2003 by ARC has resulted in partial delineation of a very prolific reservoir with three wells. These wells are capable of producing 600 to 800 barrels per day of oil each with minimal pressure drawdown, which indicates much higher production rates could be achieved under normal operating pressures. In excess of 10 per cent of our 2004 budget will be directed to more fully delineating and understanding this potentially significant new property.

The combination of Star's undeveloped properties and existing opportunities on ARC's pre-Star lands has resulted in the largest inventory of development opportunities in the Trust's history. Also of significance is the fact that Star had an excellent technical team which, combined with ARC's existing staff, will allow us to pursue these opportunities. Post-completion of the Star acquisition, ARC's 2003 capital expenditures grew to $156 million while our budget for 2004 has been set at a record $175 million excluding acquisitions. The 2004 capital expenditures are forecast to result in production levels at or above those achieved in 2003 being maintained throughout 2004. Significant further development opportunities have already been identified for 2005 on our existing lands. It is with this outlook for the next two years that the strategic transformation to an internal development focused trust supplemented by strategic, opportunistic acquisitions has been achieved. This makes ARC one of only a few trusts in the sector with this capability.

National Instrument 51-101

Effective September 30, 2003, The Alberta Securities Commission implemented new reserve reporting guidelines for all publicly traded oil and gas producers. The new guidelines known as National Instrument 51-101 ("NI 51-101") standardize disclosure requirements for all reporting issuers involved in upstream oil and gas activities. The goal of NI 51-101 is to increase public and investor confidence in the reserves information reported by public companies and to harmonize the reporting format. The new reporting format will allow investors to more readily understand the assets of the company and facilitate comparisons to other companies. Under the new guidelines, reserves reporting is more specific and subject to more strictly defined reserves definitions for proved and probable categories. One of the most notable changes under NI 51-101 is the redefinition of probable reserves to now reflect risk such that the "proved plus probable" category is now characterized as the "best estimate" of reserves and in ARC's view is essentially equivalent to prior years' "established" reserves.

Despite the more stringent requirements of NI 51-101, ARC achieved positive reserve revisions of 4.2 per cent and 6.2 per cent in the proved and proved plus probable reserve cases, respectively. In doing so, ARC recorded the seventh consecutive year in which the Trust has recorded positive reserve revisions; we remain the only trust to achieve this feat.

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

The cost structure for all oil and gas companies operating in Canada has been rising steadily for the past number of years. Most significantly, FD&A costs for 2003 are expected to be at the highest level ever for our industry. ARC has been able to buck this trend. After completing the largest acquisition in our history, as well as executing the largest development capital budget in our history, ARC's all in FD&A costs for 2003 were $8.50 per barrel of oil equivalent ("boe") for proved plus probable reserves using historic definitions for FD&A costs, which is eight per cent lower than our FD&A costs of $9.27 per boe in 2002.

All oil and gas reporting issuers in Canada must now report their reserves using the new NI 51-101 guidelines under which the method for calculating finding and development costs ("F&D") has changed compared to prior years. The new F&D calculation includes all future development capital required to bring the proved undeveloped and probable reserves to production. For a trust, FD&A is a more relevant measure, therefore ARC has chosen to report FD&A costs. ARC's annual FD&A costs are $10.54/boe for 2003 on a proved plus probable basis, down slightly from $10.79/boe in 2002 on an established basis. The calculation takes into account the reserves added through development activity (additions and revisions) and acquisitions, as well as the capital for these activities and all future development capital. At the time of writing this report, numerous companies had not yet reported their year-end reserves and FD&A costs. However, indications are that ARC's costs will be among the lowest in the industry.

Balance Sheet Strength

The Trust's capital expenditures in 2003 were a record $716 million which include $156 million in development expenditures and $560 million in net acquisitions. The development capital expenditures were funded 68 per cent ($107 million) out of cash flow and the balance with debt. The Trust also issued $640 million in new equity net of issuance costs that was used to fund the net acquisitions and reduce debt. As a result, the Trust's year-end debt was reduced to $262 million ($348 million at year-end 2002), which represented nine per cent of total capitalization (19 per cent in 2002) and a debt to cash flow ratio of 0.7 times (1.6 times in 2002). Therefore, despite the largest capital program in the Trust's history, we were able to significantly strengthen our balance sheet during 2003. As a result, the Trust is well positioned to pursue opportunities which may arise in 2004.

2004 Outlook

ARC will have another very busy year in 2004. Our $175 million capital development program will see us continue the development activity in the core areas acquired from Star, specifically in Hatton and Dawson. Development activities will also continue in all ARC's core areas. ARC plans further activity in the Prestville area as it develops the Cranberry Slave Point D Pool based on new data acquired through a 3-D seismic program being conducted during the first quarter of 2004. As Prestville is primarily a winter access area, future drilling activity will begin during the fourth quarter of 2004 and continue into the first quarter of 2005.

It is expected that competition for quality assets will remain high in 2004. At the end of 2003, there were 26 oil and gas trusts competing for assets in the acquisition market. It is of great benefit to ARC to maintain its production through internal development activities in 2004, thereby allowing it to be very selective in the acquisition market. Without the need to complete an acquisition, ARC can focus on opportunities that will enhance our portfolio of high quality properties without the pressure of having to compete in an over-heated acquisition market to maintain production at current levels.

It is expected that commodity prices will continue to be volatile in 2004. Oil inventories experienced a significant drawdown in the fourth quarter of 2003 primarily due to economic activity driven demand growth and cold weather. Rebuilding of stocks in 2004 will be largely dependent on the extent of Iraq's export recovery, activities in the oil industry in Russia, OPEC's discipline and the severity of the winter season. The forward market prices remain strong at the time of this writing and most analysts have recently raised forecast prices for WTI in recognition of the continued high price environment. A greater impact on our industry could be driven by a further elevated Canadian/U.S. dollar exchange rate. Analysts are forecasting a higher Canadian dollar for 2004. Though the price of oil may remain high, a stronger Canadian dollar will decrease revenues for oil and gas producers on a per barrel basis.

Natural gas prices are weather dependent, with the first six to eight weeks of the winter season typically setting the course for natural gas prices for the year. The moderating trend on natural gas prices was broken in mid-fourth quarter of 2003 with the onset of cold weather in key northeast U.S. markets. Withdrawals from storage were at high levels from December 2003 through February 2004 as a result of cold temperatures and greater industrial activity due to economic recovery in the United States. Analysts have also increased forecasts for the gas price for 2004 and the industry in general predicts that natural gas prices will stay relatively robust in 2004.

ARC will continue to manage its distributions through an active hedging program and a conservative distribution policy to enhance long-term returns to unitholders. A combination of an excellent management team, among the best technical expertise in our sector and a disciplined approach to acquisitions should result in continued strong returns for our unitholders.

John P. Dielwart

President and Chief Executive Officer

February 4, 2004

Myron Stadnyk, V.P. Operations

OPERATIONS REVIEW

The Star acquisition provided ARC with numerous development opportunities and as a result, 2003 proved to be the busiest year for drilling activity in ARC's history. The Star assets are relatively underdeveloped and hence opportunity rich. ARC's expanded technical team immediately assessed the areas, evaluated the opportunities and prepared a development program. ARC's existing assets and core areas also continued to have numerous opportunities and were the subject of ongoing development and optimization activities in 2003. In the second and third quarters of 2003, ARC carried out its largest shallow gas drilling program ever in southeast Alberta and southwest Saskatchewan. After the Star purchase, ARC's Board approved an increase in the 2003 capital development budget to $150 million – the largest in ARC's history. The high level of activity experienced in 2003 will continue into 2004 with a $175 million capital development budget approved by the Board. Drilling and development activities will continue in all of ARC's core areas.

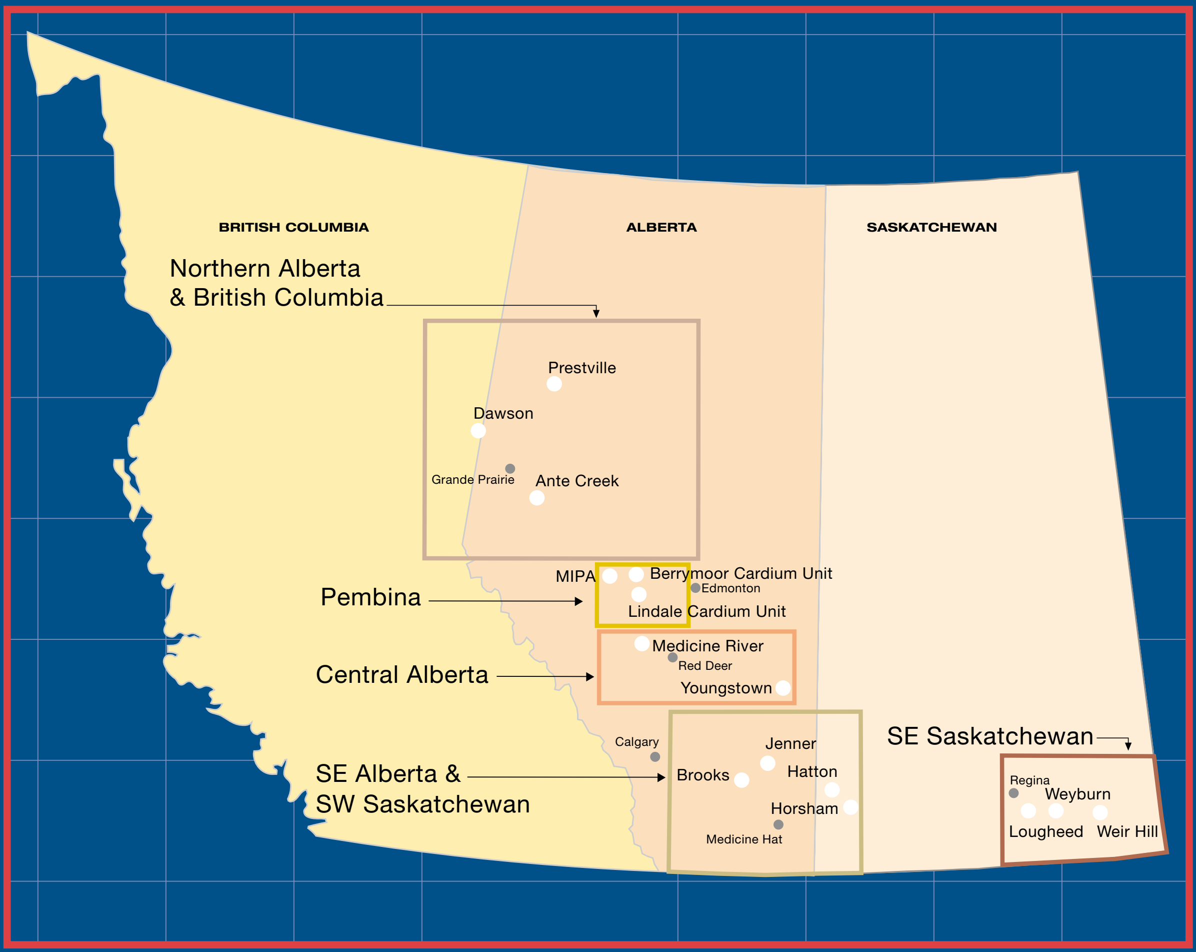
ARC once again experienced upward pressure on operating costs in 2003. The increased costs were associated with record high activity levels for the overall industry as a result of strong commodity prices and record high industry cash flow. Operating costs increased by 10 per cent in 2003 to $7.10 per boe from $6.45 per boe in 2002. This increase was primarily due to the impact of higher power costs in Alberta and increases in well service and work-over costs. These increases are consistent with those being experienced throughout the oil and gas industry. ARC strives to keep operating costs at their lowest level possible and consistently monitors costs on all of its properties.

ARC had a very successful year in 2003 with reserve additions of 84 mmboe prior to production, replacing 424 per cent of the 19.8 mmboe of production at an average FD&A cost of $8.50 per boe, excluding future development capital ("FDC") for proved plus probable reserves. Under the new NI 51-101 reserve definitions, proved plus probable reserves are considered to be the "best estimate" of reserves and are therefore essentially comparable to established reserves quoted in prior years. Using definitions that include FDC, the annual FD&A cost was $10.54 per boe. On a three year rolling average basis, FD&A costs are $9.07 per boe excluding FDC for proved plus probable reserves and $10.52 per boe including FDC. These reserve replacement costs continue to be among the lowest in the industry.

Excluding net acquisitions, finding and development ("F&D") costs were $10.19 per boe on an annual basis excluding FDC for proved plus probable reserves and $12.06 per boe including FDC. On a three year rolling average basis, F&D costs are $10.49 per boe, excluding FDC for proved plus probable reserves and $11.97 per boe including FDC.

Production volumes increased 28 per cent in 2003 to an average of 54,335 boe/d compared to 42,425 boe/d in 2002. The increase in production volumes was primarily due to the Star acquisition and excellent results from our drilling program. Oil production increased 11 per cent to 22,886 barrels per day, natural gas production increased 50 per cent to 164 million cubic feet per day (mmcfd) and natural gas liquids production increased 17 per cent to 4,086 barrels per day. ARC's production mix in 2003 was balanced with approximately 50 per cent liquids and 50 per cent natural gas.

MAJOR PROPERTIES



Total Proved Plus Probable Reserves	249,704 mboe
2003 Average Production	54,335 boe/d
Netback	$22.16 boe

Operational Summary

	2003 Gross Proved Plus Probable Reserves	Proved* plus Probable Reserves	2003 Average Production	% of Total Production	Netback
		(mboe)	(boe/d)		($/boe)
Central Alberta					
Caroline Swan Hills Gas Unit No. 1	2,190	2,190	1,336	2.5	25.39
Brown Creek	2,261	2,261	1,218	2.2	28.96
Sundre	7,156	7,156	1,146	2.1	21.22
Medicine River	4,612	4,616	1,136	2.1	22.82
Garrington	2,628	2,629	817	1.5	22.57
Other	11,650	11,815	4,263	7.8	23.45
Central Alberta	**30,497**	**30,667**	**9,916**	**18.2**	**23.99**
SE Alberta/SW Saskatchewan					
Jenner	15,259	15,260	2,105	3.9	27.36
Hatton	12,892	12,891	1,998	3.7	29.03
Brooks	5,434	5,435	1,718	3.2	25.06
Grassy Lake	2,272	2,272	781	1.4	16.69
Retlaw	1,425	1,459	601	1.1	20.85
Other	12,230	13,645	2,836	5.2	22.98
SE Alberta/SW Saskatchewan	**49,512**	**50,962**	**10,039**	**18.5**	**24.84**
Northern Alberta & BC					
Ante Creek	18,805	18,804	3,727	6.9	24.08
Pouce Coupe	5,516	5,525	2,050	3.8	19.71
Dawson	24,794	24,794	1,616	2.9	20.77
Swan Hills	6,607	6,607	1,223	2.2	19.11
Chinchaga	2,244	2,244	746	1.4	21.30
Other	26,550	27,528	8,194	15.1	22.50
Northern Alberta & BC	**84,516**	**85,502**	**17,556**	**32.3**	**22.06**
SE Saskatchewan					
Lougheed	10,648	10,677	2,921	5.4	22.43
Weyburn	10,357	10,363	1,578	2.9	22.58
Midale	6,558	6,558	1,185	2.2	21.53
Oungre	5,314	5,314	704	1.3	17.56
Alida	1,231	1,231	642	1.2	29.42
Other	10,455	10,468	2,441	4.5	19.91
SE Saskatchewan	**44,563**	**44,611**	**9,471**	**17.5**	**21.80**
Pembina					
MIPA	11,996	12,007	1,586	2.9	23.24
Berrymoor Cardium Unit	7,509	7,579	648	1.2	26.36
Minehead	4,114	4,114	628	1.2	22.48
Lindale Cardium Unit	2,824	2,829	452	0.8	27.20
Ansell	1,079	1,080	377	0.7	21.85
Other	9,858	10,353	3,662	6.7	24.13
Pembina	**37,380**	**37,962**	**7,353**	**13.5**	**24.07**

* The estimate of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation.

Northern Alberta and British Columbia

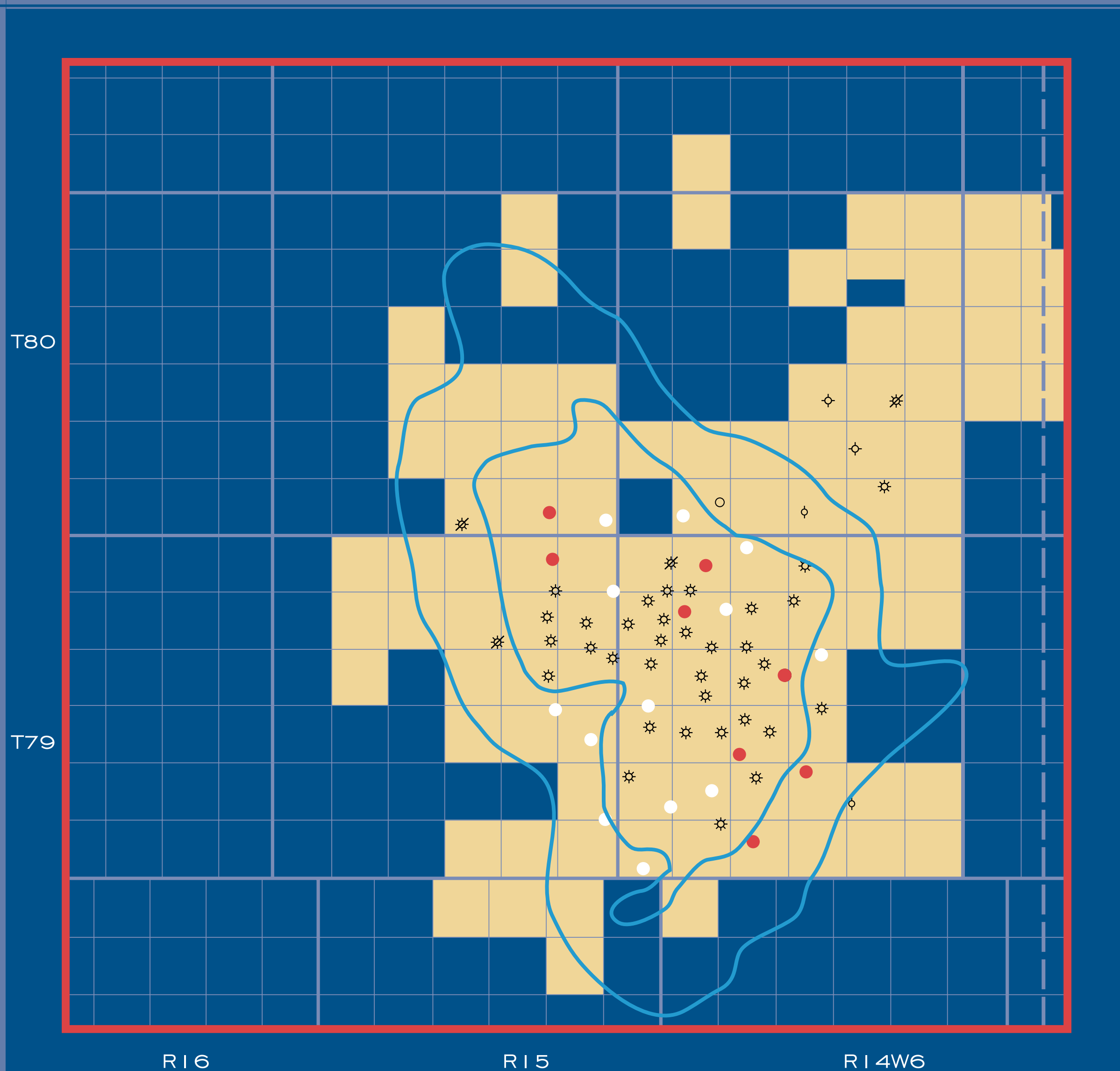
Northern Alberta and British Columbia was an active area in 2003 for ARC. This is ARC's largest core area representing approximately one-third of ARC's production. Average daily production for the area increased from 10,665 boe/d at year-end 2002 to 17,556 boe/d in 2003. Through the Star acquisition, ARC gained the new area of Dawson, a relatively immature, tight Montney natural gas development that was brought on stream in 2001. Dawson, as with many of the other Star assets, was underdeveloped and will provide ARC with substantial development opportunities in the future. Development continued in the Ante Creek area and continued to exceed ARC's expectation for exploitation opportunities. Just prior to its acquisition by ARC, Star made a potentially significant exploration discovery in the Prestville area and ARC initiated further exploration and development activities to delineate the reservoir.

Dawson

Dawson, a major property acquired in the Star transaction, is located in northeast British Columbia. ARC has an average working interest of 98 per cent in the property. At the time of the acquisition, the field had 34 wells on production. At year-end 2003, ARC's independent engineering evaluators estimated approximately 800 Bcf of initial gas-in-place for the field with an average proved ultimate recovery factor of 14 per cent. Given this low level of booked proved reserves, substantial additional development opportunities are believed to exist on these lands. The productive horizon at Dawson is the Triassic Montney formation for which ARC has developed extensive expertise through its development activities in Ante Creek. This will be of significant benefit as we move forward with development of the Dawson field.

In 2003, Star drilled eight wells and ARC drilled five successful wells in Dawson. Field compression was installed. Plans for 2004 include drilling five to seven new wells and the re-completion of three wells. ARC continues to refine fracturing techniques to improve well productivity. As development progresses at Dawson, reservoir performance, technology developments and commodity pricing will determine how much of the identified resource will ultimately be converted to reserves.

Dawson



ARC Operated Lands

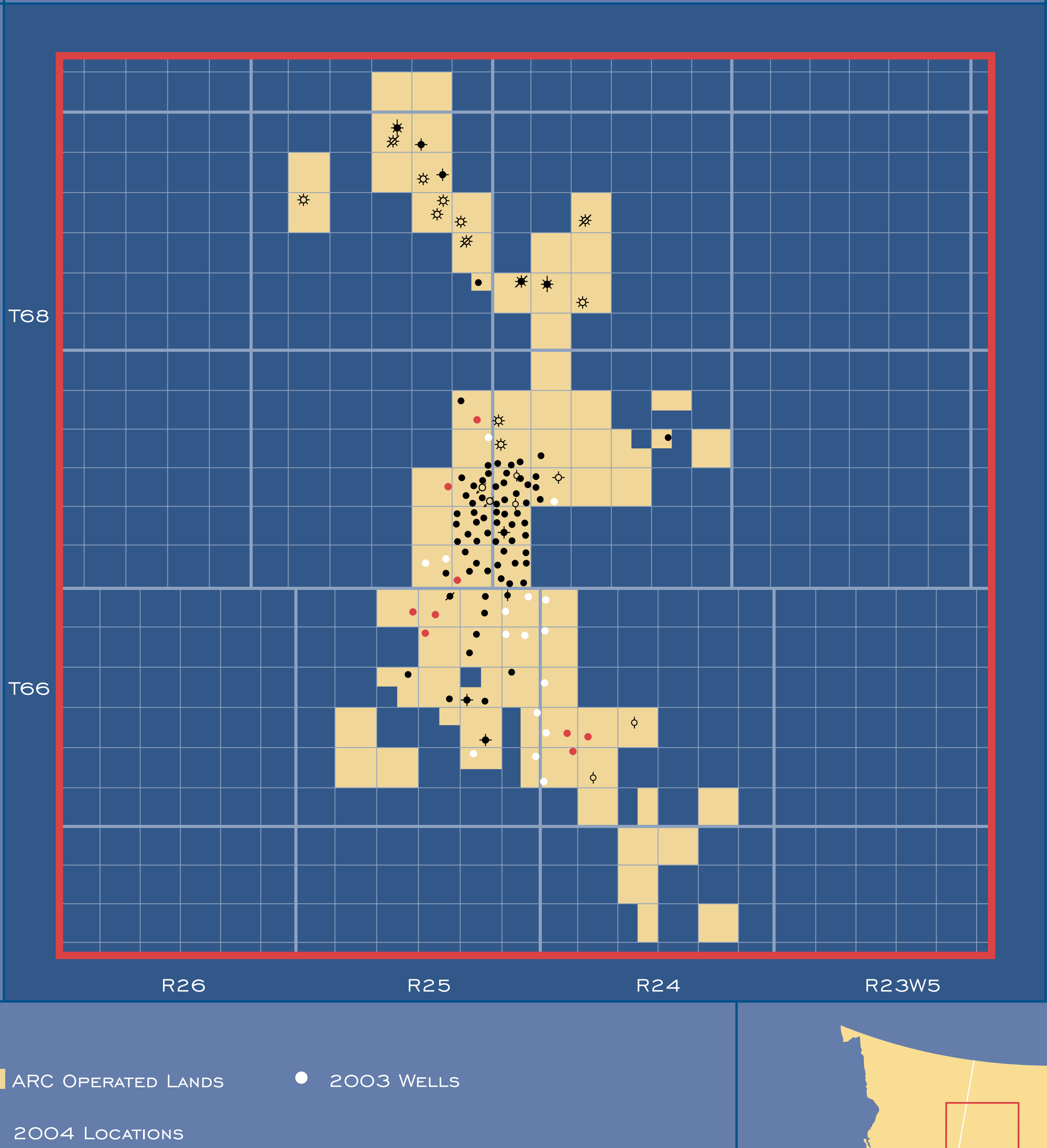
2003 Wells

2004 Locations

Ante Creek

Ante Creek continued to be a focus property for ARC in 2003. Average daily production increased in this area from 2,381 boe/d in 2002 to 3,727 boe/d in 2003. A total of 16 new wells were drilled that focused on extending pool boundaries and on continuing leases which otherwise would have expired. A majority of the wells were drilled on lands acquired in 2002. As a result of acquisitions completed in 2002, ARC effectively gained control of the entire pool. With control of the field secured, ARC can look to expand the pilot waterflood to the full field. Also in 2003, two new pilot waterflood wells commenced injection. By the first quarter of 2003, production had risen to the point where it was constrained by facility capacity. This was addressed later in the year by expansion of the compression facilities which resulted in an uplift of approximately 300 boe/d. ARC acquired third-party battery facilities from a mid-stream company and was able to simplify infrastructure ownership that will result in operating efficiencies. ARC plans to drill a further eight wells and recomplete four wells in 2004.

