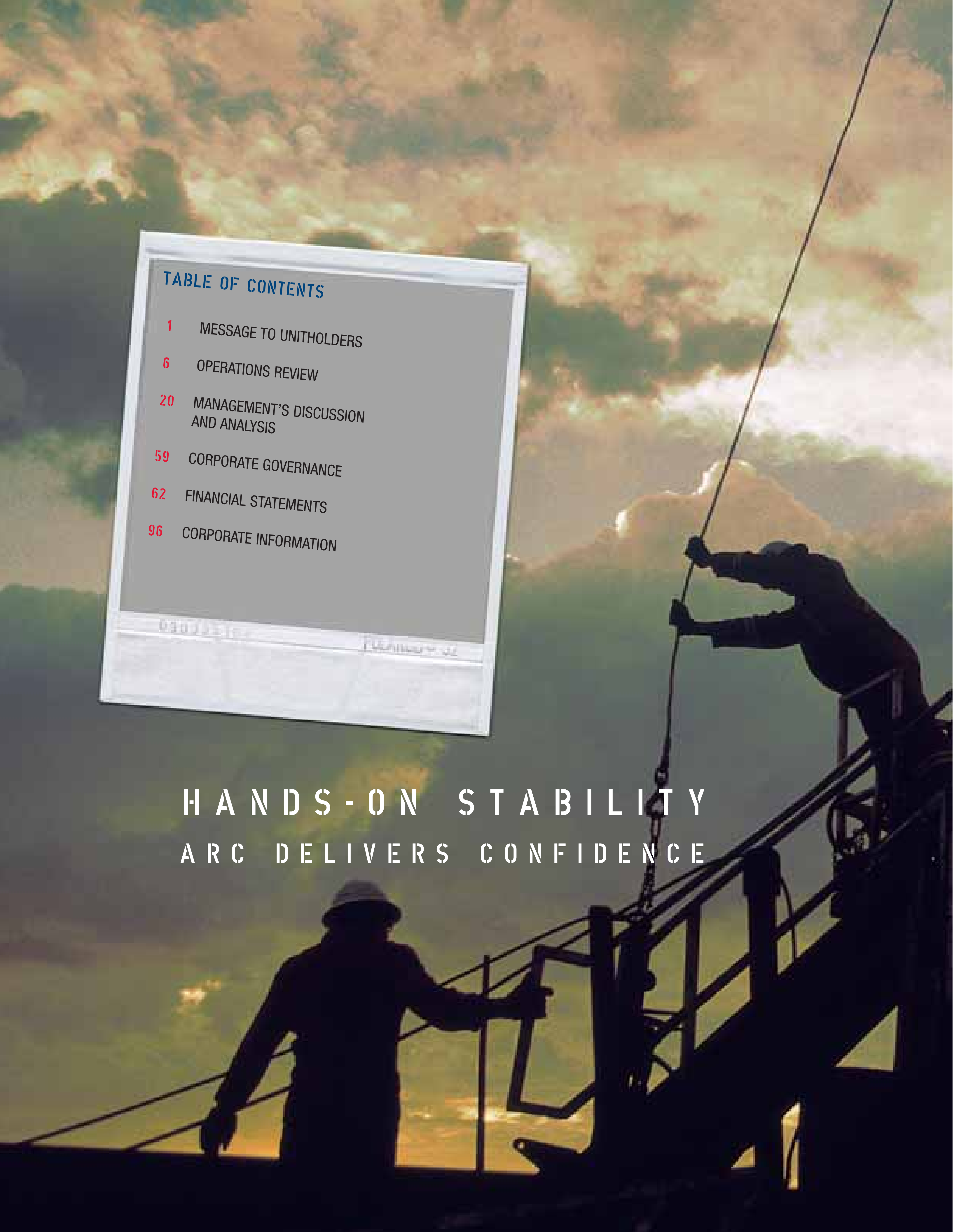
HANDS-ON PERFORMANCE

A REPORT FROM THE FIELD

ARC REPORT 2004

ARC ENERGY TRUST



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HANDS-ON STABILITY

ARC DELIVERS CONFIDENCE

HIGHLIGHTS

Year ended December 31	**2004**	2003
FINANCIAL		
(CDN$ thousands, except per unit and per boe amounts)		
Revenue before royalties (2)	**901,782**	743,182
Per unit (1)	**4.92**	4.90
Per boe (6)	**43.32**	37.47
Cash flow (3)	**448,033**	396,180
Per unit (1)	**2.45**	2.61
Per boe (6)	**21.52**	19.98
Net income (7)	**241,690**	284,559
Per unit (1) (7)	**1.32**	1.88
Cash distributions	**329,977**	279,328
Per unit (1)	**1.80**	1.80
Payout ratio	**74%**	71%
Net debt outstanding (4)	**264,842**	262,071
OPERATING		
Production		
Crude oil (bbl/d)	**22,961**	22,886
Natural gas (mcf/d)	**178,309**	164,180
Natural gas liquids (bbl/d)	**4,191**	4,086
Total (boe/d) (6)	**56,870**	54,335
Average prices (2)		
Crude oil ($/bbl)	**47.03**	36.90
Natural gas ($/mcf)	**6.78**	6.40
Natural gas liquids ($/bbl)	**39.04**	32.19
Oil equivalent ($/boe) (6)	**43.13**	37.29
Netback ($/boe)		
Commodity and other revenue (before hedging)	**43.32**	38.27
Royalties	**(8.51)**	(7.61)
Operating and transportation costs	**(7.42)**	(7.70)
Netback (before hedging)	**27.39**	22.96

(1) Per unit amounts (with the exception of per unit distributions) are based on weighted average units.

(2) 2003 prices and revenue have been reclassified to reflect prices prior to transportation charges. 2003 average prices are inclusive of gains and losses on commodity and foreign currency contracts while 2004 average prices are prior to gains and losses on commodity and foreign currency contracts, pursuant to the new policy for hedge accounting.

(3) 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 report are based on cash flow before changes in non-cash working capital.

(4) The 2004 net debt outstanding excludes amounts related to commodity and foreign exchange contracts.

Year ended December 31		**2004**	2003
RESERVES (9)	**2004 Gross Reserves**	**Company Interest Reserves**	
Proved reserves			
Crude oil and NGL's (mbbl)	**95,100**	**95,734**	102,226
Natural gas (bcf)	**576.4**	**589.4**	720.2
Total oil equivalent (mboe)	**191,160**	**193,973**	202,229
Proved plus probable reserves			
Crude oil and NGL's (mbbl)	**122,477**	**123,226**	129,663
Natural gas (bcf)	**709.9**	**724.5**	720.2
Total oil equivalent (mboe)	**240,788**	**243,974**	249,704
FINDING, DEVELOPMENT AND ACQUISITION COSTS ($/boe) (8)			
Including Future Development Capital			
Current year		**19.14**	10.54
Three year average		**11.65**	10.52
Excluding Future Development Capital			
Current year		**13.76**	8.50
Three year average		**9.30**	9.07
TRUST UNITS (thousands)			
Units outstanding, end of period		**185,822**	179,780
Units issuable for exchangeable shares		**2,982**	2,997
Total units outstanding and issuable for exchangeable shares, end of period		**188,804**	182,777
Weighted average units (5)		**183,123**	151,698
TRUST UNIT TRADING STATISTICS (CDN$, except volumes) based on intra-day trading			
High		**17.98**	14.87
Low		**13.50**	10.89
Close		**17.90**	14.74
Average daily volume (thousands)		**420**	430

(5) Excludes exchangeable shares.

(6) Barrels of oil equivalent (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:1bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. References to boe's throughout this quarterly report are based on a conversion ratio of 6:1.

(7) Net income and net income per unit is after non-controlling interest pertaining to exchangeable shares. 2003 net income and net income per unit have been restated due to the retroactive application of non-controlling interest (see "Impact of New Accounting Policies" in this MD&A and Note 3 of the consolidated financial statements for further discussion).

(8) Based on proved plus probable company interest reserves before royalties.

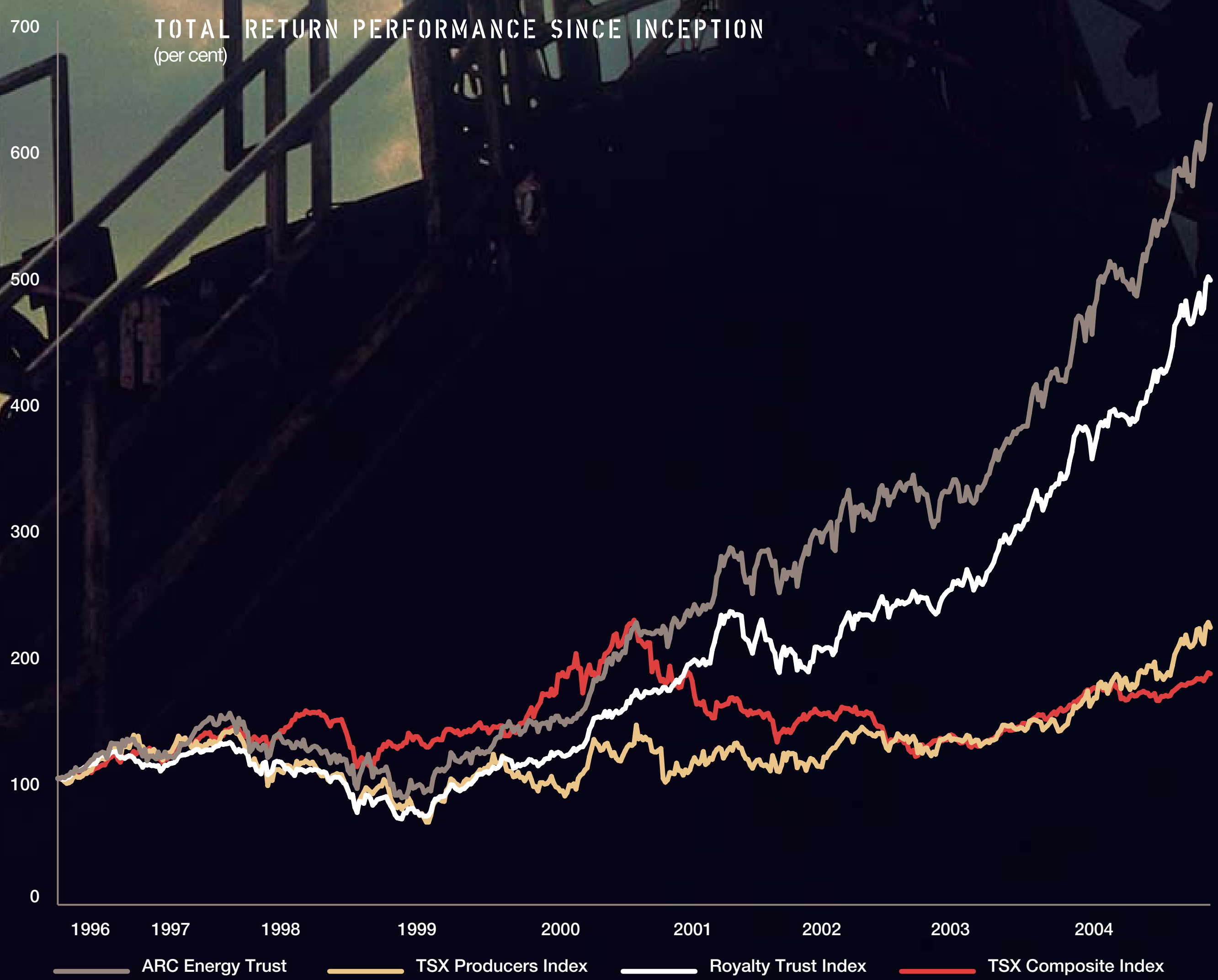
(9) Based on company interest reserves before royalties.

ARC Energy Trust (the “Trust” or “ARC”) is one of Canada's largest conventional oil and gas royalty trusts. As an actively managed royalty trust, we acquire and develop long-life, lower declining oil and gas properties in western Canada. 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.

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 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 Trust has consistently outperformed the TSX Composite Index and the TSX Producers Index. We have provided our unitholders with a superior 24.6 per cent compound annual return since our inception in 1996. Our annual return in 2004 was 35.8 per cent. We remain committed to generating superior returns and long-term value.

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



HANDS-ON STRATEGY

MESSAGE TO UNITHOLDERS

ARC Energy Trust ("ARC" or the "Trust") has a very hands-on approach to production sustainability with a focus on organic reserve replacement. Record capital expenditures of $194 million on our internal development opportunities dwarfed the $16 million spent on acquisitions net of divestments. This focus on development of our exceptional asset base will continue in 2005 with a capital budget of $240 million directed at providing growth through the drill bit.

ARC and the oil and gas industry as a whole enjoyed an unprecedented year in 2004. The significant increase in the price of West Texas Intermediate ("WTI") crude oil spurred heated activity in the oil and gas industry that created both opportunities and challenges typical to any business sector working at or near full capacity. As a result of its high-quality asset base and large inventory of value-adding development opportunities, ARC once again enjoyed a record breaking year for revenues, above forecast drilling results and maintained a balance sheet that was among the strongest in the sector.

ECONOMIC ENVIRONMENT

The strong global economy and politics were the dominant drivers for the upsurge in the price of oil in 2004. Oil prices fluctuated widely during the year with WTI achieving a high of US$55.17, a low of US$32.52 and closing the year at US$43.45. The fluctuating prices were primarily due to political uncertainty in key oil producing countries, very tight, just-in-time global supply and robust economies in many regions of the world, specifically in Asia. There is consensus among analysts that economic growth in Asia will remain strong in 2005 and political instability will continue in the Middle East, therefore oil prices are anticipated to stay high.

OPEC's spare capacity, or more correctly lack thereof, appears to be a key factor in determining oil prices. The less spare capacity – the higher the oil price. Analysts forecast that spare capacity for OPEC in 2005 will average between 1.5 mmb per day and 2 mmb per day. With worldwide demand expected to grow by 1 to 2 mmb per day as a result of continued strong economic growth in 2005, with limited new supplies expected to be brought on stream, markets are expected to remain tight, which would support a continued strong oil price environment.

North American natural gas prices also experienced a high degree of volatility in 2004 with a peak price of $8.29 per GJ at AECO, a low price of $4.10 per GJ and a year-end price of $5.90 per GJ. The weather and its impact on storage levels is typically the main driver for natural gas prices, however in 2004, the gas prices were being "pulled up" by the record oil price during the year. As a result, gas prices were higher than would normally have been the case for the actual storage levels experienced during the year. Demand for natural gas in North America throughout 2004 was at the lower end of the range for the past five years and is expected to remain relatively flat in 2005. At the same time, production has been gradually increasing resulting in storage levels at the high end of the five year range. While this outlook does create some cause for concern with respect to gas prices in 2005, anticipated strong oil prices are expected to once again lift gas prices to higher levels than would otherwise be the case.

REGULATORY CHANGES

Various legislative and regulatory changes took place in 2004 affecting our industry directly. At the end of 2003, new reserves reporting guidelines came into effect for all publicly traded oil and gas producers. National Instrument 51-101 ("NI 51-101") standardized how oil and gas producers report their reserves information resulting in many oil and gas producers writing down a portion of their reserves. ARC was pleased to announce that it suffered no negative effects with the implementation of NI 51-101. For 2004, we are pleased to record our eighth consecutive year of positive reserve revisions, clearly demonstrating the high quality nature of our assets.

In March 2004, the Federal Government proposed changes to current legislation governing mutual fund trusts to ensure that the foreign ownership of income and royalty trusts does not exceed 50 per cent. It also proposed that the 15 per cent withholding tax be applied to all distributions paid to non-residents rather than just the taxable portion of distributions. The proposed changes were of serious concern to the royalty trust sector as a number of trusts had foreign ownership levels that exceeded 50 per cent.

Although ARC's foreign ownership level is approximately 25 per cent, we were very concerned about the proposed changes since the oil and gas industry has always relied on foreign investment to support its activities. Any move by the government to impose restrictions on our access to capital could have negative implications in the future. In response to input from the trust sector, the government deferred implementation of the foreign ownership restrictions pending further discussions with the industry with the exception of the 15 per cent witholding tax. The proposed changes to the withholding tax were implemented effective year-end 2004. We will continue to work with federal finance officials on the foreign ownership issue to ensure that our sector's concerns will be heard.

On July 1, 2004, the Alberta Government passed legislation limiting the liability of investors who own units in income and royalty trusts. ARC played a major role in lobbying the government for this legislation which gives unitholders of trusts similar liability protection to that enjoyed by shareholders of corporations. Ontario passed similar legislation later in the year. This legislation was very important to the trust sector since many institutions were not able invest in our equity without this legislated protection. The lack of legislated liability protection was also cited as the major reason trusts were not included in the main stock market index that drives many fund managers' equity holdings.

In response to the legislated liability protection for unitholders of trusts, on January 26, 2005, Standard and Poors ("S&P") announced that income funds and royalty trusts would become eligible for inclusion in the S&P/TSX Composite Index. Of particular importance was the fact that trusts will be included in a new "Super Composite Index" rather than a sub-index. This decision is particularly significant since it removes the last major obstacle that prevented certain institutional investors from investing in our sector. As ARC is one of the largest trusts, it is expected to be one of the first to be added to the index (expected to occur by mid-2005). Pending index inclusion coupled with ARC's strong reputation and high quality asset base, we believe, has already resulted in buying support for our units by new institutional investors.

As the trust sector in Canada continues to grow, it is essential that entities such as ARC have access to investor capital on the basis of merit and not have restrictions imposed on certain segments of the investment community. We believe the developments in 2004 and early 2005 relating to our sector remove such restrictions, which should bode well for our access to capital in the future. We are confident that the discussions with the federal government regarding the foreign ownership issue can be resolved in a manner that does not restrict our access to future foreign investment.

RISK MANAGEMENT

A fundamental component of ARC's business plan is a comprehensive risk management program to mitigate the impact of material fluctuations in commodity prices in order to allow us to provide stable distributions to unitholders. As we entered 2004, most analysts were forecasting oil prices to be in the mid to upper US$20 range. At that level, analyst estimates included distribution cuts in 2004 for all trusts including ARC. At the same time, ARC had the opportunity to hedge its oil in the low to mid US$30 range, which would have allowed us to maintain our distribution of $0.15 per unit. Accordingly, we hedged approximately 50 per cent of our oil production at these levels using a variety of derivative instruments that protected the downside while limiting our ability to participate in any upside which may exist.

As we all now know, the oil price in 2004 was at its highest level in history, well above expectations for even the most bullish forecaster. As a result, ARC incurred significant hedge losses in 2004. In response to what we believe is a new pricing paradigm that includes a much wider potential range for prices going forward, ARC has modified its go-forward hedging strategy to include much greater use of "floors". This is comparable to buying insurance where for a known cost we can guarantee a minimum price while still participating in all of the upside above that price. We elected to unwind a number of our 2005 commodity and foreign exchange hedges late in 2004 and re-hedge using floors for the commodity contracts and swap arrangements for the foreign exchange hedges. As a result, our 2005 hedge program includes a blend of instruments that will protect our current level of distributions while exposing us to potential upside on approximately 85 per cent of production.

ACQUISITIONS AND DISPOSITIONS

The trust sector in general continues to rely on acquisitions to replace the majority of its production. As a result, acquisition prices in 2004 were at historic highs due to the ever increasing size of the sector and increased demand for assets in the acquisition market. ARC is in the enviable position of having sufficient internal development opportunities to maintain production in the near-term (12 to 24 months) without acquisitions. Accordingly, our acquisition focus in 2004 was on strategic acquisitions in our existing core areas. We completed two such acquisitions in 2004. In the second quarter, ARC increased its ownership in the Cranberry Slave Point D Pool in the Prestville area from 70 to 100 per cent through the purchase of a private company for $30 million. At the end of December, ARC purchased a group of private companies for $41 million, which increased our interest to almost 60 percent in the Crane Lake area of southwest Saskatchewan.

ARC will continue to review all acquisition opportunities in the market and pursue those opportunities that would enhance our existing portfolio of high-quality assets. ARC's acquisition strategy focuses on acquiring high-quality, long-life or stable cash flow assets in the broad energy realm, which could include assets in oilsands, coal bed methane projects, infrastructure assets and power generation projects including green power. Included in this strategy would be international assets within these areas.

ARC has a disciplined approach to asset management that includes periodic disposition of assets that no longer meet the long-term needs of the trust. We took advantage of the strong asset sale market in 2004 to dispose of $58 million of such properties under attractive terms. Although our acquisition and development activities replaced 117 per cent of production in 2004, when factoring in dispositions, our year-end reserves declined modestly.

OUTLOOK FOR 2005

ARC's guidance for 2005 includes a stable distribution of $0.15 per unit for a third consecutive year assuming the commodity price outlook does not change materially, a production target of 54,800 boe per day and a capital expenditure budget (excluding acquisitions) of $240 million. The 2005 capital expenditure budget is the largest in ARC's history and highlights our strong inventory of internal development opportunities. ARC plans on drilling 290 gross operated wells in 2005, our largest drilling program ever. With the price for assets in the acquisition market expected to remain high, ARC will continue to focus on reserve replacement through its development activities in existing properties supplemented with "tuck in" strategic acquisitions in its core operating areas. Additional asset dispositions to take advantage of the market will also be given consideration.

ARC will continue to manage its business to provide unitholders with the highest possible returns over the long term. Our focus remains to: deliver stable distributions to our unitholders, maintain a strong balance sheet to position the Trust to be able to pursue opportunistic acquisitions, continually high grade our existing high-quality asset base and retain high-quality employees to execute the Trust's strategic business plan.

John Dielwart

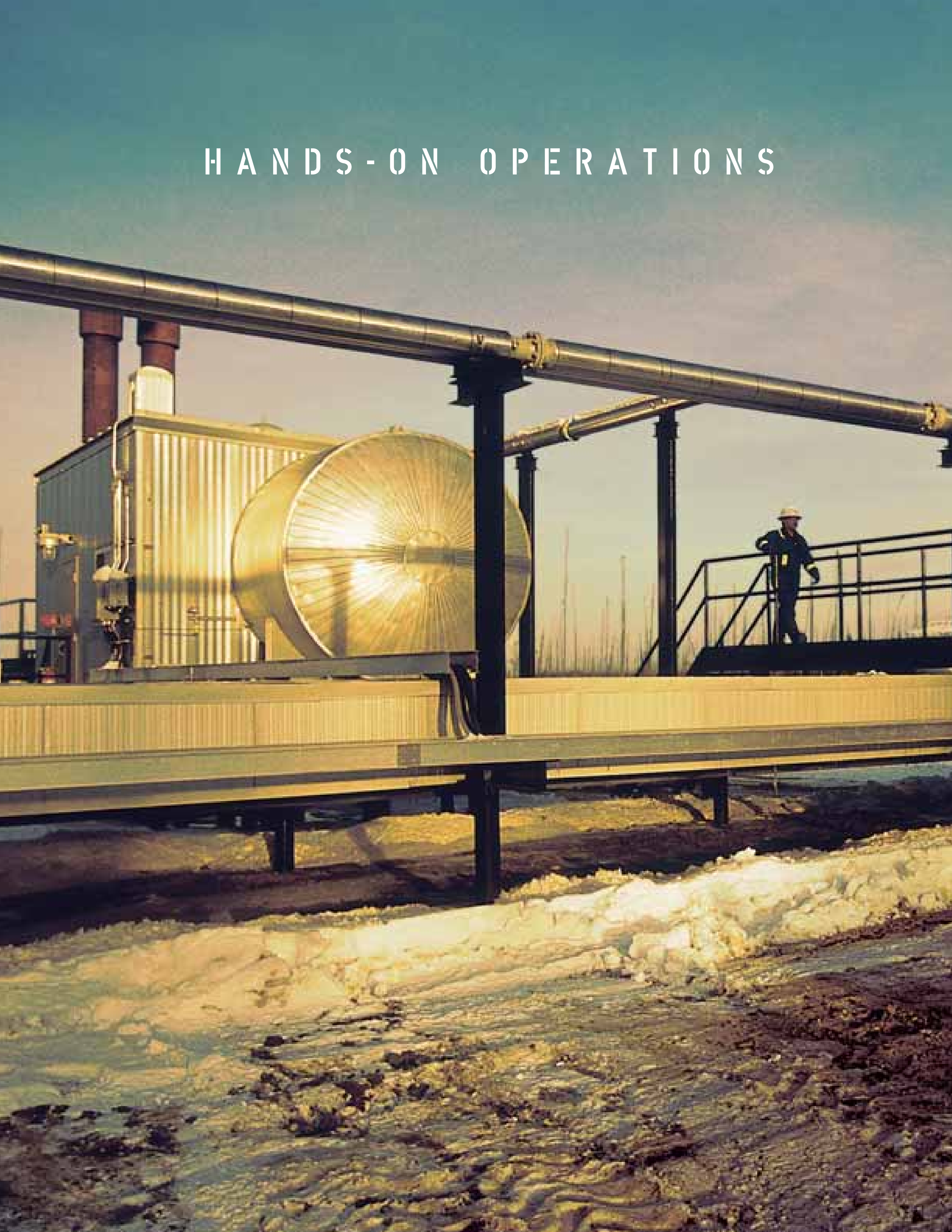
John P. Dielwart

President and Chief Executive Officer

February 10, 2005

ARC WILL CONTINUE TO FOCUS ON RESERVE REPLACEMENT THROUGH ITS DEVELOPMENT ACTIVITIES IN EXISTING PROPERTIES SUPPLEMENTED WITH "TUCK IN" STRATEGIC ACQUISITIONS IN ITS CORE OPERATING AREAS.

HANDS-ON OPERATIONS



MAJOR PROPERTIES MAP

HATTON

TOTAL PROVED PLUS PROBABLE RESERVES

243,974 MBOE

2004 AVERAGE PRODUCTION

56,870 BOE/D

NETBACK (AFTER HEDGING)

$20.67 BOE

ARC ENERGY TRUST

Background Map Courtesy of Alberta Geological Survey, EUB

OPERATIONAL SUMMARY

Area	NI 51-101 Proved plus Probable Reserves	Proved plus Probable Reserves	% of Total Proved plus Probable Reserves	2004 Average Production	% of Total Production
	(gross)	(company interest)			
Central Alberta	21,202	21,429	8.8	9,295	16.3
SE Alberta/SW Saskatchewan	52,257	53,745	22.0	10,871	19.1
Northern Alberta & BC	84,889	85,813	35.2	19,026	33.5
SE Saskatchewan	44.407	44,450	18.2	10,245	18.0
Pembina	38,033	38,537	15.8	7,433	13.1
Total	**240,788**	**243,974**	**100.0**	**56,870**	**100.0**

OPERATIONS REVIEW

In 2004, ARC safely and successfully executed the largest development program in its history. The $194 million capital program was directed at capitalizing on the numerous development opportunities that exist within our high-quality asset base.