Ante Creek


T68
T66
R26
R25
R24
R23W5
ARC Operated Lands
2003 Wells
2004 Locations


Ante Creek
Edmonton

Prestville

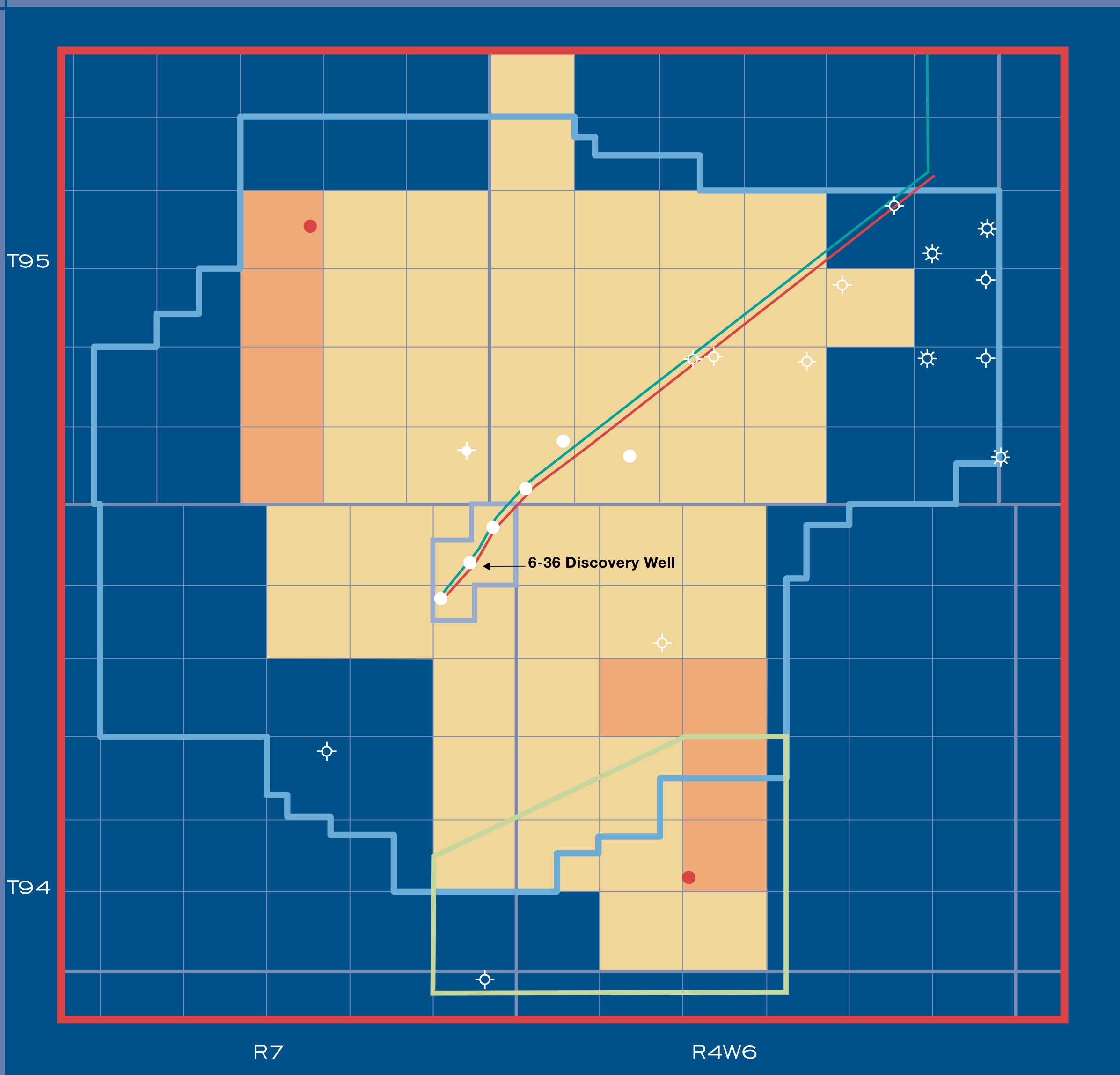
One of the more exciting developments in northern Alberta is the new Cranberry Slave Point D Pool on ARC's Prestville property. ARC announced the discovery of the Cranberry Slave Point D Pool on February 10, 2004. The field is 12 kilometres southwest of the Cranberry Slave Point gas field. The initial 6-36-94-6W6 discovery well was drilled to 2,573 metres and encountered 15 metres of net oil pay in the Slave Point formation. The well has tested light, sweet crude oil at rates of up to 650 barrels per day at minimal drawdown.

Subsequent drilling by ARC at two other locations, 10-36 and 13-25, also encountered the same thick dolomitized Slave Point interval. Restricted production rates of 600 to 850 barrels per day have been produced from these two follow-up wells, indicating comparable characteristics to the initial discovery well. Effective February 1, 2004, the Alberta Energy and Utilities Board has assigned an allowable production rate to the pool of approximately 900 barrels per day.

ARC currently has an interest in 49 sections of land in the Prestville area. In addition, through farmins, ARC will earn an interest in eight additional sections of land by drilling two wells in the first quarter of 2004.

During 2003, ARC conducted extensive testing on the three wells and commenced construction of an oil battery at the 10-36 location that was completed in the first quarter of 2004. Technical evaluation work by ARC suggests the possibility that the oil accumulation could be materially larger than currently evaluated by the independent engineers. During the first quarter of 2004, ARC will construct an 11.5 km gas pipeline and a 20 km oil sales pipeline from the new pool to existing third-party facilities. As this is a winter access area, ARC's development plans in early 2004 include the shooting of a 200 sq. km 3-D seismic program. All future development drilling will be based on the 3-D seismic.

Prestville



ARC Operated Lands
Farm-in Lands
3D Seismic Outline
Trade 3D
2003 Wells
2004 Wells
Cranberry Slave Point D Pool
Oil Pipeline

Southeast Alberta and Southwest Saskatchewan

ARC has had a presence in the Southeast Alberta and Southwest Saskatchewan area since 1999 when it acquired the Jenner shallow gas assets. Since that time, ARC has completed numerous acquisitions and expanded its ownership in existing lands. The assets in the area are comprised of sweet gas fields with low operating costs. With the Star acquisition, ARC gained three important new properties in southwest Saskatchewan – Hatton, Horsham and Crane Lake. This area was ARC's most active drilling area in 2003. ARC embarked on its largest shallow gas drilling program ever with a total of 140 gross wells drilled in Hatton, Horsham and Jenner. Average daily gas production for the area increased in 2003 to 48 mmcf per day from 35 mmcf per day in 2002. Average oil production was 2,011 barrels per day for 2003. The increase in gas production was due to the assets acquired from Star and drilling wells on both new and existing assets.

Hatton

The Hatton area in southwest Saskatchewan includes Hatton, Crane Lane and Horsham. It was acquired through Star and was Star's second largest producing area. This is a mature, high working interest, low operating cost, shallow gas development with a long reserve life index. When acquired, the land had a much lower drilling density than offsetting lands; and many more infill drilling locations were identified, only a portion of which were included in ARC's evaluation upon acquisition.

ARC drilled 92 wells in the Hatton and Horsham areas (42 in Hatton and 50 in Horsham) in 2003. These wells came on production in the third quarter of 2003 and currently produce a net incremental 6 mmcf/d. ARC plans to drill an additional 35 wells in the Hatton area in 2004 and more in future years. ARC's goal is to achieve full 80 acre spacing in the area, which is comparable to offsetting lands.

Future potential includes a further 880 gross (375 net) locations with only 417 gross wells (215 net wells) booked in our current GLJ evaluation. Other future upside may come from further increased drilling density as offset operators have started pilot programs at greater than the currently accepted density of eight wells per section. Shallower reserves in the Ribstone and facility upgrades could also lead to positive reserve revisions.

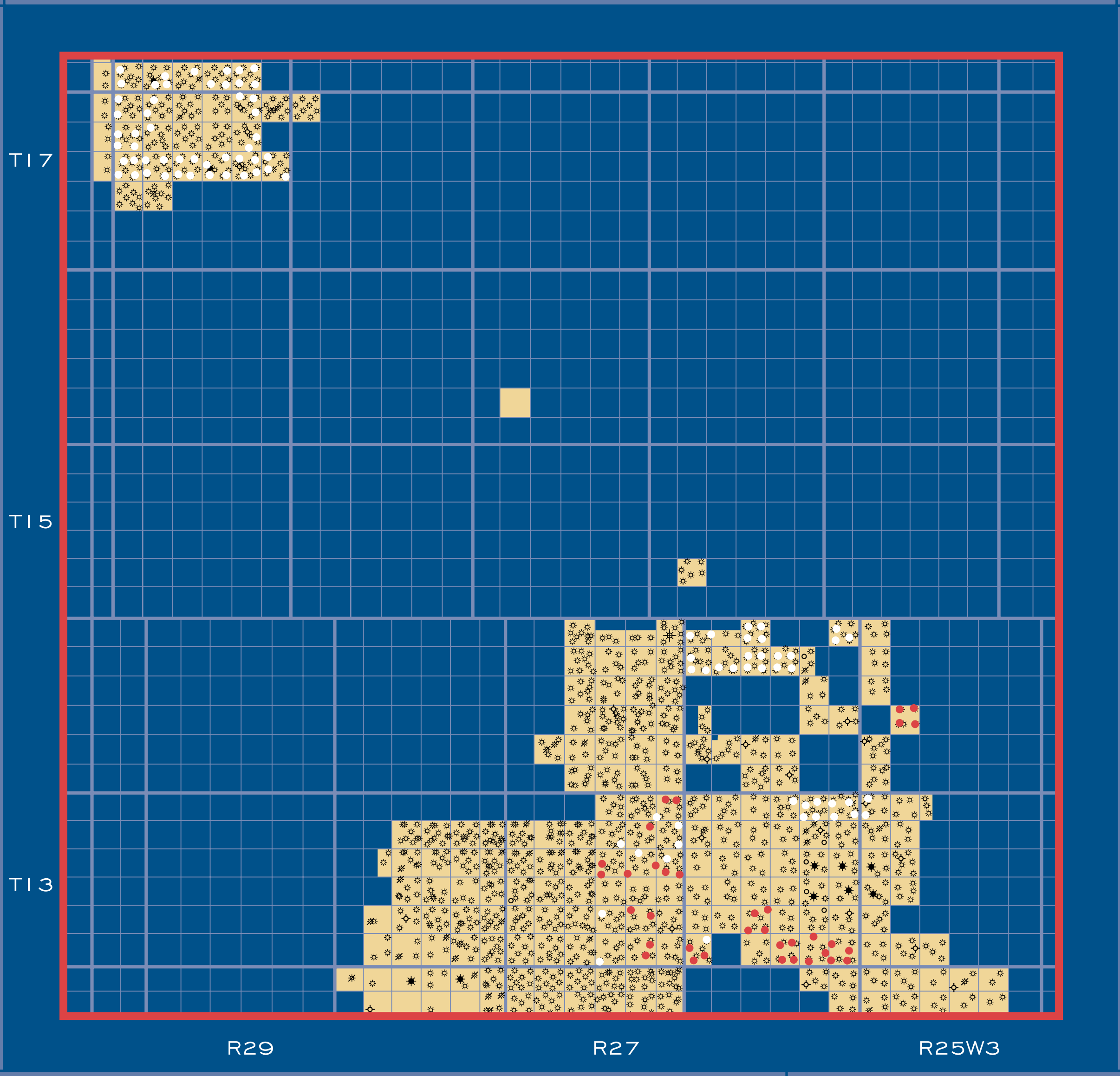
Jenner

ARC continued its strategy in growing this core, shallow gas property in 2003. ARC drilled 48 wells in Jenner and stabilized current production by adding over 4 mmcf/d. ARC is planning a 50 well drilling program for 2004 in Jenner along with some facility upgrades.

Other SE Alberta/SW Saskatchewan Areas

ARC drilled four shallow gas wells in the Brooks area with expected completion in 2004. With respect to deeper horizons, ARC participated in a non-operated program to shoot a 3-D seismic survey in Brooks that resulted in the drilling of three successful wells. In the Princess area, ARC participated in a 30 well drilling program with a 50 per cent working interest. This program added incremental production of 1.25 mmcf/d net to ARC.

Hatton



ARC Operated Lands

2003 Wells

2004 Locations

Dwayne Westman, Field Operator, Lougheed

Central Alberta

The central Alberta area comprises a diverse group of assets with multi-zone potential. Production consists of oil and liquid-rich natural gas. Production and reserves continue to grow as a result of minor acquisitions, development drilling and significant well and facility optimization opportunities identified by the area technical team. Total daily average production for the area increased in 2003 to 9,916 boe/d from 7,523 boe/d in 2002. ARC drilled eight wells on operated lands and participated in 12 net non-operated wells.

Medicine River/Gilby

Medicine River was an active property for central Alberta in 2003. A 3-D seismic survey was shot and interpreted in the Gilby area in the first quarter of 2003. The survey results and a detailed geological evaluation led to the drilling of a successful two-legged horizontal well. This 100 per cent ARC well is currently producing 150 boe/d. Optimization activities are ongoing in the Jurassic B unit and a reservoir simulation, combined with a 3-D seismic survey, are expected to generate additional opportunities in 2004. A significant recompletion added 120 boe/d and doubled current production throughput at the Medicine River 4-34 battery. Follow-up locations are being reviewed in 2004.

Youngstown

ARC has a 98 per cent average working interest in the Youngstown Arcs pool. This is a mature pool with an active aquifer and low decline rates. In late 2002, ARC drilled an outpost well extending the pool to the south. The southern extension to the pool was followed-up with three horizontal wells in 2003. The resulting incremental production from these new wells has stabilized at 200 boe/d. Three gas recompletions added both reserves and deliverability in the area. ARC has identified additional opportunities at Youngstown and plans further drilling in the area in 2004.

Other Central Alberta Areas

In Garrington, ARC's recompletion program added over 100 boe/d to existing production. Additional recompletion and compression opportunities have been identified for 2004. With the Star assets, ARC acquired interests in the Delburne Unit and non-unit lands. In 2003, optimization work was conducted to keep production flat during the year. This property underwent a thorough engineering and geological evaluation which has identified four drilling locations for 2004.

Pembina

Pembina was ARC's first operated core area and remains an excellent Trust asset due to its low decline rate and long economic reserve life. This area produces high quality light, sweet oil and has an economic reserve life in excess of 50 years. Since 1996, ARC has drilled 34 wells in Pembina. Most of the properties are under waterflood with resulting long-term, stable production rates and high reserves recovery. ARC continues its development activities in the area and production increased in 2003 to 7,353 boe/d from 7,081 boe/d in 2002.

Berrymoor

ARC has received approval from the other working interest owners to assume operatorship of the Berrymoor Cardium Unit effective March 1, 2004. ARC has a 44.12 per cent working interest in this large oil unit of 161 wells for which significant upside potential is believed to exist. Accordingly, ARC is proposing an aggressive development program and has identified numerous infill locations to achieve 80 acre spacing; eight infill wells are budgeted to be drilled in 2004.

MIPA

Certain areas within the Pembina Cardium oil field are being downspaced to 40 acres, including ARC's MIPA blocks. This tighter downspacing will increase production and ultimate recovery for the area. In the MIPA blocks, ARC upgraded a waterflood facility and drilled five Cardium oil wells in 2003. Other activity included reactivations, workovers and stimulations. As a result of this activity, production in the MIPA blocks has remained relatively flat for the last five years since ARC assumed operatorship. In 2004, ARC plans to drill six new wells in the MIPA blocks. ARC holds 100 per cent working interest in the MIPA producing properties.

Other Pembina Properties

In Lindale, efforts were concentrated on increasing and optimizing injection rates and the reactivation of several suspended wells. As a result of these activities, ARC exited the year at approximately the same production rates that were in place at the end of 2002. In Westerose/Hoadley, ARC drilled two 100 per cent interest shallow gas wells as a follow-up to a discovery well drilled in 2002. These new wells came on stream with initial production of 700 to 1,100 mcf/d. ARC plans to follow-up this program in 2004 with the drilling of five additional wells. At Minehead, ARC is participating in five non-operated Cardium gas infill wells. ARC holds a 33.25 per cent working interest in this property and plans to drill one to two wells on our 100 per cent lands in 2004. These are tight gas wells that are liquid rich and provide low long-term declines and long-life reserves.

Southeast Saskatchewan

ARC established its operating presence in this area in 2001 through assets acquired with Startech. These assets have been and continue to be high performers. Average daily production in southeast Saskatchewan increased to 9,471 boe/d in 2003 from 9,037 boe/d. The increase was attributed to development work that took place primarily in Lougheed and an increase in production at Weir Hill. Both of these properties illustrate the upside ARC seeks to create for each property in its portfolio of assets.

Lougheed

In Lougheed, production volumes increased from 2,881 boe/d to 3,005 boe/d by year-end 2003. This increase can be attributed to new drilling, optimization and recompletion activities in the area. In 2003, ARC drilled five multilateral horizontal wells, two vertical injection wells and converted an existing horizontal well to injection. In the fourth quarter of 2002, ARC expanded the waterflood in Lougheed resulting in a reversal of production declines throughout 2003 – a significant accomplishment. Also as a result of the expanded waterflood, ARC anticipates an increase in the recovery factor throughout the area. In 2004, ARC will expand the horizontal drilling program in Lougheed and also expand the waterflood onto non-unit lands.

Weir Hill

ARC consistently strives to develop further potential in an area. Weir Hill is an excellent example of the kind of upside ARC's technical team can achieve for the long-term benefit of unitholders. ARC acquired the Weir Hill property in 2001. At that time, Weir Hill was producing from a number of vertical wells at a combined rate of 85 boe/d. In 2002, ARC drilled one horizontal re-entry well and in 2003 drilled a further three horizontal wells. As a result of the new drilling, this property is now producing over 700 boe/d. ARC is planning additional development activities on this property in the future.

Acquisitions and Dispositions

ARC was very active on the acquisition and disposition fronts during 2003. The most significant event was the $722 million acquisition of Star in April 2003. This was the largest acquisition the Trust has completed to date and significantly enhanced the already high quality of ARC's properties and balanced ARC's production and reserves between crude oil and natural gas liquids and natural gas. ARC also completed $176.4 million of dispositions during 2003, most of which occurred in two separate transactions. In conjunction with the Star acquisition, ARC disposed of a large block of exploration oriented assets, then later in the year disposed of a group of minor properties that ARC no longer viewed as core to its asset base. In addition to the three transactions discussed above, ARC participated in approximately 25 other minor property acquisitions and dispositions as part of its normal course of business. In total, ARC's net acquisitions added 68.9 mmboe of proved plus probable reserves at a cost of $560 million ($8.13 per boe excluding future development capital ("FDC") and $10.19 including FDC).

2003 Acquisition/Disposition Summary

	Purchase Price	Proved Plus Probable Reserves	Reserve Purchase Price	Production Rate	Production Purchase Price	Reserve Life Index
	($ millions)	(mmboe)	($/boe)	(boe/d)	($/boe/d)	(years)
Acquisitions	736	89.0	8.27	21,800	33,800	11.2
Dispositions	176	20.1	8.78	6,200	28,300	8.8
Net Acquisitions	560	68.9	8.13	15,600	35,900	12.2

Summary of Finding, Development and Acquisition Costs (1)(4)

(Proved Plus Probable Reserves)(3) ($ thousands, except boe amounts)	**2003**	2002	2001	2000	1999	1998	1997
Net total capital expenditures	**715,745**	207,391	624,877	207,917	255,731	10,595	102,717
Net change in proved plus probable reserves after production	**64,333**	6,875	48,344	30,268	44,528	(1,722)	15,892
Annual production	**19,832**	15,485	15,736	10,012	8,093	4,649	4,375
Annual reserve additions	**84,165**	22,360	64,080	40,280	52,621	2,927	20,267
Annual finding, development and acquisition costs, excluding FDC ($/boe) (2)	**8.50**	9.27	9.75	5.16	4.86	3.62	5.07
Three year rolling average, excluding FDC ($/boe)	**9.07**	8.21	6.94	4.95	4.87	4.85	–
Cumulative since inception, excluding FDC ($/boe)	**7.08**	6.59	6.32	4.93	4.85	4.85	4.91
Net change in FDC	**171,000**	34,000	42,500	82,600	47,800	22,200	1,400
Annual finding, development and acquisition costs, including FDC ($/boe) (2)	**10.54**	10.79	10.41	7.21	5.77	11.21	5.14
Three year rolling average, including FDC ($/boe)	**10.52**	9.46	8.04	6.54	5.81	5.59	–
Cumulative since inception, including FDC ($/boe)	**8.37**	7.63	7.31	6.06	5.67	5.59	5.33

(1) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development additions for that year.

(2) FD&A is calculated as net total capital expenditures divided by the proved plus probable annual reserve additions including revisions. FD&A including FDC adds the net change in FDC to the numerator.

(3) Established reserves for 2002 and prior years.

(4) For a trust, FD&A is a more relevant measure than just F&D because of the nature of the Trust's business.

Reserves

Based on an independent engineering evaluation conducted by Gilbert Laustsen Jung Associates Ltd. ("GLJ") effective January 1, 2004 and prepared in accordance with NI 51-101, ARC had proved plus probable reserves of 250 mmboe (*see note below). This is an increase of 65 mmboe from the 185 mmboe of established reserves recorded at year-end 2002. Under NI 51-101's revised reserve definitions and evaluation standards, proved plus probable reserves represent a "best estimate" and hence are compared to prior years' "established" reserves which comprise proved plus 50 per cent of probable reserves. Reserve additions of 84 mmboe prior to production represent a 424 per cent replacement of the 19.8 mmboe produced during 2003.

Proved developed producing reserves represent 64 per cent of proved plus probable reserves while total proved reserves account for 81 per cent of proved plus probable reserves. These percentages compare to 69 and 84 per cent, respectively, last year. This modest decline primarily relates to an increase in proved undeveloped and probable reserves associated with an expanded future shallow gas drilling program in southeast Alberta and southwest Saskatchewan. At a 10 per cent discount factor, the proved producing reserves make up 77 per cent of the proved plus probable value while total proved reserves account for 88 per cent of the proved plus probable value. Approximately 52 per cent of ARC's reserves are crude oil and natural gas liquids and 48 per cent are natural gas on a 6:1 boe conversion basis.