DRILLING AND DEVELOPMENT ACTIVITY

ARC's drilling activity in its operated properties included 194 gross wells (165 net wells). Of these, 47 gross (42 net) wells were oil wells and 145 gross (121 net) were gas wells. Although ARC drilled wells in all of its core areas, the majority of the drilling was undertaken in the southeast Alberta/southwest Saskatchewan area, specifically in Jenner North where 57 gross wells (56 net) were drilled and in Hatton where ARC drilled 40 gross wells (25 net). All of these wells have been successfully tied-in and brought on production. The Hatton, Horsham and Crane Lake areas of southwest Saskatchewan will see significant ongoing drilling activity over the next three to six years as we develop over 800 infill locations required to downspace to 80 acre spacing.

In southeast Saskatchewan, 2004 proved to be the most productive year to date. Initial production of over 1,500 barrels of oil per day was added through the drilling of six horizontal wells. The positive outcome from the 2004 drilling has proved up additional drilling locations for 2005. At ARC's Lougheed field, ARC continued to expand the waterflood to the north of the field with the addition of three new injectors and also undertook significant facility expansion to increase injection pressure and capacity.

Another area with substantial activity was ARC's Cranberry Slave Point D Pool in the Prestville property in northern Alberta. The initial discovery well was drilled in 2003 and tested light, sweet crude oil at rates of up to 650 barrels per day. Subsequent drilling at two other locations also encountered the same thick dolomitized Slave Point interval. During 2004, ARC constructed production facilities capable of handling 3,000 boe per day of production and conducted technical work which confirmed that the Cranberry Slave Point D Pool is amenable to waterflooding. Five new wells planned for 2005 will be followed by waterflood facilities construction and injector conversion. This area is currently subject to rate limitations that restrict production to approximately 1,000 boe per day. Rate restrictions will be removed when ARC receives approval for a waterflood of the field. We anticipate a ramp up in production towards year-end 2005 to approximately 2,000 boe per day.

ARC continues to develop its Ante Creek and Dawson properties in its northern Alberta and British Columbia core area. ARC has developed significant expertise in developing tight oil and gas formations such as Ante Creek and Dawson, respectively. Tight reservoirs are characterized by low permeability rock. To successfully produce from these formations, large hydraulic fracture stimulations are required along with sophisticated completion techniques. Capital costs in these types of resource plays require a higher commodity price than conventional projects but deliver a much more stable long-term return. After an initial period of steep decline, these wells will produce at stable rates for a long time and have long-life reserve life index ("RLI's"). These properties are very attractive since more of the hydrocarbons-in-place will be recovered over time as drilling and completion technology advances.

ARC's major tight gas development is the Dawson field in northeast British Columbia where ARC drilled five wells in 2004. Due to the early stage nature of the development, ARC's proved reserves in Dawson are based on a 15 per cent recovery factor; however, analogous areas show recoveries of up to 25 per cent after only 10 years of production. The RLI on ARC's Dawson property is 24.2 years. Significant ongoing drilling activity will occur in Dawson over the next three to five years as we fully develop the property.

Ante Creek is ARC's major tight oil property. Since the acquisition of our initial interests in the area in 2000, ARC has amassed a significant land base in the area and has been able to undertake a disciplined drilling and optimization program. This continued in 2004 with a successful step-out drilling program that included nine vertical wells bringing the total wells drilled to date to 61 with a 100 per cent success rate.

All of ARC's core areas have significant development opportunities identified for 2005. ARC's capital development program for 2005 is budgeted at $240 million, an increase of $46 million (24 per cent) over the 2004 expenditures. The additional $46 million is budgeted to cover increases in costs and services and also to enable ARC to exploit new strategic opportunities that include natural gas from coal (NGC), also known as coal bed methane, and moderate risk exploration; and also to test some new technologies to improve production and reserves. The following table outlines ARC's 2005 capital expenditure program:

2005 Capital Budget by Type

($ millions)	2003 (Actual)	2004 (Actual)	2005 (Budget)
Development drilling	103	135	173
Facilities & pipelines	26	34	18
Natural gas from coal (NGC)	–	–	7
Maintenance	14	9	15
Optimization	–	3	6
Land	4	4	9
Seismic	6	6	5
Other	3	3	7
Total	**156**	**194**	**240**

Operated Wells Drilled

(gross)	2003 (Actual)	2004 (Actual)	2005 (Budget)
Natural gas wells	153	145	221
Oil wells	46	47	69
Dry holes	1	2	–
Total	**200**	**194**	**290**

2005 Capital Budget by Area

($ millions)	2003 (Actual)	2004 (Actual)	2005 (Budget)
Northern Alberta & British Columbia	62	93	104
Drayton Valley	13	19	29
Central Alberta	19	20	31
Southeast Alberta & Southwest Saskatchewan	27	27	34
Southeast Saskatchewan	27	26	35
Corporate	8	9	7
Total	**156**	**194**	**240**

OPERATING COSTS

With the oil and gas sector operating at a record pace, costs throughout all areas of operations have been escalating. Despite these challenges, ARC's operating costs per boe decreased five per cent in 2004 to $6.71 per boe. This was primarily due to ARC's disposition of several high operating cost properties and the slightly increased natural gas weighting of the Trust. Natural gas properties typically have lower operating costs than oil properties. ARC expects that operating costs will increase slightly in 2005 to $7.00 per boe due to further cost increases associated with an unprecedented demand for services throughout the industry. ARC will continue to strive to keep operating costs at their lowest level possible.

RESERVE ADDITIONS

ARC is pleased to report positive technical reserve revisions of 3.4 mmboe proved and 1.7 mmboe proved plus probable, continuing a tradition of positive reserve revisions for the eighth year in a row. ARC replaced 85 per cent of its production during 2004 directly through internal development activities with 17.6 mmboe of proved plus probable reserves added (including technical and economic factor revisions). Acquisitions provided another 6.7 mmboe of reserve additions for total reserve additions of 24.3 mmboe. This represents 117 per cent of the 20.8 mmboe produced during 2004.

ARC has an active asset management program, which will from time to time, result in the disposition of properties that no longer meet the long-term needs of the Trust. Such properties typically are characterized by high operating costs, significant abandonment liabilities and limited identifiable upside potential. In 2004 ARC disposed of a number of such properties for total consideration of $57.7 million for 9.2 mmboe of proved plus probable reserves. As a result of the dispositions, ARC's net proved plus probable reserve additions were 15.1 mmboe resulting in year-end 2004 proved plus probable reserves of 244 mmboe, 6 mmboe lower than year-end 2003. At year-end 2004, approximately 51 per cent of ARC's reserves were crude oil and natural gas liquids and 49 per cent were natural gas.

FINDING, DEVELOPMENT AND ACQUISITION ("FD&A" COSTS)

NI 51-101 requires that finding and development costs ("F&D") be calculated including changes in future development costs ("FDC"). Changes in forecast FDC occur annually as a result of development activities, acquisition and disposition activities and capital cost estimates that reflect the independent evaluator's best estimate of what it will cost to bring the proved undeveloped and probable reserves on production. The current high level of activity has resulted in increased capital costs throughout the industry that are now reflected in the estimates of future development costs effective December 31, 2004. In addition, ARC's independent evaluator has revised its estimate of the future cost escalation in the sector to two per cent from 1.5 per cent, thereby further increasing the FDC. Although these cost increases occur over the life of the reserves, NI 51-101 requires that all of these changes be charged to the current year's F&D costs. Approximately 40 per cent of the 2004 change in FDC is associated with these over life capital cost increases. As a result, inclusion of FDC results in a material increase in F&D costs that do not meaningfully represent the effectiveness of ARC's 2004 capital expenditures.

Excluding acquisitions and dispositions, ARC's F&D costs were $13.05 per boe proved ($15.94 per boe including FDC) and $11.02 per boe on a proved plus probable basis ($15.21 per boe including FDC).

ARC completed two strategic acquisitions and a number of minor acquisitions totaling $71.5 million in 2004. Reserves added through these activities were 5.3 mmboe proved and 6.7 mmboe proved plus probable (including revisions) resulting in acquisition costs of $13.54 per boe ($15.64 including FDC) and $10.61 per boe ($12.57 per boe including FDC), respectively. When combined with its exploration and development activities, ARC replaced 117 per cent of its 2004 production (proved plus probable reserves) at a cost of $13.20 per boe ($15.86 per boe including FDC) on a proved basis and $10.92 per boe ($14.48 per including FDC) on a proved plus probable basis.

The first strategic acquisition was the remaining working interest in ARC's Prestville property, which increased its interest from 70 per cent to 100 per cent. The Prestville assets are characterized by low operating costs ($4.95 per boe) and high netbacks ($32.00 per boe). On a proved plus probable basis 3.1 mmboe of reserves were acquired for $30.5 million at a cost of $9.40 per boe resulting in a recycle ratio of 3.4. Future abandonment obligations are minimal given the early stage nature of the development and the long period before any abandonment activities will be required.

The other strategic acquisition completed during 2004 was the purchase of a group of companies whose major asset was a significant working interest in the ARC operated Crane Lake shallow gas property. This increased ARC's average working interest in this area to 55 per cent from 29 per cent, which will prompt ARC to initiate previously identified development drilling activity. Operating costs at Crane Lake averaged $3.87 per boe in 2004 providing a high netback of $32.04 per boe. On a proved plus probable basis the reserves were acquired for $11.69 per boe resulting in a recycle ratio of 2.7. Future abandonment obligations are small given the long life and shallow sweet nature of the producing assets.

As part of its active asset management program, ARC took advantage of the strong demand for producing assets by disposing of certain properties that no longer met the long-term needs of the Trust. The properties were sold to consolidate ARC's asset base, reduce future abandonment obligations, decrease corporate operating costs and exit an area with limited future development opportunities. In contrast to the low operating cost, high netback properties purchased, the assets sold had operating costs of approximately $12.00 per boe and netbacks of just over $19.00 per boe at the time of the disposition. Anticipated future abandonment and reclamation obligations were also significantly higher than average for ARC's assets given the deep nature of the wells, their maturity and the sour nature of most of the production.

In aggregate, ARC disposed of 7.6 mmboe of proved reserves and 9.2 mmboe of proved plus probable reserves for $57.7 million for average proceeds of $7.62 per boe proved ($8.23 per boe including FDC) and $6.24 per boe ($6.88 per boe including FDC) proved plus probable. As a result of these dispositions, ARC's future abandonment obligations were reduced by $7 million, which partially accounts for the relatively low price received for the disposed assets on a $/boe basis.

Incorporating the net dispositions during the year, ARC's proved FD&A costs were $16.53 per boe ($20.46 per boe including FDC), while proved plus probable FD&A costs were $13.76 per boe ($19.14 per boe including FDC). These values have been materially impacted by the disposition of the lower quality assets and are not representative of ARC's ongoing reserve replacement costs. In the absence of the discretionary dispositions completed in 2004 the FD&A costs, excluding FDC of $13.20 per boe proved and $10.92 per boe proved plus probable, are a true indication of ARC's ongoing reserve replacement costs.

PRODUCTION VOLUMES

ARC's production volumes increased five per cent in 2004, averaging 56,870 boe per day compared to 54,335 in 2003. Productions volumes were up, primarily due to the Star Oil & Gas Ltd. ("Star") acquisition in mid-2003 and positive results from the 2004 drilling program. Natural gas production increased to 178 mmcf per day in 2004 from 164 mmcf per day in 2003. Oil production remained relatively constant at 22,961 bbl per day as new production from ARC's drilling programs offset natural declines on existing oil properties. ARC's field and operational staff also play a key role in delivering strong production volumes by minimizing downtime. It is ARC's strategy to maintain production as much as possible through internal development projects supplemented by opportunistic, strategic acquisitions. ARC's production mix in 2004 was balanced with 52 per cent of production from natural gas and the remainder from oil and natural gas liquids. In the absence of acquisitions, ARC forecasts production volumes to be down slightly in 2005 at approximately 54,800 boe per day.

ENVIRONMENT, HEALTH AND SAFETY

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

ARC participates 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". ARC is committed to CAPP Stewardship reporting at the platinum level, which is the highest reporting level and involves third party audits of ARC's reporting. ARC continually enhances its processes for reducing greenhouse gas emissions. ARC is also registered with, and reports to, the National Pollutant Release Inventory ("NPRI"), which is a federal initiative to capture information on the releases and transfers of key pollutants in communities across Canada. NPRI is emerging into a source of information to the public for corporate environmental performance. ARC effectively manages its liabilities through abandonment and reclamation of facilities, wells and leases. ARC maintains a reclamation fund to ensure that required funds are available for future reclamation of wells and facilities once they have reached the end of their economic life. ARC contributed $6 million to its reclamation fund in 2004.

In 2004 ARC introduced an updated health and safety policies and procedures manual that includes new regulatory requirements. As our operations staff expands, ARC ensures that all new employees understand the significance of operating in a safe and reliable manner. ARC conducts emergency response training on a regular basis in all of our operating fields to ensure a high level of response capability from staff in challenging situations. ARC has also held its first annual consultant's health and safety workshop. This workshop addressed individual responsibilities, changes in regulatory requirements, and changes to ARC's programs.

ARC's environmental, health and safety mandate and its community involvement is explained in more detail on its website at www.arcenergytrust.com.

ARC CONDUCTS EMERGENCY RESPONSE TRAINING ON A REGULAR BASIS IN ALL OF OUR OPERATING FIELDS TO ENSURE A HIGH LEVEL OF RESPONSE CAPABILITY FROM STAFF IN CHALLENGING SITUATIONS.

ACQUISITIONS AND DISPOSITIONS

ARC completed two strategic acquisitions and a number of minor acquisitions totaling $71.5 million in 2004. Reserves added through these activities were 5.3 mmboe proved and 6.7 mmboe proved plus probable resulting in acquisition costs before FDC of $13.54 per boe and $10.61 per boe, respectively.

The first strategic acquisition was the purchase of the remaining interest in ARC's Prestville property that increased ARC's interest from 70 per cent to 100 per cent. On a proved plus probable basis, 3.1 mmboe of reserves were acquired for $30.5 million at a cost of $9.40 per boe. The second strategic acquisition was completed during the fourth quarter of 2004 and involved the purchase of a group of companies whose major asset was a significant working interest in the ARC operated Crane Lake shallow gas property. The purchase increased ARC's average working interest to 55 per cent from 29 per cent. On a proved plus probable basis the reserves were acquired for $11.69 per boe.

As part of its active asset management program, ARC took advantage of the strong demand for producing assets by disposing of certain properties that no longer met the long-term needs of the Trust. In aggregate, ARC disposed of 7.6 mmboe of proved reserves and 9.2 mmboe of proved plus probable reserves for $57.7 million for average proceeds of $7.62 per boe proved and $6.24 per boe proved plus probable.

2004 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	71.5	6,740	10.61	1,056	67,689	17.5
Dispositions	57.7	9,244	6.24	1,872	30,818	13.5
Net Acquisitions	13.8	(2,504)	n/a	(816)	n/a	n/a

FINDING, DEVELOPMENT AND ACQUISITION ("FD&A") COSTS

Incorporating the net dispositions during the year, ARC's proved FD&A costs, excluding FDC, were $16.53 per boe while proved plus probable FD&A costs were $13.76. These values have been materially impacted by the disposition of the lower quality assets and are not representative of ARC's ongoing reserve replacement costs. In the absence of the discretionary dispositions completed in 2004, the FD&A costs, excluding FDC of $13.20 per boe proved and $10.90 per boe proved plus probable, are a true indication of ARC's ongoing reserve replacement costs.

FD&A Costs – Company Interest Reserves (1)

	Proved	Proved plus Probable
FD&A COSTS EXCLUDING FUTURE DEVELOPMENT CAPITAL		
Exploration and development capital expenditures ($ thousands)	$ 193,784	$ 193,784
Exploration and development reserve additions including revisions (mboe)	14,848	17,587
Finding and development cost ($/boe)	$ 13.05	$ 11.02
Three year average F&D cost ($/boe)	$ 11.74	$ 10.36
Acquisition capital ($ thousands)	$ 71,480	$ 71,480
Acquisition reserve additions (mboe)	5,280	6,740
Acquisition cost ($/boe)	$ 13.54	$ 10.61
Disposition proceeds ($ thousands)	$ 57,691	$ 57,691
Dispositions (mboe)	7,570	9,244
Disposition proceeds ($/boe)	$ 7.62	$ 6.24
Total capital expenditures net of dispositions ($ thousands)	$ 207,573	$ 207,573
Reserve additions net of dispositions (mboe)	12,558	15,083
Finding development and acquisition cost ($/boe)	$ 16.53	$ 13.76
Three year average FD&A cost ($/boe)	$ 11.05	$ 9.30

(1) In all cases, the F&D, or FD&A number is calculated by dividing the identified capital expenditures by the applicable reserves additions. 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.

NI 51-101 requires that FD&A costs be calculated including changes in FDC. Changes in forecast FDC occur annually as a result of development activities, acquisition and disposition activities and capital cost estimates that reflect the independent evaluator's best estimate of what it will cost to bring the proved undeveloped and probable reserves on production. The current high level of activity has resulted in increased capital costs throughout the industry that are now reflected in the estimates of future development costs effective December 31, 2004. In addition, ARC's independent evaluator has revised their estimate of the future cost escalation in the sector to two per cent from 1.5 per cent, thereby further increasing the FDC. Although these cost increases occur over the life of the reserves, NI 51-101 requires that all of these changes be charged to the current year's FD&A costs. As a result, inclusion of FDC results in a material increase in FD&A costs that do not meaningfully represent the effectiveness of ARC's 2004 capital expenditures.

Following is a summary of changes to ARC's forecast FDC broken down by individual categories.

Changes in FDC Effective December 31, 2004 (1)

($ millions)		Proved		Proved plus Probable
Development activities (2)	$	16	$	39
Acquisitions	$	11	$	13
Dispositions	$	(5)	$	(6)
Revised capital cost estimates on previously forecast FDC	$	24	$	29
Evaluator's change to cost escalation rate	$	3	$	6
Total change in forecast FDC	$	49	$	81

(1) Prepared by ARC.

(2) Development FDC increased due to future reserve adding activities such as additional wells, workovers, recompletions, CO_2 flood expansions and new CO_2 flood projects being incorporated by the independent evaluator as a result of successful activities in 2004.

FD&A Costs – Company Interest Reserves

		Proved		Proved plus Probable
FD&A COSTS INCLUDING FUTURE DEVELOPMENT CAPITAL				
Exploration and development capital expenditures ($ thousands)	$	193,784	$	193,784
Exploration and development change in FDC ($ thousands)	$	42,893	$	73,734
Exploration and development capital including change in FDC ($ thousands)	$	236,677	$	267,518
Exploration and development reserve additions including revisions (mboe)		14,848		17,587
Finding and development cost ($/boe)	$	15.94	$	15.21
Three year average F&D cost ($/boe)	$	14.04	$	13.59
Acquisition capital ($ thousands)	$	71,480	$	71,480
Acquisition FDC ($ thousands)	$	11,084	$	13,244
Acquisition capital including FDC ($ thousands)	$	82,564	$	84,724
Acquisition reserve additions (mboe)		5,280		6,740
Acquisition cost excluding dispositions ($/boe)	$	15.64	$	12.57
Disposition proceeds ($ thousands)	$	57,691	$	57,691
Disposition FDC ($ thousands)	$	4,616	$	5,865
Disposition capital including FDC ($ thousands)	$	62,307	$	63,556
Dispositions (mboe)		7,570		9,244
Disposition proceeds ($/boe)	$	8.23	$	6.88
Total capital expenditures net of dispositions ($ thousands)	$	207,573	$	207,573
Total change in FDC ($ thousands)	$	49,361	$	81,113
Total capital including change in FDC ($ thousands)	$	256,934	$	288,686
Reserve additions net of dispositions (mboe)		12,558		15,083
Finding development and acquisition cost including FDC ($/boe)	$	20.46	$	19.14
Three year average FD&A cost including FDC ($/boe)	$	13.02	$	11.65

Historic Company Interest Proved FD&A Costs

	2004	2003	2002	2001	2000	1999	1998
Annual FD&A excluding FDC	**$ 16.53**	$ 10.78	$ 8.87	$ 11.35	$ 5.73	$ 5.86	$ 3.00
Three year average FD&A excluding FDC	**$ 11.05**	$ 10.69	$ 9.07	$ 8.06	$ 5.68	$ 5.76	$ 5.59
Annual FD&A including FDC	**$ 20.46**	$ 12.66	$ 10.03	$ 11.93	$ 7.56	$ 6.78	$ 7.44
Three year average FD&A including FDC	**$ 13.02**	$ 11.96	$ 10.16	$ 9.09	$ 7.15	$ 6.64	$ 6.19

Historic Company Interest Proved Plus Probable FD&A Costs

	2004	2003	2002	2001	2000	1999	1998
Annual FD&A excluding FDC	**$ 13.76**	$ 8.50	$ 9.27	$ 9.75	$ 5.16	$ 4.86	$ 3.62
Three year average FD&A excluding FDC	**$ 9.30**	$ 9.07	$ 8.21	$ 6.94	$ 4.95	$ 4.87	$ 4.85
Annual FD&A including FDC	**$ 19.14**	$ 10.54	$ 10.79	$ 10.41	$ 7.21	$ 5.77	$ 11.21
Three year average FD&A including FDC	**$ 11.65**	$ 10.52	$ 9.46	$ 8.04	$ 6.54	$ 5.81	$ 5.59

RESERVES

Based on an independent engineering evaluation conducted by Gilbert Laustsen Jung Associates Ltd. ("GLJ") effective December 31, 2004, and prepared in accordance with NI 51-101, ARC had proved and probable reserves of 244 mmboe.[1] Reserve additions from exploration and development activities (including revisions and economic factors) were 17.6 mmboe while 6.7 mmboe were added through acquisitions, bringing the total additions to 24.3 mmboe. This represents 117 per cent of the 20.8 mmboe produced during 2004.

Dispositions of 9.2 mmboe resulted in net reserve additions for the year of 15.1 mmboe. As a result of the disposition activity, year-end 2004 reserves are 6 mmboe less than the 250 mmboe of proved plus probable reserves recorded at year-end 2003.

Proved developed producing reserves represent 63 per cent of proved plus probable reserves, while total proved reserves account for 80 per cent of proved plus probable reserves. These percentages are virtually unchanged when compared to 64 and 81 per cent, respectively at year-end 2003. At a 10 per cent discount factor, the proved producing reserves make up 76 per cent of the proved plus probable value, while total proved reserves account for 87 per cent of the proved plus probable value. Approximately 51 per cent of ARC's reserves are crude oil and natural gas liquids and 49 per cent are natural gas on a 6:1 boe conversion basis.

Net Present Value ("NPV") Summary 2004

ARC's crude oil, natural gas and natural gas liquids reserves were evaluated using GLJ's product price forecasts effective January 1, 2005 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 Using GLJ January 1, 2005 Escalated Prices and Costs

NI 51-101 Net Interest ($ thousands)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved producing	3,055	2,249	1,817	1,546	1,357
Proved developed non-producing	52	32	24	19	15
Proved undeveloped	596	364	234	155	103
Total proved	3,703	2,645	2,076	1,720	1,475
Probable	1,037	517	313	213	155
Proved plus probable	4,740	3,161	2,389	1,933	1,630

GLJ January 1, 2005 Price Forecast

Year	West Texas Intermediate Crude Oil	Edmonton Light Crude Oil	Natural Gas at AECO	Foreign Exchange
	($US/bbl)	($Cdn/bbl)	($Cdn/mmbtu)	($US/$Cdn)
2005	$42.00	$50.25	$6.60	0.820
2006	$40.00	$47.75	$6.35	0.820
2007	$38.00	$45.50	$6.15	0.820
2008	$36.00	$43.25	$6.00	0.820
2009	$34.00	$40.75	$6.00	0.820
2010	$33.00	$39.50	$6.00	0.820
2011	$33.00	$39.50	$6.00	0.820
2012	$33.00	$39.50	$6.00	0.820
2013	$33.50	$40.00	$6.10	0.820
2014	$34.00	$40.75	$6.20	0.820
2015	$34.50	$41.25	$6.30	0.820
Escalate thereafter at	2.0%/yr	2.0%/yr	2.0%/yr	0.820

(1) 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.

The reserves have also been evaluated using constant prices and costs effective December 31, 2004. Following are the values determined using this constant price analysis.

NPV of Cash Flow Using December 31, 2004 Constant Prices and Costs

NI 51-101 Net Interest ($ thousands)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved producing	3,414	2,463	1,953	1,635	1,416
Proved developed non-producing	54	35	26	21	17
Proved undeveloped	699	432	284	192	131
Total proved	4,167	2,931	2,263	1,847	1,564
Probable	1,078	560	347	239	175
Proved plus probable	5,246	3,490	2,610	2,086	1,739

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, 2004

Year	West Texas Intermediate Crude Oil	Edmonton Light Crude Oil	Natural Gas at AECO	Foreign Exchange
	(US$/bbl)	(CDN$/bbl)	(CDN$/mmbtu)	(US$/CDN$)
2005 and thereafter	$43.45	$46.54	$6.79	0.82

Net Asset Value

The following 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, 2005, distribution, the Trust has distributed $14.24 per unit. Despite having distributed more cash than the initial NAV, the NAV as at December 31, 2004, was $11.43 per unit using GLJ prices and $12.48 per unit using constant prices and costs. NAV per unit increased $3.40 per unit during 2004 after distributing $1.80 per unit to unitholders. Following is a summary of historical NAV's calculated at each of the Trust's year ends utilizing GLJ price forecasts.

Historical NAV – Discounted at 10 Per Cent, 2004 Escalated Prices and Costs

($ millions, except per unit amounts)	2004	2003	2002	2001	2000	1999	1998
Value of NI 51-101 net interest proved plus probable reserves [1]	**$ 2,389**	$ 1,689	$ 1,302	$ 1,216	$ 945	$ 530	$ 278
Undeveloped lands	**48**	50	20	22	6	12	3
Reclamation fund	**21**	17	13	10	10	7	5
Commodity and foreign currency contracts [2]	**(12)**	–	–	–	–	–	–
Long-term debt, net of working capital	**(265)**	(262)	(348)	(289)	(109)	(125)	(74)
Asset retirement obligation	**(23)**	(27)	–	–	–	–	–
Net asset value	**$ 2,158**	$ 1,467	$ 987	$ 959	$ 852	$ 424	$ 211
Units outstanding (000's)	**188,804**	182,777	126,444	111,692	72,524	53,607	25,604
NAV per unit	**$ 11.43**	$ 8.03	$ 7.81	$ 8.59	$ 11.74	$ 7.92	$ 8.25

(1) Proved plus probable in 2003 and 2004 is estimated in accordance with NI 51-101 (with risked probables) while in prior years it represents established reserves (which represents proved plus risked probables).

(2) Commodity and foreign currency contracts were included in the value of proved plus probable reserves in prior years. The 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.

Reserve Life Index (RLI)

ARC's proved plus probable RLI was 12.2 years at year-end 2004 while the proved RLI was 9.7 years based upon the GLJ reserves and ARC's 2005 production guidance of 54,800 boe per day. The following table summarizes ARC's historical RLI.

	2004	2003	2002	2001	2000	1999	1998	1997
Total proved	**9.7**	10.1	10.1	9.8	10.4	10.1	10.0	10.9
Proved plus probable (Established reserves for 2002 and prior years)	**12.2**	12.4	11.8	11.5	12.1	12.0	11.9	13.0

Reserves Summary 2004 Using GLJ January 1, 2005 Escalated Prices and Costs

Company Interest (Working Interest + Royalties Receivable)

	Light and Medium Crude Oil	Heavy Crude Oil	Total Crude Oil	NGL's	Natural Gas	Oil Equivalent 2004	Oil Equivalent 2003
	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(bcf)	(mboe)	(mboe)
Proved producing	65,749	3,112	68,861	9,647	446.8	152,968	158,990
Proved developed non-producing	659	–	659	144	9.3	2,349	4,514
Proved undeveloped	14,583	97	14,680	1,743	133.4	38,656	38,725
Total proved	80,991	3,209	84,200	11,534	589.4	193,973	202,229
Proved plus probable	104,921	4,073	108,994	14,231	724.5	243,973	249,704

Gross Interest (Working Interest Before Royalties Payable)

	Medium Crude Oil	Light and Heavy Crude Oil	Total Crude Oil	NGL's	Natural Gas	Oil Equivalent 2004	Oil Equivalent 2003
	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(bcf)	(mboe)	(mboe)
Proved producing	65,659	2,783	68,442	9,442	433.8	150,188	156,177
Proved developed non-producing	658	–	658	144	9.3	2,346	4,508
Proved undeveloped	14,575	97	14,672	1,743	133.3	38,627	38,697
Total proved	80,892	2,880	83,772	11,328	576.4	191,160	199,382
Proved plus probable	104,798	3,695	108,493	13,984	709.9	240,788	246,468

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

	Light and Medium Crude Oil	Heavy Crude Oil	Total Crude Oil	NGL's	Natural Gas	Oil Equivalent 2004	Oil Equivalent 2003
	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(bcf)	(mboe)	(mboe)
Proved producing	57,226	2,870	60,096	6,911	369.0	128,508	133,505
Proved developed non-producing	585	–	585	102	7.3	1,899	3,575
Proved undeveloped	12,569	90	12,659	1,239	109.1	32,081	32,484
Total proved	70,380	2,960	73,340	8,251	485.4	162,488	169,564
Proved plus probable	90,971	3,744	94,715	10,243	596.4	204,357	209,474

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, 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)	4,554	(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
Exploration discoveries	235	59	1.9	0.8	9	2	565	202
Drilling extensions	941	428	6.3	2.1	198	64	2,194	842
Improved recovery	1,522	180	16.4	13.3	374	149	4,629	2,542
Technical revisions	833	(1,042)	10.4	(4.0)	795	72	3,362	(1,643)
Acquisitions	2,000	986	19.5	2.8	23	5	5,280	1,460
Dispositions	(4,843)	(945)	(12.8)	(3.8)	(598)	(102)	(7,570)	(1,674)
Economic Factors	1,816	154	12.8	3.6	142	45	4,098	796
Production	(8,404)	–	(65.3)	–	(1,534)	–	(20,814)	–
Reserves at December 31, 2004	**84,200**	**24,794**	**589.4**	**135.1**	**11,534**	**2,697**	**193,973**	**50,000**

(1) Company interest reserves include working interests and royalties receivable.

(2) Heavy oil reserves reconciliation as a component of crude oil on a proved basis started with reserves at December 31, 2003, of 3,360 mbbl, exploration discoveries of 200 mbbl, improved recovery of 42 mbbl, technical revisions of (26) mbbl, economic factors of 138, production of (505) mbbl, leaving a closing balance of 3,209 mbbl.

(3) Probable reserves risked at 50 per cent for 1998 through 2002.

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

	Crude Oil (mbbl)		Natural Gas (bcf)		Natural Gas Liquids (mbbl)		Total (mboe)	
	Proved[1]	Probable[2]	Proved	Probable	Proved	Probable	Proved	Probable
Reserves at December 31, 2003	**79,309**	**21,891**	**488.2**	**97**	**8,882**	**1,851**	**169,564**	**39,910**
Exploration discoveries	215	54	1.4	0.7	6	2	458	179
Drilling extensions	1,158	–	4.8	1.6	141	46	2,100	307
Improved recovery	1,363	154	14	11.8	256	107	3,955	2,234
Technical revisions	(474)	182	8.8	(2.9)	511	25	1,502	(268)
Economic factors	1,515	745	18.3	2.5	16	3	4,579	1,166
Acquisitions	(4,402)	(806)	(10.3)	(3)	(421)	(72)	(6,543)	(1,382)
Dispositions	1,816	(845)	11.5	3.2	87	29	3,814	(277)
Production	(7,159)	–	(51.3)	–	(1,227)	–	(16,941)	–
Reserves at December 31, 2004	**73,340**	**21,375**	**485.4**	**111**	**8,251**	**1,992**	**162,488**	**41,869**

(1) Heavy oil reserves reconciliation as a component of crude oil on a proved basis started with reserves at December 31, 2003, of 3,116 mbbl, exploration discoveries of 168 mbbl, improved recovery of 38 mbbl, technical revisions of (41) mbbl, economic factors of 120 mbbl and production of (441) mbbl, leaving a closing balance of 2,960 mbbl.

(2) Heavy oil reserves reconciliation as a component of crude oil on a probable basis started with reserves at December 31, 2003, of 790 mbbl, exploration discoveries of 42 mbbl, improved recovery of 7 mbbl, technical revisions of (42) mbbl, economic factors of (13) mbbl, leaving a closing balance of 784 mbbl.

Additional Oil and Gas Disclosure

For more information in relation to gross reserves, net resources, F&D costs and other items of oil and gas disclosure mandated by NI 51-101, reference is made to the Annual Information Form of the Trust, which will be filed on SEDAR (www.sedar.com) by March 31, 2005, and will also be available on ARC's website at www.arcenergytrust.com.

HANDS-ON MANAGEMENT

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
FDC	future development costs
GAAP	generally accepted accounting principles
G&A	general and administrative
GJ	gigajoule
mbbls	thousand barrels
mboe*	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmbbls	million barrels
mmboe*	million barrels of oil equivalent
mmbtu	million British Thermal Units
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NAV	net asset value
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange
RLI	reserve life index
WTI	West Texas Intermediate

* 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 well head.

FORWARD-LOOKING STATEMENTS

This disclosure contains certain forward-looking estimates that involve substantial known and unknown risks and uncertainties, certain of which are beyond ARC's control, including: the impact of general economic conditions in Canada and the United States; industry conditions including changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; increased competition, and the lack of availability of qualified personnel or management; fluctuations in commodity prices, foreign exchange or interest rates; stock market volatility and obtaining required approvals of regulatory authorities. In addition, there are numerous risks and uncertainties associated with oil and gas operations and the evaluation of oil and gas reserves. Therefore ARC's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking estimates and if such actual results, performance or achievements transpire or occur, or if any of them do so, there can be no certainty as to what benefits ARC will derive therefrom.

Management's discussion and analysis ("MD&A") should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2004, and the audited consolidated financial statements and MD&A for the year ended December 31, 2003, and MD&A for the three quarters ended March 31, 2004, June 30, 2004, and September 30, 2004.

This MD&A was written on February 23, 2005.

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

This discussion and analysis contains forward-looking statements 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 Energy Trust ("ARC" or the "Trust"). 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 year ended December 31, 2004, which may cause actual performance and financial results in future periods to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. Accordingly, readers are cautioned that events or circumstances could cause results to differ materially from those predicted.

The Trust implemented new accounting policies in 2004 pursuant to requirements of the Canadian Institute of Chartered Accountants ("CICA"). The 2004 reported results were impacted as a result of differing presentation and disclosure under the new policies and instruments. In addition, certain amounts presented for comparative purposes have been restated as a result of the retroactive application of these new policies and instruments. See "Impact of New Accounting Policies" in this MD&A and Note 3 of the consolidated financial statements for a detailed description of the impact on reported results.

HIGHLIGHTS

(CDN$ millions, except per unit and volume data)	**2004**	2003	% Change
Cash flow from operations (1)	**448.0**	396.2	13
Cash flow from operations per unit (1)	**2.45**	2.61	(6)
Net income before taxes (2)	**215.6**	191	13
Net income	**241.7**	284.6	(15)
Distributions per unit	**1.80**	1.80	–
Payout ratio per cent (3)	**74**	71	4
Daily production (boe/d) (4)	**56,870**	54,335	5

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

(2) Represents net income after non-controlling interest and before the future income tax recovery.

(3) Based on cash distributions divided by cash flow from operations before changes in non-cash working capital.

(4) Reported production amount is based on company interest before royalty burdens.

- Unitholders of the Trust realized an annual total return of 35.8 per cent in 2004. The Trust unit price increased 21 per cent in 2004 from $14.74 per trust unit to $17.90 per trust unit and the Trust paid distributions of $1.80 per trust unit. The Trust unit price responded to normal market conditions including exceptionally strong commodity prices.
- Production averaged 56,870 boe per day in 2004 compared to 54,335 boe in 2003. Production was above forecast due to incremental production from ARC's internal development program. Capital expenditures of $193.8 million were devoted to the 2004 development program and resulted in incremental production that offset natural production declines on existing properties. With ongoing internal development and optimization activities and the largest development capital program in the Trust's history, production volumes for 2005 are expected to average approximately 54,800 boe per day. Production for the three months ended December 31, 2004 averaged 56,179 boe per day. Capital expenditures of $47.7 million were committed to ARC's internal development program during the fourth quarter of 2004.
- ARC realized record cash flow of $448 million in 2004 and declared cash distributions of $330 million, resulting in a 2004 payout ratio of 74 per cent. The remaining $118 million of 2004 cash flow was used to fund $110.8 million of the 2004 capital expenditures and a $7.2 million contribution to the reclamation fund (inclusive of $1.2 million in interest income). ARC realized cash flow of $106.9 million for the three months ended December 31, 2004, an increase of 19.3 per cent over the fourth quarter of 2003. The Trust declared cash distributions of $83.5 million ($0.45 per unit) for the three months ended December 31, 2004.
- Earnings achieved in 2004 remained relatively constant as a percentage of cash flow compared to 2003. In 2004 the Trust's earnings of $241.7 million represented 54 per cent of cash flow. In 2003 earnings of $218.5 million, prior to a one time future income tax recovery of $66.1 million, represented 55 per cent of cash flow.
- During 2004 the West Texas Intermediate ("WTI") oil price reached an all time high price of US$55.17 per barrel and closed the year at US$43.45 per barrel. This increase in U.S. oil prices was partially offset by an increase in USD/CAD exchange rate that averaged the year at approximately $0.77 and ended the year at $0.83. The strength of oil prices throughout 2004 contributed to the record annual cash flow of $448 million. The Trust's hedging program offset some of the positive impact of historic high oil prices throughout the year as the Trust's oil hedges on approximately 50 per cent of production were locked in at lower prices for the majority of 2004.
- The AECO monthly natural gas price index traded in the $5.50 per mcf to $7.50 per mcf range during most of 2004 with the only exception in the month of November when the monthly index increased to $8.00 per mcf, in line with the increase in oil prices.
- In response to the current and anticipated future commodity price environment, the Trust has adjusted its hedging strategy. The Trust's risk management strategy is to manage the downside risk associated with volatility in commodity prices, which impact both cash flow and potentially cash distributions. The revised strategy focuses on managing the downside risk while allowing more participation in commodity price increases by the use of "floors" or "puts". Previously, the Trust focused on protection of the downside risk by giving up some or all of the upside potential in the event of commodity price increases. At December 31, 2004, the Trust had 41 per cent of its 2005 production hedged at average prices, net of premiums for the cost of the floors, of US$38 per barrel for crude oil and $6.90 per mcf for natural gas. The Trust, under its revised hedging strategy, has retained approximately 85 per cent of the upside on forecast production for 2005.
- The Trust's balance sheet strengthened in 2004 as the Trust's net debt to annual cash flow ratio declined to 0.6 times as at December 31, 2004. The strength in the balance sheet was attributed to the strong commodity prices during 2004 that enabled the Trust to fund 57 per cent of its 2004 capital expenditure program with cash flow rather than debt, and the fact the strengthening Canadian dollar decreased the Canadian equivalent of the Trust's long-term US$ debt by $21.9 million in 2004.

- The Trust continues to closely monitor both operating and general and administrative ("G&A") expenses. Operating costs declined to $6.71 per boe in 2004 from $7.10 per boe in 2003 primarily due to the disposition of high-cost properties and cost reductions achieved by the operations group. Cash G&A costs increased in 2004 to $1.03 per boe in 2004 versus $0.96 in 2003 in response to industry-wide cost pressure on cash compensation. In addition, the Trust incurred non-cash expenses of $8.1 million ($0.39 per boe). The increase in non-cash G&A expenses in 2004 was due to the implementation of a new long-term stock based incentive plan in 2004 and non-cash expense associated with the Trust Unit Rights Incentive Plan.
- The Trust's foreign ownership levels as at December 31, stood at approximately 25 per cent. The Federal Government has not proceeded with proposed legislation introduced as part of its March 2004 budget that would have resulted in the loss of mutual fund status for any trust whose foreign ownership levels exceeded 50 per cent, which in turn would have impaired the tax efficiency of the trust structure. In December 2004, the Minister of Finance shelved the proposed legislation until further consultation with the industry has occurred. It is uncertain as to whether the legislation will be redrafted and brought forward in a new format in the future or if the legislation will be permanently shelved. As a result of the proposed legislation, a select few trusts had reorganized, or proposed to reorganize, their units into a dual class structure with the objective of restricting foreign ownership to less than 50 per cent in order to retain their status as a mutual fund trust in the event that the proposed legislation is enacted. ARC will continue to monitor these developments and if it is deemed appropriate, amend its capital structure as necessary to maintain the integrity of its structure.

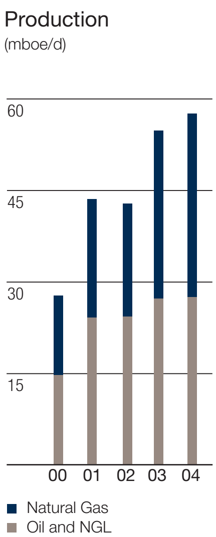
CASH FLOW FROM OPERATIONS

Cash flow from operations increased by 13 per cent in 2004 to $448 million from $396.2 million in 2003. The increase in 2004 cash flow from operations was primarily the result of higher commodity prices together with higher production volumes. Despite the 13 per cent increase in cash flow from operations in 2004, the per unit cash flow from operations decreased six per cent to $2.45 per trust unit from $2.61 per trust unit in 2003. On average there were 21 per cent more trust units outstanding in 2004 than in 2003, which contributed to the reduction in per unit cash flow from operations. The 2004 cash flow from operations included a cash loss of $86.9 million on commodity and foreign currency contracts, while 2003 cash flow included a loss of $20.3 million on commodity and foreign currency contracts,

The following is a summary of variances in cash flow from operations from 2003 to 2004:

	$ millions	$ per trust unit	% variance
2003 Cash flow from operations	**$ 396.2**	**$ 2.61**	
Volume variance	37.6	0.25	9
Price variance	105.1	0.69	27
Cash losses on commodity and			
foreign currency contracts (1)	(66.6)	(0.44)	(17)
Royalties	(26.1)	(0.17)	(7)
Expenses:			
Transportation	(2.8)	(0.02)	(1)
Operating	1.0	0.01	1
Cash G&A	(2.3)	(0.02)	(1)
Interest	5.2	0.03	1
Taxes	(1.0)	(0.01)	–
Realized foreign exchange gain (loss)	2.3	0.02	1
Other	(0.6)	–	–
Weighted average trust units	–	(0.50)	–
2004 Cash flow from operations	**$ 448.0**	**$ 2.45**	**13**

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



PRODUCTION

Production volumes averaged 56,870 boe per day in 2004 compared to 54,335 boe per day in 2003. The five per cent increase in 2004 production compared to 2003 resulted from a full year of production from the Star Oil & Gas Ltd. ("Star") properties that were acquired in April 2003, the net impact of non-core property dispositions, and positive results of the Trust's 2004 drilling program. The incremental production from the development program served to offset the natural production declines on existing properties.

Production	**2004**	2003	% Change
Crude oil (bbl/d)	**22,961**	22,886	–
Natural gas (mcf/d)	**178,309**	164,180	9
NGL (bbl/d)	**4,191**	4,086	3
Total production (boe/d) (1)	**56,870**	54,335	5
% Natural gas production	**52**	50	
% Crude oil and liquids production	**48**	50	

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

Natural gas production increased to 178.3 mmcf per day in 2004, a nine per cent increase compared to 2003 natural gas production of 164.2 mmcf per day. The increase was due primarily to a full year of natural gas production from the Star acquisition that closed in the second quarter of 2003. The Trust's 2004 percentage natural gas production increased slightly to 52 per cent from 50 per cent in 2003. The increase in the gas weighting of the Trust's production portfolio is the result of the Star acquisition that was more heavily weighted to natural gas production.

Oil production remained relatively consistent between 2004 and 2003 as new production from ARC's development program offset production declines on existing oil properties.

During the year the Trust drilled 194 gross wells (165 net wells) on operated properties; 47 gross oil wells (42 net) and 145 gross natural gas wells (121 net), most of which were shallow gas wells, and two dry holes for a total success rate of 99 per cent in 2004. Of the wells drilled in the year, approximately 25 wells were not tied in as of December 31, 2004, but are expected to be tied in during the first quarter of 2005.

In May 2004, ARC disposed of its Sundre properties in the Central Alberta area and a number of other minor properties. The disposed properties accounted for production of approximately 1,800 boe per day and proved plus probable reserves of 9,244 mboe. On June 8, 2004, the Trust acquired additional producing properties pursuant to the United Prestville corporate acquisition ("United Prestville"). Daily production from the acquired United Prestville properties was approximately 400 boe per day. On December 31, 2004, the Trust acquired additional production. Due to pursuant to the Harrington & Bibler corporate acquisition ("Harrington & Bibler") with approximately 720 boe per day of production. Due to the December 31, 2004 closing date of the Harrington & Bibler acquisition, 2004 production did not include any production from the newly acquired properties.

The following table summarizes the Trust's production by core area for 2004 and 2003:

	2004				2003			
Core Area (1)	**Total**	**Oil**	**Gas**	**NGL**	Total	Oil	Gas	NGL
	(boe/d)	(bbls/d)	(mmcf/d)	(bbls/d)	(boe/d)	(bbls/d)	(mmcf/d)	(bbls/d)
Central AB	**9,295**	**2,003**	**32.6**	**1,856**	9,916	2,540	32.7	1,934
Northern AB & BC	**19,026**	**5,733**	**71.1**	**1,441**	17,556	5,449	64.4	1,374
Pembina	**7,433**	**3,742**	**17.5**	**772**	7,353	3,808	17.3	655
SE AB & SW Sask.	**10,871**	**1,658**	**55.2**	**14**	10,039	2,011	45.1	19
SE Sask.	**10,245**	**9,825**	**1.9**	**108**	9,471	9,078	1.7	104
Total	**56,870**	**22,961**	**178.3**	**4,191**	54,335	22,886	161.2	4,086

(1) Provincial references: AB is Alberta, BC is British Columbia, Sask. is Saskatchewan, SE is Southeast, SW is Southwest.

The Trust expects 2005 production to average approximately 54,800 boe per day. The 2005 production estimate incorporates incremental production from the planned $240 million capital program in 2005 in addition to 720 boe per day of incremental production from the acquired Harrington & Bibler properties.

COMMODITY PRICES PRIOR TO HEDGING

Benchmark prices	**2004**	2003	% Change
AECO gas ($/mcf) (1)	**6.79**	6.67	2
WTI oil (US$/bbl) (2)	**41.43**	31.06	33
USD/CAD foreign exchange rate	**0.77**	0.71	8
WTI oil (CDN$/bbl)	**53.81**	43.57	24

(1) Represents the AECO monthly posting.

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

The Canadian denominated oil price received by ARC and other Canadian energy companies was negatively impacted by the continued strength of the Canadian dollar with respect to the U.S. dollar during 2004. While crude oil prices reached a historic high of US$55.17 per barrel in 2004, the Canadian dollar also reached a 12 year high of US$0.85 in 2004. The strength of the Canadian dollar served to partially offset the impact of higher U.S. dollar denominated oil prices. Despite the 33 per cent increase in the US$ WTI oil price in 2004, relative to 2003, the Canadian dollar denominated oil price increased by only 24 per cent to $53.81 per barrel in 2004 compared to $43.57 per barrel in 2003. The Trust's realized oil price, before hedging, increased by 23 per cent to $47.03 per barrel in 2004 compared to $38.15 per barrel in 2003. The Trust's oil production consists predominantly of light and medium crude oil while heavy oil accounts for approximately five per cent of the Trust's liquids production.

The differential between the Edmonton posted price and field price widened in the fourth quarter of 2004. The average quality and transportation differential on the Trust's oil production was approximately $5.50 per barrel in the first nine months of 2004 and increased to $8.20 in the fourth quarter of 2004. The widening differential was due to a global oversupply of heavy oil and sour crude production into the market, which contributed to lower realized oil prices in the fourth quarter.

Alberta AECO Hub prices averaged $6.79 per mcf in 2004 compared to $6.67 per mcf in 2003. ARC's realized gas price, before hedging, increased by four per cent to $6.78 per mcf compared to $6.49 per mcf in 2003. ARC's realized gas price is based on prices received at the various markets in which the Trust sells its natural gas. ARC's natural gas sales portfolio consists of gas sales priced at the AECO monthly index, the AECO daily spot market, eastern and mid-west United States markets and a portion to aggregators.

Prior to hedging activities, ARC realized $43.32 per boe in 2004, a 13 per cent increase over the $38.27 per boe received prior to hedging in 2003. ARC's reported price of $43.32 per boe in 2004 is not directly comparable to the $37.47 per boe price reported in 2003 as a result of new hedge accounting guidelines that were implemented in 2004. Under the new hedge accounting guideline, 2004 revenue and prices are presented prior to hedging gains or losses while 2003 revenue and prices are inclusive of realized hedging gains or losses. See "Impact of New Accounting Policies" in this MD&A and Note 3 of the consolidated financial statements for further discussion regarding the impact of Hedge Accounting that was implemented in 2004.

The following is a summary of realized prices in 2004 and 2003 before hedging activities:

ARC Realized Prices (1) (2)	**2004**	2003	% Change
Oil ($/bbl)	**47.03**	38.15	23
Natural gas ($/mcf)	**6.78**	6.49	4
NGL's ($/bbl)	**39.04**	32.19	21
Total commodity revenue before hedging ($/boe)	**43.13**	38.09	13

(1) 2004 revenue and prices as reported above are prior to gains and losses on commodity and foreign currency contracts. All gains and losses on 2004 contracts are included in "loss on commodity and foreign currency contracts" in the statement of income as these contracts have not been designated as accounting hedges. 2003 reported prices are net of hedging gains and losses.

(2) 2003 prices have been reclassified to reflect prices prior to transportation costs.

The Trust has entered into foreign currency hedging contracts to minimize the impact that fluctuations in the USD/CAD exchange rate have on cash flow (see Note 10 of the consolidated financial statements). In addition, the majority of the Trust's debt and certain of the Trust's transactions are denominated in U.S. dollars partially offsetting the negative impact of USD/CAD exchange rate fluctuations.

Reported prices reflect field prices net of quality differentials and prior to field transportation costs. This presentation standard was adopted in 2004. Prices reported in 2003 have been reclassified to reflect the same presentation. See "Impact of New Accounting Policies" in this MD&A and Note 3 of the consolidated financial statements for further discussion of the nature and impact of the transportation cost presentation.

REVENUE

Revenue before hedging increased to $901.8 million in 2004, an increase of 19 per cent compared to 2003 revenue before hedging of $759.1 million. Higher production volumes and significantly higher commodity prices contributed to the higher revenue in 2004. Revenue in 2003 included realized hedging losses of $16 million ($0.80 per boe) on commodity and foreign currency contracts. Net realized and unrealized losses on commodity and foreign currency contracts in 2004 have been presented as a separate component of revenue in the statement of income rather than being netted against revenue.

A breakdown of revenue is as follows:

Revenue ($ thousands) (1) (2)	**2004**	2003	% Change
Oil revenue	**395,203**	308,259	28
Natural gas revenue	**442,537**	383,290	15
NGL's revenue	**59,886**	47,998	25
Total commodity revenue	**897,626**	739,547	21
Other revenue	**4,156**	3,636	14
Total revenue (2)	**901,782**	743,183	21
Total revenue before hedging (2)	**901,782**	759,134	19

(1) 2003 revenue has been reclassified to reflect revenue prior to transportation costs. Revenue and transportation costs both increased by $12 million in 2003 as a result of the reclassification.

(2) Revenue for 2003 includes cash hedging losses of $21.7 million and non-cash hedging gains of $5.7 million. There are no hedging gains or losses in the reported 2004 revenue amounts. Gains and losses on commodity and foreign currency contracts in 2004 have been reported separately in the statement of income.

RISK MANAGEMENT AND HEDGING ACTIVITIES

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

- protect unitholder return on investment;
- provide for minimum monthly cash distributions to unitholders;
- 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 uses both options and swaps to manage exposure to fluctuations in commodity prices, foreign exchange rates and interest rates. The Trust considers these contracts to be effective economic hedges as they meet the objectives of the Trust's risk management mandate.

In response to the current commodity price environment, the Trust has updated its hedging strategy. Previously, the Trust's hedging portfolio consisted of a large number of costless transactions that mitigated the risk associated with downturns in commodity prices while limiting the Trust's upside participation in a rising price environment. The Trust's current strategy is to focus on price floor (put) structures that limit the Trust's exposure to downturns in commodity prices while allowing participation in commodity price increases.

During the fourth quarter, the Trust terminated certain crude oil and foreign currency contracts in response to its revised hedging strategy. The Trust paid $4.9 million to terminate certain contracts, consisting of a net payment (loss) of $29.4 million for the crude oil contracts and a net receipt (gain) of $24.5 million for the foreign currency contracts. Immediately following the termination of the contracts, the Trust entered into new crude oil floors and foreign currency swaps in accordance with its new hedging strategy. By terminating existing contracts and entering into the new contracts, the Trust was able to enter into contracts for a minimum specified price while maintaining the upside on most of the Trust's production. The $4.9 million paid by the Trust on termination has been recorded as a reduction of cash flow from operations in the fourth quarter.

The Trust's commodity and foreign currency hedging transactions are undertaken with financially sound, credit worthy counterparties, to reduce exposure to credit risk. All contracts require approval of the Trust's Risk Management Committee prior to execution.