*Note: BOE's 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.

Net Present Value ("NPV")

ARC's crude oil, natural gas and natural gas liquids reserves were evaluated using GLJ's product price forecasts effective January 1, 2004 prior to provision for income taxes, interest, debt service charges and general and administrative expenses. 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 from Net Proved Plus Probable Reserves using GLJ January 1, 2004 Escalated Prices and Costs

($ thousands)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved producing	2,164	1,613	1,308	1,112	977
Proved developed non-producing	64	42	31	25	21
Proved undeveloped	399	234	142	86	50
Total proved	2,628	1,889	1,481	1,224	1,047
Probable	674	341	208	140	101
Proved plus probable	3,302	2,231	1,689	1,364	1,148

GLJ January 1, 2004 Price Forecast

Year	WTI Crude Oil	Edmonton Light Crude Oil	Natural Gas at AECO
	($US/bbl)	($Cdn/bbl)	($Cdn/mmbtu)
2004	$29.00	$37.75	$5.85
2005	$26.00	$33.75	$5.15
2006	$25.00	$32.50	$5.00
2007	$25.00	$32.50	$5.00
2008	$25.00	$32.50	$5.00
2009	$25.00	$32.50	$5.00
2010	$25.00	$32.50	$5.00
2011	$25.00	$32.50	$5.00
2012	$25.00	$32.50	$5.00
2013	$25.00	$32.50	$5.00
2014	$25.00	$32.50	$5.00
Escalate thereafter at	1.5%/yr	1.5%/yr	1.5%/yr

It is important to recognize the significance of the price forecast used in determining the value of ARC's reserves. The GLJ price forecast is lower than the forecasts used by other Calgary based independent engineering evaluators. For reference purposes, the present value of ARC's reserves is also presented using Sproule Associates Limited's ("Sproule") January 2004 price forecast.

NPV of Cash Flow from Net Proved Plus Probable Reserves using Sproule January 1, 2004 Escalated Prices and Costs

($ thousands)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved producing	2,474	1,778	1,413	1,189	1,036
Proved developed non-producing	72	46	34	27	22
Proved undeveloped	462	268	163	100	60
Total proved	3,009	2,092	1,609	1,315	1,117
Probable	807	393	234	156	111
Proved plus probable	3,815	2,485	1,843	1,471	1,228

At a 10 per cent discount factor, the NPV of the cash flow from ARC's total proved and proved plus probable reserves is 8.6 per cent and 9.1 per cent, respectively, higher than using the GLJ price forecast. The proved producing reserves make up 77 per cent of the proved plus probable value while total proved reserves account for 87 per cent of the proved plus probable value. The increased value using the Sproule forecast results from a combination of a higher value for the GLJ assigned reserves as well as higher reserves resulting from extension of the economic life of certain properties. The Sproule forecast results in incremental reserves of 3.1 mmboe proved and 3.7 mmboe proved plus probable which are not reflected in the GLJ reserves presented herein.

Sproule's price forecast is summarized below.

Sproule January 1, 2004 Price Forecast

Year	WTI Crude Oil	Edmonton Light Crude Oil	Natural Gas at AECO
	($US/bbl)	($Cdn/bbl)	($Cdn/mmbtu)
2004	$29.63	$37.99	$6.04
2005	$26.80	$34.24	$5.36
2006	$25.76	$32.87	$4.80
2007	$26.14	$33.37	$4.91
2008	$26.53	$33.87	$4.98
2009	$26.93	$34.38	$5.05
2010	$27.34	$34.90	$5.14
2011	$27.75	$35.43	$5.24
2012	$28.16	$35.96	$5.33
2013	$28.58	$36.50	$5.43
2014	$29.01	$37.05	$5.52
Escalate thereafter at	1.5%/yr	1.5%/yr	1.5%/yr

NI 51-101 requires that the reserve evaluation also be presented using constant prices and costs effective December 31, 2003. Following are the values determined using this constant price analysis.

NPV of Cash Flow from Net Proved Plus Probable Reserves using December 31, 2003 Constant Prices and Costs

($ thousands)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved producing	3,070	2,197	1,731	1,443	1,245
Proved developed non-producing	83	54	40	32	26
Proved undeveloped	621	380	249	169	117
Total proved	3,774	2,631	2,021	1,644	1,389
Probable	923	475	294	202	148
Proved plus probable	4,697	3,105	2,314	1,846	1,537

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 87 per cent of the proved plus probable value. The prices utilized in the constant price evaluation are summarized below.

Constant Prices at December 31, 2003

Year	WTI Crude Oil	Edmonton Light Crude Oil	Natural Gas at AECO
	($US/bbl)	($Cdn/bbl)	($Cdn/mmbtu)
2004 and thereafter	$32.52	$40.81	$6.09

Net Asset Value

Net Asset Value – Discounted at 10 Per Cent (1)

($ millions, except per unit amounts)	**2003**	2002	2001	2000	1999	1998
Value of net proved plus probable reserves (2)	**$ 1,689**	$ 1,302	$ 1,216	$ 945	$530	$ 278
Undeveloped lands (3)	**50**	20	22	6	12	3
Reclamation fund	**17**	13	10	10	7	5
Long-term debt, net of working capital	**(262)**	(348)	(289)	(109)	(125)	(74)
Asset retirement obligation (4)	**(27)**	–	–	–	–	–
Net asset value	**$ 1,467**	$ 987	$ 959	$ 852	$ 424	$ 211
Units outstanding (000's) (5)	**182,777**	126,444	111,692	72,524	53,607	25,604
NAV per unit	**$ 8.03**	$ 7.81	$ 8.59	$ 11.74	$ 7.92	$ 8.25

(1) Financial information is taken from ARC's year-end audited financial statements.

(2) Probable risked at 50 per cent for 1998 through to 2002.

(3) Internal estimate based on discounted land sales values as reported in the Daily Oil Bulletin.

(4) The Asset Retirement Obligation ("ARO") was calculated on the same methodology that was used to calculate the ARO on ARC's year-end audited financial statements, except the future expected ARO costs were discounted at 10 per cent and $21.5 million relating to well abandonment was deducted as that amount has been incorporated in the value of proved plus probable reserves discounted at 10 per cent as per NI 51-101.

(5) Represents total trust units outstanding and issuable for exchangeable shares as at December 31, 2003.

The net asset value ("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. Success in this regard is reflected in the positive reserve revisions that ARC has achieved every year since inception.

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, 2004 distribution, the Trust has distributed $12.44 per unit. Despite having distributed more cash than the initial NAV, the NAV at December 31, 2003, was $8.03 per unit using GLJ prices; $8.87 per unit using Sproule Associates Limited's prices; and $11.45 per unit using constant prices and costs in effect at December 31, 2003. NAV per unit increased $0.22 per unit during 2003 after distributing $1.80 per unit to unitholders.

Reserve Life Index

ARC's proved plus probable RLI increased to 12.4 years at year-end 2003 while the proved RLI remained unchanged at 10.1 years. The 2003 RLI has been determined by using the GLJ reserves and the 2004 production guidance of 55,000 boe/d provided by ARC. The following table summarizes ARC's historical RLI using GLJ forecast information for year-end 2002 and prior years.

	2003	2002	2001	2000	1999	1998	1997
Proved	**10.1**	10.1	9.8	10.4	10.1	10.0	10.9
Proved plus probable (Established reserves for 2002 and prior years)	**12.4**	11.8	11.5	12.1	12.0	11.9	13.0

Reserves Summary and Reserve Life Index

	2003 Gross(1)	2003	2002	2001	2000	1999
		Company Interest(2)				
Crude Oil						
Proved producing (mbbl)	**73,689**	**74,148**	70,374	68,408	46,075	32,454
Proved producing reserve life index (years)	**8.9**	**8.8**	9.3	9.3	9.7	9.8
Total proved (mbbl)	**89,633**	**90,101**	85,764	82,695	58,513	39,995
Total proved reserve life index (years)	**10.8**	**10.7**	11.3	11.2	12.3	12.1
Proved plus probable (mbbl) (3)	**114,530**	**115,076**	105,141	102,632	71,663	50,245
Proved plus probable reserve life index (years)	**13.8**	**13.6**	13.5	13.5	14.7	14.8
Natural Gas Liquids						
Proved producing (mbbl)	**10,148**	**10,359**	8,863	8,823	8,175	7,774
Proved producing reserve life index (years)	**7.0**	**6.9**	7.6	7.4	7.6	7.7
Total proved (mbbl)	**11,913**	**12,125**	10,503	9,962	9,311	8,163
Total proved reserve life index (years)	**8.3**	**8.1**	9.0	8.3	8.6	8.1
Proved plus probable (mbbl) (3)	**14,341**	**14,587**	12,100	11,611	10,753	9,467
Proved plus probable reserve life index (years)	**9.9**	**9.8**	10.1	9.5	9.7	9.2
Natural Gas						
Proved producing (bcf)	**434.0**	**446.9**	296.6	279.5	202.4	184.2
Proved producing reserve life index (years)	**7.3**	**7.3**	7.5	7.2	7.3	6.7
Total proved (bcf)	**587.0**	**600.0**	356.2	330.5	243.7	203.9
Total proved reserve life index (years)	**9.9**	**9.7**	9.0	8.5	8.8	7.4
Proved plus probable (bcf) (3)	**705.6**	**720.2**	408.8	385.5	286.4	241
Proved plus probable reserve life index (years)	**11.9**	**11.7**	10.1	9.6	10.0	9.0
Oil Equivalent						
Proved producing (mboe)	**156,177**	**158,990**	128,664	123,810	87,987	70,928
Proved producing reserve life index (years)	**7.9**	**7.9**	8.4	8.2	8.4	8.7
Total proved (mboe)	**199,382**	**202,229**	155,640	147,739	108,437	82,141
Total proved reserve life index (years)	**10.1**	**10.1**	10.1	9.8	10.4	10.1
Proved plus probable (mboe) (3)	**246,468**	**249,704**	185,371	178,496	130,147	99,879
Proved plus probable reserve life index (years)	**12.5**	**12.4**	11.8	11.5	12.1	12.0

(1) Working interest reserves not including royalties receivable and before royalties payable.
(2) Working interest reserves including royalties receivable and before royalties payable.
(3) Probable reserves risked at 50 per cent for 1998 through 2002.

Reserves Reconciliation

Company Interest Reserves[1]	Crude Oil (mbbl)		Natural Gas (bcf)		Natural Gas Liquids (mbbl)		Total (mboe)	
	Proved[2]	Probable[3][4]	Proved	Probable[3]	Proved	Probable[3]	Proved	Probable[3]
Reserves at December 31, 1996	10,729	3,418	100.5	11.5	7,687	680	35,166	6,015
Acquisitions and divestments	7,961	1,552	38.8	10.3	1,104	232	15,532	3,501
Drilling and development	176	13	4.7	0.3	49	5	1,008	68
Production	(1,334)	–	(14.0)	–	(704)	–	(4,371)	–
Revisions	1,416	224	(2.3)	(1.6)	(677)	(158)	355	(201)
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)	–	(13.8)	–	(737)	–	(4,657)	–
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)	–
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)	4,556	(497)
Production	(4,219)	–	(28.2)	–	(1,085)	–	(10,012)	–
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
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)	–
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
Drilling 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

(1) Working interest reserves including royalties receivable and before royalties payable.

(2) Heavy oil reserves reconciliation as a component of crude oil on a proved basis started with reserves at December 31, 2002 of 4,928 mbbl, technical revisions of 116 mbbl, economic factors of (19) mbbl and production of (610) mbbl, leaving a closing balance of 4,415 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, 2002 of 791 mbbl, technical revisions of 234 mbbl, economic factors of 7 mbbl, leaving a closing balance of 1,032 mbbl.

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

	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, 2002	**75,135**	**16,823**	**281.8**	**41.4**	**7,567**	**1,176**	**129,672**	**24,906**
Exploration discoveries	–	–	0.9	0.2	1	–	147	37
Drilling extensions	1,856	(1,286)	3.5	(1.2)	75	(20)	2,520	(1,506)
Improved recovery	449	(436)	1.2	(0.2)	45	(13)	695	(477)
Technical revisions	3,506	4,032	29.8	12.9	325	272	8,792	6,448
Economic factors	(884)	4	(0.7)	–	(29)	1	(1,026)	8
Acquisitions	14,931	4,527	249.6	47.5	2,625	507	59,159	12,951
Dispositions	(8,631)	(1,773)	(30.7)	(3.7)	(630)	(72)	(14,379)	(2,457)
Production	(7,052)	–	(47.2)	–	(1,097)	–	(16,017)	–
Reserves at December 31, 2003	**79,309**	**21,891**	**488.2**	**97.0**	**8,882**	**1,851**	**169,564**	**39,910**

(1) Heavy oil reserves reconciliation as a component of crude oil on a proved basis started with reserves at December 31, 2002 of 4,040 mbbl, technical revisions of 295 mbbl, economic factors of (18) mbbl and production of (512) mbbl, leaving a closing balance of 3,805 mbbl.

(2) Heavy oil reserves reconciliation as a component of crude oil on a probable basis started with reserves at December 31, 2002 of 669 mbbl, technical revisions of 241 mbbl, economic factors of 6 mbbl, leaving a closing balance of 916 mmbl.

Additional Oil and Gas Disclosure

For more information in relation to gross reserves, net resources, finding and development 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 mid-April, 2004 after the date of mailing of this Annual Report to Unitholders.

ENVIRONMENT, HEALTH AND SAFETY

ARC's commitment to leadership extends to all of its business activities including safety management and operating with respect for the environment. ARC operates in a socially responsible manner and supports the communities that our employees and contractors work and live in. ARC believes in building relationships with industry partners, government and its communities based on mutual trust, transparency and respect.

With the continued strong growth of the Trust, a separate Asset Integrity group was established in 2003 within Operations to manage ARC's safety, environmental and technical integrity programs. This group ensures that our operations meet or exceed regulatory requirements and comprises experts in safety and environmental management, as well as technical engineering expertise with respect to maintenance management and facility integrity.

Safety

Protecting the health and safety of ARC's employees, contractors and the public is of primary importance. We develop and implement training programs to enhance health and safety awareness for both employees and contractors. All of our employees clearly understand our goal to have the highest standards in our health and safety practices. We will not compromise these standards to achieve other corporate goals.

ARC maintained its safety record of zero lost time accidents for employees and contract operators directly employed by ARC for the eighth year in a row. ARC also expects a high standard of safety performance from third-party contractors. Contractors are required to have their own approved safety program and are also required to comply with standards set out in the ARC Contractor's Health and Safety Handbook. The third-party contractors' employees are further provided with an orientation of ARC's Health and Safety program at the job site prior to commencing work.

In 2003, ARC continued its implementation of SAFETY 2000 as its standard for safety training for our entire field staff. The course enables field employees to obtain 16 different certifications over a five-day training period. This exceeds industry recommendations. ARC conducts emergency response exercises to ensure a high level of response capability from staff under challenging situations.

Legal proceedings relating to a contractor's fatality that occurred on an ARC lease site in Drayton Valley in November 2001 were completed in January 2004. The fatality was associated with a third-party contractor retained by ARC to perform a well servicing operation. In its judgment, the court recognized that ARC's actions were not a contributing factor to the fatality; however, ARC was fined for failing to ensure, on the day of the incident, that a complete technical review of the contents of ARC's MSDS (Material Safety Data Sheet) for sweet crude oil occurred.

ARC maintains its standards through an internal auditing system. Self-audits are conducted on a regular basis and ARC also performs annual audits on a chosen group of vendors from each business unit to ensure they have proper health and safety programs in place. ARC is continuously improving its safety management systems to reflect ongoing changes to regulations.

Air Quality and Climate Change

ARC continues to perform very well in managing air emissions. Once again ARC was awarded a Gold Champion Level Reporter Status from Canada's Voluntary Challenge and Registry for reducing per unit emissions. In 2003, ARC filed its fourth annual report to Canada's Climate Change Voluntary Challenge and Registry (VCR) program. This report provides annual updates on our progress in managing our greenhouse gas (GHG) emissions.

ARC participates in the Canadian Association of Petroleum Producers ("CAPP") Stewardship Program. CAPP defines stewardship as "analysis, planning, implementation, measurement and review of social, environmental and economic performance". One of the advantages of participating in the CAPP stewardship program is the ability to benchmark company performance relative to its peers. ARC is performing very well in managing air quality and exceeds the CAPP benchmarks in conserving flared gas, low levels of SO_2 emissions and overall reduction in GHG emissions.

Protecting Land

Once again, ARC is performing above industry benchmarking for performance in protecting land and water. Of particular note are the real improvements made in reducing pipeline spills where ARC significantly outperforms benchmarked companies.

ARC minimizes its current and long-term impact on land use by maintaining pro-active, preventative measures and, where necessary, implementing effective remediation programs.

In conducting its operations and significant capital programs, ARC undertakes initiatives to ensure environmental impacts are minimized. We have a minimal disturbance policy in our drilling and construction activity in southeast Alberta and southwest Saskatchewan. Land clearing activity for roads and leases is kept to a minimum to ensure that native prairie is maintained and wildlife protected. In northern Alberta, ARC avoids drilling in sensitive wildlife corridors, where possible. This protects wildlife from external influences. In addition, we also drill numerous wells from "pad" locations. This means drilling two to five wells from a single surface location. For example, if we were to drill five separate wells, they would occupy 15 acres of land. A drilling pad would have five wells on three acres of land. This minimizes disturbance and ensures preservation and sustainability of the environment.

Reclamation Fund

In 1996, ARC established a reclamation fund to ensure that required funds were available for future reclamation of wells and facilities once they have reached the end of their economic life. ARC contributed $6.2 million in cash and interest income to the fund during 2003 and withdrew approximately $1.9 million, which was spent on reclamation activities. Future contributions are set at approximately $6 million per year. At December 31, 2003, the fund had a balance of $17.2 million.

Supporting Communities

Vibrant and healthy communities are integral to our future. ARC places a high value on community development and encourages its employees to contribute to the communities in which they live and work. Communities in which ARC operates all derive benefits from direct employment. ARC employs over 137 permanent staff and contractors throughout western Canada and an additional 176 employees in Calgary. Employees are encouraged to contribute to their communities through volunteerism and ARC, in turn, contributes financially to those causes that are important to its employees. ARC also directs funds to organizations within each of the areas that it operates in. Contributions are made to environmental programs, education, health and community services and Canadian amateur sports. ARC is a major supporter of the United Way with $128 thousand in combined corporate and employee contributions during 2003.

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CAPP Stewardship Initiative

In 2003, ARC played a major role in fundraising for the Alberta Cancer Board's Science in Motion Research. This campaign aims to raise $6 million to establish a molecular cancer epidemiology research program in Calgary, Alberta. ARC has committed $400,000 over a period of four years in support of reaching the final $6 million goal.

ARC has also committed $250,000 over a period of five years to the Shock Trauma Air Rescue ("STARS Air Ambulance") Society. STARS operates two medivac helicopters that serve approximately 93 per cent of Alberta's population. Two additional helicopters are used for training, community outreach and backup support. STARS provides care and transport for critically ill and injured patients.

ARC continued its five year sponsorship of the new Calgary Children's Hospital in 2003. ARC donates $50,000 to this program each year. Also in 2003, ARC continued to support the YMCA's School Support Program and Stampede Foundation as part of a three year program. ARC donates $35,000 per year and $10,000 per year respectively to these programs.

ARC has created a partnership with the Canadian Sport Centre of Calgary ("CSCC"), one of the top Olympic sports training environments in the world. The partnership embraces the relationship between Olympic athletes and ARC's culture of passion, commitment, balanced lifestyle, team effort and innovation. This initiative will offer ARC employees opportunities to learn from successes, attitudes and behaviors of Canadian Olympic athletes and their support teams. The fundamental goal of the ARC/CSCC partnership is to enrich the lives of ARC employees and their families while providing funding to the CSCC through involvement with Olympic athletes, events and facilities.

In total, ARC contributed $746 thousand to charitable organizations throughout western Canada in 2003.

David Carey, V.P. Business Development, Susan Healy, V.P. Land and Doug Bonner V.P. Engineering

MANAGEMENT'S DISCUSSION AND ANALYSIS

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Glossary of Abbreviations

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
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
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.

Management's discussion and analysis ("MD&A") should be read in conjunction with the audited consolidated financial statements for the year-ended December 31, 2003 and the audited consolidated financial statements and MD&A for the year-ended December 31, 2002.

Management uses cash flow (before changes in non-cash working capital) 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 MD&A are based on cash flow before changes in non-cash working capital.

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

This discussion and analysis contains forward-looking statements relating to future events or future performance. 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. The projections, estimates and beliefs contained in such forward-looking statements necessarily involve known and unknown risks and uncertainties, including the business risks discussed in the MD&A as at and for the years ended December 31, 2003 and 2002, 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.

Highlights

(CDN$ millions, except per unit and volume data)		**2003**		2002 (3)
Cash flow (1)	**$**	**396**	$	224
Cash flow per unit	**$**	**2.56**	$	1.87
Net Income	**$**	**290**	$	71
Net Income prior to non recurring items (2)	**$**	**290**	$	97
Distributions per unit	**$**	**1.80**	$	1.56
Daily production (boe/d) (4)		**54,335**		42,425

(1) Before changes in non-cash working capital.

(2) Prior to a one time charge related to the internalization of the management contract in 2002.

(3) 2002 net income has been restated for a retroactive change in accounting policy relating to Asset Retirement Obligations.

(4) Production amounts are based on company interest before royalties.

- On April 16, 2003, ARC Energy Trust ("ARC" or "the Trust") completed the acquisition of Star Oil and Gas Ltd. ("Star") for total consideration of $721.6 million after final closing adjustments. Subsequent to closing, ARC completed the disposition of certain Star properties for total proceeds of $78.2 million.
- Strong commodity prices, excellent drilling results and increased production volumes as a result of the Star acquisition resulted in record cash flow of $396.2 million ($2.56 per unit) in 2003 compared to $224 million ($1.87 per unit) for 2002. The year-over-year increase in cash flow of $172 million was due primarily to the Star acquisition and higher commodity prices, especially for natural gas. The continued strengthening of the Canadian dollar relative to the U.S. dollar had a negative impact in the third and fourth quarters. The rise of the Canadian/U.S. exchange rate by 22 per cent during 2003 materially decreased the Canadian dollar denominated commodity prices realized by the Trust and all other Canadian energy companies.
- The Trust declared distributions of $279.3 million in 2003 ($1.80 per unit) and $183.6 million in 2002 ($1.56 per unit), representing 71 per cent and 82 per cent of 2003 and 2002 cash flow. The payout ratio would have been 72 per cent and 83 per cent of cash flow in 2003 and 2002, respectively, taking into account that holders of the exchangeable shares forego cash distributions in favour of an increase in exchange ratios thereby effectively re-investing approximately $5.5 million and $3.2 million in 2003 and 2002, respectively.
- During the third quarter, ARC completed the disposition of certain of its minor, non-core properties for total consideration of $77 million before final closing adjustments. The disposition of the minor, non-core properties will allow the Trust to focus on development opportunities in its core areas.
- The Trust successfully completed three major equity offerings: February 2003 and November 2003 equity offerings netted $136 million and $184 million respectively. In addition, in conjunction with the Star acquisition, $320 million of debentures were issued and subsequently converted into 27 million trust units between May and August 2003.
- The Trust has obtained Board of Director approval to proceed with a $175 million capital expenditure program in 2004.

Acquisition of Star Oil and Gas Ltd.

On April 16, 2003, ARC completed the acquisition of Star for total consideration of $721.6 million after final closing adjustments. The acquisition was funded through a combination of bank debt and the issuance to the vendor of $320 million in special convertible subordinated debentures. In related transactions that closed on May 2, 2003, ARC sold certain producing properties and undeveloped acreage comprising part of the acquired assets to third parties for $78.2 million.

The Trust recorded goodwill of $157.6 million on the acquisition of Star. The goodwill arose as a result of the Trust purchasing tax pool deficient oil and gas reserves. The goodwill value was determined based on the excess of total consideration paid plus the future income tax liability recorded upon acquisition less the deemed fair value of the Star assets. The fair value, for accounting purposes, of the Star assets of $794 million was determined based on a 10 per cent discounted value of established reserves as per an independent reserve evaluation, which compares favourably to the $721.6 million consideration paid after closing adjustments. The difference represents ARC's view of the fair value of the tax pool deficiency.

The operations of Star have been included in the consolidated financial statements of the Trust effective April 16, 2003, the closing date of the acquisition.

All of the convertible debentures that were issued as partial consideration for the Star acquisition were converted into trust units by the end of the third quarter of 2003.

Production

Production volumes during 2003 averaged 54,335 boe/d compared to 42,425 boe/d in 2002. This represents a 28 per cent increase. The Trust's 2003 production portfolio was weighted 42 per cent oil, 50 per cent natural gas and eight per cent natural gas liquids ("NGL's") on a per boe basis. The increase in production was attributed to the acquisition of Star that closed on April 16, 2003 and the results of the 2003 capital expenditure program. The acquisition of Star (net of related property dispositions) resulted in an increase in production of approximately 18,000 boe/d from April 16, 2003 to year-end. Production was impacted by the sale of minor properties with production of approximately 3,700 boe/d, most of which closed on August 14, 2003.

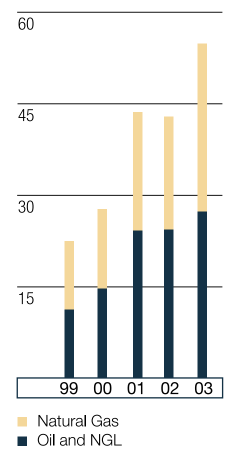
In 2003, 11 properties located within the Trust's five core areas accounted for 42 per cent of the Trust's production with no one property accounting for more than eight per cent of total production. This diversification of production minimizes the risk that operating problems at a specific property will materially impact the Corporation.

Production	**2003**	2002	% Change
Crude oil (bbl/day)	**22,886**	20,655	10.8
Gas (mcf/day)	**164,180**	109,745	49.6
NGL (bbl/day)	**4,086**	3,479	17.4
Total Production (boe/d)	**54,335**	42,425	28.1

Production Split	**2003**	2002
Crude oil and natural gas liquids	**50%**	57%
Natural Gas	**50%**	43%
Total (boe/d)	**100%**	100%

ARC expects 2004 production to average approximately 55,000 boe/d after incorporating production declines on existing properties and the positive impact of ongoing development activities on the assets.

Production
(mboe/d)



Marketing and Prices

	2003	2002	% Change
Benchmark prices			
AECO gas ($/mcf)	**$ 6.67**	$ 4.08	63
WTI oil (U.S. $/bbl)	**$ 31.06**	$ 26.10	19
CDN/USD Foreign exchange rate	**$ 0.71**	$ 0.64	11
WTI oil (CDN equivalent/$/bbl)	**$ 43.57**	$ 41.06	6
Average ARC prices*			
Natural gas ($/mcf)	**$ 6.21**	$ 4.41	41
Oil ($/bbl)	**$ 34.48**	$ 31.63	9
Natural gas liquids ($/bbl)	**$ 32.19**	$ 24.01	34
Total oil equivalent ($/boe)	**$ 36.87**	$ 28.73	28

* Includes commodity and foreign currency hedging gains and losses. See hedging section for details.

West Texas Intermediate at Cushing, Oklahoma (WTI) is the benchmark for North American crude oil prices. The WTI oil price averaged US$31.06 per barrel in 2003, up from US$26.10 per barrel in 2002. Canadian crude oil prices are based upon refiners' postings, primarily at Edmonton, Alberta, and represent the WTI price, adjusted for transportation and quality differentials and the Canadian/U.S. exchange rate. ARC's average field price reflects the refiners' posted price at Edmonton, Alberta less deductions for transportation from the field and adjustments for ARC's product quality relative to the posted price. ARC's average field price in 2003 was $38.04 per barrel ($35.27 per barrel in 2002) compared to $43.11 per barrel ($39.71 per barrel in 2002) for the average of the light sweet postings at Edmonton. The small discount to the average Edmonton posted price reflects the high quality of ARC's crude oil mix, which comprises 44 per cent light sweet (greater than 35º API) crude, 51 per cent medium gravity and five per cent heavy gravity oil (less than 23º API). ARC's average oil price, net of all hedging transactions, in 2003 was $34.48 per barrel, as compared to $31.63 per barrel in 2002.

U.S. natural gas prices are typically referenced off NYMEX at the Henry Hub, Louisiana, while western Canada natural gas prices are referenced to the AECO Hub in Alberta.

AECO Hub prices were $6.67 per mcf and $4.08 per mcf for 2003 and 2002, respectively, an increase of 63 per cent. ARC's average well head gas price, prior to hedging transactions, increased by 63 per cent to $6.30 per mcf in 2003 from $3.86 per mcf in 2002. ARC's average gas price after hedging transactions was $6.21 per mcf and $4.41 per mcf in 2003 and 2002, respectively.

The 22 per cent increase in the Canadian dollar relative to the U.S. dollar had a negative impact on the Canadian denominated prices received by the Trust in 2003.

The Trust has entered into foreign exchange hedging contracts to somewhat mitigate the impact that fluctuations in the CDN/USD exchange rate have on cash flow. In addition, certain of the Trust's payments are denominated in U.S. dollars which partially offsets the negative impact of CDN/USD exchange rate fluctuations.

In July 2003, the Trust announced the formation of Energy Trust Marketing Ltd. ("ETML"), a natural gas marketing company, which is jointly owned by ARC, four other Alberta based energy trusts, and the management of ETML. ETML enhances ARC's options for marketing its natural gas production.

Hedging and Risk Management

The Trust uses a variety of derivative instruments to manage its exposure to fluctuations in commodity prices and foreign currency rates. The types of contracts consist primarily of fixed price swaps, collared contracts, max payouts and three-way collars. As at December 31, 2003, the Trust would have had to pay $18.6 million to terminate these contracts. See Note 9 to the financial statements for further details of the derivative instruments.

The Trust's hedging activities are conducted by an internal Risk Management Committee, which has the following objectives as its mandate:

- protect unitholder return on investment;
- stabilize monthly distributions;
- employ a portfolio approach to hedging 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.

The Trust's 2003 prices included a hedging loss of $0.09 per mcf for natural gas, a loss of $3.56 per barrel for oil and a gain of $0.98 per boe for foreign currency hedge contracts. The 2002 prices included a hedging gain of $0.55 per mcf for natural gas, a loss of $3.64 per barrel for oil and a loss of $0.12 per boe for foreign currency hedge contracts.

For 2004, ARC has currently hedged approximately 44 per cent of oil production volumes at an average WTI price of approximately US$28.00 per barrel and 32 per cent of natural gas production volumes utilizing a variety of contracts at an average AECO price of approximately $5.95 per mcf. The Trust's Risk Management Committee is authorized by the Board of Directors of ARC Resources Ltd. ("ARC Resources" or "ARL") to hedge up to 50 per cent of the Trust's production on a boe basis for a period of up to 12 months, and up to 25 per cent of the Trust's production for the next consecutive 12 month period.

2003 cash flow from operations includes $11.9 million that was received upon termination of foreign exchange hedge contracts. This one-time cash settlement was included in 2003 cash flow from operations and is being amortized to earnings over the term of the original contracts to March 2004. The Trust has entered into foreign exchange hedge contracts to manage its exposure to fluctuations in CDN/USD exchange rate (see Note 9 to the audited consolidated financial statements ("Financial Statements") for details on ARC's commodity and foreign exchange hedging contracts).

Revenue ($ millions, includes hedging)	**2003**	2002	% Change
Oil revenue	**288.0**	238.5	21
Natural gas revenue	**372.2**	176.6	111
Condensate and NGL revenue	**48.0**	30.5	57
Other revenue	**23.0**	(0.8)	–
Total revenue	**731.2**	444.8	64

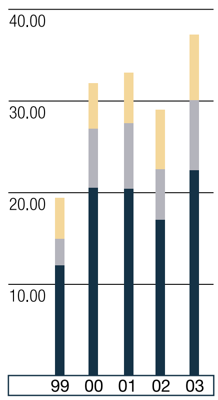
Revenue, prior to commodity and foreign currency hedging transactions, increased to $747.2 million in 2003 compared to $453.6 million in 2002. The increase was primarily due to the acquisition of Star and higher commodity prices. Hedging losses on commodities and foreign currency of $16 million in 2003 and $8.8 million in 2002 resulted in production revenue net of hedging losses of $731.2 million in 2003 and $444.8 million in 2002.

Operating Netbacks

A 2003 operating netback of $22.16 per boe compared to $16.78 per boe in 2002 reflected the 63 per cent increase in natural gas prices and 19 per cent increase in crude oil prices offset by the 11 per cent decline in the average CDN/USD exchange rate.

Operating costs include all costs associated with the production of oil and natural gas from the time the well commences commercial production to the point at which the product enters a pipeline for transport or is trucked to a commercial market. Gathering and processing costs are also included in operating costs. Costs to transport the product from the wellsite to the commercial market are not reflected as an operating cost but are netted against the revenue received for the product. Revenue received from the processing of third-party production at ARC's facilities is netted against operating costs.

Average Selling Price
($/boe)



Operating costs, net of processing income, increased to $140.7 million ($7.10 per boe) for 2003 from $99.9 million ($6.45 per boe) for the same period in 2002. The increase in the dollar amount of operating costs from 2002 to 2003 was primarily due to the acquisition of Star. The increase in 2003 electricity rates in the province of Alberta had a direct impact on operating costs as electricity is one of the largest components of the Trust's operating cost structure. ARC has hedged approximately 20 per cent of its total electricity usage at a price of $63 per megawatt hour through to December 2010. Increases in well service and work-over costs impacted operating costs in total and on a per boe basis in 2003. ARC continues to closely manage and monitor costs on operated and non-operated properties. In benchmarking operating costs to our peer group, it is evident that the increase in operating costs per boe is in line with overall industry trends and is consistent with similar cost increases facing our peers.

The Trust pays crown, freehold and overriding royalties that are dependent upon production volumes, commodity prices, location and age of producing wells and type of production. Oil crown royalty volume, which is taken in kind in Alberta, is assigned a dollar value based on the sales price that otherwise would have been received for the oil crown royalty volume. Crown royalties for natural gas, NGL's, and oil produced outside of Alberta are assigned a dollar value based on a posted reference price. Gas crown royalties are reduced by Gas Cost Allowance ("GCA") deductions. The GCA deductions are based on processing fees and allowable capital costs incurred at a property and are in accordance with royalty agreements for the property. Royalty income received is included in revenue. The effective royalty rates applicable to the Trust's 2003 oil, natural gas and NGL production were 19 per cent, 21 per cent, and 26 per cent, respectively.

Total royalties increased to $7.61 per boe in 2003 as compared to $5.50 per boe in 2002. Royalties as a percentage of pre-hedged revenue increased to 20.2 per cent as compared to 18.8 per cent for the same period in 2002. The higher royalty rate in 2003 is attributed to the higher commodity price environment and the increased gas weighting of the Trust's production, as the Trust's effective royalty rate on natural gas is higher than oil. The increase in 2003 royalties per boe is attributed to the higher commodity price environment and the drilling of higher production rate wells.

The components of operating netbacks are shown below:

Netback	Oil ($/bbl)	Gas ($/mcf)	NGL ($/bbl)	Total ($/boe)
2003				
Market price	**38.04**	**6.30**	**32.19**	**37.67**
Cash hedging gain (loss) (2)	**(3.56)**	**(0.16)**	**–**	**(1.09)**
Non-cash hedge gain (loss) (2)	**–**	**0.07**	**–**	**0.29**
Selling price	**34.48**	**6.21**	**32.19**	**36.87**
Royalties	**(7.09)**	**(1.32)**	**(8.55)**	**(7.61)**
Operating costs (1)	**(8.38)**	**(1.02)**	**(6.51)**	**(7.10)**
Netback	**19.01**	**3.87**	**17.13**	**22.16**
2002				
Market price	35.27	3.86	25.24	29.31
Cash hedging gain (loss) (2)	(2.01)	0.18	(1.23)	(0.83)
Non-cash hedge gain (loss) (2)	(1.63)	0.37	–	0.25
Selling price	31.63	4.41	24.01	28.73
Royalties	(6.47)	(0.71)	(6.31)	(5.50)
Operating costs (1)	(7.37)	(0.92)	(5.79)	(6.45)
Netback	17.79	2.78	11.91	16.78

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

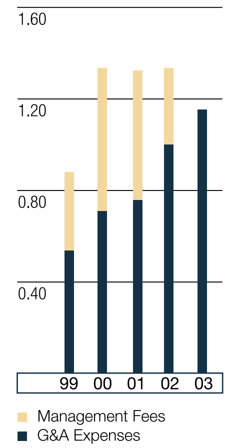
(2) Gains and losses on foreign currency hedge contracts are not allocated to the individual commodity netbacks. Foreign currency hedging gains of $0.98/boe have been included in the total 2003 netback and losses of $0.12/boe have been included in the total 2002 netback.

General and Administrative Expenses

General and administrative expenses ("G&A") include costs incurred by the Trust which are not directly associated with the production of oil and natural gas. The most significant components of G&A expenses are office employee compensation costs and office rent. Employee compensation costs for field employees are charged to operating expenses. Overhead recoveries resulting from the allocation of administrative costs to partners are recorded as a reduction of G&A expenses.

G&A expenses, net of overhead recoveries on operated properties, increased in 2003 to $22.6 million ($1.14/boe) from $15.4 million ($0.99/boe) in 2002. The increase in total G&A costs was due primarily to costs associated with an increase in staffing levels as a result of the Star acquisition and a $3.5 million ($0.18/boe) non-cash G&A item relating to the value of benefits given to officers, directors, employees and contract employees under the Trust's Trust Unit Incentive Plan (see Notes 3 and 15 to the Financial Statements for additional information). The Trust's G&A costs per boe excluding non-cash G&A have remained relatively consistent year-over-year and are continuously monitored internally by management and are benchmarked against other comparable sized Trusts. The Trust expects 2004 G&A costs excluding non-cash G&A to increase slightly as a result of a full year of increased G&A costs following the Star acquisition and the increased capital expenditure program of $175 million in 2004.

G&A and Management Fees
($/boe)



	2003		2002	
General and Administrative Expense	**$ millions**	**$ per Boe**	$ millions	$ per Boe
Cash G&A	**19.1**	**0.96**	15.4	0.99
Non-cash G&A	**3.5**	**0.18**	–	–
Total G&A	**22.6**	**1.14**	15.4	0.99

Prior to the internalization of the management contract in the third quarter of 2002, the Manager received three per cent of net operating revenue. In 2002, management fees through to the August 29 internalization date, amounted to $5.2 million ($0.33/boe). There are no management fees payable subsequent to the internalization that occurred on August 29, 2002.

Interest Expense

Interest expense increased to $18.5 million in 2003 from $12.6 million in 2002 as a result of a higher monthly average debt balance following the Star acquisition and in addition, a higher effective interest rate during the year. The Trust's effective interest rate increased to 5.3 per cent in 2003 compared to 4.4 per cent in 2002. This was due primarily to weighting of fixed rate debt to short-term debt as a result of proceeds received from the two equity offerings completed in 2003. Long-term debt was reduced in February and November with net proceeds from equity offerings of $136 million and $184 million, respectively. Interest expense was minimized over the course of the year by financing debt through the issuance of lower cost bankers' acceptances as opposed to borrowing at the prevailing bank prime interest rates.

On April 16, 2003, the Trust issued $320 million of convertible debentures to the shareholders of Star as partial consideration for the acquisition. Throughout the second and third quarters, the debentures were converted into 27 million trust units. Due to the equity classification of the debentures, interest on the debentures has not been included in interest expense but has been recorded as a reduction of accumulated earnings. In 2003, $4.1 million of interest on the convertible debentures was paid to debenture holders.

Foreign Currency Gains and Losses

ARC has US$93.4 million in U.S. denominated long-term debt that is subject to changes in the Canadian/U.S. dollar exchange rate. The unrealized gains and losses associated with the fluctuations in the exchange rate are recorded in income based upon the change in foreign exchange rates between reporting periods (see Note 7 to the Financial Statements for additional information).

Due to the strengthening of the Canadian dollar in relation to the U.S. dollar during 2003, ARC recorded an $18.6 million foreign exchange gain compared to a gain of $0.6 million in 2002. Of this amount, $18.7 million is an unrealized gain relating to the U.S. debt and has no impact on cash flow.

The $11.9 million cash settlement received upon termination of foreign exchange hedge contracts was included in 2003 cash flow from operations. The settlement amount was recorded on the balance sheet and is being amortized into income over the remaining term of the contracts that were to expire at various dates through March 2004. As at December 31, 2003, $10.5 million of foreign exchange hedge termination amount has been included in 2003 revenue and the remaining $1.4 million will be amortized in the first quarter of 2004. An additional non-cash amortization gain of $1.5 million relating to foreign exchange hedge contracts was included in 2003 revenue.

Taxes

Capital taxes paid or payable by ARC, based on debt and equity levels at the end of the year, amounted to $1.8 million in 2003 versus $1.4 million in 2002. The increase in 2003 capital taxes was attributed to the higher taxable capital base as a result of the Star acquisition.

In 2003, a future income tax recovery of $93.5 million was included in income compared to a $27.9 million recovery in 2002. The significant 2003 future income tax recovery is due to reductions in federal and provincial income tax rates. The reductions in future tax rates were substantively enacted late in the second quarter of 2003 and were subsequently legislated on November 7, 2003 when Royal Assent was received. The future rate reductions will be phased in over five years commencing in 2003. The rate changes incorporate a reduction in the applicable tax rate on resource income from 28 per cent to 21 per cent, provide for the deduction of crown royalties and eliminate over time the deduction for resource allowance. ARC's expected future income tax rate incorporating these changes is 35 per cent compared to 42 per cent as at December 31, 2002. Of the $93.5 million 2003 future income tax recovery, $66.1 million was attributed to the reduction in the future tax rate.

A future tax liability of $242 million was recorded upon acquisition of Star as a result of the fair market value for accounting purposes of the assets acquired being in excess of the associated tax basis. The future tax liability was based on the tax rate at the time of acquisition of approximately 42 per cent. The subsequent reduction in the future income tax rates resulted in a $39.2 million recovery of the future income tax liability recorded on the Star acquisition.

In the Trust's structure, payments are made between ARC Resources and the Trust, transferring both income and future tax liability to the unitholders. At the current time, ARC does not anticipate any cash taxes will be paid by ARC Resources.

Depletion, Depreciation and Asset Retirement Obligation

The 2003 depletion, depreciation and accretion ("DD&A") rate increased to $11.02 per boe from $10.13 per boe in 2002 primarily due to the Star acquisition. The DD&A rate includes depletion of $4.2 million ($3.2 million in 2002) on the capitalized cost associated with the asset retirement obligation as well as accretion expense on the asset retirement obligation of $3 million in 2003 ($2.6 million in 2002). The retroactive application of the new accounting policy for asset retirement obligations required restatement of prior periods, which resulted in a decrease in the 2002 DD&A rate to $10.13 per boe from the previously reported DD&A rate of $10.45 per boe.

The increase in the 2003 DD&A rate is primarily due to the acquisition of Star, which increased property, plant and equipment ("PP&E") by $794 million. This amount was included in the depletable base effective April 16, 2003. Besides the Star acquisition, assets to be depleted were increased by future development costs of $315.8 million and reduced by $19.3 million for the estimated future net realizable value of production equipment, $50 million for the value of unproven properties, and $161.6 million for the proceeds of net property dispositions completed in 2003.

The goodwill value of $157.6 million was determined based on the excess of total consideration paid plus the future income tax liability less the fair value of the Star assets. The future income tax liability is based on the difference between the value allocated to Star's net assets and their respective tax basis. The fair value, for accounting purposes, of the Star assets of $794 million was determined based on a 10 per cent discounted value of established reserves as per an independent reserve evaluation, which compares favourably to the $721.6 million consideration paid after closing adjustments. The difference represents ARC's view of the fair value of the tax pool deficiency, which is different from the amount of future taxes that must be provided on the acquisition under Canadian GAAP.

Accounting standards require that the goodwill balance be assessed for impairment at least annually and if such an impairment exists that it be charged to income in the period in which the impairment occurs. The Trust has determined that there is no goodwill impairment as of December 31, 2003.

Capital Expenditures and Net Acquisitions

Total capital expenditures, including net property and corporate acquisitions, aggregated to $715.7 million in 2003 ($207.4 million in 2002). Of the total, $155.8 million was incurred on drilling and completions, geological, geophysical and facilities expenditures, as ARC continues to develop its asset base, with the remaining $560 million attributable to net property and corporate acquisitions. Total reserve acquisition and development costs for 2003, including the change in future development costs per the independent engineering reports, were $10.54 per boe compared to $10.79 per boe in 2002.

2003 capital expenditures and net property acquisitions include the corporate acquisition of Star for total consideration of $721.6 million after closing adjustments. PP&E increased by $794 million as a result of the acquisition. PP&E includes an incremental amount to reflect the acquired assets at fair value for accounting purposes after consideration of the future income tax liability recorded on the acquisition.

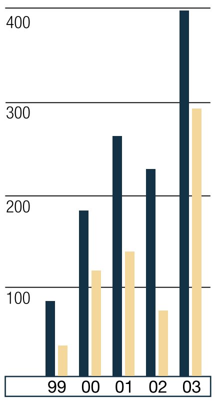
A breakdown of capital expenditures by category is shown below:

Capital expenditures ($ thousands)	**2003**	2002
Geological and geophysical	**5,671**	1,966
Drilling and completions	**110,277**	70,074
Plant and facilities	**36,457**	14,357
Other capital	**3,359**	1,881
Total capital expenditures	**155,764**	88,278
Producing property net acquisitions (dispositions) (1)	**(161,609)**	119,113
Corporate acquisition (2)	**721,590**	–
Total capital expenditures and net acquisitions	**715,745**	207,391
Total capital expenditures financed with cash flow	**106,625**	35,612
Total capital expenditures financed with debt & equity	**609,120**	171,779

(1) Value is net of post-closing adjustments.

(2) Corporate acquisition of $721.6 million represents total consideration after closing adjustments. PP&E increased by an additional $72.5 million as a result of the future income tax liability arising upon acquisition.

Cash Flow
and Earnings
($ millions)



(1) Earnings for 2002 and prior years have been restated to reflect the retroactive application of the change in accounting policy relating to asset retirement obligations.

The Board of Directors of ARC Resources has approved a capital budget of $175 million for 2004. This budget ranks individual projects to allow for revisions during the year in the event the Trust acquires additional properties with associated development opportunities, or there is a change in the business environment which may result in the acceleration or delay of certain expenditures. The Trust intends to withhold up to 20 per cent of 2004 cash flow to fund the 2004 capital expenditure program with the remainder to be funded with debt. The net proceeds of the November 2003 equity offering of $184 million were applied to reduce the long-term debt balance in anticipation of the 2004 capital expenditure program.

Abandonments

ARC Resources takes a proactive approach to environmental issues and abandonments and reclamation of associated well and facility sites as required. ARC Resources annually carries out a program to abandon and reclaim wells and facilities, which have reached the end of their economic lives. ARC has established a reclamation fund into which $6.2 million cash and interest income was contributed during the year ($4.8 million in 2002). During 2003, $2.2 million of actual abandonment costs were incurred of which $1.9 million was funded out of the reclamation fund balance. At December 31, 2003, there was a fund balance of $17.2 million. This fund, invested in money market instruments, is established to provide for future abandonment liabilities. Future contributions are currently set at approximately $6 million per year in order to provide for the total estimated future abandonment and site reclamation costs. ARC has been active in improving the quality of its oil and gas reserve base by purchasing properties and then selling smaller lower quality properties that tend to have a shorter reserve life and therefore a shorter time period to the eventual abandonment of the property. This practice will continue in the future in order to mitigate actual future abandonment costs.