The following is a summary of contracts in place as at December 31, 2004. Refer to Note 10 of the consolidated financial statements for complete details of contracts in place at December 31, 2004.

	2005			2006 and beyond (3)	
	Contract Volume (2)	Contract Prices Net of Premiums Price $ (1)	Percentage Upside Retained Above Contract Price (1)	Contract Volume (2)	Contract Price (1)
Oil (bbl/d)	13,000	US$38.06/bbl	83%	992	US$40.27/bbl
Natural gas (mcf/d)	58,041	CDN$6.90/GJ	87%	–	–
Total boe/d (2)	22,674	US$35.67/boe	85%	992	US$40.27/boe
Total boe (3)	8,277,093	US$35.67/boe	85%	181,000	US$40.27/boe
AECO/NYMEX basis (mcf/d)	5,863	US$0.865/mcf	–	–	–
Foreign currency (sell US$) (4)	US$146.7 Million	CDN$1.21	–	US$13 Million	CDN$1.21
Electricity (MW/h)	5	$63.00	–	5	$63.00
Interest rates (5)	US$62.5 Million	LIBOR+38.25 bps	–	US$62.5 Million	LIBOR+38.25 bps

(1) Oil prices, AECO basis and total boe prices are in US$; natural gas, foreign currency and electricity are in CDN$. Prices represent average prices as of December 31, 2004. Average hedged prices are net of premiums and are calculated with reference to futures pricing at year end, detailed contract prices are contained in Note 10 of the financial statements.

(2) Volumes represent average daily volume for oil, natural gas and electricity transactions for the entire period.

(3) The amounts presented for the remaining contract period represent contracts in place for commodity contracts to June 2006, for electricity until 2010 and for interest rate hedges until 2014.

(4) Total contract volume for foreign currency contracts represents the net USD notional amount for the respective term.

(5) A fixed interest rate of 4.62 per cent has been swapped to a floating rate of LIBOR plus 38.25 basis points.

For 2004 the Trust had contracts in place for approximately 64 per cent of liquids production and 37 per cent of natural gas production resulting in approximately 49 per cent of production being hedged. As at December 31, 2004, the Trust had approximately 41 per cent of total 2005 production hedged with 49 per cent of liquids production hedged (13,000 bbls per day) at a net average price of US$38.06 per bbl and approximately 34 per cent of natural gas production (61,233 GJ per day) is hedged at an average price of $6.54 per GJ. Average prices are net of hedging premiums and are calculated with reference to futures pricing at year end. The Trust is committed to pay $29.4 million of premiums relating to put contracts entered into for 2005. The premiums on the put contracts will be recorded as a realized hedge loss when payment is made in a future period. The Trust's oil contracts are based on the WTI index and the majority of the Trust's natural gas contracts are based on the AECO monthly index.

The table below illustrates ARC's average hedged price, total corporate price in 2005 and commodity hedge gains and losses as a result of the Trust's 2005 commodity hedging program in place as of December 31, 2004, at various commodity prices. The foreign exchange table illustrates the gains and losses pursuant to the Trust's foreign exchange hedges at various USD/CAD exchange rates.

Impact of 2005 Hedging	2005 Commodity Price and Foreign Exchange Rate Assumptions			
Oil				
Oil price per barrel (US$/WTI)	$ 30.00	$ 40.00	$ 50.00	$ 60.00
ARC's average hedged price (US$/barrel) (1)	37.28	37.97	39.95	46.30
Average price on forecasted volumes (US$/WTI) (1)	33.56	39.01	45.09	53.31
Oil hedging gains (losses) (CDN$ millions) (2)	34.3	(9.2)	(47)	(73)
Natural Gas				
Natural gas price per gigajoule (CDN$/GJ)	$ 6.00	$ 7.00	$ 8.00	$ 9.00
ARC's average hedged price (CDN$/GJ)	6.43	6.77	7.56	8.25
Average price on forecasted volumes (CDN$/GJ)	6.16	6.93	7.85	8.74
Natural gas hedging gains (losses) (CDN$ millions)	14.9	2.8	(7.2)	(15.6)
Foreign Exchange				
Foreign exchange rate (USD/CAD)	$ 0.78	$ 0.80	$ 0.82	$ 0.84
Foreign exchange hedge gains (losses) (CDN$ millions)	(10.3)	(5.6)	(1.1)	3.1

(1) Incorporates the impact of hedging premiums.

(2) Based on foreign exchange rate assumption of CDN/US$0.80.

GAIN OR LOSS ON COMMODITY AND FOREIGN CURRENCY CONTRACTS

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

The Trust recorded a loss on commodity and foreign currency contracts of $86.1 million in 2004, consisting of an unrealized fair value loss of $4 million and a realized loss of $82 million.

The following is a summary of the gain (loss) on commodity and foreign currency contracts for 2004:

Commodity and Foreign Currency Contracts

($ thousands)	Crude Oil & Liquids	Natural Gas	Foreign Currency	2004 Total	2003 Total
Realized cash (loss) gain on contracts (1)	**(109,558)**	**(6,457)**	**29,106**	**(86,909)**	(21,653)
Non-cash gain on contracts (2)	**–**	**3,508**	**1,375**	**4,883**	5,702
Non-cash amortization of opening deferred hedge (loss) gain (3)	**(15,974)**	**(3,894)**	**5,293**	**(14,575)**	–
Unrealized (loss) gain on contracts, change in fair value (4)	**(4,749)**	**18,764**	**(3,482)**	**10,533**	–
Total gain (loss) on commodity and foreign currency contracts	**(130,281)**	**11,921**	**32,292**	**(86,068)**	(15,951)

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

(2) Non-cash gains of $4.9 million and $5.7 million for 2004 and 2003, respectively, represent non-cash amortization of deferred commodity and foreign currency contracts.

(3) Represents non-cash amortization of the opening deferred hedge loss of $14.6 million to income over the terms of the contracts in place at January 1, 2004. The opening deferred hedge loss has been fully amortized at December 31, 2004.

(4) The unrealized loss on contracts represents the change in fair value of the contracts during the period. The fair value of the contracts was a loss of $14.6 million at January 1, 2004 and a loss of $4 million at December 31, 2004.

The 2004 $86.1 million loss on commodity and foreign currency contracts consisted of a realized (cash) loss of $86.9 million, an unrealized (non-cash) fair value loss of $4 million, and a non-cash gain of $4.9 million.

The unrealized loss on commodity and foreign currency contracts reflects the change in the fair value of commodity and foreign exchange contracts during each reporting period. To the end of the third quarter of 2004, the Trust had recorded an unrealized fair value loss of $63.6 million on commodity and foreign currency contracts. During the fourth quarter of 2004, the Trust recorded an unrealized gain of $59.6 million on commodity and foreign currency contracts to arrive at a net year-to-date loss of $4 million. The significant unrealized gain recorded in the fourth quarter was attributed to the termination of existing contracts and entering into new contracts at higher effective hedged prices. At the same time, the decrease in forward prices from September 30, 2004, to December 31, 2004, also contributed to the unrealized gain in the fourth quarter. In 2003 there were no unrealized gains or losses on commodity and foreign currency contracts, as all contracts were deemed to be effective accounting hedges up to December 31, 2003.

OPERATING NETBACKS

The Trust's operating netback, after realized hedging losses, increased six per cent to $23.46 per boe in 2004 compared to $22.16 per boe in 2003. The increase in netbacks in 2004 is due primarily to higher realized prices partially offset by increased hedging losses.

The netbacks incorporate realized losses on commodity and foreign currency contracts of $3.94 per boe for 2004, compared to losses of $0.80 per boe in 2003. Fair value loss on commodity and foreign currency contracts of $4 million in 2004 were not recorded as a reduction of the netback.

The components of operating netbacks are shown below:

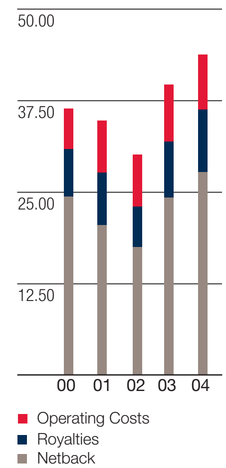
Netback	Oil	Gas	NGL	2004 Total	2003 Total
	($/bbl)	($/mcf)	($/bbl)	($/boe)	($/boe)
Weighted average sales price (1)	**47.03**	**6.78**	**39.04**	**43.13**	38.09
Other revenue	**–**	**–**	**–**	**0.19**	0.18
Total revenue	**47.03**	**6.78**	**39.04**	**43.32**	38.27
Royalties	**(8.30)**	**(1.39)**	**(10.72)**	**(8.51)**	(7.61)
Transportation (1)	**(0.19)**	**(0.20)**	**–**	**(0.71)**	(0.60)
Operating costs (3)	**(8.46)**	**(0.93)**	**(5.28)**	**(6.71)**	(7.10)
Netback prior to hedging	**30.08**	**4.26**	**23.04**	**27.39**	22.96
Loss on commodity and foreign currency contracts (2)	**(9.41)**	**(0.05)**	**–**	**(3.94)**	(0.80)
Netback after hedging	**20.67**	**4.21**	**23.04**	**23.45**	22.16

(1) 2003 revenue and transportation costs have been reclassified to reflect revenue prior to transportation costs. Previously, revenue was presented net of transportation cost. This reclassification did not impact the netback.

(2) Excludes unrealized fair value loss on commodity and foreign currency contracts of $4 million in 2004 (nil in 2003).

(3) 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.

Average Selling Price*
($/boe)



*Before hedging

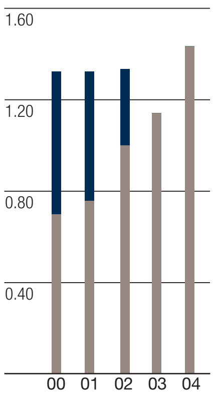
Royalties increased to $8.51 per boe in 2004 compared to $7.61 per boe in 2003. Royalties are calculated and paid based on commodity revenue net of associated transportation costs and before any commodity hedging gains or losses. Royalties as a percentage of pre-hedged commodity revenue net of transportation costs remained unchanged at 20 per cent.

Operating costs, net of processing income, remained relatively consistent at $139.7 million in 2004 compared to $140.7 million in 2003. Operating costs per boe decreased five per cent to $6.71 per boe in 2004 compared to $7.10 per boe in 2003. Despite higher average production in 2004, total operating costs remained relatively constant as a result of two property divestitures, one in the third quarter of 2003 and one in the second quarter of 2004, which carried higher proportionate operating costs per boe. The increased natural gas weighting of the Trust's 2004 production also served to reduce operating costs in total and per boe as natural gas production typically incurs a lower operating cost than oil. In addition, cost adjustments on ARC's non-operated properties for pre-2003 production periods negatively impacted the Trust's operating costs in 2003. The cost savings realized in 2004 from higher cost property divestitures and increased natural gas production were somewhat offset by the impact of higher costs of services throughout the industry particularly for service rigs, trucking costs and mechanical services.

The Trust expects the trend of increasing costs to continue in 2005 as the demand for services is expected to continue at unprecedented levels. Consequently, ARC expects 2005 operating costs to increase slightly from 2004 levels to approximately $7.00 per boe.

Effective for 2004, ARC's transportation costs have been presented as an expense in the statement of income, whereas previously they were recorded as a reduction of revenue. For comparative purposes, 2003 amounts have been reclassified. Transportation costs as presented in the statement of income are defined by the point of legal transfer of the product. Transportation costs are dependent upon where the product is sold, product split, location of properties, and industry transportation rates. For the majority of ARC's gas production, legal title transfers at the intersection of major pipelines (referred to as "the Hub") whereas the majority of ARC's oil production is sold at the outlet to the field oil battery. Consequently, there are higher transportation costs incurred directly by ARC with gas production due to the distance from the wellhead to the Hub. Transportation costs increased 18 per cent to $0.71 per boe in 2004 compared to $0.60 per boe in 2003.

G&A and
Management Fees
($/boe)



■ Management Fees*
■ G&A Expenses
*Management contract terminated in 2002.

GENERAL AND ADMINISTRATIVE EXPENSES AND TRUST UNIT INCENTIVE COMPENSATION

Cash general and administrative expenses ("G&A"), net of overhead recoveries on operated properties increased to $21.4 million ($1.03 per boe) in the 2004 from $19.1 million ($0.96 per boe) in 2003. Increases in cash G&A expenses in total and per boe for 2004 relative to 2003 were the result of the Star acquisition and increasing costs to manage the business associated with increased staff levels. As well, due to unprecedented levels of activity for ARC and for the industry as a whole in 2004, the costs associated with hiring, compensating and retaining employees and consultants has risen. It is essential for the Trust to maintain competitive compensation levels to ensure that we continue to attract and retain the most qualified individuals.

A non-cash trust unit incentive compensation expense ("non-cash compensation expense") of $8.1 million ($0.39 per boe) was recorded in 2004 compared to $3.5 million ($0.18 per boe) in 2003. This non-cash amount relates to both the Trust Unit Incentive Rights Plan ("Rights Plan") and the Whole Trust Unit Incentive Plan.

The $5.2 million non-cash expense for the Rights Plan was determined based upon the prospective adoption of a fair value calculation. Only the rights that were issued on or after January 1, 2003 are subject to valuation and expense in the statement of income.

Previously, the Trust recorded compensation expense for the rights based on the intrinsic value methodology, which resulted in the expense amount being based on the underlying trust unit price at each period end. In accordance with CICA Handbook Section 3870, an entity may apply an intrinsic value methodology if it is impossible to estimate a fair value at grant date, and in particular, for situations where there is a declining exercise price which is subject to uncertainty. In the fourth quarter of 2004, the Trust adopted the fair value methodology of valuation of the rights based on certain assumptions and estimates. The Trust was enabled to determined fair value estimates given that the rights plan has now been discontinued, the remaining vesting period of rights is more determinable and there is more predictability regarding future distributions and future reductions in the rights exercise price. As the change in methodology qualifies as a change in estimate under accounting standards, the fair value methodology has been applied prospectively without restatement of prior periods.

The Trust has estimated the fair value of the rights issued in 2003 and 2004 based on the following assumptions and estimates:

	2004
Expected annual dividend	**$ 1.80**
Expected annual right's exercise price reduction	**$ 0.72**
Expected volatility	**13.2%**
Risk-free interest rate	**3.7%**
Expected life of rights (years)	**1.1**
Expected annual forfeitures (per cent)	**–**

As at December 31, 2004, the fair value calculation resulted in cumulative expense of $8.7 million compared to the $10.2 million recorded as cumulative compensation expense to September 30, 2004, under the intrinsic value methodology. The $1.5 million was recorded as compensation recovery in the fourth quarter of 2004. The remaining future fair value of the rights of $3.7 million will be recognized in earnings over the remaining vesting period of the rights outstanding.

In March 2004 the Board of Directors upon recommendation by the Compensation Committee, approved a new Whole Unit Plan to replace the existing Rights Plan for new awards granted subsequent to the first quarter of 2004. The new Whole Unit Plan will result in employees, officers and directors (the "plan participants") receiving cash compensation in relation to the value of a specified number of underlying trust units. The Whole Unit Plan consists of Restricted Trust Units ("RTU's") for which the number of trust units is fixed and that will vest over a period of three years and Performance Trust Units ("PTU's") for which the number of trust units is variable and will vest at the end of three years. The Trust issued 226,837 RTU's and 128,908 PTU's to employees, officers and directors in 2004, of which 2,439 RTU's and 577 PTU's were subsequently forfeited in 2004. Upon vesting, the plan participant is entitled to receive a cash payment based on the fair value of the underlying trust units plus accrued distributions. The cash compensation issued upon vesting of the PTU's is dependent upon the future performance of the Trust compared to its peers based on certain key industry benchmarks. The value associated with the RTU's and PTU's will be expensed in the statement of income over the vesting period with the expense amount being determined by the trust unit price, the number of PTU's to be issued on vesting, and distributions. Therefore, the expense recorded in the statement of income may fluctuate over time. The $1.9 million ($0.14 per boe) non-cash expense attributed to the new Whole Unit Plan is based on 352,729 committed trust units under the Whole Unit Plan as at December 31, 2004. The 2004 expense consists of a short-term portion of $1 million and a long-term portion of $1.9 million. Under the new Whole Unit Plan, a non-cash expense will be recorded each period in the statement of income. A realization of the expense and a resulting reduction in cash flow will occur each year when a cash payment is made upon vesting in the second quarter of each year. The Whole Unit Plan expense does not impact cash flow until a cash payment is made.

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

G&A and Trust Unit Incentive Compensation Expense

($ thousands except per boe)	**2004**	2003	% Change
G&A expenses	**30,733**	25,346	21
Operating recoveries	**(9,307)**	(6,250)	49
Cash G&A expenses	**21,426**	19,096	12
Non-cash compensation – Rights Plan	**5,171**	3,470	49
Accrued cash compensation – Whole Unit Plan	**2,915**	–	–
Total G&A and trust unit incentive compensation expense	**29,512**	22,566	31
Cash G&A expenses per boe	**1.03**	0.96	7
Total G&A and trust unit incentive compensation expense per boe	**1.42**	1.14	25

The Trust expects 2005 G&A costs, excluding non-cash G&A associated with the Trust's Rights Plan and Whole Unit Plan, to be approximately $1.25 per boe. In addition, the Trust expects 2005 non-cash G&A of approximately $0.30 per boe for the non-cash trust unit incentive compensation expense associated with the Rights Plan and Whole Unit Plan. The increasing G&A costs in 2005 are the result of higher compensation levels associated with hiring and retaining the most qualified employees and consultants as it is expected that the robust levels of activity will continue throughout the industry in 2005.

INTEREST EXPENSE

Interest expense decreased to $13.3 million in 2004 from $18.5 million in 2003. The decrease in interest expense is attributed to a lower average debt balance in 2004 compared to 2003 as a result of increased cash flow and a higher portion of the Trust's 2004 capital program having been cash funded.

On April 27, 2004, with the issuance of US$125 million of long-term notes, the Trust repaid all Canadian denominated debt. As at December 31, 2004, the Trust's debt balance was almost entirely U.S.-denominated fixed rate debt with an average rate of 4.86 per cent (3.81 per cent including the current impact of the interest rate swap contracts) and an average life of 6.5 years. With the issuance of the fixed rate notes and repayment of variable rate debt, the Trust's effective interest rate, before the impact of interest rate swaps, increased slightly.

In order to capitalize on low short-term interest rates in the United States, the Trust entered into interest rate swap agreements to convert US$62.5 million of fixed rate debt into floating rate debt at a rate equal to the three month LIBOR rate plus 38.25 basis points through to 2014. The Trust realized a cash gain of $1.4 million on the interest rate swap in 2004 and this amount has been netted against interest expense in the statement of income. The average rate on the interest rate swap was approximately 2.4 per cent during 2004.

The following is a summary of the debt balance and interest expense for 2004 and 2003:

Interest Expense

($ thousands)	**2004**	2003	% Change
Period end debt balance (1)	**220,549**	232,402	(5)
Fixed rate debt	**220,259**	84,006	162
Floating rate debt	**290**	148,396	(100)
Interest expense before interest rate swaps (2)	**14,675**	18,482	(21)
Gain on interest rate hedge	**(1,355)**	–	–
Net interest expense (3)	**13,320**	18,482	(28)

(1) Includes both long-term and current portions of debt.

(2) The interest rate swap was designated as an effective hedge for accounting purposes whereby actual realized gains and losses are netted against interest expense.

(3) 2003 interest expense excludes interest on convertible debentures.

FOREIGN EXCHANGE GAINS AND LOSSES

The Trust recorded a gain of $20.7 million ($1.00 per boe) on foreign exchange transactions compared to a gain of $18.6 million ($0.94 per boe) in 2003. These amounts include both realized and unrealized foreign exchange gains and losses. Unrealized foreign exchange gains and losses are due to revaluation of U.S. denominated debt balances. The volatility of the Canadian dollar during the reporting period has a direct impact on the unrealized component of the foreign exchange gain or loss. The unrealized gain/loss impacts net income but does not impact cash flow as it is a non-cash amount. Realized foreign exchange gains or losses arise from U.S. denominated transactions such as interest payments, debt repayments and hedging settlements.

The following is a breakdown of the total foreign exchange gain (loss):

Foreign Exchange Gain (Loss)

($ thousands except per boe)	**2004**	2003	% Change
Unrealized gain on U.S. denominated debt	**21,923**	18,700	17
Realized (loss) on U.S. denominated debt repayments	**(3,495)**	–	–
Realized gain (loss) on U.S. denominated transactions	**2,285**	(136)	–
Total foreign exchange gain	**20,713**	18,564	12
Total foreign exchange gain per boe	**1.00**	0.94	6

TAXES

Capital taxes paid or payable by ARC, based on debt and equity levels at the end of the year, amounted to $2.8 million in 2004 compared to $1.8 million in 2003. The increase in 2004 capital taxes was attributed to the higher taxable capital base as a result of the Star acquisition, as well as a lower installment base for the first quarter of 2003 due to prior year excess installments having been made.

In 2004 a future income tax recovery of $26.1 million was included in income compared to a $93.5 million recovery in 2003. The lower future income tax recoveries in 2004 relative to 2003 are due to a recovery of $66.1 million being recorded in 2003 as a result of reductions in future corporate income tax rates that became effective in 2003. The 2004 future income tax recovery of $26.1 million includes a recovery of $5.9 million due to the change in Alberta corporate income tax rates and the reduction in the Trust's future expected income tax rate. The current year recovery also includes a $1.4 million recovery due to the net derivative liability recorded on the balance sheet at December 31, 2004 pursuant to hedge accounting (nil in 2003).

In the first quarter of 2004 the Alberta government passed legislation to reduce provincial corporate income tax rates to 11.5 per cent from 12.5 per cent effective April 1, 2004. ARC's expected future income tax rate incorporating this rate reduction is approximately 34 per cent (35 per cent in 2003) compared to the current rate of approximately 39 per cent applicable to the 2004 income tax year.

Corporate acquisitions completed in 2004 resulted in the Trust recording a future income tax liability of $24.5 million due to the difference between the tax basis and the fair value assigned to the acquired assets. The amount of tax pools versus asset value is one of the parameters that impacts the Trust's acquisition bid levels.

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 ACCRETION OF ASSET RETIREMENT OBLIGATION

The depletion, depreciation and accretion ("DD&A") rate increased slightly to $11.51 per boe in 2004 from $11.02 per boe in 2003. The higher DD&A rate is due to the Star acquisition in the second quarter of 2003 for which the Trust recorded a higher proportionate cost per barrel of proved reserves of the acquired Star properties compared to the existing ARC properties. In addition, the higher asset retirement obligation recorded in 2004 has resulted in higher accretion expense in 2004.

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

DD&A Rate

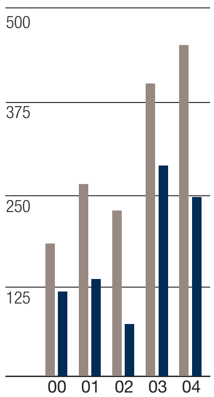
($ thousands except per boe amounts)	**2004**	2003	% Change
Depletion of oil & gas assets (1)	**235,094**	215,593	9
Accretion of asset retirement obligation (2)	**4,580**	2,958	55
Total DD&A	**239,674**	218,551	10
DD&A Rate per boe	**11.51**	11.02	4

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

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

The costs subject to depletion included $42.3 million relating to the capitalized portion of the asset retirement obligation as at December 31, 2004 ($41.1 million as at December 31, 2003), net of accumulated depletion.

Cash Flow
and Earnings
($ millions)



GOODWILL

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

Accounting standards require that the goodwill balance be assessed for impairment at least annually or more frequently if events or changes in circumstances indicate that the balance might be impaired. If such an impairment exists, it would be charged to income in the period in which the impairment occurs. The Trust has determined that there was no goodwill impairment as of December 31, 2004.

CAPITAL EXPENDITURES AND NET ACQUISITIONS

Total capital expenditures, excluding acquisitions and dispositions, totaled $193.8 million in 2004 compared to $155.8 million in 2003. This amount was incurred on drilling and completions, geological, geophysical and facilities expenditures, as ARC continues to develop its asset base. The significant increase in 2004 capital expenditures relative to 2003 is due to a larger capital development program in 2004 to capture value from increased development opportunities as a result of the Star acquisition.

In addition to the capital expenditures, the Trust completed net property dispositions of $58.2 million, net of post closing adjustments, in 2004. The Trust also completed two corporate acquisitions, United Prestville in June 2004, for total consideration of $30.6 million and Harrington & Bibler in December 2004, for total consideration of $41.4 million. Both corporate acquisitions were undertaken by the Trust to increase the Trust's ownership interest in existing key properties.

The capital expenditures resulted in an increase in oil and gas reserves, before dispositions, as detailed in the February 16, 2005, Year End Reserves press release.

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

Capital Expenditures

($ thousands)	**2004**	2003	% Change
Geological and geophysical	**5,388**	5,671	(5)
Drilling and completions	**144,487**	110,277	31
Plant and facilities	**41,089**	36,457	13
Other capital	**2,820**	3,359	(16)
Total capital expenditures	**193,784**	155,764	24
Producing property acquisitions (1)	**(529)**	14,783	(104)
Producing property dispositions (1)	**(57,691)**	(176,392)	67
Corporate acquisitions (2)	**72,009**	721,590	(90)
Total capital expenditures and net acquisitions	**207,573**	715,745	(71)
Total capital expenditures financed with cash flow	**110,846**	106,625	4
Total capital expenditures financed with debt & equity	**96,727**	609,120	(84)

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

(2) Represents total consideration for the transactions, including fees but is prior to the related future income tax liability and working capital assumed on acquisition.

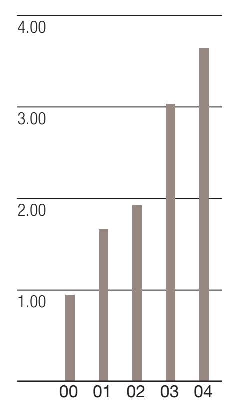
ARC expects to undertake significant development projects in 2005 to fully execute the capital program of approximately $240 million.

ASSET RETIREMENT OBLIGATION AND RECLAMATION FUND

At December 31, 2004, the Trust has recorded an Asset Retirement Obligation ("ARO") of $73 million ($66.7 million at December 31, 2003) for future abandonment and reclamation of the Trust's properties. The ARO increased by $4.9 million during 2004 as a result of liabilities associated with the acquisitions of United Prestville and Harrington & Bibler and with additional wells drilled in 2004, partially offset by the sale of properties in the second quarter of 2004. The ARO further increased by $4.6 million for accretion expense in 2004 ($3 million in 2003) and was reduced by $3.2 million ($2.2 million in 2003) for actual abandonment expenditures incurred in 2004. The Trust did not record a gain or loss on actual abandonment expenditures incurred in 2004 as the costs closely approximated the liability value included in the ARO.

ARC contributed $6 million cash to its reclamation fund in 2004 ($5.5 million in 2003) and earned interest of $1.2 million ($0.7 million in 2003) on the fund balance. The fund balance was reduced by $3.1 million for cash-funded abandonment expenditures in 2004 ($1.9 million in 2003). This fund, invested in money market instruments, was established to provide for future abandonment and reclamation liabilities. Future contributions are currently set at approximately $6 million per year over 20 years in order to provide for the total estimated future abandonment and reclamation costs that are to be incurred over the next 61 years.

Total Capitalization
($ billions)



CAPITALIZATION, FINANCIAL RESOURCES AND LIQUIDITY

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

($ thousands except per unit and per cent amounts)	**2004**	2003
Long-term debt	**211,834**	223,355
Short-term debt	**8,715**	9,047
Working capital deficit (surplus) excluding short-term debt (1)	**44,293**	29,669
Net debt obligations	**264,842**	262,071
Units outstanding and issuable for exchangeable shares (thousands)	**188,804**	182,777
Market price per unit at end of period	**17.90**	14.74
Market value of trust units and exchangeable shares	**3,379,592**	2,694,133
Total capitalization (2)	**3,644,434**	2,956,204
Net debt as a percentage of total capitalization	**7.3%**	8.9%
Net debt obligations	**264,842**	262,071
Cash flow from operations	**448,033**	396,180
Net debt to cash flow	**0.6**	0.7

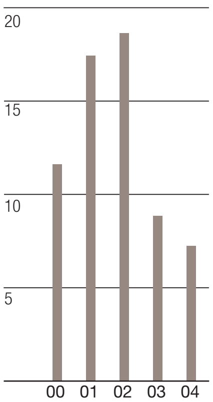
(1) The 2004 working capital deficit excludes the balances for commodity and foreign currency contracts.

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

On April 27, 2004, the Trust completed the issuance of US$125 million of long-term secured notes ("US Notes") via a private placement to a small group of Canadian and United States financial institutions and insurance companies. The notes were issued in two tranches of US$62.5 million each. The first tranche of US$62.5 million has a final life of 10 years (average life of 7.5 years) and pays a semi-annual coupon of 4.62 per cent per annum. The second tranche of US$62.5 million has a final life of 12 years (average life of 10 years) and pays a semi-annual coupon of 5.10 per cent per annum. Repayments of the notes will occur in years 2009 through 2016.

Net Debt as a Percentage of Total Capitalization

(%)



The Trust consolidated its five credit facilities into one syndicated credit facility with a total borrowing base of $620 million in the second quarter of 2004. The syndication of the credit facilities did not impact the Trust's borrowing base nor did it impact other key terms of the credit facility such as security or covenants. Borrowing rates under the syndicated facility decreased slightly. ARC Resources' and ARC (Sask) Trust's oil and gas properties continue to secure the debt. The next annual credit review will occur in April 2005 with the expectation that the current agreement will be renewed under identical or similar terms and conditions.

The following is a summary of total debt outstanding at the end of the year:

Total Debt

($ thousands)	**2004**	2003
Revolving credit facilities		
Working capital facility, current	**290**	–
CAD credit facility, 364 day revolving	**–**	111,298
USD credit facility, 364 day revolving	**–**	37,098
Senior secured notes (1)		
US$35 million, 8.05%, 2004 – 2008	**33,701**	45,234
US$30 million, 4.94%, 2006 – 2010	**36,108**	38,772
Long-term notes (1)		
US$62.5 million, 4.62%, 2009 – 2014	**75,225**	–
US$62.5 million, 5.10%, 2011 – 2016	**75,225**	–
Total debt outstanding, long-term and current	**220,549**	232,402
Current portion of debt	**8,715**	9,047
Long-term portion of debt	**211,834**	223,355

(1) Both the senior secured notes and the long-term notes rank pari passu to the revolving credit facilities.

Concurrent with the issuance of the Long-term Notes, the Trust entered into interest rate swap transactions to effectively convert the fixed interest rate on US$62.5 million of the US Notes into a floating rate, based on the three month LIBOR rate plus 38.25 basis points, in order to capitalize on historic low interest rates in the United States. As a result, the Trust effectively issued US$125 million notes at an average rate of 3.3 per cent, with this rate increasing by one half of a percentage point for every one percentage point increase in short-term U.S. interest rates. The short-term US LIBOR interest rate was 2.6 per cent at December 31, 2004.

As at December 31, 2004, the Trust had a working capital deficiency excluding short-term debt, of $48.3 million. Included in the working capital deficit is a net current liability of $4 million for the fair value loss on commodity and foreign currency contracts under new hedge accounting guidelines implemented in 2004. Excluding the Trust's net current liability for commodity and foreign currency contracts and short-term debt, the Trust had a working capital deficit of $44.3 million at December 31, 2004.

The Trust's working capital deficit, excluding the net liability for commodity and foreign currency contracts, was significantly higher at December 31, 2004, compared to December 31, 2003. The Trust fully funded the $41.4 million Harrington & Bibler acquisition on December 31, 2004, with cash.

December 31, 2004, net debt to total capitalization was 7.3 per cent and net debt to annual 2004 cash flow was approximately 0.6 times (0.7 times as at December 31, 2003).

The Trust intends to finance a portion of the $240 million 2005 capital program with cash flow, proceeds of the distribution reinvestment program and the remainder will be financed with debt.

UNITHOLDERS' EQUITY

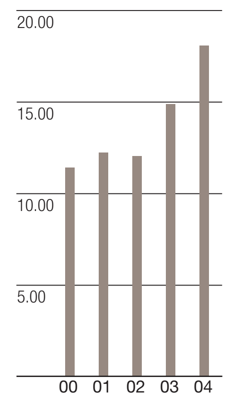
At December 31, 2004, there were 188.8 million trust units issued and issuable for exchangeable shares, a three per cent increase from the 182.8 million trust units issued and issuable for exchangeable shares at December 31, 2003. The increase in the number of trust units outstanding is attributable to two million trust units issued as consideration for the acquisition of United Prestville at a price of $15.00 per trust unit, 1.9 million trust units issued pursuant to the Distribution Reinvestment Incentive Plan ("DRIP") at an average price of $14.72 per trust unit, 1.7 million trust units issued pursuant to the exercise of employee rights at an average price of $11.70 per trust unit, and 0.4 million trust units issued upon conversion of exchangeable shares.

The Trust made its final issuance of 27,000 additional rights under the Rights Plan during the first quarter of 2004. There will be no future issuances of rights as the rights plan was replaced with a new Whole Unit Plan in the second quarter of 2004. The existing rights plan will be in place until the remaining three million rights outstanding as of December 31, 2004, are exercised or cancelled. The holder has the option to exercise the rights at the original grant price or a price that is adjusted downward over time by the amount, if any, of the annual distributions that exceed 10 per cent of the net book value of the 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 three million trust units at an average adjusted exercise price of $10.92 were outstanding at December 31, 2004. These rights have an average remaining contractual life of 3.1 years and expire at various dates to March 22, 2009. Of the rights outstanding at December 31, 2004, a total of 0.8 million were exercisable at that time.

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

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

Unit Market Price
($/unit at December 31)



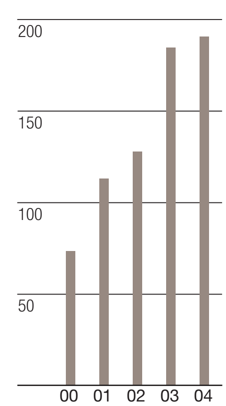
NON-CONTROLLING INTEREST – EXCHANGEABLE SHARES

The Trust has recorded non-controlling interest attributed to the issued and outstanding exchangeable shares of ARC Resources Ltd. ("ARL") in accordance with new accounting requirements pursuant to the Canadian Institute of Chartered Accountants Emerging Issues Committee's Pronouncement 151 ("EIC-151") (see "Impact of New Accounting Policies" in this MD&A and Note 3 of the consolidated financial statements for further discussion). The intent of the new standard is that exchangeable shares of a subsidiary which are transferable to third parties represent a non-controlling interest in the subsidiary.

The exchangeable shares of ARL are publicly traded and therefore are transferable to third parties. In all circumstances, including in the event of the liquidation or insolvency of ARL, holders of exchangeable shares will receive trust units in exchange for their exchangeable shares and as a result the exchangeable shares and trust units are considered to be economically equivalent. The Trust does not believe that there is a permanent non-controlling interest as all exchangeable shares will ultimately be exchanged for trust units by passage of time. Over time, the non-controlling interest will decrease and eventually will be nil when all exchangeable shares have been exchanged for trust units on or before August 29, 2012.

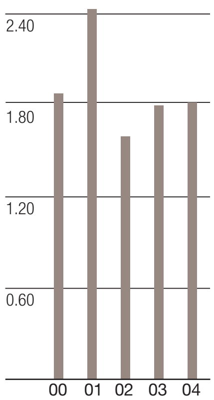
The non-controlling interest in 2004 of $36 million ($36.3 million in 2003) on the consolidated balance sheet represents the book value of exchangeable shares plus accumulated earnings attributable to the outstanding exchangeable shares. The reduction in 2004 and 2003 net income, respectively, of $4 million and $5.6 million, represents the net income attributable to the exchangeable shareholders for 2004 and 2003. As the exchangeable shares are converted to trust units, Unitholders' capital is increased for the book value of the trust units issued.

Units Outstanding at Year End*
(millions)



*includes units issuable for exchangeable shares

Cash Distributions
($/unit)



As at December 31, 2004, there were 1.8 million exchangeable shares of ARL outstanding at exchange ratio of 1.67183 whereby three million trust units would be issuable upon conversion. The exchangeable shares can be converted into trust units or redeemed by the exchangeable shareholder for trust units at any time. ARL may redeem all outstanding exchangeable shares on or before August 29, 2012, and may redeem the exchangeable shares at any time if the number of exchangeable shares outstanding falls below 100,000 shares. ARL may issue cash or trust units upon redemption of exchangeable shares and it is the intention to issue trust units upon redemption.

CASH DISTRIBUTIONS

ARC declared cash distributions of $330 million ($1.80 per unit), representing 74 per cent of 2004 cash flow compared to cash distributions of $279.3 million ($1.80 per unit), representing 71 per cent of cash flow in 2003. The remaining 26 per cent of 2004 cash flow ($118 million) was used to fund 57 per cent of ARC's 2004 capital expenditures ($110.8 million), and make contributions, including interest, to the reclamation fund ($7.2 million). The actual amount of cash flow withheld to fund the Trust's capital expenditure program is dependent on the commodity price environment and is at the discretion of the Board of Directors.

Cash flow and cash distributions in total and per unit for 2004 and 2003 were as follows:

2004 Cash Flow and Distributions

	2004	2003	% Change	**2004**	2003	% Change
		($ millions)			($ per unit)	
Cash flow from operations	**448.0**	396.2	13	**2.45**	2.61	(6)
Reclamation fund contributions (1)	**(7.2)**	(6.2)	16	**(0.04)**	(0.04)	–
Capital expenditures funded with cash flow	**(110.8)**	(106.6)	4	**(0.61)**	(0.70)	(13)
Interest on convertible debentures	**–**	(4.1)	–	**–**	(0.03)	–
Other (2)	**–**	–	–	**–**	(0.04)	–
Cash distributions	**330.0**	279.3	18	**1.80**	1.80	–

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

(2) Other represents the difference due to cash distributions paid being based on actual units at each distribution date whereas per unit cash flow, reclamation fund contributions and capital expenditures funded with cash flow are based on weighted average trust units in the year.

Monthly cash distributions for the first quarter of 2005 have been set at $0.15 per trust unit subject to monthly review based on commodity price fluctuations. Revisions, if any, to the monthly distribution are normally announced on a quarterly basis in the context of prevailing and anticipated commodity prices at that time.

HISTORICAL CASH DISTRIBUTIONS BY CALENDAR YEAR

The following table presents cash distributions paid in each calendar period. Cash distributions for 2004 include distributions paid up to and including December 15, 2004:

Calendar Year	Distributions (1)	Taxable Portion	Return of Capital
2005 YTD (2)	0.30	0.29 (2)	0.01 (2)
2004	1.80	1.69 (3)	0.11 (3)
2003	1.78	1.51	0.27
2002	1.58	1.07	0.51
2001	2.41	1.64	0.77
2000	1.86	0.84	1.02
1999	1.25	0.26	0.99
1998	1.20	0.12	1.08
1997	1.40	0.31	1.09
1996	0.81	–	0.81
Cumulative	**$ 14.39**	**$ 7.73**	**$ 6.66**

(1) Based on cash distributions paid in the calendar year.

(2) Based on cash distributions paid in 2005 up to and including February 15, 2005, and estimated taxable portion of 2005 distributions of 95 per cent.

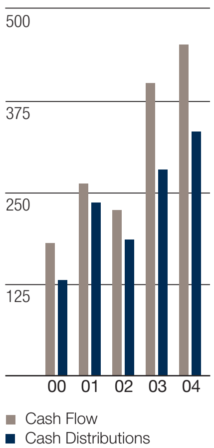
(3) Based on taxable portion of 2004 distributions of 94 per cent.

2004 MONTHLY CASH DISTRIBUTIONS

Actual cash distributions paid for 2004 along with relevant payment dates are as follows:

Ex-Distribution Date	Record Date	Distribution Payment Date	Total Distribution	Taxable Portion	Return of Capital
December 29, 2003	December 31, 2003	January 15, 2004	0.15	0.141	0.009
January 28, 2004	January 31, 2004	February 16, 2004	0.15	0.141	0.009
February 25, 2004	February 29, 2004	March 15, 2004	0.15	0.141	0.009
March 29, 2004	March 31, 2004	April 15, 2004	0.15	0.141	0.009
April 28, 2004	April 30, 2004	May 17, 2004	0.15	0.141	0.009
May 27, 2004	May 31, 2004	June 15, 2004	0.15	0.141	0.009
June 28, 2004	June 30, 2004	July 15, 2004	0.15	0.141	0.009
July 28, 2004	July 31, 2004	August 16, 2004	0.15	0.141	0.009
August 27, 2004	August 31, 2004	September 15, 2004	0.15	0.141	0.009
September 28, 2004	September 30, 2004	October 15, 2004	0.15	0.141	0.009
October 27, 2004	October 31, 2004	November 15, 2004	0.15	0.141	0.009
November 26, 2004	November 30, 2004	December 16, 2004	0.15	0.141	0.009
Total 2004			**1.80**	**1.69**	**0.11**

Cash Available for Distribution
($ millions)



TAXATION OF CASH DISTRIBUTIONS

Cash distributions comprise a return of capital portion (tax deferred) and a return on capital portion (taxable). The return of capital component reduces the cost basis of the trust units held. The tables above and following discussion relate to taxation of Canadian unitholders. For a more detailed breakdown and for tax information for foreign or U.S. investors, please visit our website at www.arcenergytrust.com.

For 2004, cash distributions paid in the calendar year will be 94 per cent return on capital (taxable) and six per cent return of capital (tax deferred). The increase in the taxable portion of distributions to 94 per cent is the result of increasing commodity prices and in turn, increasing cash flow of the Trust. Actual taxable amounts may differ from the estimated amount as they are dependent on commodity prices experienced throughout the year. Changes in the estimated taxable and deferred portion of the distributions will be announced quarterly.

The 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 taxed, in most circumstances, as a capital gain rather than income and is therefore subject to a lower effective tax rate. Tax on the exchangeable shares is deferred until the exchangeable share is sold or converted into a trust unit.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The Trust has contractual obligations in the normal course of operations, including purchase of assets and services, operating agreements, transportation commitments, sales commitments, royalty obligations and lease rental obligations. These obligations are of a recurring and consistent nature and impact cash flow in an ongoing manner. The Trust also has contractual obligations and commitments that are of a less routine nature and that are disclosed in Note 18 of the consolidated financial statements.

The Trust enters into commitments for capital expenditures in advance of the expenditures being made. At a given point in time, it is estimated that the Trust has committed to approximately $40 to $60 million of capital expenditures by means of giving the necessary authorizations to incur the capital in a future period. This commitment has not been disclosed in the above commitment table as it is of a routine nature and is part of normal course of operations for active oil and gas companies and trusts.

The Trust has certain sales contracts with aggregators whereby the price received by the Trust is dependent upon the contracts entered into by the aggregator. The Trust has an obligation for future fixed transportation charges, pursuant to one aggregator contract, for which the transportation is not physically being utilized due to a shortage of demand. The Trust has estimated that its total liability for the future transportation charges approximates $10 million over the period 2005 through 2012. This transportation liability will be realized as a reduction of the Trust's net gas price over the corresponding period as the charges are incurred. For all other aggregator contracts, prices received by the Trust closely track to market prices.

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

OFF BALANCE SHEET ARRANGEMENTS

The Trust has certain lease agreements that are entered into in the normal course of operations. All leases are treated as operating leases whereby the lease payments are included in operating expenses or G&A expenses depending on the nature of the lease. No asset or liability value has been assigned to these leases in the balance sheet as of December 31, 2004. The total obligation for future lease payments under all operating leases is disclosed in the "Contractual Obligations and Commitments" section above.

The Trust entered into agreements to pay premiums pursuant to certain crude oil derivative put contracts. Premiums of approximately $29.4 million will be paid in 2005 for the put contracts in place at year end. As the premiums are part of the underlying derivative contract, they have been recorded at fair market value at December 31, 2004, on the balance sheet. The total obligation for future premium payments is disclosed in the "Contractual Obligations and Commitments" section above and Note 18 of the consolidated financial statements.

IMPACT OF NEW ACCOUNTING POLICIES

In 2004 the Trust implemented the following new accounting policies and instruments pursuant to requirements of the Canadian Institute of Chartered Accountants ("CICA"). The implementation of these new policies impacted the financial results for 2004 and comparative periods of 2003 as follows:

Non-Controlling Interest – On January 19, 2005, the CICA issued EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts" which states that exchangeable securities issued by a subsidiary of an income trust should be reflected as either non-controlling interest or debt on the consolidated balance sheet unless they meet certain criteria. The exchangeable shares issued by ARL, a corporate subsidiary of the Trust, are publicly traded and therefore must be presented as non-controlling interest, outside of Unitholders' equity. Previously, the exchangeable shares were reflected as a component of Unitholders' equity. Accordingly, the Trust has reflected a non-controlling interest of $36 million and $36.3 million, respectively, on the Trust's consolidated balance sheet as at December 31, 2004, and 2003. Consolidated net income has been reduced for net income attributable to the non-controlling interest of $4 million and $5.6 million, respectively, in 2004 and 2003. In accordance with the transitional provisions of EIC-151, retroactive application has been applied with restatement of prior periods. As a result of retroactive restatement, opening accumulated earnings for 2003 decreased by $5.5 million for the cumulative net income attributable to the non-controlling interest, Unitholders' equity was reduced by $31.7 million and non-controlling interest on the balance sheet increased by $37.2 million.

Hedge Accounting – In December 2001, the CICA issued Accounting Guideline 13 "Hedging Relationships" and EIC-128 "Accounting for Trading, Speculative, or Non-Hedging Derivative Financial Instruments" that deal with the identification, designation, documentation and measurement of effectiveness of hedging relationships for the purposes of applying hedge accounting. Accounting Guideline 13 ("AcG-13") is intended to harmonize Canadian GAAP with SFAS No.133 "Accounting for Derivatives Instruments and Hedging Activities". AcG-13 is effective for fiscal years beginning on or after July 1, 2003, and upon implementation of AcG-13, accounting in accordance with EIC-128 is required.

The Trust implemented AcG-13 in the first quarter of 2004 along with accounting in accordance with EIC-128. As a result, certain of the Trust's derivative contracts were designated as effective hedges for accounting purposes at January 1, 2004. Commodity and foreign currency contracts that were designated as effective hedges continue to be accounted for in the same manner as in previous periods whereby realized gains and losses on effective hedges are netted against the item to which they relate in the statement of income. Commodity and foreign currency contracts that were not designated as effective hedges for accounting purposes are subject to fair value accounting in accordance with EIC-128, which requires that changes in the fair value of these derivative contracts be reported as income or expense in each reporting period. The income or expense relating to the change in fair value of the derivative contracts is a non-cash (unrealized) expense that has no impact on cash flow but may result in significant fluctuations in net income due to volatility in the underlying market commodity prices and foreign exchange rates.

Prior to implementation of AcG-13 and EIC-128, the Trust accounted for all derivative contracts as effective hedges whereby realized gains and losses on such contracts were included in the statement of income within the corresponding item to which the hedge pertained. Following implementation, realized and unrealized gains and losses on derivative contracts that do not qualify as effective hedges are reported as a separate expense in the statement of income. In accordance with the transitional provisions of AcG-13 and EIC-128, this new guideline has been applied prospectively whereby prior periods have not been restated.

As an example of a commodity derivative contract, the Trust enters into oil and natural gas put options as part of its commodity risk management portfolio. The Trust considers such a transaction to be an effective economic hedge as it reduces exposure to decreases in commodity prices that would adversely impact cash flow and allows the Trust to participate in 100 per cent of the upside over and above the contract price. Per new hedge accounting requirements, this transaction does not qualify as an effective accounting hedge and therefore is subject to fair value accounting.

As a result of implementation of this new standard, 2004 net income decreased by $2.6 million ($4 million before a future income tax recovery of $1.4 million). The entire $4 million decrease in 2004 pre-tax net income was the result of non-cash losses due to changes in the fair value of the contracts. On initial implementation of this standard on January 1, 2004, the Trust recorded an opening deferred charge of $14.6 million equal to the fair value of derivative contracts at that time. The deferred charge was amortized to earnings over the life of the respective contracts in place at January 1, 2004, and was fully amortized as of December 31, 2004. The Trust recorded a derivative asset of $22.3 million and a derivative liability of $26.3 million for the fair value of the derivative contracts as at December 31, 2004 (nil impact in 2003). There was no impact on cash flow as a result of implementing this new standard.

Transportation Costs – Effective in 2004, the Trust revised its presentation of transportation costs in accordance with CICA Handbook Section 1100 "Generally Accepted Accounting Principles". As a result, revenue has been presented prior to transportation costs and a separate expense for transportation costs has been presented in the statement of income. The Trust has reclassified previously reported amounts to be consistent with the presentation under this new policy. Transportation costs of $14.8 million and $12 million, respectively, were recorded in 2004 and 2003 as a result of this new policy. There was no impact on net income or cash flow in 2004 nor did it impact restated net income or cash flow in 2003.

Recognition of Temporary Equity for US GAAP Purposes – For Canadian income tax purposes the Trust qualifies as a mutual fund trust by the fact that the Trust's indenture contains redemption provisions. For US GAAP purposes this redemption feature has resulted in the Trust reflecting all of its equity in 2004 and restating its 2003 accounts to record "temporary equity" as prescribed under Emerging Issues Task Force D-98 due to the fact unitholders have a right to have the Trust redeem their units rather than selling the units on the Toronto Stock Exchange. The reclassification of Unitholders' equity to temporary equity is recorded at fair market value of the trust units at year end (see Note 19 of the consolidated financial statements).The Trust's redemption features allow for cash redemptions to a maximum of $100,000 per month at a price calculated at a discount to the market trading price with redemption requests in excess of the $100,000 monthly maximum being satisfied by issuing a 15 year note from ARC Resources Ltd. for a maximum amount of $500 million that would rank subordinate to all other creditors and not be listed on any exchange resulting in limited liquidity. Further, the Trust has a termination date of December 31, 2095, if not extended by the unitholders prior to that time, at which time the Trust would commence wind-up activities by redeeming all outstanding units and distributing the remaining assets, if any, to unitholders. As such, it is in management's opinion that the required classification of the Trust's units as "temporary equity" does not meaningfully represent the true nature of the Trust's financial picture. For Canadian GAAP purposes the proceeds of units issued has been classified on the balance sheet as "Unitholder's Capital".

FINANCIAL REPORTING UPDATE

In addition to the above policies implemented in 2004, the following new and amended standards and proposed standards have been reviewed by the Trust:

Variable Interest Entities – In June 2003 the CICA issued Accounting Guideline 15 "Consolidation of Variable Interest Entities" that deals with the consolidation of entities which are subject to control on a basis other than ownership of voting interests. This new guideline is effective for fiscal years beginning on or after November 1, 2004. The Trust has assessed that this guideline has no current or future impact based on the current structure. The Trust will consider the applicability of this guideline in the future and assess the appropriate financial statement implications at that time.

Redeemable or Retractable Shares – On November 5, 2004, the CICA issued EIC-149 "Accounting for Retractable or Mandatorily Redeemable Shares" that lists specific criteria required to be met in order for entities to reflect trust units and exchangeable shares as either a liability or equity in their financial statements. The trust units and exchangeable shares meet the required criteria to be reflected as Unitholders' equity and no additional presentation or disclosure is required.

Financial Instruments – Recognition and Measurement – On January 27, 2005, the Accounting Standard's Board (AcSB) issued CICA Handbook section 3855 "Financial Instruments – Recognition and Measurement", CICA Handbook section 1530 "Comprehensive Income" and CICA Handbook section 3865 "Hedges" that deal with the recognition and measurement of financial instruments and comprehensive income. The new standards are intended to harmonize Canadian standards with United States and International accounting standards and are effective for annual and interim periods in fiscal years beginning on or after October 1, 2006. These new standards will impact the Trust in future periods and the resulting impact will be assessed at that time.

CRITICAL ACCOUNTING ESTIMATES

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

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

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;
c) estimated depletion, depreciation and accretion that are based on estimates of oil and gas reserves which the Trust expects to recover in the future;
d) estimated fair values of derivative contracts that are subject to fluctuation depending upon the underlying commodity prices and foreign exchange rates;
e) estimated value of asset retirement obligations that are dependent upon estimates of future costs and timing of expenditures; and
f) estimated future recoverable value of property, plant and equipment and goodwill.

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

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

SARBANES-OXLEY UPDATE

On July 31, 2002, the United States Congress enacted the Sarbanes-Oxley Act ("SOX"). SOX applies to all companies registered with the Securities and Exchange Commission ("SEC"). Although ARC is not listed on a U.S. stock exchange, the Trust is registered with the SEC as a result of having acquired Startech Energy Inc. in 2001 and therefore is required to comply with the SOX legislation. There are various components to the SOX legislation, however the most comprehensive is Section 404 "Internal Controls Over Financial Reporting". Section 404 requires that management undertake the following:

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

ARC is currently required to comply with section 404 of the SOX legislation on December 31, 2005. In conjunction with the 2005 year end audit, ARC's external auditors will audit the Trust's internal controls and will issue two opinions, one on the auditor's assessment of the effectiveness of internal controls and one on the auditor's opinion on management's assessment of the same internal controls.

The Trust currently has a comprehensive plan and a dedicated team of individuals in place to execute the plan of meeting the SOX Section 404 compliance date.