Capitalization, Financial Resources and Liquidity

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

($ thousands except per unit and per cent amounts)	**2003**	2002
Long-term debt	**223,355**	337,728
Short-term debt	**9,047**	–
Working capital deficit excluding short-term debt	**29,669**	10,067
Net debt obligations	**262,071**	347,795
Units outstanding and issuable for exchangeable shares (thousands)	**182,777**	126,444
Market price at end of period	**$ 14.74**	$ 11.90
Market value of Trust units and exchangeable shares	**2,694,133**	1,504,684
Total ARC capitalization (1)	**2,956,204**	1,852,479
Net debt as a percentage of total capitalization	**8.9%**	18.8%
Net debt obligations	**262,071**	347,795
Cash flow	**396,180**	223,969
Net debt to cash flow	**0.7**	1.6

(1) 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.

As at December 31, 2003, the Trust had a working capital deficiency excluding short-term debt, of $29.7 million compared to $10.1 million as at December 31, 2002. The 2003 year-end working capital deficit is a result of normal operating conditions in periods when the Trust incurs significant capital expenditures. ARC participated in significant capital projects near the end of the year resulting in accrued capital expenditures of $33 million at December 31, 2003 compared to $21.6 million at December 31, 2002.

Total debt outstanding, inclusive of short and long-term debt, at December 31, 2003 was $232.4 million, which includes Canadian dollar bank debt of $111.3 million, U.S. dollar bank debt of US$28.4 million (CDN$37 million) and US$65 million (CDN$84 million) of Senior Secured Notes. ARC Resources' oil and gas properties secure the debt. The Trust expects to be able to keep its credit lines at $620 million, pending the annual credit review with its lenders.

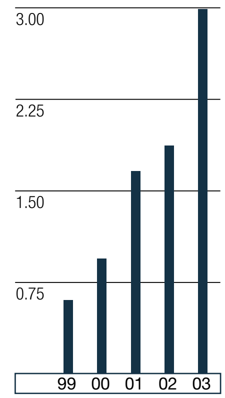
The Trust's lending facilities consist of bilateral agreements with five Canadian chartered banks and one U.S. insurance company. As the Trust's revenue stream is tied to the value of oil and natural gas in the United States, the Trust has chosen to borrow approximately one-half of its debt in U.S. dollars. The Trust now has one-third of its debt locked in at fixed interest rates averaging 6.6 per cent and the remaining two-thirds floating based upon Canadian and U.S. banker's acceptance rates plus a bank stamping fee.

End-of-year 2003 net debt to total capitalization was 8.9 per cent (18.8 per cent in 2002) and net debt to annualized cash flow was approximately 0.7 times (1.6 times in 2002) based upon cash flow from operations of $396.2 million and net debt of $262.1 million. With the low level of debt, the 2004 repayment of CDN$9 million (US$7 million) on the Secured Notes will be financed by a draw on the ARC Resources credit facilities.

The Trust's current plans are to finance the approved 2004 capital budget of $175 million with a combination of cash flow and debt. Debt balances were reduced by the proceeds of the November 2003 equity offering (see Unitholders' Equity).

Currently, several Canadian conventional oil and gas trusts have obtained stock exchange listings in the United States in order to make their trust units more accessible to U.S. investors. We are monitoring this situation and at this time have chosen not to pursue a U.S. listing. The Trust is a reporting company with the Securities and Exchange Commission ("SEC") in the United States and electronically files its financial statements and other disclosures as required with the SEC for the benefit of current and potential unitholders residing in the United States.

Total Capitalization
($ billions)



Unitholders' Equity

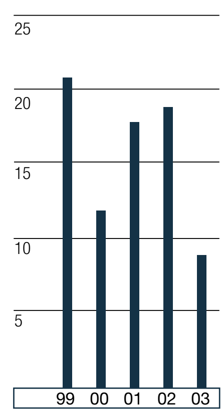
ARC's total capitalization increased 60 per cent to $3 billion during 2003 with the market value of trust units representing 91 per cent of total capitalization. During 2003, the market price of the trust units traded in the $10.89 to $14.87 range with an average daily trading volume of 430,000 units per day.

On May 16, 2003, the holders of ARC Resources Management Ltd. exchangeable shares were issued exchangeable shares of ARC Resources Ltd. on a pro-rata basis as determined by the relative exchange ratio of each series of exchangeable shares. This transaction had no impact on the total number of trust units outstanding or issuable for exchangeable shares.

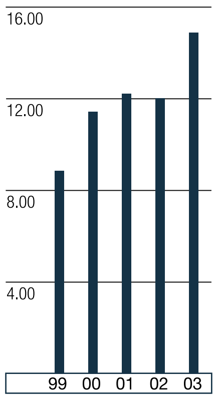
At December 31, 2003, there were 182.8 million trust units issued, issuable for exchangeable shares and outstanding, a 45 per cent increase from the 126.4 million trust units issued, issuable and outstanding at December 31, 2002. The significant increase in the number of trust units outstanding is mainly attributable to the following:

- the February 25, 2003 equity offering of 12.5 million trust units at $11.50 per trust unit (before issuance costs). The equity financing raised $144 million gross proceeds ($136 million net of issuance costs). The proceeds were used to reduce existing debt levels on an interim basis and to partially fund 2003 capital expenditures;

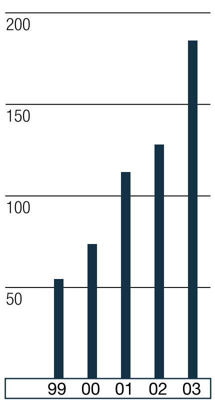
Net Debt as a Percentage of Total Capitalization
(%)



Unit Market Price
($/unit at December 31)



Units Outstanding at Year End*
(millions)



*includes units issuable for exchangeable shares

- the November 17, 2003 equity offering of 14.5 million trust units at $13.40 per trust unit (before issuance costs). The equity financing raised $194 million gross proceeds ($184 million net of issuance costs). The proceeds were used to reduce existing debt levels on an interim basis and to partially fund 2003 and 2004 capital expenditures; and,
- the issuance of 27 million trust units at $11.84 per trust unit upon conversion of the $320 million convertible debentures issued during the Star acquisition.

Unitholders electing to reinvest distributions or make optional cash payments to acquire trust units from treasury under the Distribution Reinvestment Incentive Plan (DRIP) may do so at a five per cent discount to the prevailing market price with no additional fees or commissions. The DRIP plan resulted in an additional 982,563 trust units being issued in 2003 at an average price of $12.68 raising a total of $12.5 million. In 2002, a total of 242,496 trust units were issued under the DRIP program at an average price of $12.15 per trust unit.

During 2003, as part of ARC's long-term incentive plan, 2,991,099 trust unit incentive rights (1,334,072 rights in 2002) were issued to office and field employees, long-term consultants and independent directors at prices ranging from $11.59 to $14.74 per trust unit ($11.47 to $12.80 in 2002). The exercise price of the rights is adjusted downward over time by the amount, if any, that annual distributions exceed 10 per cent of the net book value of property, plant and equipment. The rights have a five-year term and vest equally over three years from the date of grant. Rights to purchase 4,868,888 trust units at an average adjusted exercise price of $11.29 were outstanding at December 31, 2003. These rights have an average remaining contractual life of 3.8 years and expire at various dates to December 2008. Of the rights outstanding at December 31, 2003, a total of 803,255 were exercisable at that time.

Contractual Obligations

The following is a summary of the Trust's contractual obligation detailing payment due for each of the next five years and thereafter:

Payments Due By Period

Contractual Obligations ($ thousands)	Total	2004	2005-2006	2007-2008	2009 and thereafter
Total debt outstanding (1)	232,402	9,047	174,244	33,602	15,509
Operating leases	19,594	3,003	5,587	5,502	5,502
Purchase commitments (2)	37,808	3,611	8,591	6,481	19,125
Retention bonuses	4,000	1,000	2,000	1,000	–
Net contractual obligations	293,804	16,661	190,422	46,585	40,136

(1) Based on the existing terms of the revolving credit facility whereby the first payment would be required in 2005. However, it is expected that the revolving credit facility will be extended and no repayments will be required in the near term. See Note 7 in the financial statements for additional information.

(2) See Note 17 in the financial statements for additional information.

Off Balance Sheet Arrangements

The Trust has certain lease agreements which are entered into in the normal course of operations. All leases are treated as operating leases whereby the lease payments are included in operating expenses or G&A expenses depending on the nature of the lease. No asset or liability value has been assigned to these leases in the balance sheet as of December 31, 2003.

The Trust is required to disclose the nature, terms and estimated fair value of guarantees in the notes to the financial statements in accordance with Accounting Guideline 14 – Disclosure of Guarantees ("AcG-14") which is effective for fiscal years beginning on or after January 1, 2003. The Trust implemented this new standard in 2003, however there was no impact on the 2003 financial statements nor disclosure in the Notes to the Financial Statements as a result of implementation.

Cash Distributions

ARC declared cash distributions of $279.3 million ($1.80 per unit), representing 71 per cent of 2003 cash flow, bringing total cumulative distributions since inception to $968.3 million ($12.44 per Trust unit). If cash had been paid out to the owners of exchangeable shares, the payout ratio would have been 72 per cent. The remaining 29 per cent of cash flow ($116.9 million) was used to fund 68 per cent of ARC's 2003 capital expenditures ($106.6 million), make contributions to the reclamation fund ($6.2 million), and make interest payments on the convertible debentures ($4.1 million). In 2002, declared cash distributions were $183.6 million ($1.56 per unit), representing 82 per cent of cash flow. The actual amount withheld is dependent on the commodity price environment and is at the discretion of the Board of Directors. This holdback policy differs among the conventional oil and gas trusts. ARC believes it is essential to focus on production replacement activities partially funded by cash flow in order to enhance long-term unitholder returns.

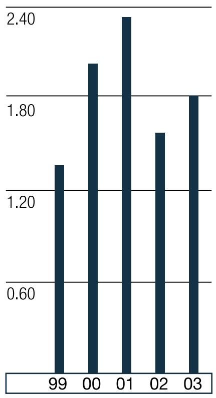
Monthly cash distributions for the first quarter of 2004 have been set at $0.15 per trust unit subject to review monthly based on commodity price fluctuations. Revisions, if any, to the monthly distribution are normally announced on a quarterly basis in the context of prevailing and anticipated commodity prices at that time. The Trust expects to fund the 2004 cash distributions from cash flow.

Historical Distributions by Calendar Year

Calendar Year	Distributions	Taxable	Return of Capital
2003 (1)	$ 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	$ 12.44	$ 5.88	$ 6.56

(1) Based on taxable portion of 85 per cent for 2003 distributions.

Cash Distributions
($/unit)



Taxation of Cash Distributions

Cash distributions comprise a return of capital portion (tax deferred) and a return on capital portion (taxable). For cash distributions received by a Canadian resident, outside of a registered pension or retirement plan in the 2003 taxation year, the split between the two is 85 per cent taxable with the remaining 15 per cent being tax deferred. For a more detailed breakdown, please visit our website at www.arcresources.com.

For 2004, ARC estimates that 85 per cent of cash distributions may be taxable; 15 per cent may be return of capital and used to reduce a unitholder's cost base on trust units held. Actual taxable amounts will be dependent on commodity prices experienced throughout the year.

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

2003 Distributions by Month

Payment Date	Taxable Amount	Tax Deferred Amount (Return of Capital)	Total Distribution
January 15, 2003	$ 0.1105	$ 0.0195	$ 0.13
February 15, 2003	0.1275	0.0225	0.15
March 15, 2003	0.1275	0.0225	0.15
April 15, 2003	0.1275	0.0225	0.15
May 15, 2003	0.1275	0.0225	0.15
June 15, 2003	0.1275	0.0225	0.15
July 15, 2003	0.1275	0.0225	0.15
August 15, 2003	0.1275	0.0225	0.15
September 15, 2003	0.1275	0.0225	0.15
October 15, 2003	0.1275	0.0225	0.15
November 15, 2003	0.1275	0.0225	0.15
December 15, 2003	0.1275	0.0225	0.15
Total	$ 1.5130	$ 0.2670	$ 1.78(1)

(1) Total is based upon cash distributions paid during 2003.

Financial Reporting and Regulatory Update

There have been several changes in the financial reporting and securities regulatory environment in 2003 that have impacted the Trust and all public companies. Canadian securities regulators and the Canadian Institute of Chartered Accountants ("CICA") are undertaking these measures to increase investor confidence through increased transparency, consistency and comparability of financial statements and financial information. As well, the goal of these changes is to align Canadian standards more closely with those in the United States.

The following new and amended standards were implemented by the Trust in 2003 with the following impact on the 2003 financial statements:

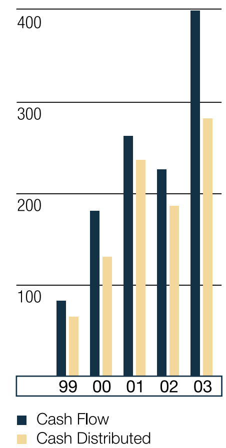
Asset Retirement Obligations – The CICA issued Section 3110 which harmonizes Canadian GAAP with SFAS No.143 "Accounting for Asset Retirement Obligations". The new standard requires that companies recognize the liability associated with future site reclamation costs in the financial statements at the time when the liability is incurred. The new Canadian standard is effective for fiscal years beginning on or after January 1, 2004, however, earlier adoption is recommended. The Trust implemented this standard in 2003 in accordance with the early adoption provisions of the standard. As a result of implementation, the liability for future abandonment costs (the "Asset Retirement Obligation" or "ARO") increased to $66.7 million, the PP&E balance increased by $41.1 million and the future income tax liability increased by $9 million as at December 31, 2003. Net income after applicable income taxes for 2003 increased by $6.4 million compared to net income which would have been reported under the old standard. The transitional provisions of this section require that the standard be applied retroactively with restatement of comparative periods. As a result of the retroactive application, 2002 comparative numbers have been restated to reflect the impact of this standard on the 2002 financial statements. Net income after applicable income taxes for 2002 increased by $3.2 million, the ARO increased by $8.4 million, the PP&E balance increased by $24.4 million, the future tax liability increased by $8.8 million as at December 31, 2002 and opening 2002 retained earnings increased by $8.9 million net of applicable income taxes. Opening 2003 accumulated earnings increased by $12.1 million net of applicable income taxes for the cumulative impact of retroactive restatement of all prior years.

Stock Based Compensation and Other Stock Based Payments – In September 2003, the CICA issued an amendment to section 3870 "Stock based compensation and other stock based payments". The amended section is effective for fiscal years beginning on or after January 1, 2004, however, earlier adoption is recommended. The amendment requires that companies measure all stock based payments using the fair value method of accounting and recognize the compensation expense in their financial statements. The Trust implemented this amended standard in 2003 in accordance with the early adoption provisions of the standard. Per the transitional provisions, early adoption requires that compensation expense be calculated and recorded in the income statement for rights issued on or after January 1, 2003. As a result of implementation of this amended standard, net income of the Trust decreased and contributed surplus increased by $3.5 million due to the estimated compensation expense on employee rights issued on or after January 1, 2003.

Full Cost Accounting Guideline – In September 2003, the CICA issued Accounting Guideline 16 "Oil and Gas Accounting – Full Cost" to replace CICA Accounting Guideline 5. The new guideline proposes amendments to the ceiling test calculation applied by the Trust. The new guideline is effective for fiscal years beginning on or after January 1, 2004. The Trust implemented this new guideline in 2003 in accordance with the transitional provisions that encouraged early adoption. Implementation of this new guideline did not impact the Trust's financial results for 2003.

Disclosure of Guarantees – In February 2003, the CICA issued Accounting Guideline 14 "Disclosure of Guarantees" which requires that all guarantees be disclosed in the notes to the financial statements along with a description of the nature and term of the guarantee and an estimate of the fair value of the guarantee. The new guideline is effective for fiscal years beginning on or after January 1, 2003. Implementation of this new guideline did not impact the Trust's financial results for 2003.

Cash Available for Distribution
($ millions)



The following new and amended standards are expected to impact the Trust in 2004 as follows:

Hedging Relationships – In December 2001, the CICA issued Accounting Guideline 13 "Hedging Relationships" that deals with the identification, designation, documentation and measurement of effectiveness of hedging relationships for the purposes of applying hedge accounting. Accounting Guideline 13 is intended to harmonize Canadian GAAP with SFAS No.133 "Accounting for Derivatives Instruments and Hedging Activities". The guideline is effective for fiscal years beginning on or after July 1, 2003. The Trust has formally documented all transactions that were determined to meet the criteria of effective hedges as at December 31, 2003. The Trust has assessed the implications of this new guideline that will be implemented in 2004.

Continuous Disclosure Obligations – Effective March 31, 2004, the Trust and all reporting issuers in Canada will be subject to new disclosure requirements as per National Instrument 51-102 "Continuous Disclosure Obligations". This new instrument is effective for fiscal years beginning on or after January 1, 2004. The instrument proposes shorter reporting periods for filing of annual and interim financial statements, MD&A and the Annual Information Form ("AIF"). The instrument also proposes enhanced disclosure in the annual and interim financial statements, MD&A and AIF. Under this new instrument, it will no longer be mandatory for the Trust to mail annual and interim financial statements and MD&A to unitholders, but rather these documents will be provided on an "as requested" basis. The Trust continues to assess the implications of this new instrument which will be implemented in 2004.

Exchangeable Share Accounting – On November 10, 2003, the CICA issued a draft EIC (D37) on "Income Trusts – Exchangeable Units". The EIC proposes that the retained interest of the exchangeable shareholders should be presented on the balance sheet as a non-controlling interest separate and distinct from unitholder's equity. This draft EIC is currently under review and was not enacted in final form as of the time of publication of the Trust's consolidated financial statements.

Variable Interest Entities – In June 2003, the CICA issued Accounting Guideline 15 "Consolidation of Variable Interest Entities" which deals with the consolidation of entities that are subject to control on a basis other than ownership of voting interests. This guideline is effective for annual and interim periods beginning on or after November 1, 2004. The Trust has assessed that this new guideline is not applicable based on the current structure of the Trust and therefore will have no impact on the financial statements of the Trust. However, this new guideline will be assessed in future periods to determine the applicability and resulting financial statement implications at that time.

Impact on Net Income of Change in Accounting Policies

The implementation of new accounting policies in 2003 relating to stock-based compensation and asset retirement obligations has resulted in restatements of previously reported annual and quarterly net income. The restatements were required per the transitional provisions of the respective accounting standards.

The following table illustrates the impact of the new accounting policies on annual net income for years which have been presented for comparative purposes:

($ thousands)	**2003**	2002	2001	2000	1999
Net income before change in accounting policies (1)	**287,307**	67,892	138,202	110,872	29,835
Increase (decrease) in net income:					
Stock-based compensation (2)	**(3,471)**	–	–	–	–
Asset retirement obligation (3)	**6,575**	4,855	4,383	3,203	3,154
Future income tax recovery (expense) (4)	**(210)**	(1,700)	(7,113)	–	–
Net income (loss) after change in accounting policies	**290,201**	71,047	135,472	114,075	32,989

The following table illustrates the impact of the new accounting policies on quarterly net income for periods which have been presented for comparative purposes:

	2003				2002			
($ thousands)	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Net Income (loss) before change in accounting policies (1)	**55,107**	**41,217**	**125,994**	**64,988**	27,596	(3,505)	28,831	14,970
Increase (decrease) in net income:								
Stock-based compensation (2)	**(2,260)**	**(1,063)**	**(147)**	**–**	–	–	–	–
Asset retirement obligation (3)	**1,774**	**1,812**	**1,739**	**1,250**	1,114	1,198	1,192	1,351
Future income tax recovery (expense) (4)	**(156)**	**(431)**	**573**	**(196)**	(336)	(432)	(380)	(552)
Net income (loss) after change in accounting policies	**54,465**	**41,535**	**128,159**	**66,042**	28,374	(2,739)	29,643	15,769

(1) This represents net income as reported before retroactive restatement for changes in accounting policies.

(2) The new accounting policy for stock-based compensation was implemented in the fourth quarter of 2003. The first three quarters of 2003 have been restated as a result of this new policy which required restatement of prior periods presented for comparative purposes.

(3) The new accounting policy for asset retirement obligations was implemented in the fourth quarter of 2003. This new standard required retroactive application with restatement of all periods presented for comparative purposes. All periods 1996 through 2003 have been restated on an annual and quarterly basis as a result of this new policy.

(4) Future income tax expense/recovery has been restated to reflect the impact of the retroactive restatement of prior periods for the accounting for asset retirement obligations. No future income tax expense/recovery adjustment was recorded for 1999 and 2000 due to the fact that the Trust had future tax assets in excess of future tax liabilities in those years.

Assessment of Business Risks

The ARC management team is focused on long-term strategic planning and has identified the following items as risks and in certain cases, opportunities associated with the Trust's business.

Reserve Estimates

The reserve and recovery information contained in ARC's independent reserve 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 reserve evaluator. A significant portion of the principal properties acquired in the Star acquisition have relatively short production histories which may make estimates on those properties more subject to revisions. The reserve report was prepared using certain commodity price assumptions that are described in the notes to the reserve 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 reserve 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.

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 natural 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 hedges. If ARC hedges its commodity price exposure, the Trust will forego the benefits it would otherwise experience if commodity prices were to increase. In addition, commodity hedging 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 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. 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 U.S. dollar has increased significantly over the last 12 months, resulting in the receipt by the Trust of fewer Canadian dollars for its production which may affect future distributions. ARC has initiated certain hedges 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/United States exchange rates will impact future distributions and the future value of the Trust's reserves as determined by independent evaluators.

Changes in Legislation

Income tax laws, or other laws or government incentive programs relating to the oil and gas industry, such as the treatment of mutual fund trusts and resource taxation, may in the future be changed or interpreted in a manner that adversely affects the Trust and its unitholders. Tax authorities having jurisdiction over the Trust or the unitholders may disagree with how the Trust calculates its income for tax purposes or could change administrative practices to the detriment of the Trust or the detriment of its unitholders. ARC intends that the Trust will continue to qualify as a mutual fund trust for purposes of the Tax Act. The Trust may not, however, always be able to satisfy any future requirements for the maintenance of mutual fund trust status. Should the status of the Trust as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise for the Trust and its unitholders.

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 therefrom, are largely dependent upon the ability of the operator of the property. 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.

Expansion of Operations

The operations and expertise of management of the Trust are currently focused on conventional oil and gas production and development in the western Canadian sedimentary basin. In the future, the Trust may acquire oil and gas properties outside this geographic area. In addition, the Trust Indenture does not limit the activities of the Trust to oil and gas production and development, and the Trust could acquire other energy related assets, such as oil and natural gas processing plants or pipelines, or an interest in an oil sands project. Expansion of our activities into new areas may present new additional risks or alternatively, significantly increase the exposure to one or more of the present risk factors, which may result in future operational and financial conditions of the Trust being adversely affected.

Acquisitions

The price paid for reserve 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 which 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 petroleum, 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 trust units. In addition, all such estimates involve a measure of geological and engineering uncertainty which 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

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. 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. Additionally, the potential impact on the Trust's operations and business of the December 1997 Kyoto Protocol, which has now 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.

Debt Service

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.

Depletion of Reserves

The Trust has certain unique attributes which differentiate it from other oil and gas industry participants. Distributions, absent commodity price increases or cost effective acquisition and development activities, will decline over time in a manner consistent with declining production from typical oil, natural gas and natural gas liquids reserves. ARC will not be reinvesting cash flow in the same manner as other industry participants as ARC conducts only minimal exploratory activities; nor to the same extent as other industry participants as one of the main objectives of the Trust is to maximize long-term distributions. Accordingly, absent capital injections, ARC's initial production levels and reserves will decline.

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 reserve base and acquiring additional reserves. Without reserve additions through acquisition or development activities, the Trust's reserves and production will decline over time as reserves are exploited.

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 will be impaired. To the extent that ARC is required to use cash flow to finance capital expenditures or property acquisitions, the level of distributions will be reduced.

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.

Net Asset Value

The net asset value of the assets of the Trust will vary from time to time dependent upon a number of factors beyond the control of management, including oil and gas prices. The trading prices of the trust units from time to time are also determined by a number of factors that are beyond the control of management and such trading prices may be greater than the net asset value of the Trust's assets.

Additional Financing

In the normal course of making capital investments to maintain and expand the oil and gas reserves of the Trust, additional trust units are issued from treasury which may result in a decline in production per trust unit and reserves per trust unit. Additionally, from time to time the Trust issues trust 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 trust 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.