In addition to SOX, ARC is required to comply with Multilateral Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings", otherwise referred to as Canadian SOX ("C-Sox"). ARC is currently complying with this legislation by filing Bare Interim and Annual Certificates. It is expected that ARC will be required to file a Full Annual certificate in conjunction with the December 31, 2006, year end. The Canadian requirements closely parallel the SEC's certification rules; however, currently there is no requirement to have an external auditor's opinion on the Trust's internal controls or management's assessment thereof.

OBJECTIVES AND 2005 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. The Trust has provided unitholders with the following one, three and five year returns:

Total Returns

($ per trust unit except for per cent)	One year	Three year	Five year
Distributions per trust unit	1.80	5.16	9.48
Capital appreciation per trust unit	3.16	5.80	9.15
Total return per trust unit	**$ 4.96**	**$ 10.96**	**$ 18.63**
Annualized total return per trust unit	**35.8%**	**29.3%**	**39.6%**

To the end of 2004, the Trust has provided cumulative cash distributions of $14.24 per trust unit and capital appreciation of $7.90 per trust unit for a total return of $22.14 per trust unit (24.3 per cent annualized total return) for unitholders who invested in the Trust at inception.

The key future objectives of the Trust's business plan, as identified below, are reviewed by the Board annually. In 2004 the Trust was successful in meeting all of its objectives, which are individually addressed below.

- **Annual reserve replacement** – The Trust incurred a slight decrease in 2004 reserves as a result of the divestment of non-core assets in 2004. However, the Trust's change in oil and gas reserves, excluding the disposition, validated the successful nature of the Trust's internal development program in 2004.
- **Ensuring acquisitions are strategic and enhance unitholder returns** – The Trust completed two small corporate acquisitions in 2004, which resulted in increased ownership in certain key properties and provide for future development potential for the Trust.
- **Controlling costs** – Costs of developing properties, operating costs and G&A expenses – In 2004 the Trust continued to closely monitor operating expenses and divested of higher cost properties. This resulted in relatively unchanged operating costs despite increasing cost trends throughout the industry in 2004. The Trust realized lower interest expense due to lower debt levels in 2004. Cash G&A expenses increased slightly in 2004 as a result of increased industry competition for employees resulting in increased compensation levels. The Trust's three year average cost of developing properties is expected to be one of the lowest in the trust sector as disclosed in a press release dated February 16, 2005, on year end 2004 oil and gas reserves.
- **Actively hedging a portion of the Trust's production to protect minimum distributions** – The Trust updated its hedging strategy in late 2004 with the objective of maintaining cash flow and distributions, while allowing the Trust to participate in a greater portion of the upside in a rising commodity price environment.
- **Conservative utilization of debt** – The Trust's debt levels were under 10 per cent of total capitalization and debt to 2004 cash flow was 0.6 times for the year ended 2004.
- **Continuously developing the expertise of our staff and seeking to hire and retain the best in the industry** – The Trust continued to assess compensation levels in the industry to ensure that the Trust's compensation is competitive so as to ensure that we can attract and retain the best employees. In addition, the Trust implemented a new Whole Unit Plan that is a long-term incentive based plan for all employees of the Trust.
- **Demonstrating leadership** – The Trust led an industry initiative to lobby the Province of Alberta to provide limited liability protection for investors in income and royalty trusts. On July 1, 2004, limited liability protection was put in place for Alberta registered trusts. ARC continues to be viewed as an industry leader on this and other industry initiatives.
- **Promoting the use of proven and effective technologies** – The Trust continues to research new technologies in an effort to conduct its operations in the most efficient and cost effective manner.
- **Being an industry leader in the environment, health and safety area** – The Trust was recognized as a Gold Champion Level Reporter again in 2004 under the Canada Climate Change VCR initiative for reducing greenhouse gas emissions. In addition, the Trust continues to focus on safety as a number one consideration in conducting its operations.
- **Continuing to actively support local initiatives in the communities in which we operate and live** – The Trust is actively involved in charitable and philanthropic causes both in Calgary and in the rural communities in which it operates. ARC continued to be a strong supporter of the United Way, Alberta Cancer Foundation, Alberta Children's Hospital and many community organizations in rural centres.

During 2005 ARC will continue to be active with a robust drilling and development program on its diverse asset base. The $240 million capital expenditure budget for 2005 is the largest in the Trust's history, excluding acquisitions. The Trust will prudently deploy capital with a balanced drilling program of low and moderate risk wells. The 2004 drilling program resulted in a 99 per cent success rate. The Trust continues to focus on major properties with significant upside, with the objective to replace production declines through internal development opportunities.

The low debt levels and strong working capital position provide the Trust with the financial flexibility to fund the 2005 capital expenditure program and be poised to take advantage of accretive acquisition opportunities.

Following is a summary of the Trust's 2005 Guidance issued by way of press release on January 3, 2005:

	2005 Guidance	**Actual 2004**	% Change
Production (boe/d)	54,800	**56,870**	(4)
Expenses ($/boe):			
Operating costs	7.00	**6.71**	4
Transportation	0.70	**0.71**	(1)
G&A expenses – cash	1.25	**1.03**	21
G&A expenses – stock compensation plans	0.30	**0.39**	(23)
Interest	0.75	**0.64**	17
Taxes	0.15	**0.14**	7
Capital expenditures ($ millions)	240	**194**	24
Weighted average trust units (millions)	191.0	**183.1**	3

2005 CASH FLOW SENSITIVITY

Below is a table that illustrates sensitivities to pre-hedged 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] $/Unit
Business environment					
Oil price (US$WTI/barrel) [1]	$40.00	$ 1.00	$ 0.05	2.1%	$ 0.04
Natural gas price (CDN$AECO/mcf) [1]	$ 6.00	$ 0.10	$ 0.03	1.1%	$ 0.02
USD/CAD exchange rate	$ 0.82	$ 0.01	$ 0.04	1.7%	$ 0.03
Interest rate on debt	4.9%	1.0%	$ 0.01	0.6%	$ 0.01
Operational					
Liquids production volume (bbls/d)	26,500	1.0%	$ 0.01	0.6%	$ 0.01
Gas production volumes (mmcf/d)	170.0	1.0%	$ 0.02	0.6%	$ 0.01
Operating expenses per boe	$ 7.00	1.0%	$ 0.01	0.3%	$ 0.01
Cash G&A expenses per boe	$ 1.25	10.0%	$ 0.02	0.6%	$ 0.01

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

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

ASSESSMENT OF BUSINESS RISKS

The ARC management team is focused on long-term strategic planning and has identified the key risks, uncertainties and opportunities associated with the Trust's business that can impact the financial results as follows:

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 that 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 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/U.S. exchange rates will impact future distributions and the future value of the Trust's reserves as determined by independent evaluators.

The Trust carries on all of its Saskatchewan operations through a trust structure. As a result of this structure, the Trust is not subject to Saskatchewan capital tax because the Saskatchewan capital tax legislation only applies to corporations. Due to the increase in the number of oil and gas producers that are now operating in Saskatchewan through a trust structure, the Saskatchewan government is currently considering the inclusion of trusts into its capital tax legislation. If the Saskatchewan capital tax legislation is amended to include trusts, the Trust will effectively be subject to a 3.6 per cent resource surcharge on all of its oil and gas working interest revenue earned in Saskatchewan.

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, assessment of provincial capital taxes and resource taxation deductions and allowances, 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 oilsands 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 that will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the operators of the working interests, management and the Trust. In particular, changes in the prices of and markets for petroleum, natural gas, natural gas liquids and sulphur from those anticipated at the time of marking 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 that could result in lower production and reserves than attributed to the working interests. Actual reserves could vary materially from these estimates. Consequently, the reserves acquired may be less than expected, which could adversely impact cash flows and distributions to unitholders.

Environmental Concerns

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 that 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 distributors 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, utilizing assumptions by independent engineers, 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 that 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 of 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.

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.

Additional Information

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

ANNUAL HISTORICAL REVIEW

For the years ended December 31 (CDN$ thousands, except per unit amounts)		2004	2003	2002	2001	2000
FINANCIAL						
Revenue before royalties		**901,782**	743,182	444,835	515,596	316,270
Per unit (1)		**4.92**	4.90	3.82	5.11	4.97
Cash flow		**448,033**	396,180	223,969	260,270	179,349
Per unit – basic (1)		**2.45**	2.61	1.92	2.58	2.82
Per unit – diluted		**2.38**	2.48	1.86	2.54	2.79
Net income (5)		**241,690**	284,559	69,981	130,993	114,075
Per unit – basic (5) (6)		**1.32**	1.88	0.60	1.30	1.79
Per unit – diluted		**1.31**	1.82	0.59	1.32	1.77
Cash distributions		**329,977**	279,328	183,617	234,053	128,958
Per unit (2)		**1.80**	1.80	1.56	2.31	2.01
Total assets (10)		**2,304,998**	2,281,775	1,467,918	1,380,004	662,854
Total liabilities (10)		**755,650**	730,039	599,252	563,882	180,599
Net debt outstanding (4)		**264,842**	262,071	347,795	288,684	108,729
Weighted average units (thousands) (3)		**183,123**	151,698	116,474	100,896	63,681
Units outstanding and issuable at period end (thousands) (3)		**188,804**	182,777	126,444	111,692	72,524
CAPITAL EXPENDITURES						
Geological and geophysical		**5,388**	5,671	1,966	2,215	466
Drilling and completions		**144,487**	110,277	70,074	73,147	39,021
Plant and facilities		**41,089**	36,457	14,357	22,970	13,999
Other capital		**2,820**	3,359	1,881	3,886	554
Total capital expenditures		**193,784**	155,764	88,278	102,218	54,040
Property acquisitions (dispositions), net		**(58,219)**	(161,609)	119,113	12,911	153,877
Corporate acquisitions (8)		**72,009**	721,590	–	509,748	–
Total capital expenditures and net acquisitions		**207,574**	715,745	207,391	624,877	207,917
OPERATING						
Production						
Crude oil (bbl/d)		**22,961**	22,886	20,655	20,408	11,528
Natural gas (mmcf/d)		**178.3**	164.2	109.8	115.2	77.2
Natural gas liquids (bbl/d)		**4,191**	4,086	3,479	3,511	2,965
Total (boe/d 6:1)		**56,870**	54,335	42,425	43,111	27,355
Average prices (7)						
Crude oil ($/bbl)		**47.03**	36.90	31.63	31.70	36.74
Natural gas ($/mcf)		**6.78**	6.40	4.41	5.72	4.48
Natural gas liquids ($/bbl)		**39.04**	32.19	24.01	31.03	31.52
Oil equivalent ($/boe)		**43.13**	37.29	28.73	32.76	31.59
RESERVES (9)	**2004 Gross Reserves**	**Company Interest Reserves**				
Proved plus probable reserves						
Crude oil and NGL's (mbbl)	**122,477**	**123,226**	129,663	117,241	114,243	82,419
Natural gas (bcf)	**709.9**	**724.5**	720.2	408.8	385.5	286.4
Total (mboe)	**240,788**	**243,974**	249,704	185,371	178,496	130,147
TRUST UNIT TRADING (based on intra-day trading)						
Unit prices						
High		**17.98**	14.87	13.44	13.54	12.15
Low		**13.50**	10.89	11.04	10.25	8.35
Close		**17.90**	14.74	11.90	12.10	11.30
Average daily volume (thousands)		**420**	430	305	414	151

* (Refer to footnotes on page 57)

QUARTERLY REVIEW

(CDN$ thousands, except per unit amounts)	2004 Q4	2004 Q3	2004 Q2	2004 Q1	2003 Q4	2003 Q3	2003 Q2	2003 Q1
FINANCIAL								
Revenue before royalties	**232,112**	**230,769**	**233,307**	**205,594**	182,558	184,166	198,542	177,917
Per unit (1)	**1.25**	**1.25**	**1.28**	**1.14**	1.06	1.13	1.39	1.39
Cash flow	**106,935**	**110,835**	**122,249**	**108,014**	89,617	87,511	116,546	102,506
Per unit – basic (1)	**0.58**	**0.60**	**0.67**	**0.60**	0.52	0.54	0.82	0.80
Per unit – diluted	**0.56**	**0.59**	**0.65**	**0.58**	0.51	0.52	0.72	0.78
Net income (5)	**112,995**	**38,897**	**50,338**	**39,460**	53,492	40,785	125,740	64,542
Per unit – basic (5) (6)	**0.61**	**0.21**	**0.28**	**0.22**	0.31	0.25	0.88	0.50
Per unit – diluted	**0.60**	**0.21**	**0.27**	**0.22**	0.31	0.25	0.79	0.50
Cash distributions	**83,531**	**83,178**	**82,053**	**81,215**	78,603	73,890	67,495	59,340
Per unit (2)	**0.45**	**0.45**	**0.45**	**0.45**	0.45	0.45	0.45	0.45
Total assets (10)	**2,304,998**	**2,316,297**	**2,309,599**	**2,278,608**	2,281,775	2,251,273	2,332,734	1,512,514
Total liabilities (10)	**755,650**	**804,603**	**768,073**	**752,166**	730,039	886,887	941,215	500,023
Net debt outstanding (4)	**264,842**	**220,500**	**220,074**	**284,001**	262,071	412,686	466,988	226,583
Weighted average units (thousands) (3)	**185,539**	**184,675**	**181,948**	**180,283**	171,993	163,334	142,526	128,328
Units outstanding and issuable at period end (thousands) (3)	**188,804**	**188,185**	**187,296**	**183,980**	182,777	167,531	163,184	139,239
CAPITAL EXPENDITURES ($ thousands)								
Geological and geophysical	**867**	**828**	**1,373**	**2,320**	2,846	1,171	656	998
Drilling and completions	**39,125**	**42,553**	**24,867**	**37,942**	37,738	31,661	23,834	17,037
Plant and facilities	**6,183**	**11,668**	**7,282**	**15,956**	15,512	11,917	4,831	4,204
Other capital	**1,480**	**394**	**605**	**341**	1,418	391	1,325	224
Total capital expenditures	**47,655**	**55,443**	**34,127**	**56,559**	57,515	45,140	30,646	22,463
Property acquisitions (dispositions), net	**(1,036)**	**(5,345)**	**(53,412)**	**1,574**	(3,693)	(81,166)	(79,750)	3,000
Corporate acquisitions (8)	**41,449**	**–**	**30,560**	**–**	–	258	721,332	–
Total capital expenditures and net acquisitions	**88,068**	**50,098**	**11,275**	**58,133**	53,822	(35,768)	672,228	25,463

(CDN$ thousands, except per unit amounts)	**2004** Q4	Q3	Q2	Q1	2003 Q4	Q3	Q2	Q1
OPERATING								
Production								
Crude oil (bbl/d)	**22,969**	**22,496**	**22,720**	**23,663**	22,851	23,522	24,078	21,065
Natural gas (mmcf/d)	**174.7**	**177.4**	**186.7**	**174.5**	180.8	182.0	175.7	117.3
Natural gas liquids (bbl/d)	**4,097**	**4,034**	**4,313**	**4,323**	4,140	4,105	4,397	3,696
Total (boe/d 6:1)	**56,179**	**56,096**	**58,147**	**57,075**	57,120	57,968	57,759	44,313
Average prices (7)								
Crude oil ($/bbl)	**49.48**	**51.00**	**47.43**	**40.41**	35.21	35.33	36.61	40.92
Natural gas ($/mcf)	**6.82**	**6.65**	**6.99**	**6.64**	5.85	5.64	6.59	8.16
Natural gas liquids ($/bbl)	**43.72**	**42.30**	**38.22**	**32.30**	30.14	30.92	28.83	39.99
Oil equivalent ($/boe)	**44.62**	**44.54**	**43.82**	**39.58**	34.78	34.53	37.77	44.61
TRUST UNIT TRADING (based on intra-day trading)								
Unit prices								
High	**17.98**	**17.38**	**15.74**	**15.74**	14.87	13.88	12.84	12.34
Low	**14.80**	**15.02**	**14.28**	**13.50**	13.31	12.51	11.29	10.89
Close	**17.90**	**16.85**	**15.35**	**15.64**	14.74	13.55	12.50	11.59
Average daily volume (thousands)	**456**	**384**	**337**	**502**	395	551	503	313

(1) Based on weighted average trust units.

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

(3) Excludes trust units issuable for outstanding exchangeable shares.

(4) Total current and long-term debt net of working capital. The 2004 net debt outstanding excludes unrealized commodity and foreign currency contracts, the deferred hedge loss and deferred commodity and foreign currency contracts.

(5) Net income and net income per unit have been restated due to the retroactive application of the change in accounting policies relating to asset retirement obligations, stock based compensation and non-controlling interest that were implemented in 2003 and 2004.

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

(7) Average prices have been restated to be prior to transportation costs in order to be consistent with 2004 presentation.

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

(9) Established reserves for 2002 and prior years.

(10) Total assets and total liabilities have been restated for the retroactive application of change in accounting policy for asset retirement obligations.

ARC ENERGY TRUST IS COMMITTED TO THE HIGHEST STANDARDS FOR ITS CORPORATE GOVERNANCE PRACTICES AND PROCEDURES.

HANDS-ON GOVERNANCE
COMMITTED TO THE HIGHEST STANDARDS

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 that are appropriate for ARC. 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.

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

MANDATE OF THE BOARD

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

ARC's principal objective in directing and managing its business and affairs is to enhance unitholder value. ARC believes that effective corporate governance improves corporate performance and benefits all unitholders. ARC also believes that director, management and employee honesty and integrity are important factors in ensuring good corporate governance. To that end, ARC has adopted codes of business ethics for its directors, its employees and its President and Chief Executive Officer, Chief Financial Officer and Vice-President, Business Development. ARC's code of business conduct and ethics states 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. The code mandates 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.arcenergytrust.com.

The Board discharges its responsibilities directly and through committees. At regularly scheduled meetings, members of the Board and management discuss a broad range of issues relevant to ARC's strategy and business interests and the Board participates annually in establishing ARC's long-term strategic plan.

COMMITTEES OF THE BOARD

The Board has established an Audit Committee, a Reserve Audit Committee, a Human Resources and Compensation Committee, a Board Governance Committee and a Health, Safety and Environmental Committee to assist it in the discharge of its duties and responsibilities. All of the committees are comprised of unrelated and independent directors and report to the Board of Directors of ARC Resources Ltd. There is no executive committee of the Board. Mandates for each of the committees are reviewed annually to ensure such mandates meet regulatory obligations as well as obligations, to unitholders.

Audit Committee

Members: Fred Dyment (Chair), Walter DeBoni, Michael Kanovsky and Mac Van Wielingen, all of whom are unrelated and independent 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 and accompanying management discussion and analysis provided to unitholders and regulatory bodies; compliance with accounting and finance based legal and regulatory requirements; review of the independence and performance of the external auditor, internal accounting systems and procedures. The committee is responsible for recommending, for Board of Director approval, the audited financial statements and related management discussion and analysis and selected disclosure documents containing financial information before they are released to the public. The committee reviews the audit plans of the external auditors and meets with them at the time of each committee meeting, in each case independently of management. The committee receives and reviews annually the external auditor's formal written statement of independence delineating all relationships between itself and ARC and its report on recommendations to management regarding internal controls and procedures. The committee pre-approves all audit services and all permitted non-audit services.

There were five meetings of the committee in 2004.

Reserves Audit Committee

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

The Reserves Audit Committee assists the Board in meeting its 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 annual independent engineering report. The committee reviews and recommends for approval by the Board on an annual basis the statements of reserve data and other information specified in National Instrument 51-101. The committee also reviews any other oil and gas reserve report prior to release by ARC to the public and reviews all of the disclosure in the Annual Information Form related to the oil and gas activities of ARC.

There were three meetings of the committee in 2004.

Human Resources and Compensation Committee

Members: John Stewart (Chair), Fred Coles and Mac Van Wielingen, all of whom are unrelated and independent 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 ARC; and in consultation with the Board, undertakes an annual performance review with the President and CEO, and reviews the CEO's appraisal of the other executive officers' performance. The committee reviews the salary, bonus and other remuneration for the executive officers of ARC. The committee also reviews and recommends for approval to the Board the principal compensation plans of ARC, such as the long-term incentive program and any awards under such plans.

There were seven meetings of the committee in 2004.

Health, Safety and Environmental Committee

Members: Walt DeBoni (Chair), Fred Coles and John Stewart, all of whom are unrelated and independent directors.

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

The committee was formed in August, 2004 and held two meetings in 2004.

Board Governance Committee

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

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

There were four meetings of the committee in 2004.

ARC BELIEVES THAT EFFECTIVE CORPORATE GOVERNANCE IMPROVES CORPORATE PERFORMANCE AND BENEFITS ALL UNITHOLDERS.

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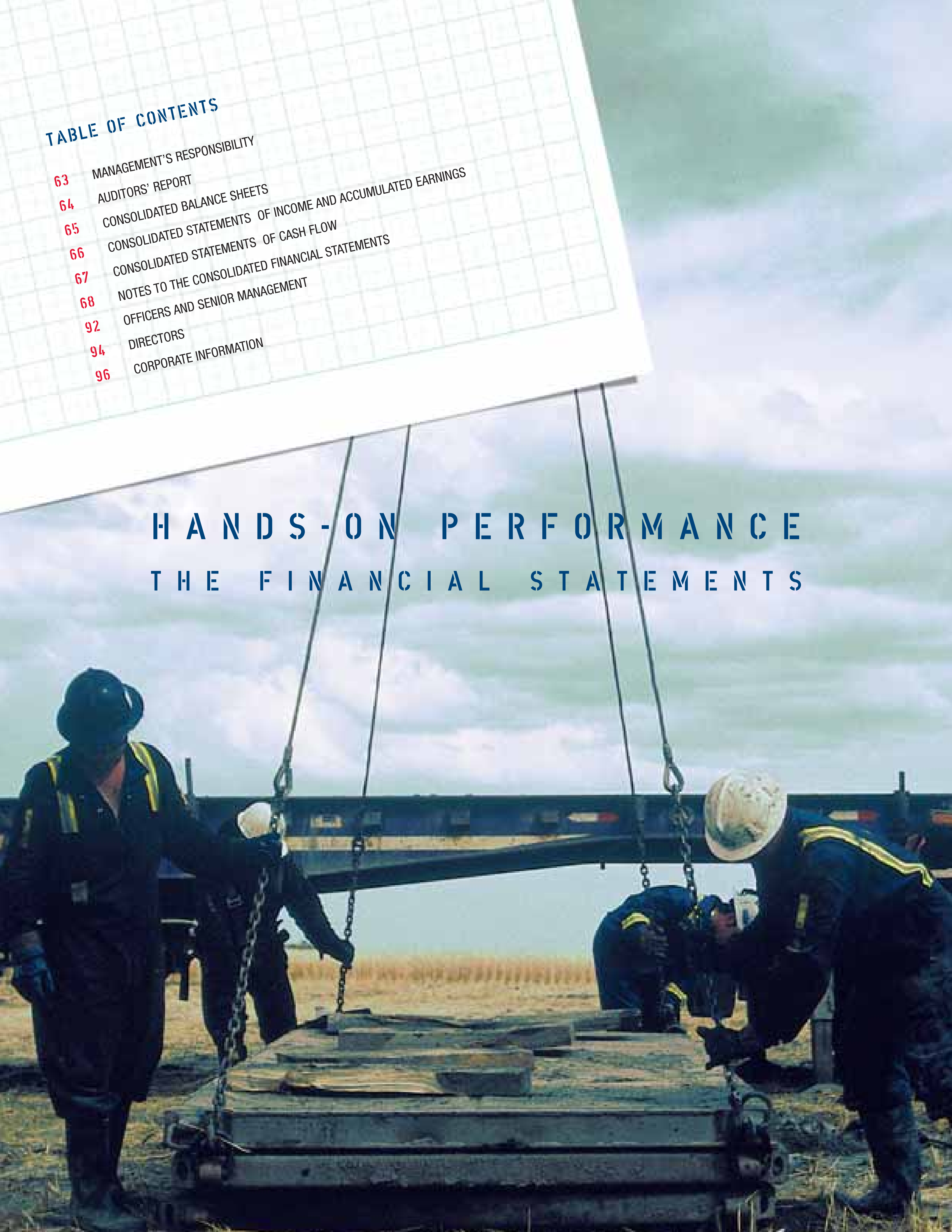
HANDS-ON PERFORMANCE

THE FINANCIAL STATEMENTS



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
Vice-President Finance and Chief Financial Officer

Calgary, Alberta
February 23, 2005

AUDITORS' REPORT

To the Unitholders of ARC Energy Trust:

We have audited the consolidated balance sheets of ARC Energy Trust as at December 31, 2004 and 2003 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, 2004 and 2003 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

The Trust is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Trust's internal control over financial reporting. Accordingly we express no such opinion.