Competition

There is strong competition relating to all aspects of the oil and gas industry. There are numerous trusts in the oil and gas industry that are competing for the acquisitions of properties with longer life reserves and properties with exploitation and development opportunities. As a result of such increasing competition, it will be more difficult to acquire reserves on beneficial terms. ARC competes for reserve acquisitions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial and other resources than the Trust.

Return of Capital

Trust units will have no value when reserves from the properties can no longer be economically produced and, as a result, cash distributions do not represent a "yield" in the traditional sense as they represent both a return of capital and a return on investment.

Maintenance of Distributions

ARC has adopted a general policy of investing approximately 20 per cent of annual cash flow from the properties in capital expenditures for the development and exploitation of the properties in order to mitigate the natural declines in production from the properties. There can be no assurance that capital expenditures in the amounts invested and planned to be invested can be maintained nor that the volumes of production can be maintained at current levels; nor as a consequence, that the amount of distributions by the Trust to unitholders can be maintained at current levels.

Non-resident Ownership of Trust Units

In order for the Trust to maintain its status as a mutual fund trust under the Tax Act, the Trust intends to comply with the requirements of the Tax Act for "mutual fund trusts" at all relevant times. In this regard, the Trust shall among other things, monitor the ownership of the trust units to carry out such intentions. The Trust Indenture provides that if at any time the Trust becomes aware that the beneficial owners of 50 per cent or more of the trust units then outstanding are or may be non-residents or that such a situation is imminent, the Trust shall take such action as may be necessary to carry out the foregoing intention.

Accounting Write-Downs as a Result of GAAP

Canadian Generally Accepted Accounting Principles ("GAAP") require that management apply certain accounting policies and make certain estimates and assumptions that affect reported amounts in the consolidated financial statements of the Trust. The accounting policies may result in non-cash charges to net income and write-downs of net assets in the financial statements. Such non-cash charges and write-downs may be viewed unfavorably by the market and result in an inability to borrow funds and/or may result in a decline in the trust unit price. The carrying value of property, plant and equipment, the carrying value of goodwill and the value of hedging instruments are some of the items which are subject to valuation and potential non-cash write-downs.

Nature of Trust Units

The trust units do not represent a traditional investment in the oil and natural gas sector and should not be viewed by investors as shares in a corporation. The trust units represent a fractional interest in the Trust. As holders of trust units, unitholders will not have the statutory rights normally associated with ownership of shares of a corporation. The Trust's sole assets will be the royalty interests in the properties. The price per trust unit is a function of anticipated distributable income, the properties acquired by ARC and ARC's ability to effect long-term growth in the value of the Trust. The market price of the trust units will be sensitive to a variety of market conditions including, but not limited to, interest rates and the ability of the Trust to acquire suitable oil and natural gas properties. Changes in market conditions may adversely affect the trading price of the trust units.

Management and Financial Reporting Systems

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:

a) 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;

b) estimated capital expenditures on projects that are in progress; and

c) estimated depletion, depreciation and accretion and reported FD&A costs that are based on estimates of oil and gas reserves which the Trust expects to recover in the future.

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

The ARC management 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.

2004 Cash Flow Sensitivity

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

	Assumption	Change	Impact on Annual Cash Flow $/Unit	Impact on Annual Cash Flow %	Impact on Annual Distributions [2] $/Unit
Business environment					
Price per barrel of oil (US$WTI) [1]	$30.00	$1.00	$0.05	3.2%	$0.04
Price per mcf of natural gas (CDN$AECO) [1]	$ 5.25	$0.10	$0.03	1.6%	$0.02
CDN/USD exchange rate	$ 0.75	$0.01	$0.03	2.0%	$0.03
Interest rate on debt	4.3%	1.0%	$0.02	1.0%	$0.01
Operational					
Liquids production volume	27,000	1.0%	$0.01	0.5%	$0.01
Gas production volumes	168,000	1.0%	$0.01	0.6%	$0.01
Operating expenses per boe	$ 7.20	1.0%	$0.01	0.4%	$0.01
G&A expenses per boe	$ 1.10	10.0%	$0.01	0.7%	$0.01

(1) Analysis does not include the effect of hedging.

(2) Analysis assumes a 20 per cent holdback on distributions.

The Trust is continually evaluating potential acquisitions with all acquisitions in excess of $10 million subject to Board approval. The Trust's business plan could result in multiple acquisitions in one fiscal year. As the nature of acquisitions in the energy business usually involves a competitive bid process, we cannot predict whether the Trust will execute any acquisitions in the future. The Trust's scope of acquisitions being evaluated encompasses energy assets, including conventional oil and gas assets, oil sands interests, coal bed methane, electricity or power generating assets and pipeline, gathering and transportation assets.

The management of the Trust has financed the purchase of conventional oil and gas assets in the past primarily by the issue of trust units and has ensured the Trust's financial ratios are comparable to other similar organizations. If the Trust acquired energy assets other than conventional oil and gas assets it would review alternatives for financing such acquisitions, which may result in a higher use of debt, but with the view of having the Trust's debt to total capitalization being comparable to similar sized organizations with a similar mix of assets.

Outlook

It is the Trust's objective to provide the highest possible long-term returns to unitholders by focusing on the key strategic objectives of the business plan. This focus has resulted in ARC Energy Trust achieving excellent results since inception in July 1996, by providing unitholders with cash distributions of $12.44 per trust unit and capital appreciation of $4.74 per trust unit for a total return of $17.18 per trust unit for unitholders who invested in the Trust at inception.

The key future objectives of the business plan, which is reviewed with the Board of Directors, includes:

- annual reserve replacement;
- ensuring acquisitions are strategic and enhance unitholder returns;
- controlling costs – FD&A costs, operating costs and G&A expenses;
- actively hedging a portion of the Trust's production to stabilize distributions;
- conservative utilization of debt;
- continuously developing the expertise of our staff and seeking to hire and retain the best in the industry;
- building business relationships so as to be viewed as fair and equitable in all business dealings;
- promoting the use of proven and effective technologies;
- being an industry leader in the environment, health and safety area; and
- continuing to actively support local initiatives in the communities in which we operate and live.

In 2003, the Trust was successful in meeting or exceeding all of the above objectives and will continue to focus on and closely monitor these core objectives in 2004 and beyond.

In 2004, ARC will be busy with an active drilling and development program on its expanded asset base. The $175 million capital expenditure budget is the largest in its history. The Trust will focus on major properties with significant upside, with the objective to replace production declines with internal development opportunities.

The equity offering that closed on November 17, 2003, raised $184 million of net proceeds for the Trust, reducing the Trust's net debt at year-end to $262 million or approximately 0.7 times 2003 cash flow. This low level of debt provides the Trust the financial flexibility to fund the 2004 capital expenditure program and be poised to take advantage of positive acquisition opportunities.

Additional Information

Additional information relating to ARC, including the Annual Information Form which is filed yearly within 140 days after year-end, can be found on SEDAR at www.sedar.com.

Historical Review

For the years ended December 31 ($ thousands, except per unit and volume amounts)	**2003**	2002	2001	2000	1999
FINANCIAL					
Revenue before royalties	**731,233**	444,835	515,596	316,270	155,191
Per unit (1)	**$ 4.73**	$ 3.72	$ 5.05	$ 4.97	$ 3.34
Cash flow	**396,180**	223,969	260,270	179,349	80,814
Per unit (1)	**$ 2.56**	$ 1.87	$ 2.55	$ 2.82	$ 1.74
Net income (5) (6)	**290,201**	71,047	135,472	114,075	32,989
Per unit (1) (5) (6) (7)	**$ 1.85**	$ 0.59	$ 1.33	$ 1.79	$ 0.71
Cash distributions	**279,328**	183,617	234,053	128,958	63,773
Per unit (2)	**$ 1.80**	$ 1.56	$ 2.31	$ 2.01	$ 1.35
Net debt outstanding	**262,071**	347,795	288,684	108,729	125,239
Weighted average trust units and exchangeable shares (3)	**154,695**	119,613	101,979	63,681	46,480
Trust units and units issuable for exchangeable shares at end of period (3)	**182,777**	126,444	111,692	72,524	53,607
CAPITAL EXPENDITURES					
Geological and geophysical	**5,671**	1,966	2,215	466	186
Drilling and completions	**110,277**	70,074	73,147	39,021	20,974
Plant and facilities	**36,457**	14,357	22,970	13,999	2,743
Other capital	**3,359**	1,881	3,886	554	347
Total capital expenditures	**155,764**	88,278	102,218	54,040	24,250
Property acquisitions (dispositions), net	**(161,609)**	119,113	12,911	153,877	(10,964)
Corporate acquisitions	**721,590**	–	509,748	–	242,446
Total capital expenditures and net acquisitions	**715,745**	207,391	624,877	207,917	255,732
OPERATING					
Production					
Crude oil (bbl/d)	**22,886**	20,655	20,408	11,528	8,408
Natural gas (mmcf/d)	**164.2**	109.8	115.2	77.2	66.5
Natural gas liquids (bbl/d)	**4,086**	3,479	3,511	2,965	2,687
Total (boe/d) (4)	**54,335**	42,425	43,111	27,355	22,172
Average prices					
Crude oil ($/bbl)	**34.48**	31.63	31.70	36.74	24.85
Natural gas ($/mcf)	**6.21**	4.41	5.72	4.48	2.54
Natural gas liquids ($/bbl)	**32.19**	24.01	31.03	31.52	17.43
Oil equivalent ($/boe)	**36.87**	28.73	32.76	31.59	19.15

RESERVES*	**2003 Gross Reserves**	**Company Interest Reserves**				
Proved plus probable reserves						
Crude oil and NGL (mbbl)	**128,871**	**129,663**	117,241	114,243	82,419	59,712
Natural gas (bcf)	**705.6**	**720.2**	408.8	385.5	286.4	241.0
Total (mboe)	**246,468**	**249,704**	185,371	178,496	130,147	99,879

TRUST UNIT TRADING (based on intra-day trading)					
Unit Prices					
High	**$ 14.87**	$ 13.44	$ 13.54	$ 12.15	$ 9.35
Low	**$ 10.89**	$ 11.04	$ 10.25	$ 8.35	$ 6.10
Close	**$ 14.74**	$ 11.90	$ 12.10	$ 11.30	$ 8.75
Daily average trading volume (thousands)	**430**	305	414	151	68

* Established reserves for 2002 and prior years.

Quarterly Review

($ thousands, except per unit and volume amounts)	2003 Q4	2003 Q3	2003 Q2	2003 Q1	2002 Q4	2002 Q3	2002 Q2	2002 Q1
FINANCIAL								
Revenue before royalties	**178,927**	**180,596**	**195,081**	**176,629**	117,639	113,625	112,707	100,864
Per unit (1)	**1.02**	**1.09**	**1.34**	**1.34**	0.93	0.91	0.98	0.90
Cash flow	**89,617**	**87,511**	**116,546**	**102,506**	61,495	56,603	56,677	49,194
Per unit (1)	**0.51**	**0.53**	**0.80**	**0.78**	0.49	0.45	0.49	0.44
Net income (loss) (5) (6)	**54,465**	**41,535**	**128,159**	**66,042**	28,374	(2,739)	29,643	15,769
Per unit (7)	**0.31**	**0.25**	**0.85**	**0.50**	0.22	(0.02)	0.26	0.14
Cash distributions	**78,603**	**73,890**	**67,495**	**59,340**	48,060	47,644	44,684	43,229
Per unit (2)	**0.45**	**0.45**	**0.45**	**0.45**	0.39	0.39	0.39	0.39
Net debt outstanding	**262,071**	**412,686**	**466,988**	**226,583**	347,795	271,203	209,674	312,821
Weighted average units (thousands) (3)	**174,991**	**166,365**	**145,546**	**131,379**	126,370	124,794	115,235	111,838
Units outstanding and issuable at period end (3)	**182,777**	**167,531**	**163,184**	**139,239**	126,444	126,270	122,359	111,957
CAPITAL EXPENDITURES ($ thousands)								
Geological and geophysical	**2,846**	**1,171**	**656**	**998**	556	619	519	272
Drilling and completions	**37,738**	**31,661**	**23,834**	**17,037**	21,047	12,025	13,538	23,464
Plant and facilities	**15,512**	**11,917**	**4,831**	**4,204**	4,265	3,115	2,944	4,033
Other capital	**1,418**	**391**	**1,325**	**224**	861	380	285	355
Total capital expenditures	**57,515**	**45,140**	**30,646**	**22,463**	26,729	16,139	17,286	28,124
Property acquisitions (dispositions), net	**(3,693)**	**(81,166)**	**(79,750)**	**3,000**	61,952	46,018	9,344	1,799
Corporate acquisitions	**–**	**258**	**721,332**	**–**	–	–	–	–
Total capital expenditures and net acquisitions	**53,822**	**(35,768)**	**672,228**	**25,463**	88,681	62,157	26,630	29,923
OPERATING								
Production								
Crude oil (bbl/d)	**22,851**	**23,522**	**24,078**	**21,065**	20,256	20,809	20,366	21,196
Natural gas (mmcf/d)	**180.8**	**182.0**	**175.7**	**117.3**	109.2	109.1	106.9	113.9
Natural gas liquids (bbl/d)	**4,140**	**4,105**	**4,397**	**3,696**	3,355	3,408	3,527	3,631
Total (boe/d 6:1)	**57,120**	**57,968**	**57,759**	**44,313**	41,808	42,394	41,713	43,805
Average prices								
Crude oil ($/bbl)	**31.69**	**32.76**	**33.71**	**40.41**	30.20	33.68	32.40	30.22
Natural gas ($/mcf)	**5.65**	**5.44**	**6.39**	**8.04**	5.26	4.11	4.67	3.61
Natural gas liquids ($/bbl)	**30.14**	**30.92**	**28.83**	**39.99**	27.49	25.23	23.38	20.17
Oil equivalent ($/boe 6:1)	**34.05**	**33.86**	**37.12**	**44.29**	30.58	29.13	29.69	25.58
TRUST UNIT TRADING (based on intra-day trading)								
Unit Prices								
High	**$ 14.87**	**$13.88**	**$12.84**	**$ 12.34**	$12.74	$12.98	$13.44	$13.18
Low	**$ 13.31**	**$12.51**	**$11.29**	**$ 10.89**	$11.04	$11.05	$11.85	$11.35
Close	**$ 14.74**	**$13.55**	**$12.50**	**$ 11.59**	$11.90	$12.80	$12.77	$13.14
Daily average trading volume (thousands)	**395**	**551**	**503**	**313**	269	256	252	446

(1) Based on weighted average trust units and exchangeable shares.

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

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

(4) Natural gas converted at 6:1.

(5) 2001 net income and net income per unit have been restated for the retroactive change in accounting policy for deferred foreign exchange translation.

(6) Net income and net income per unit have been restated for years 1999 through 2002 and for the first quarter of 2003 through the third quarter of 2003. The restatement was the result of the retroactive application of the change in accounting policy relating to Asset Retirement Obligations that was implemented in the fourth quarter of 2003.

(7) Net income in the basic per trust unit calculation has been reduced by interest on the convertible debentures.

CORPORATE GOVERNANCE

ARC Energy Trust is committed to the highest standards for its corporate governance practices and procedures. As corporate governance practices continue to evolve we constantly review, appraise and modify our governance program to ensure that we meet the current expectations for best practices. ARC's approach to corporate governance meets the guidelines established by the Toronto Stock Exchange ("TSX") in 1995 and modified in 1999, but we have also reviewed and updated our corporate governance practices to be consistent with emerging trends.

This past year has seen several important initiatives undertaken by the Board and its various committees. These include the recruitment of a new director with formal accounting accreditation to fill a void on the board, the oversight of the design of a new long-term compensation plan, implementation of a formal performance review process for the directors and the Board and a review of new and/or proposed regulations with regards to the functions of the audit committee and corporate governance.

Independence of the Board

ARC is in full compliance with governance best practices calling for the majority of directors to be independent and unrelated. ARC's board comprises eight members, all of whom are "unrelated" and "independent" directors except for the Chief Executive Officer within the meaning of the current TSX and the proposed OSC guidelines. The Chairman of the Board is an independent director and is responsible for leading and managing the Board in discharging its responsibilities. This position is separate from the President and Chief Executive officer of ARC Resources Ltd.

Mandate of the Board

The Board of Directors of ARC is responsible for the stewardship of ARC Resources and for overseeing the management of the business and affairs of ARC, with the goal of achieving the Trusts' 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 integrity of the Trust's internal financial controls and management systems.

The Board makes significant operational decisions and all decisions relating to: the acquisition and disposition of properties for a purchase price or proceeds in excess of $10 million; the approval of capital expenditure budgets; the establishment of credit facilities; the issuance of trust units; and the determination of distributable income.

The Board holds regularly scheduled quarterly meetings with additional meetings scheduled to address specific topics as required.

Committees of the Board

The Board has established an Audit Committee, a Reserve Audit Committee, a Compensation Committee, a Board Governance Committee and a Management Advisory Committee to assist it in the discharge of its duties. All of the committees are comprised of unrelated directors and report to the Board of Directors of ARC Resources Ltd.

Audit Committee

Members: Fred Dyment (Chair), Walter DeBoni, Michael Kanovsky and Mac Van Wielingen, all of whom are unrelated directors.

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 provided to shareholders and regulatory bodies; compliance with accounting and finance based legal and regulatory requirements; ensuring the independence of the external auditor, accounting systems and procedures; and recommending, for Board of Director approval, the audited financial statements and other mandatory releases containing financial information. The Chair of the committee is a Chartered Accountant.

Reserves Audit Committee

Members: Fred Coles (Chair), John Beddome, Fred Dyment and Michael Kanovsky, all of whom are unrelated directors.

The Reserves Audit Committee assists the Board in meeting their responsibilities to review the qualifications, experience, reserve audit approach and costs of the independent engineering firm that performs ARC's reserve audit and to review the report. The Chair of the Committee is a professional engineer and was formerly a principal for an independent reserves evaluation firm.

Human Resources and Compensation Committee

Members: Walter DeBoni (Chair), Fred Coles, John Stewart and Mac Van Wielingen, all of whom are unrelated directors.

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 the organization; and in consultation with the Board, undertake an annual performance review with the President and CEO, and review the CEO's appraisal of Officers' performance.

Management Advisory Committee

Members: John Stewart (Chair) and Mac Van Wielingen, both of whom are unrelated directors.

The mandate of the Management Advisory Committee is to provide executive leadership support and provide advice to management in various broad areas including: maintaining a long-term vision; assisting management in development and planning of strategies and advising on issues relating to human resource development.

Corporate Governance Committee

Members: Walter DeBoni (Chair), John Beddome, John Stewart and Mac Van Wielingen, all of whom are unrelated directors.

The Corporate Governance Committee assists the Board in fulfilling its oversight responsibilities with respect to: reviewing the effectiveness of the Board and its Committees; to develop and review the Corporation's approach to corporate governance matters; to develop and recommend to the Board for approval and periodically review structures and procedures designed to ensure that the Board can function independently of management; and to recruit and recommend new members to fill Board vacancies as required giving consideration to the competencies, skills and personal qualities of the candidates and of the existing Board.

Code of Business Conduct and Ethics

ARC has in place a Code of Business Conduct and Ethics, specifically stating that all directors, officers and other employees must demonstrate a commitment to fair, open and honest business practices and procedures in all business relationships both within and outside of ARC. Included are clauses relating to the ethical handling and avoidance of conflicts of interest, honest and complete disclosure in external reports, compliance with all applicable laws and regulations and the protection of corporate information and property. The full text of the policy is available on our website at www.arcresources.com.

FINANCIAL STATEMENTS

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Steve Sinclair, V.P. Finance and CFO

MANAGEMENT'S RESPONSIBILITY

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.

Management maintains a system of internal controls to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable and timely information.

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.

John P. Dielwart
President and Chief Executive Officer

Steven W. Sinclair
V.P. Finance and Chief Financial Officer

Calgary, Alberta

February 4, 2004

AUDITORS' REPORT

TO THE UNITHOLDERS OF ARC ENERGY TRUST:

We have audited the consolidated balance sheets of ARC Energy Trust as at December 31, 2003 and 2002 and the consolidated statements of income and accumulated earnings 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.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Calgary, Alberta
February 4, 2004

Deloitte & Touche LLP
Chartered Accountants

CONSOLIDATED BALANCE SHEETS

As at December 31 (CDN$ thousands)	2003	2002
ASSETS		
Current assets		
Cash	**$ 12,295**	$ 835
Accounts receivable	**68,768**	49,631
Prepaid expenses	**10,400**	6,965
	91,463	57,431
Reclamation fund	**17,181**	12,924
Property, plant and equipment (Note 6)	**2,015,539**	1,424,291
Goodwill (Note 4)	**157,592**	–
Total assets	**$ 2,281,775**	$ 1,494,646
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	**$ 94,152**	$ 51,454
Cash distributions payable	**26,980**	16,044
Current portion of long-term debt (Note 7)	**9,047**	–
	130,179	67,498
Long-term debt (Note 7)	**223,355**	337,728
Asset retirement obligations (Notes 3 and 8)	**66,657**	42,250
Commodity and foreign currency contracts (Note 9)	**4,883**	9,210
Retention bonuses (Note 10)	**3,000**	4,000
Future income taxes (Note 11)	**301,965**	153,209
Total liabilities	**730,039**	613,895
UNITHOLDERS' EQUITY		
Unitholders' capital (Note 12)	**1,838,580**	1,172,199
Exchangeable shares (Note 13)	**29,656**	35,326
Contributed surplus (Notes 3 and 15)	**3,471**	–
Accumulated earnings (Note 3)	**648,304**	362,173
Accumulated cash distributions (Note 14)	**(968,275)**	(688,947)
Total unitholders' equity	**1,551,736**	880,751
Total liabilities and unitholders' equity	**$ 2,281,775**	$ 1,494,646

See accompanying notes to consolidated financial statements

Approval on behalf of the Board

Mac H. Van Wielingen
Director

Fred Dyment
Director

CONSOLIDATED STATEMENTS OF INCOME AND ACCUMULATED EARNINGS

For the years ended December 31 (CDN$ thousands, except per unit amounts)		2003		2002
Revenues				
Oil, natural gas, natural gas liquids and sulphur sales	**$**	**731,233**	$	444,835
Royalties		**(150,995)**		(85,155)
		580,238		359,680
Expenses				
Operating		**140,734**		99,876
General and administrative (Note 3)		**22,566**		15,365
Management fee (Note 10)		**–**		5,161
Interest on long-term debt (Note 7)		**18,482**		12,606
Depletion, depreciation and accretion (Notes 6 and 8)		**218,551**		156,904
Capital taxes		**1,812**		1,370
Gain on foreign exchange		**(18,564)**		(607)
Internalization of management contract (Note 10)		**–**		25,892
		383,581		316,567
Income before future income tax recovery		**196,657**		43,113
Future income tax recovery (Note 11)		**93,544**		27,934
Net income		**290,201**		71,047
Accumulated earnings, beginning of year		**350,088**		282,195
Retroactive application of change in accounting policy (Note 3)		**12,085**		8,931
Accumulated earnings, beginning of year, as restated		**362,173**		291,126
Interest on convertible debentures (Note 4)		**(4,070)**		–
		358,103		291,126
Accumulated earnings, end of year		**648,304**		362,173
Net income per unit (Note 16)				
Basic	**$**	**1.85**	$	0.59
Diluted	**$**	**1.82**	$	0.59

See accompanying notes to consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOW

For the years ended December 31 (CDN$ thousands)	2003	2002
Cash Flow from Operating Activities		
Net Income	**$ 290,201**	$ 71,047
Add items not involving cash:		
Future income tax recovery	**(93,544)**	(27,934)
Depletion, depreciation and accretion (Notes 6 and 8)	**218,551**	156,904
Amortization of commodity and foreign currency contracts	**(15,687)**	(1,766)
Trust unit incentive compensation (Notes 3 and 15)	**3,471**	–
Internalization of management contract (Note 10)	**–**	25,892
Unrealized gain on foreign exchange	**(18,700)**	(174)
Cash received on terminated hedge contracts (Note 9)	**11,888**	–
Cash flow before change in non-cash working capital	**396,180**	223,969
Change in non-cash working capital	**17,114**	999
	413,294	224,968
Cash Flow from Financing Activities		
Repayments of long-term debt, net	**(276,127)**	(3,750)
Issue of senior secured notes	**–**	47,163
Issue of Trust units	**358,526**	128,481
Trust unit issue costs	**(17,815)**	(6,459)
Cash distributions paid	**(268,392)**	(184,167)
Interest paid on convertible debentures	**(4,070)**	–
Payment of retention bonuses	**(1,000)**	–
	(208,878)	(18,732)
Cash Flow from Investing Activities		
Acquisition of Star, net of cash received (Note 4)	**(196,444)**	–
Acquisition of petroleum and natural gas properties	**(14,783)**	(131,761)
Proceeds on disposition of petroleum and natural gas properties	**166,392**	12,647
Capital expenditures	**(141,651)**	(75,796)
Reclamation fund contributions and actual expenditures (Note 5)	**(6,470)**	(5,806)
Internalization of management contract (Note 10)	**–**	(5,331)
	(192,956)	(206,047)
Increase in Cash	**11,460**	189
Cash, Beginning of Year	**835**	646
Cash, End of Year	**12,295**	835

See accompanying notes to consolidated financial statements

1. STRUCTURE OF THE TRUST

ARC Energy Trust (the "Trust") was formed on May 7, 1996 pursuant to a Trust indenture (the "Trust Indenture") which has been amended from time to time, most recently on May 16, 2003. 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" or "ARL") 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 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, oil sands interests, electricity or power generating assets and pipeline, 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 18. 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 period. Actual results could differ from those estimated.