Deloitte & Touche LLP

Calgary, Alberta
February 23, 2005

Deloitte & Touche LLP
Chartered Accountants

CONSOLIDATED BALANCE SHEETS

As at December 31 (CDN$ thousands)	2004	2003
ASSETS		Restated (Note 3)
Current assets		
Cash and cash equivalents	**$ 4,413**	$ 12,295
Accounts receivable	**72,881**	68,768
Prepaid expenses	**9,878**	10,400
Commodity and foreign currency contracts (Notes 3 and 10)	**22,294**	–
	109,466	91,463
Reclamation fund (Note 5)	**21,294**	17,181
Property, plant and equipment (Notes 4 and 6)	**2,016,646**	2,015,539
Goodwill (Note 4)	**157,592**	157,592
Total assets	**$ 2,304,998**	$ 2,281,775
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	**$ 103,572**	$ 94,152
Cash distributions payable	**27,893**	26,980
Current portion of long-term debt (Note 7)	**8,715**	9,047
Commodity and foreign currency contracts (Notes 3 and 10)	**26,336**	–
	166,516	130,179
Long-term debt (Note 7)	**211,834**	223,355
Other long-term liabilities (Note 8)	**3,893**	7,883
Asset retirement obligations (Note 9)	**73,001**	66,657
Future income taxes (Note 11)	**300,406**	301,965
Total liabilities	**755,650**	730,039
NON-CONTROLLING INTEREST		
Exchangeable shares (Note 14)	**35,967**	36,311
UNITHOLDERS' EQUITY		
Unitholders' capital (Note 12)	**1,926,351**	1,843,112
Contributed surplus (Note 15)	**6,475**	3,471
Accumulated earnings	**878,807**	637,117
Accumulated cash distributions (Note 14)	**(1,298,252)**	(968,275)
Total unitholders' equity	**1,513,381**	1,515,425
Total liabilities and unitholders' equity	**$ 2,304,998**	$ 2,281,775

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)	2004	2003
Revenues		Restated (Note 3)
Oil, natural gas, natural gas liquids and sulphur sales	**$ 901,782**	$ 743,183
Royalties	**(177,032)**	(150,995)
	724,750	592,188
Loss on commodity and foreign currency contracts (Notes 3 and 10)	**86,068**	–
	638,682	592,188
Expenses		
Transportation (Note 3)	**14,798**	11,950
Operating	**139,716**	140,734
General and administrative	**21,426**	19,096
Non-cash trust unit incentive compensation (Notes 15 and 16)	**8,086**	3,470
Interest on long-term debt (Note 7)	**13,320**	18,482
Depletion, depreciation and accretion (Notes 6 and 9)	**239,674**	218,551
Capital taxes	**2,834**	1,812
Gain on foreign exchange	**(20,713)**	(18,564)
	419,141	395,531
Income before future income tax recovery	**219,541**	196,657
Future income tax recovery (Note 11)	**26,100**	93,544
Net income before non-controlling interest	**245,641**	290,201
Non-controlling interest (Notes 3 and 13)	**(3,951)**	(5,642)
Net income	**241,690**	284,559
Accumulated earnings, beginning of year	**648,304**	362,173
Retroactive application of change in accounting policy (Note 3)	**(11,187)**	(5,545)
Accumulated earnings, beginning of year as restated	**637,117**	356,628
Interest on convertible debentures (Note 4)	**–**	(4,070)
Accumulated earnings, end of year	**$ 878,807**	$ 637,117
Net income per unit (Note 17)		
Basic	**$ 1.32**	$ 1.88
Diluted	**$ 1.31**	$ 1.82

See accompanying notes to consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOW

For the years ended December 31 (CDN$ thousands)	2004	2003
Cash Flow from Operating Activities		Restated (Note 3)
Net Income	**$ 241,690**	$ 284,559
Add items not involving cash:		
Non-controlling interest	**3,951**	5,642
Future income tax recovery	**(26,100)**	(93,544)
Depletion, depreciation and accretion (Notes 6 and 9)	**239,674**	218,551
Non-cash gain on commodity and foreign currency contracts	**(10,533)**	–
Non-cash gain on foreign exchange	**(18,427)**	(18,700)
Amortization of commodity and foreign currency contracts	**9,692**	(15,687)
Non-cash trust unit incentive compensation (Notes 15 and 16)	**8,086**	3,471
Cash received on terminated hedge contracts (Note 10)	**–**	11,888
Cash flow before change in non-cash working capital	**448,033**	396,180
Change in non-cash working capital	**1,617**	9,104
	449,650	405,284
Cash Flow from Financing Activities		
Repayments of long-term debt, net	**(162,555)**	(276,127)
Issuance of long-term notes	**168,975**	–
Issue of trust units	**19,301**	346,321
Trust unit issue costs	**(152)**	(17,815)
Cash distributions paid, net of distribution reinvestment	**(301,936)**	(256,187)
Interest paid on convertible debentures	**–**	(4,070)
Payment of retention bonus	**(1,000)**	(1,000)
Change in non-cash working capital	**(397)**	8,217
	(277,764)	(200,661)
Cash Flow from Investing Activities		
Acquisition of Star, net of cash received (Note 4)	**–**	(196,444)
Acquisition of United Prestville, net of cash received (Note 4)	**(60)**	–
Acquisition of Harrington & Bibler, net of cash received (Note 4)	**(39,325)**	–
Acquisition of petroleum and natural gas properties	**529**	(14,783)
Proceeds on disposition of petroleum and natural gas properties	**57,691**	166,392
Capital expenditures	**(192,591)**	(141,651)
Reclamation fund contributions and actual expenditures (Note 5)	**(7,345)**	(6,470)
Change in non-cash working capital	**1,333**	(207)
	(179,768)	(193,163)
(Decrease) Increase in Cash and Cash Equivalents	**(7,882)**	11,460
Cash and Cash Equivalents, Beginning of Year	**12,295**	835
Cash and Cash Equivalents, End of Year	**$ 4,413**	$ 12,295

See accompanying notes to consolidated financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2004 and 2003 (all tabular amounts in thousands CDN$, except per unit and volume amounts)

1. STRUCTURE OF THE TRUST

ARC Energy Trust (the "Trust") was formed on May 7, 1996, pursuant to a Trust indenture (the "Trust Indenture") that has been amended from time to time, most recently on May 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") 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, oilsands 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 19. 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.

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.

Unit Based Compensation

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

Whole Trust Unit Incentive Plan Compensation

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

The Trust has not incorporated an estimated forfeiture rate for RTU's and PTU's that will not vest, rather, the Trust accounts for actual forfeitures as they occur.

Cash and Cash Equivalents

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

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

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

Impairment

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

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

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

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

Income Taxes

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

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

Derivative Financial Instruments

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

Policies and procedures are in place with respect to the required documentation and approvals for the use of derivative financial instruments and specifically ties their use, in the case of commodities, to the mitigation of market price risk associated with cash flows expected to be generated. When applicable, the Trust also identifies all relationships between hedging instruments and hedged items, as well as its risk management objective and the strategy for undertaking hedge transactions. This would include linking the particular derivative to specific assets and liabilities on the consolidated balance sheet or to specific firm commitments or forecasted transactions. Where specific hedges are executed, the Trust assesses, both at the inception of the hedge and on an ongoing basis, whether the derivative used in the particular hedging transaction is effective in offsetting changes in fair value or cash flows of the hedged item. For instruments that do not meet this effectiveness test, the Trust applies the mark-to-market accounting method.

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.

Gains and losses on terminated contracts are recognized immediately to the statement of income.

Foreign Currency Translation

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

Non-Controlling Interest

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

Reclassification

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2004.

3. CHANGES IN ACCOUNTING POLICIES

Exchangeable Securities – Non-Controlling Interest

On January 19, 2005, the CICA issued EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts" which states that exchangeable securities issued by a subsidiary of an Income Trust should be reflected as either non-controlling interest or debt in the consolidated balance sheet unless they meet certain criteria. The exchangeable shares issued by ARL, a corporate subsidiary of the Trust, are publicly traded and therefore must be recorded as non-controlling interest outside of Unitholders' equity. EIC-151 states that if the exchangeable shares are transferable to a third party, they should be reflected as non-controlling interest. Previously, the exchangeable shares were reflected as a component of Unitholders' equity.

As a result of this change in accounting policy, the Trust has reflected non-controlling interest of $36 million and $36.3 million, respectively, in the Trust's consolidated balance sheet as at December 31, 2004 and 2003. Consolidated net income has been reduced for net income attributable to the non-controlling interest of $4 million and $5.6 million, respectively, in 2004 and 2003. In accordance with the transitional provisions of EIC-151, retroactive application has been applied with restatement of prior periods. Opening accumulated earnings for 2003 were decreased by $5.5 million for the cumulative net income attributable to the non-controlling interest, Unitholders' equity was reduced by $31.7 million and non-controlling interest on the consolidated balance sheet increased by $37.2 million. The new accounting policy resulted in a change in the calculation of weighted average trust units. Previously, weighted average trust units included outstanding exchangeable shares at the period end exchange ratio whereas under the new accounting policy, the weighted average trust units excludes trust units issuable for exchangeable shares. There was no change to net income per basic trust unit as a result of this change in accounting policy.

Hedge Accounting

The CICA issued Accounting Guideline 13 ("AcG -13") "Hedging relationships", effective January 1, 2004, to clarify circumstances in which hedge accounting is appropriate. In addition, the CICA simultaneously amended EIC 128, "Accounting for Trading, Speculative or Non-Trading Derivative Financial Instruments" to require that all derivative instruments which do not qualify as a hedge under AcG-13, or are not designated as a hedge, be recorded in the consolidated balance sheet as either an asset or a liability with the changes in fair value recognized in earnings.

The Trust uses derivative instruments to reduce its exposure to fluctuations in commodity prices, foreign exchange and interest rates. The Trust formally documents all relationships between hedging instruments and hedged items, as well as its risk management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives to specific assets and liabilities on the consolidated balance sheet or to specific firm commitments or forecasted transactions. The Trust also formally assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items.

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

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

As a result of this change in accounting policy, the Trust's net income for the year decreased by $2.6 million ($4 million net of a future tax recovery of $1.4 million). Total assets increased by $22.3 million and total liabilities increased by $24.9 million ($26.3 million net of a future tax asset of $1.4 million) as at December 31, 2004, as a result of this new accounting policy. Cash flow was not impacted by this change. In accordance with the transitional provisions of AcG-13 and EIC-128, this new guideline has been applied prospectively whereby prior periods have not been restated.

Transportation Costs

Effective for fiscal years beginning on or after October 1, 2003, the CICA issued Handbook Section 1100 "Generally Accepted Accounting Principles", which defines the sources of GAAP that companies must use and effectively eliminates industry practice as a source of GAAP. In prior years, it had been industry practice for companies to net transportation charges against revenue rather than showing transportation as a separate expense on the consolidated income statement. Beginning January 1, 2004, the Trust has recorded revenue before transportation charges and a transportation expense on the consolidated income statement. Prior periods have been reclassified for comparative purposes. This adjustment has no impact on net income per trust unit calculations, or cash flow for the Trust.

4. CORPORATE ACQUISITIONS

Star Oil & Gas Ltd.

Effective April 16, 2003, the Trust acquired all of the issued and outstanding shares of Star Oil & Gas Ltd. ("Star"). The allocation of the purchase price and consideration was 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 property, plant and equipment 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 a 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.

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 the operations of Star effective April 16, 2003.

United Prestville Ltd.

On June 8, 2004, the Trust acquired all of the issued and outstanding shares of United Prestville Ltd. ("United Prestville") for total consideration of $30.6 million. The allocation of the purchase price and consideration was paid as follows:

Net Assets Acquired		
Working capital deficit	$	(2,569)
Property, plant and equipment		40,412
Future income taxes		(7,283)
Total net assets acquired	**$**	**30,560**

Consideration Paid		
Cash fees paid	$	60
Trust units issued		30,500
Total consideration paid	**$**	**30,560**

Pursuant to EIC-124, the acquisition of United Prestville did not meet the necessary criteria in order to be classified as a business. As a result, no goodwill was recorded on this transaction. Therefore, the acquisition has been accounted for as an asset acquisition.

The future income tax liability on acquisition was based on the difference between the fair value of the acquired net assets of $33.1 million and the associated tax basis of $19.3 million.

These consolidated financial statements incorporate the operations of United Prestville effective June 8, 2004.

Harrington & Bibler

On December 31, 2004, the Trust acquired all of the issued and outstanding shares of four legal entities – Harrington Oil & Gas Ltd., Bibler Oil & Gas Ltd., Lesco Oil & Gas Ltd., and Bibco Oil & Gas Ltd. ("Harrington & Bibler") – for total consideration of $41.4 million. The allocation of the purchase price and consideration was paid as follows:

Net Assets Acquired		
Working capital surplus (including cash of $2,124)	$	3,479
Property, plant and equipment		55,229
Future income taxes		(17,259)
Total net assets acquired	**$**	**41,449**

Consideration Paid		
Cash and fees paid	$	41,449
Total consideration paid	**$**	**41,449**

Pursuant to EIC-124, the acquisition of Harrington & Bibler did not meet the necessary criteria in order to be classified as a business. Therefore, the acquisition has been accounted for as an asset acquisition.

The future income tax liability on acquisition was based on the difference between the fair value of the acquired net assets of $38 million and the associated tax basis of $5.3 million.

Due to the December 31, 2004, closing date, the consolidated financial statements do not include any results of operations for the acquired Harrington & Bibler properties.

5. RECLAMATION FUND

	2004	2003
Balance, beginning of year	**$ 17,181**	$ 12,924
Contributions, net of actual expenditures	**2,903**	3,600
Interest earned on fund	**1,210**	657
Balance, end of year	**$ 21,294**	$ 17,181

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 that results in minimum annual contributions of $6 million ($5.5 million in 2003) based upon properties owned as at December 31, 2004. 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, $3.1 million ($1.9 million in 2003) of actual expenditures were charged against the reclamation fund.

6. PROPERTY, PLANT AND EQUIPMENT

	2004	2003
Property, plant and equipment, at cost	**$ 2,969,319**	$ 2,733,118
Accumulated depletion and depreciation	**(952,673)**	(717,579)
Property, plant and equipment, net	**$ 2,016,646**	$ 2,015,539

The calculation of 2004 depletion and depreciation included an estimated $374.2 million ($315.8 million in 2003) for future development costs associated with proved undeveloped reserves and excluded $52.5 million ($50 million in 2003) for the estimated value of unproved properties.

Included in the Trust's PP&E balance is $42.3 million ($41.1 million in 2003), net of accumulated depletion, relating to the ARO.

The Trust performed a ceiling test calculation at December 31, 2004, to assess the recoverable value of PP&E. Based on the calculation, the present value of future net revenues from the Trust's proved plus probable reserves exceeded the carrying value of the Trust's PP&E at December 31, 2004. The benchmark prices used in the calculation are as follows:

Year	WTI Oil (US$/bbl)	USD/CAD Exchange Rate	WTI Oil (CDN$/bbl)	AECO Gas (CDN$/mmbtu)
2005	42.00	0.82	51.22	6.60
2006	40.00	0.82	48.78	6.35
2007	38.00	0.82	46.34	6.15
2008	36.00	0.82	43.90	6.00
2009	34.00	0.82	41.46	6.00
2010 – 2015	33.50	0.82	40.85	6.10
Remainder (1)	2.0%	0.82	2.0%	2.0%

(1) Percentage change represents the change in each year after 2015 to the end of the reserve life.

7. LONG-TERM DEBT

		2004		2003
Revolving credit facilities				
Working capital facility	$	290	$	–
CAD denominated facilities		–		111,298
USD denominated facilities		–		37,098
Senior secured notes				
8.05% USD Note, US $35 million		33,701		45,234
4.94% USD Note, US $30 million		36,108		38,772
Long-term notes				
4.62% USD Note, US $62.5 million		75,225		–
5.10% USD Note, US $62.5 million		75,225		–
Total debt outstanding	$	220,549	$	232,402
Current portion of debt		8,715		9,047
Long-term debt	$	211,834	$	223,355

In April 2004, the Trust consolidated its credit facilities into one syndicated facility. The syndication did not impact security or covenants under the credit facility. As at December 31, 2004, the Trust has one syndicated credit facility and one working capital facility to a combined maximum of $620 million including the US$58 million of Senior secured notes and US$125 million of long-term notes.

Revolving Credit Facilities

The syndicated revolving credit facility has a 364 day extendable revolving period and a two year term. Borrowings under the facility bear interest at bank prime (4.25 per cent and 4.50 per cent at December 31, 2004, and December 31, 2003, respectively) or, at the Trust's option, Canadian dollar or U.S. dollar bankers' acceptances plus a stamping fee. The lenders review the credit facility each year and determine whether they will extend the revolving periods for another year. The term date of the current credit facility is March 31, 2005.

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 outstanding on the term date payable on March 31, 2006, followed by three quarterly payments of five per cent of the loan balance. The remaining 65 per cent of the loan balance is payable in one lump sum at the end of the term period. Collateral for the loan is in the form of floating charges on all lands and assignments and negative pledges on specific petroleum and natural gas properties.

The working capital facility allows for maximum borrowings of $15 million and is due and payable immediately upon demand by the bank. The facility is secured and is subject to the same covenants as the Credit Facility.

Senior Secured Notes

The Senior secured notes were issued in two separate issues pursuant to an Uncommitted Master Shelf Agreement. The first issue of US$35 million Senior secured notes were issued in 2000, bear interest at 8.05 per cent, have a remaining final life of 3.9 years (remaining average life of 2.3 years) and require equal principal payments of US$7 million over a five year period commencing in 2004. During the year, the Trust repaid $8.3 million (US$7 million) of the 8.05 per cent notes. As at December 31, 2004, US$28 million was outstanding on the principal. The second issue of US$30 million Senior secured notes were issued in 2002, bear interest at 4.94 per cent, have a remaining final life of 5.8 years (remaining average life of 3.8 years) and require equal principal payments of US$6 million over a five year period commencing in 2006. Security for the Senior secured notes is in the form of floating charges on all lands and assignments. The Senior secured notes rank pari passu to the revolving credit facilities.

Long-term Notes

The long-term notes were issued on April 27, 2004, via a private placement in two tranches of US$62.5 million each. The first tranche of US$62.5 million has a remaining final life of 9.3 years (remaining average life of 6.8 years) and pays a semi-annual coupon of 4.62 per cent per annum. Immediately following the issuance, the Trust entered into interest rate swap contracts that effectively changed the interest rate from fixed to floating (see Note 10). The second tranche of US$62.5 million has a remaining final life of 11.3 years (remaining average life of 9.3 years) and pays a semi-annual coupon of 5.10 per cent per annum. Repayments of the notes will occur in years 2009 through 2016. Security for the long-term notes is in the form of floating charges on all lands and assignments. The long-term notes rank pari passu to the revolving credit facilities.

The current portion of debt at December 31, 2004, represents the required principal repayment under the Senior secured notes in November 2005 of US$7 million and the $0.3 million drawn on the working capital facility.

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. OTHER LONG-TERM LIABILITIES

		2004		2003
Retention bonuses	**$**	**2,000**	$	3,000
Accrued long-term incentive compensation		**1,893**		–
Commodity and foreign currency contracts		**–**		4,883
Total other long-term liabilities	**$**	**3,893**	$	7,883

The retention bonuses arose upon internalization of the management contract in 2002. The long-term portion of retention bonuses will be paid in August 2006 through August 2007.

The accrued long-term incentive compensation represents the long-term portion of the Trust's estimated liability for the Whole Unit Plan as at December 31, 2004 (see Note 16). This amount is payable in 2006 through 2007.

The commodity and foreign currency contracts relate to a natural gas fixed price contract that was assumed upon acquisition of Startech in 2001. This contract expired during 2004 and the balance has been fully amortized to earnings as at December 31, 2004.

9. 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 $73 million as at December 31, 2004, based on a total future liability of $247 million ($218 million in 2003). These payments are expected to be made over the next 61 years with the majority of costs incurred between 2015 and 2019. The Trust's weighted average credit adjusted risk free rate of 6.9 per cent (seven per cent in 2003) and an inflation rate of 1.5 per cent (1.5 per cent in 2003) were used to calculate the present value of the asset retirement obligations. During the year, no gains or losses were recognized on settlements of asset retirement obligations.

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

		2004		2003
Carrying amount, beginning of year	**$**	**66,657**	$	42,250
Increase in liabilities during the year		**4,996**		23,662
Settlement of liabilities during the year		**(3,232)**		(2,213)
Accretion expense		**4,580**		2,958
Carrying amount, end of year	**$**	**73,001**	$	66,657

10. FINANCIAL INSTRUMENTS

Financial instruments of the Trust carried on the consolidated balance sheet consist mainly of cash and cash equivalents, accounts receivable, reclamation fund investments, current liabilities, other long-term liabilities, asset retirement obligations, commodity and foreign currency contracts and long-term debt. Except as noted below, as at December 31, 2004 and 2003, 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. With respect to counterparties to financial instruments, the Trust partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings.

The fair value of the US$183 million fixed rate Senior Secured and Long-term notes (US$65 million in 2003) approximated CDN$219 million as at December 31, 2004 (CDN$85.3 million in 2003).

During the year, the Trust terminated certain crude oil and foreign currency contracts that resulted in a net cash payment made by the Trust of $4.9 million, consisting of a payment (loss) of $29.4 million for the crude oil contracts and a receipt (gain) of $24.5 million for the foreign currency contracts. The net loss has been recorded in earnings for the year ended December 31, 2004.

Following is a summary of all derivative contracts in place as at December 31, 2004:

Financial WTI Crude Oil Contracts

Term	Contract	Volume bbl/d	Swap USD/bbl	Bought Put USD/bbl	Sold Put USD/bbl	Sold Call USD/bbl
2005						
Jan 05 – Jan 05	3 Way	3,500	–	49.70	42.00	52.00
Feb 05 – Mar 05	Put Spread	3,500	–	49.70	29.00	–
Jan 05 – Mar 05	3 Way	500	–	34.00	29.00	40.10
Jan 05 – Jun 05	Max Payout	4,000	28.95	–	26.00	–
Jan 05 – Dec 05	Put Spread	2,000	–	47.32	29.00	–
Jan 05 – Dec 05	Put Spread	2,000	–	47.05	29.00	–
Jan 05 – Dec 05	Put Spread	1,000	–	46.65	33.00	–
Apr 05 – Dec 05	3 Way	500	–	34.00	30.00	41.75
Apr 05 – Dec 05	Put Spread	3,500	–	46.36	30.00	–
Jul 05 – Dec 05	Swaption(1)	4,000	28.95	–	–	–
2005 Weighted Average		**13,000**	**28.95**	**46.39**	**29.45**	**45.32**
2006						
Jan 06 – Mar 06	3 Way	2,000	–	36.00	29.00	40.00
Apr 06 – Jun 06	3 Way	2,000	–	36.00	29.00	40.65
2006 Weighted Average		**992**	**–**	**36.00**	**29.00**	**40.33**

(1) Counterparty can exercise their option on June 30, 2005, for a fixed price swap at US$28.95 (CDN$38.80) for the period July through December 2005.

Financial AECO Natural Gas Contracts

Term	Contract	Volume GJ/d	Swap CAD/GJ	Bought Put CAD/GJ	Sold Put CAD/GJ	Sold Call CAD/GJ
2005						
Jan 05 – Jan 05	Put Spread	10,000	–	8.05	6.50	–
Jan 05 – Jan 05	Put Spread	10,000	–	8.67	6.50	–
Jan 05 – Jan 05	Put Spread	10,000	–	9.41	7.00	–
Feb 05 – Feb 05	Put Spread	10,000	–	9.41	6.00	–
Jan 05 – Mar 05	3 Way	10,000	–	6.75	5.50	8.10
Jan 05 – Mar 05	3 Way	10,000	–	7.25	5.75	8.76
Jan 05 – Mar 05	3 Way	10,000	–	7.75	6.25	9.20
Jan 05 – Mar 05	Collar	10,000	–	7.00	–	9.90
Feb 05 – Mar 05	Floor	10,000	–	8.05	–	–
Feb 05 – Mar 05	Floor	10,000	–	8.67	–	–
Mar 05 – Mar 05	Floor	10,000	–	9.41	–	–
Apr 05 – Oct 05	3 Way	10,000	–	6.00	5.00	8.00
Apr 05 – Oct 05	3 Way	5,000	–	6.50	5.50	7.55
Apr 05 – Oct 05	3 Way	5,000	–	6.50	5.50	8.00
Apr 05 – Oct 05	Floor	5,000	–	6.75	–	–
Apr 05 – Oct 05	Floor	10,000	–	6.99	–	–
Apr 05 – Oct 05	Floor	10,000	–	7.42	–	–
Apr 05 – Oct 05	Floor	10,000	–	6.65	–	–
Apr 05 – Oct 05	Floor	10,000	–	6.63	–	–
Apr 05 – Oct 05	Floor	10,000	–	6.85	–	–
2005 Weighted Average		**61,233**		**7.04**	**5.63**	**8.39**

Financial AECO/NYMEX Natural Gas Basis Contracts

Term	Contract	Volume mmbtu/d	Swap USD/mmbtu
2005			
Apr 05 – Oct 05	Swap	10,000	(0.865)
2005 Weighted Average		**5,863**	**(0.865)**

Financial Foreign Exchange Contracts

Term	Contract	Volume MM USD	Swap CAD/USD	Swap USD/CAD
USD Sales Contracts				
2005				
Jan 05 – Dec 05	Swap	43.1	1.2153	0.8228
Jan 05 – Dec 05	Swap	54.6	1.2115	0.8254
Jan 05 – Dec 05	Swap	36.0	1.2169	0.8218
Jan 05 – Dec 05	Swap	28.7	1.2000	0.8333
Total and 2005 Weighted Average		**162.4**	**1.2117**	**0.8253**
2006				
Jan 06 – Jun 06	Swap	6.5	1.2115	0.8254
Jan 06 – Jun 06	Swap	6.5	1.2000	0.8333
Total and 2006 Weighted Average		**13.0**	**1.2058**	**0.8294**
USD Purchase Contracts				
2005				
Jan 05 – Dec 05	Swap	15.6	1.1966	0.8357

Financial Electricity Contracts (1)

Term	Contract	Volume MWh	Swap CAD/MWh
Jan 05 – Dec 10	Swap	5.0	63.00

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

Financial Interest Rate Contracts (1)

Term	Contract	Principal MM USD	Fixed Annual Rate (%)	Spread on 3 Mo. LIBOR
Jan 05 – Apr 14	Swap	30.5	4.62	38.5 bps
Jan 05 – Apr 14	Swap	32.0	4.62	38.0 bps
Total and Annual Weighted Average		**62.5**	**4.62**	**38.2 bps**

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

The Trust has designated its fixed price electricity contract as an effective accounting hedge as at January 1, 2004. A realized loss of $0.4 million (nil in 2003) on the electricity contract has been included in operating costs. The fair value unrealized loss on the electricity contract of $3.6 million has not been recorded on the consolidated balance sheet at December 31, 2004.

The Trust has entered into interest rate swap contracts to manage a portion of the Company's interest rate exposure on debt instruments. These contracts have been designated as effective accounting hedges. A realized gain of $1.4 million for 2004 ($0.008 million gain in 2003) on the interest rate swap contracts has been included in interest expense. The fair value unrealized loss on the interest rate swap contracts of $0.04 million has not been recorded on the consolidated balance sheet at December 31, 2004.

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

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

Fair value at January 1, 2004 (1)	$	(14,575)
Change in fair value of contracts in the period		10,533
Fair value at December 31, 2004 (1)		(4,042)
Realized losses in the period		(86,909)
Non-cash amortization of crystallized hedging gains		4,883
Loss on commodity and foreign currency contracts (1)	$	(86,068)
Commodity and foreign currency contracts liability at December 31, 2004	$	(26,336)
Commodity and foreign currency contracts asset at December 31, 2004	$	22,294

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

Upon implementation of the new hedge accounting guideline on January 1, 2004, the Trust recorded a liability and corresponding deferred hedge loss of $14.6 million for the fair value of the contracts at that time. The opening deferred hedge loss was amortized to income over the terms of the contracts in place at January 1, 2004. As at December 31, 2004, the deferred hedge loss had been fully amortized. At December 31, 2004, the fair value of the contracts that were not designated as accounting hedges was a loss of $4 million.

The Trust recorded a loss on commodity and foreign currency contracts of $86.1 million in the statement of income for 2004. This amount includes the realized and unrealized gains and losses on derivative contracts that do not qualify as effective accounting hedges. Included in this amount is an unrealized gain of $10.5 million due to the change in fair value of the contracts in the period. Realized cash losses on contracts during the year of $86.9 million and amortization expense of $14.6 million of the opening deferred hedge loss have been included in this amount. In addition, this amount includes a non-cash amortization gain of $4.9 million relating to contracts that were previously recorded on the consolidated balance sheet.

11. INCOME TAXES

Effective April 1, 2004, the Alberta government enacted a reduction in provincial corporate income tax rates to 11.5 per cent from 12.5 per cent.

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 changes to the income tax rates, the Trust's future income tax rate applied to temporary differences decreased to approximately 34 per cent in 2004 (35 per cent in 2003) compared to the tax rate of 39 per cent applicable to the 2004 income tax year. Due to the reductions in the future income tax rates, the Trust recorded a future income tax recovery of $5.9 million in 2004 ($66.1 million in 2003). Of the $66.1 million future income tax recovery recorded in 2003, $39.2 million was attributed to the future income tax liability recorded on the Star acquisition (see Note 4).

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

	2004	2003
Income before future income tax recovery	**$ 219,541**	$ 196,657
Expected income tax expense at statutory rates	**85,410**	80,118
Effect on income tax of:		
Net income of the Trust	**(86,547)**	(92,299)
Effect of change in corporate tax rate	**(5,861)**	(66,099)
Resource allowance	**(13,341)**	(10,857)
Unrealized (gain) loss on foreign exchange	**(8,412)**	(7,618)
Non-deductible crown charges	**1,304**	2,434
Alberta Royalty Tax Credit	**244**	39
Capital tax	**1,103**	738
Future income tax recovery	**$ (26,100)**	$ (93,544)

The net future income tax liability comprises the following:

	2004	2003
Future tax liabilities:		
Capital assets in excess of tax value	**$ 345,987**	$ 350,837
Future tax assets:		
Non-capital losses	**(19,429)**	(23,068)
Asset retirement obligations	**(19,434)**	(17,721)
Commodity and foreign currency contracts	**(1,384)**	(1,049)
Attributed Canadian royalty income	**(5,289)**	(6,767)
Deductible share issue costs	**(45)**	(267)
Net future income tax liability	**$ 300,406**	$ 301,965

The petroleum and natural gas properties and facilities owned by the Trust's corporate subsidiaries have an approximate tax basis of $364.6 million ($288.9 million in 2003) available for future use as deductions from taxable income. Included in this tax basis are estimated non-capital loss carry forwards of $56.7 million ($66 million in 2003) that expire in the years through 2010.

No current income taxes were paid or payable in 2004 or 2003.

12. UNITHOLDERS' CAPITAL

The Trust is authorized to issue 650 million trust units of which 185.8 million units were issued and outstanding as at December 31, 2004 (179.8 million as at December 31, 2003).

On June 8, 2004, the Trust issued 2,032,358 trust units at $15.01 per unit for proceeds of $30.5 million in conjunction with the acquisition of United Prestville Ltd.

The Trust has in place a Distribution Reinvestment and Optional Cash Payment Program 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.

The Trust is an open ended mutual fund under which unitholders have the right to request redemption directly from Trust. Units tendered by holders are subject to redemption under certain terms and conditions including the determination of the redemption price at the lower of the closing market price on the date units are tendered or 90 per cent of the weighted average trading price for the 10 day trading period commencing on the tender date. Cash payments for units tendered for redemption are limited to $100,000 per month with redemption requests in excess of this amount eligible to receive a note from ARC Resources Ltd. for a maximum of $500 million accruing interest at six per cent and repayable within 15 years.

	2004		2003	
	Number of Trust Units	**$**	Number of Trust Units	$
Balance, beginning of year [1]	**179,780**	**1,843,112**	123,305	1,175,149
Issued for properties (Note 4)	**2,032**	**30,500**	–	–
Issued for cash	**–**	**–**	27,000	338,050
Issued on conversion of				
convertible debentures (Note 4)	**–**	**–**	27,027	320,000
Issued on conversion of				
ARML exchangeable shares (Note 13)	**–**	**–**	60	708
Issued on conversion of				
ARL exchangeable shares (Note 13)	**363**	**4,295**	504	6,544
Issued on exercise of employee rights (Note 15)	**1,751**	**20,672**	901	8,015
Distribution reinvestment program	**1,896**	**27,924**	983	12,461
Trust unit issue costs	**–**	**(152)**	–	(17,815)
Balance, end of year	**185,822**	**1,926,351**	179,780	1,843,112

(1) Opening balances have been restated for the retroactive change in accounting policy for non-controlling interest pertaining to exchangeable securities (see Note 3 for further discussion).

13. EXCHANGEABLE SHARES

The ARC Resources Ltd. exchangeable shares ("ARL Exchangeable Shares") were issued on January 31, 2001, at $11.36 per exchangeable share as partial consideration for the Startech 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 10 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 ARC Resources Management Ltd. exchangeable shares ("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. The issue price of the exchangeable shares was determined based on the 10-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 that 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 10-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 whereby outstanding shares, are redeemable by the Trust for trust units on or after August 30, 2005, until August 29, 2012.

ARL Exchangeable Shares	**2004**	2003
Balance, beginning of year	**2,011**	637
Exchanged for trust units	**(227)**	(361)
Issued on conversion of ARML exchangeable shares	**–**	1,735
Balance, end of year	**1,784**	2,011
Exchange ratio, end of year	**1.67183**	1.49013
Trust units issuable upon conversion, end of year	**2,982**	2,997

ARML Exchangeable Shares	**2004**	2003
Balance, beginning of year	**–**	2,206
Exchanged for trust units	**–**	(56)
Converted to ARL exchangeable shares	**–**	(2,150)
Balance, end of year	**–**	–

The Trust retroactively applied EIC-151 "Exchangeable Securities Issued by a Subsidiary of an Income Trust" in 2004. The non-controlling interest on the consolidated balance sheet consists of the fair value of the exchangeable shares upon issuance plus the accumulated earnings attributable to the non-controlling interest. The net income attributable to the non-controlling interest on the consolidated statement of income represents the cumulative share of net income attributable to the non-controlling interest based on the trust units issuable for exchangeable shares in proportion to total trust units issued and issuable at each period end during the year.

Following is a summary of the non-controlling interest for 2004 and 2003:

	2004	2003
Non-controlling interest, beginning of year	**$ 36,311**	$ 37,213
Exchanged for trust units	**(4,295)**	(6,544)
Current period net income attributable to non-controlling interest	**3,951**	5,642
Non-controlling interest, end of year	**$ 35,967**	$ 36,311
Accumulated earnings attributable to non-controlling interest	**$ 15,139**	$ 11,187

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.

	2004	2003
Cash flow from operations before changes in non-cash working capital	**$ 448,033**	$ 396,180
Add (deduct):		
Cash withheld to fund current period capital expenditures	**(110,846)**	(106,625)
Reclamation fund contributions and interest earned on fund	**(7,210)**	(6,157)
Interest on convertible debentures	**–**	(4,070)
Cash distributions	**329,977**	279,328
Accumulated cash distributions, beginning of year	**968,275**	688,947
Accumulated cash distributions, end of year	**$ 1,298,252**	$ 968,275
Cash distributions per unit (1)	**$ 1.80**	$ 1.80
Accumulated cash distributions per unit, beginning of year	**12.44**	10.64
Accumulated cash distributions per unit, end of year	**$ 14.24**	$ 12.44

(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 Trust Unit Incentive Rights Plan (the "Rights Plan") was established in 1999 that authorized the Trust to grant up to 8,000,000 rights to its employees, independent directors and long-term consultants to purchase trust units, of which 7,866,088 were granted to December 31, 2004. The initial exercise price of rights granted under the Rights 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. In general, these rights have a five year term and vest equally over three years commencing on the first anniversary date of the grant. In addition, the exercise price of the rights is to be adjusted downwards from time to time by the amount, if any, that distributions to unitholders in any calendar quarter exceeds 2.5 per cent (10 per cent annually) of the Trust's net book value of property, plant and equipment (the "Excess Distribution"), as determined by the Trust.

During the year, the Trust granted 27,000 rights (2,991,099 rights in 2003) to employees, independent directors and long-term consultants to purchase trust units at an exercise price of $15.42 per trust unit. No future rights will be issued as the rights plan was replaced with a Whole Unit Plan during 2004 (see Note 16). The existing Rights Plan will be in place until the remaining three million rights outstanding as at December 31, 2004 are exercised or cancelled.

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

	2004		2003	
	Number of Rights	**Weighted Average Exercise Price ($)**	Number of Rights	Weighted Average Exercise Price ($)
Balance, beginning of year	**4,869**	**11.29**	3,041	10.64
Granted	**27**	**15.42**	2,991	12.15
Exercised	**(1,751)**	**10.57**	(901)	8.89
Cancelled	**(136)**	**11.60**	(262)	11.61
Balance before reduction of exercise price	**3,009**	**11.72**	4,869	11.84
Reduction of exercise price	**–**	**(0.80)**	–	(0.55)
Balance, end of year	**3,009**	**10.92**	4,869	11.29

A summary of the plan as at December 31, 2004, 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
9.10	5.38	41	0.33	41
11.94	9.64	146	1.48	146
12.56	12.27	596	2.39	225
12.17	11.07	2,199	3.38	376
15.42	15.08	27	4.23	–
12.23	10.92	3,009	3.05	788

The Trust recorded compensation expense of $5.2 million for the year ($3.5 million in 2003) for the cost associated with the rights. Of the 3,013,569 rights issued on or after January 1, 2003, that were subject to recording compensation expense, 190,866 rights have been cancelled and 596,928 rights have been exercised to December 31, 2004.

On December 31, 2004, the Trust prospectively applied the fair value based method of accounting for the rights plan. Previously, the Trust applied the intrinsic value methodology due to the number of uncertainties regarding the reduction in the exercise price of the rights that deemed a fair value calculation to be inappropriate. The Trust has now applied the fair value calculation as the variables have become more certain, including the life of the plan, future expected distributions and expected reduction in the rights price, where applicable.

The Trust used the Black-Scholes option-pricing model to calculate the estimated fair value of the outstanding rights issued on or after January 1, 2003. The following assumptions were used to arrive at the estimate of fair value as at December 31, 2004:

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

As at December 31, 2004, the fair value calculation resulted in cumulative expense of $8.7 million compared to the $10.2 million recorded as cumulative compensation expense to September 30, 2004, under the intrinsic value methodology. The $1.5 million difference was recorded as compensation recovery in the fourth quarter of 2004. The remaining future fair value of the rights of $3.7 million will be recognized in earnings over the remaining vesting period of the rights outstanding.

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

	2004	2003
Balance, beginning of year	**$ 3,471**	$ –
Compensation expense	**5,171**	3,471
Net benefit on rights exercised [1]	**(2,167)**	–
Balance, end of year	**$ 6,475**	$ 3,471

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

For rights granted in 2002, the Trust has disclosed pro forma results as if the amended accounting standard had been applied retroactively.

Pro Forma Results	2004	2003
Net income as reported	**241,690**	284,559
Less: compensation expense for rights issued in 2002	**3,189**	3,483
Pro forma net income	**238,501**	281,076
Basic net income per trust unit		
As reported	**1.32**	1.88
Pro forma	**1.30**	1.85
Diluted net income per trust unit		
As reported	**1.31**	1.82
Pro forma	**1.29**	1.79

16. WHOLE TRUST UNIT INCENTIVE PLAN

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

Upon vesting, the plan participant is entitled to receive a cash payment based on the fair value of the underlying trust units plus notional accrued distributions. The cash compensation issued upon vesting of the PTU's is dependent upon the future performance of the Trust compared to its peers based on a performance multiplier. The performance multiplier is based as to 75 per cent on the percentile rank of the Trust's Total Unitholder Return and as to 25 per cent on the percentile rank of the Trust's Recycle Ratio relative to a defined peer group subject to approval from the Compensation Committee. The cash compensation issued upon vesting of the PTU's may range from zero to two times the number of the PTU's originally granted.

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

The Trust recorded compensation expense of $2.9 million in 2004 for the estimated cost of the plan. The compensation expense was based on the December 31, 2004 unit price of $17.90, distributions of $0.15 per unit per month during the year, and management's estimate of the number of RTU's and PTU's to be issued on maturity.

	Number of RTU's	Number of PTU's
Balance, beginning of year	–	–
Granted	226,837	128,908
Forfeited	(2,439)	(577)
Balance, end of year	224,398	128,331

17. BASIC AND DILUTED PER TRUST UNIT CALCULATIONS

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

	2004	2003 [4]
Weighted average trust units [1]	**183,123**	151,698
Trust units issuable on conversion of exchangeable shares [2]	**2,982**	2,997
Dilutive impact of rights and convertible debentures [3]	**1,756**	5,105
Diluted trust units	**187,861**	159,800

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

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

(3) All outstanding rights were dilutive and therefore none have been excluded in the diluted unit calculation (118,700 rights excluded in 2003).

(4) Weighted average trust units have been restated to exclude trust units issuable for exchangeable shares in accordance with the retroactive change in accounting policy for non-controlling interest.

In 2003 net income in the basic per trust unit calculation was reduced by interest on the convertible debentures of $4.1 million. No such adjustments were made for the 2004 calculation.

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

18. COMMITMENTS AND CONTINGENCIES

Following is a summary of the Trust's contractual obligations and commitments as at December 31, 2004:

Payments Due By Period

($ millions)	2005	2006-2007	2008-2009	Thereafter	Total
Debt repayments [1]	8.7	31.3	35.4	145.1	220.5
Operating leases	4.3	7.2	6.5	3.2	21.2
Purchase commitments	4.4	3.4	2.7	8.0	18.5
Retention bonuses	1.0	2.0	–	–	3.0
Derivative contract premiums [2]	29.4	–	–	–	29.4
Total contractual obligations	47.8	43.9	44.6	156.3	292.6

(1) Includes long-term and short-term debt.

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

In addition to the above, the Trust has commitments related to its risk management program (see Note 10).

The Trust enters into commitments for capital expenditures in advance of the expenditures being made. At a given point in time, it is estimated that the Trust has committed to approximately $40 to $60 million of capital expenditures by means of giving the necessary authorizations to incur the capital in a future period. This commitment has not been disclosed in the above commitment table as it is of a routine nature and is part of normal course of operations for active oil and gas companies and trusts.

The Trust has certain sales contracts with aggregators whereby the price received by the Trust is dependent upon the contracts entered into by the aggregator. The Trust has an obligation for future fixed transportation charges, pursuant to one aggregator contract, for which the transportation is not physically being utilized due to a shortage of demand. The Trust has estimated that its total future liability for the future transportation charges approximates $10 million over the period 2005 through 2012. This transportation liability will be realized as a reduction of the Trust's net gas price over the corresponding period as the charges are incurred. For all other aggregator contracts, prices received by the Trust closely track to market prices.

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.

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

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

The application of US GAAP would have the following effect on net income as reported.

	2004	2003
Net income as reported for Canadian GAAP	**$ 241,690**	$ 284,559
Adjustments:		
Depletion and depreciation (a)	**19,004**	22,258
Unrealized gain (loss) on derivative instruments (e)	**13,721**	3,706
Interest on convertible debentures (d)	**–**	(4,070)
Unit based compensation (c)	**(9,219)**	(6,991)
Non-controlling interest (g)	**3,951**	5,642
Effect of applicable income taxes on the above adjustments	**(2,142)**	(2,835)
Net income under US GAAP before cumulative effect of change in accounting principles	**267,005**	302,269
Cumulative effect of change in accounting principle, net of applicable income taxes (b)	**–**	12,085
Net income under US GAAP	**$ 267,005**	$ 314,354
Net income per trust unit		
Basic (h)		
Net income before cumulative effect of change in accounting principle	**$ 1.43**	$ 1.95
Cumulative effect of change in accounting principle	**–**	0.08
Net income after cumulative effect of changes in accounting principle	**$ 1.43**	$ 2.03
Diluted (h)		
Net income before cumulative effect of change in accounting principle	**$ 1.42**	$ 1.89
Cumulative effect of change in accounting principle	**–**	0.08
Net income after cumulative effect of changes in accounting principle	**$ 1.42**	$ 1.97
Comprehensive income:		
Net income under US GAAP	**$ 267,005**	$ 314,354
Unrealized gain (loss) on derivative instruments, net of applicable income taxes	**(2,441)**	3,692
Comprehensive income (e)	**$ 264,564**	$ 318,046

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

	2004		2003	
	Canadian GAAP	**US GAAP**	Canadian GAAP	US GAAP
				(Restated (Note f))
Property, plant and equipment	**$ 2,016,646**	**$ 1,868,428**	$ 2,015,539	$ 1,848,317
Commodity and foreign currency contracts	**(4,042)**	**(7,685)**	(4,883)	(18,558)
Future income taxes	**(300,406)**	**(270,173)**	(301,965)	(270,838)
Non-controlling interest	**(35,967)**	**–**	(36,311)	–
Temporary equity (f)	**–**	**(3,379,594)**	–	(2,694,138)
Unitholders' capital	**(1,926,351)**	**–**	(1,843,112)	–
Contributed surplus	**(6,475)**	**–**	(3,471)	–
Accumulated earnings	**(878,807)**	**651,227**	(637,117)	323,943
Accumulated other comprehensive income	**–**	**2,395**	–	(46)

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.

(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 who otherwise meet the definition of an employee of the Trust under its Trust Unit Incentive Rights Plan. For the years ended December 31, 2004 and 2003, 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. At that time, as the Trust could not determine a reasonable estimate of the fair value of the rights granted using an option pricing model, compensation expense was determined using the intrinsic value of the rights at the exercise date or at the date of the consolidated financial statements for unexercised rights. In the fourth quarter of 2004 the Trust was able to develop a reasonable estimate for the fair value of the rights, and has adjusted compensation expense prospectively as a change in estimate.

For US GAAP purposes, the Plan has been accounted for as 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, for US GAAP purposes and for the difference between the intrinsic value and the fair value of rights issued since that time which are still outstanding at December 31, 2004.

(d) Under Canadian GAAP, the convertible debentures were classified as Unitholders' equity and interest paid on the convertible debentures was recorded as a reduction of retained earnings and as a reduction in cash flow from financing activities. Under US GAAP, convertible debentures are classified as long-term debt and interest paid has been classified in cash flow from operating activities. 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. As at December 31, 2004 and 2003, the Trust had no convertible debentures outstanding.

(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. Under Canadian GAAP, derivative instruments that meet these specific hedge accounting criteria are not recorded on the consolidated balance sheet. In addition, unrealized gains and losses on effective hedges are not recorded in the financial statements. The Trust formally documented and designated all hedging relationships and verified that its hedging instruments were effective in offsetting changes in actual prices and rates received by the Trust. Hedge effectiveness is monitored and any ineffectiveness is reported in the consolidated statement of income.

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

	2004		2003	
	Gross	**After Tax**	Gross	After Tax
Accumulated other comprehensive income (loss) beginning of year	**$ 78**	**$ 46**	$ (6,350)	$ (3,646)
Effect of change in corporate tax rate	**–**	**(5)**	–	(118)
Reclassification of net realized (gains) losses into earnings	**(969)**	**(637)**	(2,677)	(1,586)
Net change in fair value of derivative instruments	**(2,752)**	**(1,799)**	9,105	5,396
Accumulated other comprehensive income (loss), end of year	**$ (3,643)**	**$ (2,395)**	$ 78	$ 46

(f) Under US GAAP, as the trust units are redeemable at the option of the unitholder, the trust units must be valued at their redemption amount and presented as temporary equity in the consolidated balance sheet. The redemption value of the trust units is determined with respect to the trading value of the trust units and the trust unit equivalent of the exchangeable shares at each balance sheet date. Under Canadian GAAP, all trust units are classified as permanent equity. As at December 31, 2004 and 2003, the Trust has classified $3.4 billion and $2.7 billion, respectively, as temporary equity in accordance with US GAAP. Changes in redemption value between periods are charged or credited to accumulated earnings.

In 2003 and prior years, the Trust believed there were adequate restrictions on the redemption feature to classify the trust units as permanent equity for US GAAP purposes. Upon further review, it was determined that the trust units should be accounted for as temporary equity as set out in the prior paragraph. Prior year amounts have been restated to reduce Unitholders' capital and accumulated earnings by $1.9 billion and $0.8 billion, respectively.

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

(h) Under Canadian GAAP, basic net income per unit is calculated based on net income after non-controlling interest divided by the weighted average trust units and diluted net income per unit is calculated based on net income before non-controlling interest divided by diluted trust units (see Note 17). Under US GAAP, as the ARL Exchangeable shares are not classified as a non-controlling interest, basic net income per unit is calculated based on net income divided by the weighted average trust units and the trust unit equivalent of the outstanding ARL Exchangeable shares. Diluted net income per unit is calculated based on net income divided by a sum of the weighted average trust units, the trust unit equivalent of the outstanding ARL Exchangeable shares, and the dilutive impact of the rights granted under the Trust Unit Incentive Rights Plan.

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

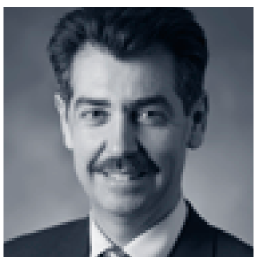
(j) In 2004 the FASB issued new and revised standards, all of which were assessed by Management to be not applicable to the Trust with the exception of the following:

- In June 2004 the FASB issued an exposure draft of a proposed Statement, "Fair Value Measurements" to provide guidance on how to measure the fair value of financial and non-financial assets and liabilities when required by other authoritative accounting pronouncements. The proposed statement attempts to address concerns about the ability to develop reliable estimates of fair value and inconsistencies in fair value guidance provided by current US GAAP, by creating a framework that clarifies the fair value objective and its application in GAAP. In addition, the proposal expands disclosures required about the use of fair value to remeasure assets and liabilities. The standard would be effective for financial statements issued for fiscal years beginning after June 15, 2005.
- In December 2004, the FASB Issued SFAS No. 123R, "Share Based Payments", which addresses the issue of measuring compensation cost associated with Share Based Payment plans. This statement requires that all such plans, for public entities, be measured at fair value using an option pricing model whereas previously certain plans could be measured using either a fair value method or an intrinsic value method. The revision is intended to increase the consistency and comparability of financial results by only allowing one method of application. This revised standard is effective for the first interim or annual period beginning on or after June 15, 2005, for awards granted on or after the effective date. Management will assess the impact of this revised standard in 2005.
- In 2004 FASB issued FAS 153 "Exchange of Non-monetary Assets". This statement is an amendment of APB Opinion No. 29 "Accounting for Non-monetary Transactions". Based on the guidance in APB Opinion No. 29, exchanges for non-monetary assets are to be measured based on the fair value of the assets exchanged. Furthermore, APB Opinion No. 29 previously allowed for certain exceptions to this fair value principle. FAS 153 eliminates APB Opinion No. 29's exception to fair value for non-monetary exchanges of similar productive assets and replaces this with a general exception for exchanges of non-monetary assets which do not have commercial substance. For purposes of this statement, a non-monetary exchange is defined as having commercial substance when the future cash flows of an entity are expected to change significantly as a result of the exchange. The provisions of this statement are effective for non-monetary asset exchanges that occur in fiscal periods beginning after June 15, 2005, and are to be applied prospectively. Earlier application is permitted for non-monetary asset exchanges that occur in fiscal periods beginning after the issue date of this statement. Currently, this statement does not have an impact on the Trust; however, this may result in a future impact to the Trust if it enters into any non-monetary asset exchanges.

OFFICERS AND SENIOR MANAGEMENT

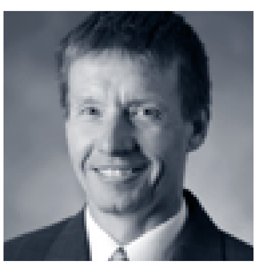
John P. Dielwart, B.Sc., P.Eng.

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 a past Chairman of the board of governors for the Canadian Association of Petroleum Producers (CAPP). He holds a Bachelor of Science with Distinction (Civil Engineering) degree, University of Calgary. He has also been a Director of ARC since inception in 1996.



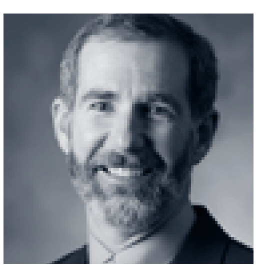
Steven W. Sinclair, B. Comm., CA

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. Mr. Sinclair is a member of both the Alberta and Canadian Institute of Chartered Accountants.



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 over 20 years of diverse experience in the Canadian and International energy industries covering exploration, production and project evaluations in western Canada, oilsands, the Canadian frontiers and internationally. 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.

Susan D. Healy, P. Land

Ms. Healy is Vice-President, Corporate Services of ARC Resources Ltd. and oversees all Office Services and Human Resources related activities. 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, Land and Operations of ARC Resources Ltd. and is responsible for all of ARC's operational activities. He has over 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 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.

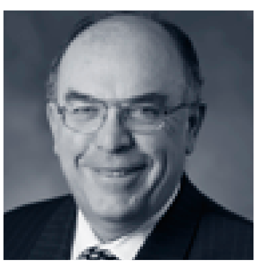
DIRECTORS

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 Vice-President, 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 since 1996.

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

Mr. Dielwart is President and CEO of ARC Resources Ltd. and has overall management responsibility for the Trust. Prior to joining ARC in 1994, Mr. Dielwart spent 12 years with a major Calgary based oil and natural gas engineering consulting firm, as senior Vice-President and a Director, where he gained extensive technical knowledge of oil and natural gas properties in western Canada. He began his career working for five years with a major oil and natural gas company in Calgary. Mr. Dielwart is a past Chairman of the board of governors for the Canadian Association of Petroleum Producers (CAPP). 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, 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 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 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 Vice-President 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, Devon Energy Corporation, TransAlta Corporation and several smaller companies. 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 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 Co-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)
Chairman

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

John P. Dielwart
President and Chief Executive Officer

John M. Beddome (2) (4)

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

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 Health, Safety and Environment 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, Corporate Services

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

Myron M. Stadnyk
Vice-President, Land and Operations

Allan R. Twa
Corporate Secretary

EXECUTIVE OFFICES

ARC Resources Ltd.
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Facsimile: (403) 503-8609
Website: www.arcenergytrust.com
E-Mail: ir@arcresources.com

TRUSTEE AND TRANSFER AGENT

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

AUDITORS

Deloitte & Touche LLP
Calgary, Alberta

ENGINEERING CONSULTANTS

Gilbert Laustsen Jung Associates Ltd.
Calgary, Alberta

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP
Calgary, Alberta

STOCK EXCHANGE LISTING

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

INVESTOR INFORMATION

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

PRIVACY OFFICER

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

UNITHOLDER INFORMATION

NOTICE OF ANNUAL SPECIAL MEETING

The Annual Special Meeting will be held on May 12, 2005 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.arcenergytrust.com or contact Computershare.

CORPORATE CALENDAR

2005

April 15	Announcement of Q2 distribution monthly amounts
May 4	2005 Q1 Results
May 12	Annual General Meeting
July 15	Announcement of Q3 distribution monthly amounts
October 17	Announcement of Q4 distribution monthly amounts

CAPP **Stewardship** Initiative

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

vcr-mvr inc. *Gold™ Champion Level Reporter*

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

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GET INTERACTIVE WITH ARC ENERGY TRUST

Along with our 2004 print annual report, we are providing an online version containing the identical information, easy to access with interactive navigation.

www.aetreports.com

TSX: AET.UN

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