In particular, the amounts recorded for depletion and depreciation 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 owned by the Trust are recognized when title passes from the Trust to its customers.

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 which 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.

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;

(b) total capitalized costs plus estimated future development costs of proved undeveloped reserves, including future estimated asset retirement costs, and less the estimated net realizable value of production equipment and facilities after the proved reserves are fully produced; 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.

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.

The cost of unproved properties are excluded from the ceiling test calculation and subject to a separate impairment test.

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. 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.

Unit Based Compensation

The Trust has established a Trust Unit Incentive Rights Plan (the "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 amount of the reduction cannot be reasonably estimated as it is dependent upon a number of factors including, but not limited to, future prices received on the sale of oil and natural gas, future production of oil and natural gas, determination of amounts to be withheld from future distributions to unitholders to fund capital expenditures and the purchase and sale of PP&E. Therefore, it is not possible to determine a fair value for the rights granted under the Plan using a traditional option pricing model and compensation expense has been determined based on the intrinsic value of the rights at the date of exercise or at the date of the financial statements for unexercised rights.

Compensation expense associated with rights granted under the Plan is deferred and recognized in earnings over the vesting period of the Plan with a corresponding increase or decrease in contributed surplus. Changes in the intrinsic value of unexercised rights after the vesting period are recognized in earnings in the period of change with a corresponding increase or decrease in contributed surplus. This method of determining compensation expense may result in large fluctuations, even recoveries, in compensation expense due to changes in the underlying Trust unit price. Recoveries of compensation expense will only be recognized to the extent of previously recorded cumulative compensation expense associated with rights exercised or outstanding at the date of the financial statements.

Consideration paid upon the exercise of the rights together with the amount previously recognized in contributed surplus is recorded as an increase in unitholders' capital.

The Trust has not incorporated an estimated forfeiture rate for rights that will not vest, rather, the Trust accounts for actual forfeitures as they occur.

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.

Hedging

The Trust uses derivative instruments to reduce its exposure to fluctuations in commodity prices and foreign exchange rates. Gains and losses on these contracts are recognized as a component of the related transaction.

Gains and losses on terminated contracts are deferred under commodity and foreign currency contracts on the balance sheet and amortized to earnings over the remaining term of the original contract.

Foreign Currency Translation

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

3. CHANGES IN ACCOUNTING POLICIES

Full Cost Accounting Guideline

In December 2003, the Trust adopted AcG-16 "Oil and Gas Accounting – Full Cost", the new guideline issued by the Canadian Institute of Chartered Accountants ("CICA") which replaces AcG-5 "Full Cost Accounting in the Oil and Gas Industry".

Under AcG-5, future net revenues for ceiling test purposes were based on proved reserves and were not discounted. Estimated future general and administrative costs and financing charges associated with the future net revenues were deducted in arriving at the "ceiling".

There were no changes to net income, PP&E or any other reported amounts in the consolidated financial statements as a result of adopting this guideline.

Asset Retirement Obligations

In December 2003, the Trust adopted CICA Handbook Section 3110 "Asset Retirement Obligations". This change in accounting policy has been applied retroactively with restatement of prior periods presented for comparative purposes.

Previously, the Trust recognized a provision for future site reclamation and abandonment costs calculated on the unit-of-production method over the life of the petroleum and natural gas properties based on total estimated proved reserves and the estimated future liability.

As a result of this change, net income for the year ended December 31, 2003 increased by $6.4 million ($6.6 million net of a future income tax expense of $0.2 million). The ARO increased by $13.6 million, PP&E net of accumulated depletion increased by $41.1 million and the future income tax liability increased by $9 million as at December 31, 2003. Opening 2003 accumulated earnings increased by $12.1 million ($20.9 million net of a future income tax expense of $8.8 million) to reflect the cumulative impact of accretion and depletion expense, net of the cumulative site restoration provision, on the asset retirement obligation recorded retroactively to 1996. Basic and diluted per trust unit calculations for 2003 increased by $0.04 and $0.04, respectively, as a result of adopting this new policy.

The previously reported amounts for 2002 have been restated due to the retroactive application of this new standard. Net income for the year ended December 31, 2002 increased by $3.2 million ($4.9 million net of a future income tax expense of $1.7 million). The ARO liability as at December 31, 2002 increased by $5.8 million to $42.3 million, PP&E increased by $26.7 million to $1.4 billion, net of accumulated depletion and future income tax liability increased by $8.8 million as at December 31, 2002. Opening 2002 accumulated earnings increased by $8.9 million ($16 million net of a future income tax expense of $7.1 million) to reflect the cumulative impact of accretion and depletion expense, less the previously recorded cumulative site restoration provision. Basic and diluted per trust unit calculations for 2002 increased by $0.02 and $0.03, respectively, as a result of adopting this new policy.

There was no impact on the Trust's cash flow as a result of adopting this new policy. See Note 8 for additional information on the asset retirement obligation and impact on the consolidated financial statements.

Unit-Based Compensation Plan

The Trust elected to prospectively adopt amendments to CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments" pursuant to the transitional provisions contained therein. Under this amended standard, the Trust must account for compensation expense based on the fair value of rights granted under its unit-based compensation plan (see Note 15). As the Trust is unable to determine the fair value of the rights granted, compensation expense has been determined based on the intrinsic value of the rights at the exercise date or at the date of the financial statements for unexercised rights. Previously, the Trust accounted for compensation expense based on the intrinsic value of the rights at the grant date.

For rights granted in 2002 and prior years, the Trust elected to continue accounting for the related compensation expense based on the intrinsic value at the grant date and, for rights granted in 2002, to disclose pro forma results as if the amended accounting standard had been adopted retroactively. Accordingly, net income for 2002 and subsequent years remains unchanged with respect to rights granted in 2002 and the pro forma results are disclosed in Note 15.

As a result of adopting this amended standard, net income for the year ended December 31, 2003 decreased by $3.5 million and contributed surplus increased by $3.5 million. Basic and diluted per trust unit calculations for 2003 decreased by $0.02 as a result of adopting this new policy. See Note 15 for additional information regarding the nature of the plan and the associated compensation expense.

Disclosure of Guarantees

In January 2003, the Trust adopted AcG-14 "Disclosure of Guarantees". This guideline requires the Trust to disclose all guarantees issued to third parties. There was no impact on net income as a result of adopting this new guideline.

4. ACQUISITION OF STAR OIL AND GAS LTD.

Effective April 16, 2003, the Trust acquired all of the issued and outstanding shares of Star. The transaction was accounted for using the purchase method of accounting with the allocation of the purchase price and consideration paid as follows:

Net assets acquired		
Working capital (including cash of $5,646)	$	17,273
Property, plant and equipment		794,043
Site reclamation liability		(5,019)
Future income taxes		(242,299)
Goodwill		157,592
Total net assets acquired	**$**	**721,590**
Financed by:		
Cash fees paid	$	2,177
Cash paid for shares		199,913
Convertible debentures		320,000
Debt assumed		199,500
Total purchase price	**$**	**721,590**

The amount recorded to PP&E of $794 million represents the fair value, for accounting purposes, of the acquired assets as determined by an independent reserve evaluation. Included in this amount is a $72.5 million adjustment to reflect a portion of the future income tax liability recorded on acquisition up to the fair value of the acquired assets. The remaining $157.6 million of the future income tax liability recorded on acquisition has been recorded as goodwill.

The future income tax liability was determined based on the enacted income tax rate of 42 per cent as at April 16, 2003. The future income tax liability on the acquisition of Star was not adjusted for the subsequent reduction in corporate income tax rates.

In conjunction with the Star acquisition, the Trust issued $320 million of convertible debentures to the shareholder of Star.

Between May 30, 2003 and August 5, 2003, all $320 million of the convertible debentures were converted into trust units. A total of 27,027,027 units were issued as a result of the conversions.

Based on the terms of the convertible debentures, interest of $4.1 million for the year ended December 31, 2003 has been recorded as a reduction of the accumulated earnings in accordance with the equity classification of the debentures.

The convertible debentures were subordinated to senior debt and paid a quarterly coupon commencing on June 30, 2003 of eight per cent per annum to March 31, 2005 and increasing to 10 per cent per annum from June 30, 2005 through to maturity on June 30, 2008. The Trust had the right to redeem the debentures in full at any time with cash or the Trust could have redeemed $40 million per quarter commencing on June 30, 2003, using a combination of cash and Trust units. The Trust had the right to satisfy payment at maturity by issuing trust units. Holders of the convertible debentures could have converted the debentures into trust units at $11.84 per unit through June 30, 2005 and $11.38 per unit after June 30, 2005 to maturity.

Certain properties acquired in conjunction with the Star acquisition were subsequently sold to third parties for proceeds of $78.2 million. These transactions closed on May 2, 2003.

These consolidated financial statements incorporate operations of Star effective April 16, 2003.

5. RECLAMATION FUND

	2003	2002
Balance, beginning of year	**$ 12,924**	$ 10,147
Contributions, net of actual expenditures	**3,600**	2,000
Interest earned on fund	**657**	777
Balance, end of year	**$ 17,181**	$ 12,924

A reclamation fund was established to fund future asset retirement obligation costs. The Board of Directors of ARC Resources has approved contributions over a 20-year period which results in minimum annual contributions of $6 million ($4 million in 2002) based upon properties owned as at December 31, 2003. Contributions to the reclamation fund and interest earned on the reclamation fund balance have been deducted from the cash distributions to the unitholders. During the year, $1.9 million ($2 million in 2002) of actual expenditures were charged against the reclamation fund.

6. PROPERTY, PLANT AND EQUIPMENT

	2003	2002
Property, plant and equipment, at cost	**$ 2,733,118**	$ 1,926,277
Accumulated depletion and depreciation	**(717,579)**	(501,986)
Property, plant and equipment, net	**$ 2,015,539**	$ 1,424,291

The calculation of 2003 depletion and depreciation included an estimated $315.8 million ($190.1 million in 2002) for future development costs associated with proved undeveloped reserves and excluded $19.3 million ($12.6 million in 2002) for the estimated future net realizable value of production equipment and facilities and $50 million ($19.7 million in 2002) for the estimated value of unproved properties.

Included in the Trust's PP&E balance is $41.1 million ($26.7 million in 2002), net of accumulated depletion, relating to the ARO.

The Trust performed a ceiling test calculation at December 31, 2003 to assess the recoverable value of PP&E. The crude oil and natural gas futures prices were obtained from third parties and were adjusted for commodity differentials specific to the Trust. Future prices were obtained for the period of 2004 to 2008 inclusive and then escalated based on escalation factors in the Trust's year-end independent reserve evaluation. Based on these assumptions, 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, 2003.

Year	WTI Oil (US$/bbl)	Foreign Exchange Rate	WTI Oil (CDN$/bbl)	AECO Gas (CDN$/mmbtu)
2004	30.18	0.77	39.43	5.72
2005	27.44	0.76	36.12	5.42
2006	26.67	0.75	35.33	5.27
2007	26.61	0.75	35.43	5.23
2008	26.78	0.75	35.77	5.18
2009 – 2014 (1)	–			–
Remainder (2)	1.5%			1.5%

(1) Percentage change represents the average for the period noted.

(2) Percentage change represents the change in each year after 2014 to the end of the reserve life.

7. LONG-TERM DEBT

	2003	2002
Revolving credit facilities – CDN denominated	**$ 111,298**	$ 235,054
Revolving credit facilities – USD denominated (US$28.4 million)	**37,098**	–
Senior secured notes:		
Senior secured notes (2000 issue – US$35 million)	**45,234**	55,286
Senior secured notes (2002 issue – US$30 million)	**38,772**	47,388
Total debt outstanding	**$ 232,402**	$ 337,728
Current portion of debt	**9,047**	–
Long-term debt	**$ 223,355**	$ 337,728

The Trust has five revolving credit facilities to a combined maximum of $620 million including US$65 million of Senior Secured Notes (the "Notes").

The revolving credit facilities each have a 364 day extendable revolving period and a two year term. Borrowings under the facilities bear interest at bank prime (4.5 per cent at December 31, 2003) or, at the Trust's option, Canadian or U.S. dollar bankers' acceptances plus a stamping fee. The lenders review the credit facilities by April 30 each year and determine whether they will extend the revolving periods for another year. In the event that the revolving periods are not extended, the loan balance will become repayable over a two year term period with 20 per cent of the loan balance payable on April 30, 2005, followed by three quarterly payments of five per cent of the loan balance and a lump sum payment of 65 per cent of the loan balance at the end of the term period. Collateral for the loans is in the form of floating charges on all lands and assignments and negative pledges on specific petroleum and natural gas properties.

The US$65 million Notes were issued in two separate issues pursuant to an Uncommitted Master Shelf Agreement. The first issue of US$35 million Notes was issued in 2000, bears interest at 8.05 per cent, and requires equal principal payments of US$7 million over a five year period commencing in 2004. The second issue of US$30 million Notes was issued in 2002, bears interest at 4.94 per cent, and requires equal principal payments of US$6 million over a five year period commencing in 2006. Security for the Notes is in the form of floating charges on all lands and assignments. The Notes rank *pari pasu* to the revolving credit facilities.

The payment of principal and interest are allowable deductions in the calculation of cash available for distribution to unitholders and rank in priority to 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.

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

8. ASSET RETIREMENT OBLIGATIONS

The total future asset retirement obligation was 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 $66.7 million as at December 31, 2003 based on a total future liability of $218 million. These payments are expected to be made over the next 61 years with the majority of costs incurred between 2014 and 2018. The Trust's credit adjusted risk free rate of seven per cent and an inflation rate of 1.5 per cent were used to calculate the present value of the asset retirement obligation.

The following table reconciles the Trust's total asset retirement obligation:

	2003	2002
Carrying amount, beginning of year	**$ 42,250**	$ 37,239
Increase in liabilities during the year	**23,662**	5,434
Settlement of liabilities during the year	**(2,213)**	(3,030)
Accretion expense	**2,958**	2,607
Carrying amount, end of year	**$ 66,657**	$ 42,250

9. 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 and foreign exchange 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 is exposed to losses in the event of default by the counterparties to these derivative instruments. The Trust manages this risk by diversifying its derivative portfolio amongst a number of financially sound counterparties.

Financial instruments of the Trust carried on the balance sheet consist mainly of current assets, reclamation fund investments, current liabilities, retention bonuses, commodity and foreign currency contracts and long-term debt. Except as noted below, as at December 31, 2003 and 2002, there were no significant differences between the carrying value of these financial instruments and their estimated fair value.

Substantially all of the Trust's accounts receivable are due from customers in the oil and gas industry and are subject to the normal industry credit risks. The carrying value of accounts receivable reflects management's assessment of the associated credit risks.

The fair value of the US$65 million fixed rate Notes approximated CDN$85.3 million as at December 31, 2003 (CDN$109.5 million in 2002).

During the year, the Trust terminated foreign exchange contracts with four different counterparties which resulted in a cash payment to the Trust of $11.9 million. To December 31, 2003, $10.5 million of the payment had been amortized to earnings and the remaining $1.4 million has been recorded on the consolidated balance sheet as commodity and foreign currency contracts.

The following derivative contracts were outstanding as at December 31, 2003. Settlement of these contracts, which have no book value, would have resulted in a net payment by the Trust of $14.8 million as at December 31, 2003.

Commodity Contracts	Daily Quantity	Average Contract Prices ($) (1)	Price Index	Term
Crude oil fixed price contracts (2)	6,500 bbls	34.89	WTI	January – March 2004
	2,000 bbls	33.60	WTI	April – June 2004
Crude oil fixed price contracts (embedded put option) (3)	7,000 bbls	35.91 (30.09)	WTI	January – March 2004
	11,000 bbls	37.13 (31.02)	WTI	April 2004
	11,000 bbls	37.20 (31.02)	WTI	May – June 2004
	5,000 bbls	36.72 (31.02)	WTI	July – December 2004
Crude oil collared contracts (embedded put option) (3)	2,000 bbls	31.02 – 35.54 (25.85)	WTI	January – December 2004
Natural gas fixed price contracts	15,000 GJ	6.75	AECO	January – March 2004
	10,000 mmbtu	5.23	NYMEX	January – March 2004
	5,000 GJ	6.25	AECO	April – October 2004
	10,000 mmbtu	4.65	NYMEX	April – October 2004
Natural gas collared contracts	15,000 GJ	5.00 – 6.63	AECO	April – October 2004
Natural gas collared contracts (embedded put option) (3)	30,000 mmbtu	6.68 – 10.06 (5.39)	NYMEX	January – March 2004
Natural gas fixed differential contracts (4)	30,000 mmbtu	0.6467	AECO/NYMEX	January – March 2004
Natural gas put option	25,000 GJ	5.00	AECO	January – March 2004
Natural gas call option	5,000 GJ	7.00	AECO	January – March 2004
Natural gas fixed price physical delivery contract	5,275 GJ	6.74	AECO	January – March 2004

Foreign Currency Contracts	Average Monthly Contract Amount (US$000)	Average Contract Rate	Term
Fixed rate foreign exchange contracts (sell)	6,518	1.3575	January – December 2004
Fixed rate foreign exchange contracts (sell) (embedded put option) [(3)]	5,579	1.3418 (1.2686)	January – December 2004

Electricity Contract	Hourly Quantity	Contract Price ($)	Term
Fixed price electricity contract	5 MW/h	$63.00	January 2004 – December 2010

Of the remaining $4.9 million commodity and foreign currency contracts balance on the consolidated balance sheet, $3.5 million relates to the following natural gas contract which was assumed in conjunction with the Startech Energy Inc. acquisition. Settlement of this contract would have resulted in a net payment by the Trust of $3.8 million as at December 31, 2003.

Commodity Contracts	Daily Quantity	Average Contract Prices ($) [(1)]	Price Index	Term
Natural gas fixed price contracts	4,000 GJ	2.71	AECO	January – October 2004

(1) Commodity contracts denominated in US$ have been converted to CDN$ at the period end exchange rate of 1.2924.

(2) Counterparty exercised option on December 31, 2003 for a fixed price contract pursuant to a "swaption contract". The option was for a US$26.00/bbl fixed price oil contract for the period from January – June 2004.

(3) The counterparty may exercise a put option if index falls below the specified price (as denoted in brackets) on a monthly settlement basis.

(4) The differential between the AECO and NYMEX price indices has been fixed.

10. INTERNALIZATION OF MANAGEMENT CONTRACT

Effective August 29, 2002, the Trust acquired all of the outstanding common shares of ARC Resources Management Ltd., ("ARML"), the Manager of the Trust. Total consideration for the transaction consisted of a cash payment of $4.3 million, the issuance of 298,648 trust units and 3,281,279 exchangeable shares to the shareholders of ARML and the assumption of a liability to pay retention bonuses to the Management of the Trust in the amount of $5 million as detailed below:

Total consideration	
Cash	$ 4,247
Trust units issued	3,802
Exchangeable shares issued	41,771
Assumption of liability for retention bonuses	5,000
Costs associated with the transaction	1,083
Total purchase price	$ 55,903

Prior to the acquisition, the Trust paid fees to ARML equal to three per cent of net production revenue and fees of 1.5 per cent and 1.25 per cent, respectively, on the purchase price of acquisitions and dispositions in accordance with the terms of the management agreement between the Trust and ARML. The acquisition resulted in the elimination of all fees under the existing management agreement which would have otherwise been in effect for a minimum five year period. Effective August 29, 2002, all fees under the management agreement between the Manager and the Trust were eliminated pursuant to the internalization of the management contract.

Of the total purchase price, $30 million was capitalized as PP&E. The capitalized amount includes $25 million for ARML's three per cent interest in the net production revenue of the Trust over the agreement term based on existing established reserves at the time of the transaction and $5 million for the retention bonuses. The retention bonuses are to be paid over a five year period to former management of ARML who are continuing in their capacities with the Trust.The remaining portion of the purchase price of $25.9 million was expensed in the current period. The expensed portion represents future management, acquisition and disposition fees on incremental reserves over the remaining five year term of the management agreement and the value of directly hiring existing management and staff of ARML.

Total acquisition and disposition fees paid to the Manager in 2002, prior to the elimination of the management agreement on August 29, 2002, were $895,000. These fees were accounted for as either part of the purchase price or as a reduction of the proceeds of disposition of PP&E. During 2002, the Manager was reimbursed $9,327,000 for general and administrative expenses incurred on behalf of the Trust to the date of the elimination of the management agreement on August 29, 2002.

11. INCOME TAXES

In 2003, Royal Assent was received, thereby legislating certain reductions in corporate income tax rates. The rate reductions are to be phased in over five years commencing in 2003. The rate changes incorporate a reduction in the applicable tax rate on resource income from 28 per cent to 21 per cent, provide for the deduction of crown royalties and eliminate the deduction for resource allowance. As a result of the rate changes, the Trust's income tax rate applied to temporary differences decreased to approximately 35 per cent compared to 42 per cent effective January 1, 2003.

As a result of the change in corporate income tax rates, the Trust recorded a future income tax recovery of $66.1 million in 2003. Of this amount, $39.2 million was attributed to the future income tax liability recorded on the Star acquisition.

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

	2003	2002
Income before future income tax recovery	**$ 196,657**	$ 43,113
Expected income tax expense at statutory rates	**80,118**	18,366
Effect on income tax of:		
Net income of the Trust	**(92,299)**	(46,441)
Effect of change in corporate tax rate	**(66,099)**	–
Resource allowance	**(10,857)**	(3,820)
Non-deductible crown charges	**2,434**	3,681
Alberta Royalty Tax Credit	**39**	(230)
Capital Tax	**738**	584
Unrealized gain on foreign exchange	**(7,618)**	(74)
Future income tax recovery	**$ (93,544)**	$ (27,934)

The net future income tax liability is comprised of:

	2003	2002
Future tax liabilities:		
Capital assets in excess of tax value	**$ 326,720**	$ 173,848
Future tax assets:		
Attributed Canadian royalty income	**(6,767)**	(6,356)
Asset retirement obligations	**(17,721)**	(13,456)
Deductible share issue costs	**(267)**	(827)
Net future income tax liability	**$ 301,965**	$ 153,209

The petroleum and natural gas properties and facilities owned by the Trust's corporate subsidiaries have an approximate tax basis of $288.9 million ($210 million in 2002) available for future use as deductions from taxable income. Included in this tax basis are estimated non-capital loss carry forwards of $66 million ($74 million in 2002) which expire in the years through 2010.

No current income taxes were paid or payable in 2003 or 2002.

12. UNITHOLDERS' CAPITAL

The Trust is authorized to issue 650 million trust units of which 179.8 million units were issued and outstanding as at December 31, 2003.

On February 25, 2003, the Trust issued 12,500,000 trust units at $11.50 per unit for proceeds of $143.8 million ($136.4 million net of issue costs) pursuant to a public offering prospectus dated February 18, 2003.

On November 17, 2003, the Trust issued 14,500,000 trust units at $13.40 per trust unit for proceeds of $194.3 million ($184.4 million net of issue costs) pursuant to a public offering prospectus dated November 10, 2003.

Effective August 6, 2003, the Trust amended the Distribution Reinvestment Plan ("DRIP") in conjunction with the Trust's 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. In 2003, the Trust issued 982,563 units for proceeds of $12.5 million (242,000 units for proceeds of $2.9 million in 2002) pursuant to the DRIP.

	2003		2002	
Trust Units Issued	**Number of Trust Units**	**$**	Number of Trust Units	$
Balance, beginning of year	**123,305**	**1,172,199**	110,609	1,029,538
Issued for cash	**27,000**	**338,050**	10,000	120,500
Issued on conversion of convertible debentures (Note 4)	**27,027**	**320,000**	–	–
Issued to ARML shareholders (Note 10)	**–**	**–**	299	3,802
Issued on conversion of ARML exchangeable shares (Note 13)	**60**	**708**	1,086	13,683
Issued on conversion of ARL exchangeable shares (Note 13)	**504**	**4,962**	343	3,154
Issued on exercise of employee rights (Note 15)	**901**	**8,015**	726	5,035
Distribution reinvestment program	**983**	**12,461**	242	2,946
Trust unit issue costs	**–**	**(17,815)**	–	(6,459)
Balance, end of year	**179,780**	**1,838,580**	123,305	1,172,199

The Trust has a Unitholders' Rights Plan which provides for the issuance of additional Trust units in certain events when one party acquires more than 20 per cent of the outstanding units of the Trust.

13. EXCHANGEABLE SHARES

The 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.

ARL exchangeable shares 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. 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 or after February 1, 2004 until February 1, 2010. The ARL exchangeable shares are publicly traded.

The ARML exchangeable shares were issued on August 29, 2002 to shareholders of ARML at $12.73 per exchangeable share pursuant to the acquisition of all of the outstanding common shares of ARML (see Note 10). The issue price of the exchangeable shares was determined based on the ten day weighted average trading price of the trust units preceding the date of announcement of the transaction. The exchangeable shares issued to ARML shareholders were a new series of exchangeable shares which were not publicly traded. The ARML exchangeable shares had an exchange ratio of 1:1 at the time of issuance.

The ARML exchangeable shares were convertible (at the option of the holder) into trust units at any time. The number of trust units issuable upon conversion was based upon the exchange ratio in effect at the conversion date. The exchange ratio was calculated monthly based on the exchange ratio for the prior month times the cash distribution paid to unitholders divided by the ten day weighted average unit price preceding the record date. The exchangeable shares were not eligible for distributions and, any outstanding shares were redeemable by the Trust for trust units on or after August 30, 2005 until August 29, 2012.

On May 16, 2003, the Trust merged ARC Resources and ARML and in turn converted all issued and outstanding ARML exchangeable shares into ARL exchangeable shares. Pursuant to the merger, holders of ARML exchangeable shares received 0.80676 ARL exchangeable shares for each ARML exchangeable share. This transaction had no impact on the total number of Trust units outstanding or issuable for exchangeable shares. The terms of the ARL exchangeable shares were revised upon conversion to carry the same terms and provisions as had applied to the ARML exchangeable shares.

	2003		2002	
ARL Exchangeable Shares	**Number of Shares**	**$**	Number of Shares	$
Balance, beginning of year	**637**	**7,238**	915	10,392
Exchanged for trust units	**(361)**	**(4,962)**	(278)	(3,154)
Issued on conversion of ARML exchangeable shares	**1,735**	**27,380**	–	–
Balance, end of year	**2,011**	**29,656**	637	7,238
Exchange ratio, end of year	**1.49013**	**–**	1.31350	–
Trust units issuable upon conversion, end of year	**2,997**	**29,656**	837	7,238

ARML Exchangeable Shares	**2003** Number of Shares	$	2002 Number of Shares	$
Balance, beginning of year	**2,206**	**28,088**	–	–
Issued to ARML shareholders	**–**	**–**	3,281	41,771
Exchanged for Trust units	**(56)**	**(708)**	(1,075)	(13,683)
Converted to ARL exchangeable shares	**(2,150)**	**(27,380)**	–	–
Balance, end of year	**–**	**–**	2,206	28,088
Exchange ratio, end of year	**–**	**–**	1.04337	–
Trust units issuable upon conversion, end of year	**–**	**–**	2,302	28,088

14. RECONCILIATION OF CASH FLOW AND DISTRIBUTIONS

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

	2003	2002
Cash flow from operations before changes in non-cash working capital	**$ 396,180**	$ 223,969
Add (deduct):		
Cash withheld to fund current period capital expenditures	**(106,625)**	(35,612)
Reclamation fund contributions and interest earned on fund	**(6,157)**	(4,777)
Interest on convertible debentures	**(4,070)**	–
Current period accruals	**–**	37
Cash distributions	**279,328**	183,617
Accumulated cash distributions, beginning of year	**688,947**	505,330
Accumulated cash distributions, end of year	**$ 968,275**	$ 688,947
Cash distributions per unit (1)	**$ 1.80**	$ 1.56
Accumulated cash distributions per unit, beginning of year	**10.64**	9.08
Accumulated cash distributions per unit, end of year	**$ 12.44**	$ 10.64

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

15. TRUST UNIT INCENTIVE RIGHTS PLAN

The Plan was established in 1999. The Trust is authorized to grant up to 8,000,000 rights to its employees, independent directors and long-term consultants to purchase trust units, of which 7,839,088 rights were granted to December 31, 2003. The initial exercise price of rights granted under the Plan may not be less than the current market price of the trust units as at the date of grant and the maximum term of each right is not to exceed 10 years. 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 (10 per cent annually) of the Trust's net book value of PP&E (the "Excess Distribution"), as determined by the Trust.

During the year, the Trust granted 2,991,099 rights (1,334,072 in 2002) to employees, independent directors and long-term consultants to purchase Trust units at exercise prices ranging from $11.59 to $14.74 per Trust unit ($11.47 to $12.80 in 2002). Rights granted under the plan generally have a five year term and vest equally over three years commencing on the first anniversary date of the grant. In accordance with the Plan, the exercise price of the rights granted was reduced as a result of calendar year distributions to unitholders exceeding 10 per cent of the Trust's net book value of PP&E.

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

	2003		2002	
	Number of Rights	**Weighted Average Exercise Price ($)**	Number of Rights	Weighted Average Exercise Price ($)
Balance, beginning of year	**3,041**	**10.64**	2,509	9.05
Granted	**2,991**	**12.15**	1,334	12.57
Exercised	**(901)**	**8.89**	(726)	6.94
Cancelled	**(262)**	**11.61**	(76)	10.91
Balance before reduction of exercise price	**4,869**	**11.84**	3,041	11.05
Reduction of exercise price	**–**	**(0.55)**	–	(0.41)
Balance, end of year	**4,869**	**11.29**	3,041	10.64

A summary of the Plan as at December 31, 2003 is as follows:

Exercise Price at Grant Date ($)	Adjusted Exercise Price ($)	Number of Rights Outstanding	Remaining Contractual Life of Right (years)	Number of Rights Exercisable
8.20	4.58	81	0.33	81
9.10	6.11	103	1.33	104
11.94	10.24	680	2.34	309
12.57	12.28	1,114	3.42	309
12.15	11.77	2,891	4.39	–
12.09	11.29	4,869	3.75	803

The Trust recorded compensation expense and contributed surplus, based on the year-end unit price, of $3.5 million for three million rights issued on or after January 1, 2003. This amount was reduced by $0.01 million for rights issued on or after January 1, 2003, which were subsequently cancelled prior to vesting.

For rights granted in 2002, the Trust has elected to disclose pro forma results as if the amended accounting standard had been applied retroactively. For the year ended December 31, 2003, the Trust's net income would have decreased by $3.5 million for the estimated compensation cost associated with rights granted under the Plan between January 1 and December 31, 2002.

Pro Forma Results	**2003**	2002
Net income as reported	**290,201**	71,047
Less: compensation expense for rights issued in 2002 (1)	**3,483**	–
Pro forma net income	**286,718**	71,047
Basic net income per trust unit (2)		
As reported	**1.85**	0.59
Pro forma	**1.83**	0.59
Diluted net income per trust unit		
As reported	**1.82**	0.59
Pro forma	**1.79**	0.59

(1) No compensation expense has been recorded for 2002 as the adjusted exercise price of the rights exceeded the market price of the trust units.

(2) Net income in the basic per trust unit calculation has been reduced by interest on the convertible debentures of $4.1 million in 2003 (nil 2002).

16. BASIC AND DILUTED PER TRUST UNIT CALCULATIONS

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

	2003	2002
Weighted average trust units	**151,698**	116,474
Trust units issuable on conversion of exchangeable shares	**2,997**	3,139
Weighted average trust units and exchangeable shares (1)	**154,695**	119,613
Dilutive impact of rights and convertible debentures (2)	**5,105**	561
Dilutive trust units and exchangeable shares	**159,800**	120,174

(1) Weighted average trust units and exchangeable shares reflects the exchangeable shares outstanding at year-end having been converted at the year-end exchange ratio to represent the trust unit equivalent.

(2) Diluted unit calculations excluded 118,700 rights in 2003 (1,326,490 rights in 2002) which would have been anti-dilutive.

Net income in the basic per trust unit calculation has been reduced by interest on the convertible debentures of $4.1 million in 2003 (nil in 2002). There were no adjustments to net income in calculating diluted per share amounts.

2002 net income per trust unit has been restated for the change in accounting policy for asset retirement obligations.

17. COMMITMENTS AND CONTINGENCIES

The Trust is involved in litigation and claims arising in the normal course of operations. Management is of the opinion that any resulting settlements would not materially affect the Trust's financial position or reported results of operations.

The Trust has natural gas supply contracts with the Pan Alberta Aggregator Pool (the "Pool") which is expected to be terminated in 2004. Upon termination, the transportation and marketing commitments of the Pool will be assigned to the respective producers who hold natural gas supply contracts. Although amounts have not been determined at this time, it is expected that the Trust's portion of the commitments will not exceed $12 million from the date of termination date through to 2012.

The Trust has certain commitments regarding the purchase of fluids for reservoir injection purposes. The commitment amount is for the period 2004 through 2016. The Trust's portion of the commitment is currently estimated to be US$29 million for the period of 2004 through 2016. The annual amount is expected to vary over the commitment period.

18. 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 to 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.

	2003	2002
Net income as reported for Canadian GAAP	**$ 290,201**	$ 71,047
Adjustments:		
Depletion and depreciation (a,b)	**22,258**	22,932
Accretion of asset retirement obligation (b)	**–**	2,607
Unrealized gain (loss) on derivative instruments (e)	**3,706**	(28,943)
Interest on convertible debentures (d)	**(4,070)**	–
Unit based compensation (c)	**(6,991)**	(4,040)
Effect of applicable income taxes on the above adjustments	**(2,835)**	10,623
Net income under US GAAP before cumulative effect of change in accounting principle	**302,269**	74,226
Cumulative effect of change in accounting principle, net of applicable income taxes	**12,085**	–
Net income under US GAAP after cumulative effect of change in accounting principle	**$ 314,354**	$ 74,226
Net income per trust unit (Note 16)		
Basic		
Net income before cumulative effect of change in accounting principle	**1.95**	0.62
Cumulative effect of change in accounting principle	**0.08**	–
Net income after cumulative effect of change in accounting principle	**$ 2.03**	$ 0.62
Diluted		
Net income before cumulative effect of change in accounting principle	**1.89**	0.62
Cumulative effect of change in accounting principle	**0.08**	–
Net income after cumulative effect of change in accounting principle	**$ 1.97**	$ 0.62
Comprehensive income:		
Net income under US GAAP	**$ 314,354**	$ 74,226
Unrealized gain (loss) on derivative instruments, net of applicable income taxes	**3,692**	(11,897)
Comprehensive income (e)	**$ 318,046**	$ 62,329

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

	2003		2002	
	Canadian GAAP	**US GAAP**	Canadian GAAP	US GAAP
Property, plant and equipment	**$ 2,015,539**	**$ 1,848,317**	$ 1,424,291	$ 1,208,084
Commodity and foreign currency contracts	**(4,883)**	**(18,558)**	(9,210)	(33,020)
Future income taxes	**(301,965)**	**(270,838)**	(153,209)	(107,697)
Asset retirement obligation	**(66,657)**	**(66,657)**	(42,250)	(36,421)
Unitholders' capital	**(1,838,580)**	**(1,862,493)**	(1,172,199)	(1,185,551)
Contributed surplus	**(3,471)**	**–**	–	–
Accumulated earnings	**(648,304)**	**(478,146)**	(362,173)	(163,792)
Accumulated other comprehensive income	**–**	**(46)**	–	3,646

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 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) During 2003, the Trust adopted CICA Handbook Section 3110 – "Asset Retirement Obligations" for Canadian GAAP and SFAS 143 – "Accounting for Asset Retirement Obligations" for US GAAP. The transitional provisions differ between Canadian GAAP and US GAAP in that Canadian GAAP requires restatement of comparative amounts whereas US GAAP does not allow restatement. An adjustment to income under Canadian GAAP has been recorded to reflect the 2002 comparative amounts prior to restatement in accordance with US GAAP.

(c) Prior to January 1, 2003, compensation expense was recognized for Canadian GAAP based on the intrinsic value at the grant date of the rights granted to employees, directors and long-term consultants of the Trust under its Trust Unit Incentive Rights Plan. For the years ended December 31, 2003 and 2002, pro forma disclosures are included in the notes to the consolidated financial statements of the impact on net income and net income per trust unit had the Trust accounted for compensation expense based on the fair value of rights granted during 2002. Effective January 1, 2003, the Trust accounts for compensation expense for rights granted on or after January 1, 2003 based on the fair value method of accounting. The fair value of the rights has been determined as the intrinsic value of the rights at the exercise date or at the date of the financial statements for unexercised rights.

For US GAAP purposes, the Plan is a variable compensation plan as the exercise price of the rights is subject to downward revisions from time to time. Accordingly, compensation expense is determined as the excess of the market price over the adjusted exercise price of the rights at the end of each reporting period and is deferred and recognized in income over the vesting period of the rights. After the rights have vested, compensation expense is recognized in income in the period in which a change in the market price of the trust units or the exercise price of the rights occurs.

An adjustment to earnings has been recorded to reflect the additional compensation expense on rights issued prior to January 1, 2003.

(d) Under Canadian GAAP, convertible debentures are classified as unitholders' equity and interest paid on the convertible debentures has been recorded as a reduction of retained earnings. Under US GAAP, the convertible debentures are classified as long-term debt. Accordingly, an adjustment has been recorded to earnings to record interest expense on the convertible debentures. The applicable income tax has been included in the provision for income taxes.

(e) 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 document, designate, and assess the effectiveness of derivative instruments that receive hedge accounting treatment. 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. Certain contracts entered into during 2002 and 2003 were not eligible for hedge accounting treatment under US GAAP and the change in fair value of these contracts has been reported in net income under US GAAP. Hedge effectiveness is monitored and any ineffectiveness is reported in the consolidated statements of income.

The Trust's derivative positions consist of contracts entered into by the Trust and derivative positions assumed in conjunction with the Startech acquisition.

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

	2003		2002	
	Gross	**After Tax**	Gross	After Tax
Accumulated other comprehensive income (loss) beginning of period	**$ (6,350)**	**$ (3,646)**	$ 14,376	$ 8,251
Effect of change in corporate tax rate	**–**	**(118)**	–	–
Reclassification of net realized (gains) losses into earnings	**(2,677)**	**(1,586)**	1,038	596
Net change in fair value of derivative instruments	**9,105**	**5,396**	(21,764)	(12,493)
Accumulated other comprehensive income (loss), end of period	**$ 78**	**$ 46**	$ (6,350)	$ (3,646)

(f) The following standards and interpretations have been issued by the Financial Accounting Standards Board ("FASB") and the Trust has assessed the impact to be as follows:

- In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Instruments with Characteristics of Both Liabilities and Equity", which established standards for classifying and measuring certain financial instruments with characteristics of both liabilities and equity. It requires a financial instrument that is within its scope to be classified as a liability. SFAS No. 150 is effective for financial instruments entered into or modified after May 31, 2003, otherwise effective at the beginning of the first interim period beginning after June 15, 2003. The Trust has reflected this new standard in the December 31, 2003 US GAAP reconciliation by reclassing interest expense on convertible debentures from accumulated earnings as per Canadian GAAP to interest expense as per US GAAP. As at December 31, 2003 there were no instruments in place which would fall under the classifications of this standard. Management will continue to assess the applicability of this standard in future periods.

- FIN No. 46, "Consolidation of Variable Interest Entities," was issued in January 2003. FIN No.46 addresses consolidation by business enterprises of variable interest entities. In general, VIEs are entities that either do not have equity investors with voting rights or have equity investors that do not provide sufficient financial resources for the entity to support its activities. In December 2003, the FASB issued FIN No. 46R to clarify some of the provisions of FIN No. 46 and to exempt certain entities from its requirements. Application of FIN No. 46R (or FIN No. 46) is required in financial statements for periods ending after March 15, 2004. Management has determined that this standard was not applicable at December 31, 2003 based on the nature of the Trust's structure at that time. Management will continue to assess the applicability of this standard in future periods.

(g) The Trust presents cash flow before changes in non-cash working capital as a subtotal in the Consolidated Statements of Cash Flows. Under U.S. GAAP, this subtotal would not be presented.

OFFICERS AND SENIOR MANAGEMENT

The officers and senior management of ARC Resources are:

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 member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta. Mr. Dielwart is currently 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 from the University of Calgary. He has also been a Director of ARC since inception 1996.

Steven W. Sinclair, B. Comm., CA

Mr. Sinclair is Vice-President Finance and Chief Financial Officer of ARC Resources Ltd. and oversees all of the financial affairs of ARC Energy Trust. Mr. Sinclair has a Bachelor of Commerce degree 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.

Douglas J. Bonner, B.Sc., P.Eng.

Mr. Bonner is Vice-President, Engineering of ARC Resources Ltd. and is responsible for all exploitation and development activities. 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. Mr. Bonner is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta. 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, B.Sc., P.Eng., MBA

Mr. Carey is Vice-President, Business Development of ARC Resources Ltd. and is responsible for all facets of business development and investor relations. He holds both a B.Sc. in Geological Engineering and a MBA from Queen's University. Mr. Carey brings 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. Mr. Carey is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta. 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.

Danny G. Geremia, B. Comm., CA

Mr. Geremia is Treasurer of ARC Resources Ltd. and is responsible for all treasury-related activities. Mr. Geremia has a Bachelor of Commerce degree from the University of Calgary and obtained his Chartered Accountant's designation in 1999. Prior to joining the Trust in December 1999, Mr. Geremia worked with a major public accounting firm in both their audit and taxation departments. Mr. Geremia is currently a member of the Treasury Management Association of Canada.

Susan D. Healy, P. Land

Ms. Healy, Vice-President, Land is responsible for all Land related activities for ARC Resources Ltd. Ms. Healy joined the Trust at inception in July 1996, and has over 24 years of diverse experience gained from working with junior and senior oil and gas companies. Ms. Healy has a Professional Land designation granted by the Canadian Association of Petroleum Landmen.

Myron M. Stadnyk, B.Sc., P.Eng.

Mr. Stadnyk is Vice-President, Operations of ARC Resources Ltd. and is responsible for all of ARC's operational activities. He has 18 years experience in all aspects of oil and gas production operations. Prior to joining ARC Resources Ltd. in 1997, Mr. Stadnyk worked with a major oil and gas company in both domestic and international operations and oil and gas facility design and construction. He has a B.Sc. in Mechanical Engineering and is a member of the Association of Professional Engineers, Geologists and Geophysicists in Alberta and the Association of Professional Engineers and Geoscientists in Saskatchewan.

Allan R. Twa, Q.C.

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. Mr. Twa is the Corporate Secretary.

DIRECTORS

John M. Beddome, B.Sc. Chem. Eng.

Mr. Beddome has been responsible for many significant projects in oil and gas exploration, production, transportation and processing during a career that included assignments as President of Dome Petroleum Ltd., Chairman of TransCanada Pipelines Ltd., CEO of Alberta Natural Gas Company Ltd. and other executive positions in the industry. Now an independent businessman and consultant, Mr. Beddome recently retired as a Director of PanCanadian Petroleum Ltd. and Chairman of IPSCO Steel Inc. Mr. Beddome is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta. Mr. Beddome has been a Director of ARC since 1996.

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 of 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, B.A.Sc., P.Eng., MBA

Mr. DeBoni currently holds the position of VP, Canada Frontier & International Business, for Husky Energy Inc. and was formerly CEO of Bow Valley Energy for a number of years. He has 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, an 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 currently past Chairman of the board of governors for the Canadian Association of Petroleum Producers (CAPP). Mr. Dielwart is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta. He holds a Bachelor of Science with Distinction (Civil Engineering) degree from the University of Calgary. He has also been a Director of ARC since 1996.

Fred Dyment

Mr. Dyment has 29 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, ZCL Composites Inc. and Transglobe Energy Corporation. 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 Energy Trust and Devon Energy Corporation. He has been a Director of ARC since 1996.

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 an MBA from the University of British Columbia. Prior to joining ARC Financial, he was a Director and Vice-President of a major national investment firm. His career and experience span over 30 years with a focus on oil and gas and finance. Mr. Stewart has been a Director of ARC Resources Ltd. since 1998.

Mac H. Van Wielingen

Mr. Van Wielingen became Chairman of ARC in 2003, prior to which he served as Vice-Chairman and Director of ARC Resources Ltd. since its formation in 1996. He is Chairman and was a founder of ARC Financial Corporation in 1989. 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) (5)
Chairman

Walter DeBoni (1) (3) (4)
Vice-Chairman

John P. Dielwart
President and Chief Executive Officer

John M. Beddome (2) (4)

Frederic C. Coles (2) (3)

Fred J. Dyment (1) (2)

Michael M. Kanovsky (1) (2)

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) Member of Management Advisory Committee

OFFICERS

John P. Dielwart
President and Chief Executive Officer

Doug J. Bonner
Vice-President, Engineering

David P. Carey
Vice-President, Business Development

Susan D. Healy
Vice-President, Land

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

Myron M. Stadnyk
Vice-President, Operations

Allan R. Twa
Corporate Secretary

Danny G. Geremia
Treasurer

EXECUTIVE OFFICES

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Gilbert Laustsen Jung Associates Ltd.
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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

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www.arcresources.com
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(403) 503-8600 or
1-888-272-4900 (Toll Free)

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UNITHOLDER INFORMATION

Notice of the Annual General Meeting

The Annual General Meeting will be held on May 12, 2004 at 3:30 p.m. in the Belair Room at the Westin Hotel, 320 – 4 Avenue SW, Calgary, Alberta.

Distribution Reinvestment and Optional Cash Payment Program

New ARC Energy Trust unitholders should be aware of the Distribution Reinvestment Plan (DRIP) under which a registered unitholder can elect to reinvest cash distributions into new ARC Energy Trust units. If distributions are reinvested, a unitholder can elect to make optional cash payment under the DRIP between a minimum of $500 to a maximum of $3,000 per distribution date to purchase additional trust units. All units purchased under the DRIP are made at 95 per cent of the prevailing market prices without any additional fees or commissions. For further details on the DRIP please refer to our website, www.arcresources.com or contact Computershare.

U.S. Tax Information

ARC Energy Trust is considered a "corporation" for U.S. Tax reporting purposes. For 2003 (and prior years), U.S. unitholders should prepare their U.S. Individual Tax Returns on the basis that the Trust is a "corporation" for U.S. tax purposes. As a corporation, distributions paid by the Trust in 2003 will be viewed as dividends that may be eligible for the new low rate of tax on certain "qualified dividends". For additional information, please access our website at www.arcresources.com.

Corporate Calendar

2004

April 16	Announcement of Q2 distribution Monthly Amounts
May 5	2004 Q1 Results
May 12	Annual General Meeting
July 16	Announcement of Q3 distribution Monthly Amounts
October 15	Announcement of Q4 distribution Monthly Amounts

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