



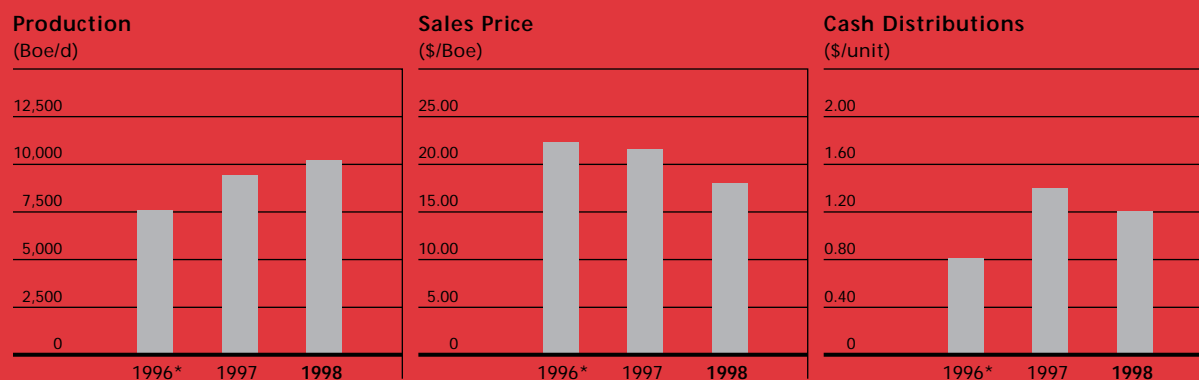
# leadership

ARC ENERGY TRUST

2	MESSAGE TO UNITHOLDERS	6	BUSINESS COMBINATIONS WITH STARCOR AND ORION
9	OPERATIONS REVIEW	14	ACQUISITIONS AND DIVESTMENTS
14	RESERVES	17	MARKETING
		17	ENVIRONMENT AND SAFETY
19	MANAGEMENT'S DISCUSSION AND ANALYSIS	27	COMBINED FINANCIAL STATEMENTS
30	NOTES TO THE COMBINED FINANCIAL STATEMENTS	33	FACTS AND STRUCTURE
35	HISTORICAL REVIEW		IBC CORPORATE INFORMATION

# vision

ARC Energy Trust (the "Trust") was formed in 1996 with the vision of becoming the premier "blue chip" conventional oil and gas trust in Canada as measured by quality of assets, management expertise and long-term investor returns. Since its inception, the Trust has been a top performer in the royalty trust sector and has emerged as a leader in the sector as investors increasingly discriminate on the basis of performance and positive underlying fundamentals. Completion of the acquisitions of Starcor Energy Royalty Fund and Orion Energy Trust in the first quarter of 1999 has enhanced the Trust's leadership position and has further advanced our progress towards realizing our vision.



\*for the six-month period

Notice of Annual Meeting: The Annual Meeting of unitholders will be held on Monday, June 7, 1999, at 3:30 pm at The Westin Hotel, Lakeview Room, 320 - 4th Avenue S.W., Calgary, Alberta.

**HIGHLIGHTS**

(\$ thousands, except per unit amounts)	Year Ended December 31, 1998	Year Ended December 31, 1997
<b>Financial</b>		
Revenue before royalties	67,124	74,103
Per unit	2.62	3.24
Cash flow	30,040	37,757
Per unit	1.17	1.65
Net income*	(14,093)	9,165
Per unit	(0.55)	0.40
Cash distributions	30,724	33,242
Per unit**	1.20	1.40
Working capital	(1,688)	4,647
Long-term debt	72,499	65,955
Unitholders' equity	167,323	212,140
Weighted average units (thousands)	25,604	22,837
Units outstanding at year end (thousands)	25,604	25,604

\* Reflects \$14.7 million ceiling test writedown in 1998

\*\* Based on the number of units outstanding at each cash distribution date

**Operating**

Production		
Crude oil (Bbl/d)	4,439	3,656
Natural gas (Mmcfd)	37.68	38.40
Natural gas liquids (Bbl/d)	2,018	1,929
Total (Boe/d)	10,225	9,425
Average prices		
Crude oil (\$/Bbl)	18.99	26.35
Natural gas (\$/Mcf)	1.93	1.82
Natural gas liquids (\$/Bbl)	13.17	18.27
Oil equivalent (\$/Boe)	17.99	21.54

(based on daily closing price)	1998 Fourth Quarter	1998 Third Quarter	1998 Second Quarter	1998 First Quarter	1997
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**Trust Unit Trading**

Prices (\$)					
High	8.65	9.25	10.50	11.40	13.00
Low	6.10	7.00	8.85	9.40	10.15
Close	6.15	8.95	9.25	10.25	10.45
Average daily volume (thousands)	35	25	33	35	55



Mac H. Van Wielingen  
Director, Vice-Chairman  
and Chief Executive Officer



John P. Dielwart  
Director and President

## MESSAGE TO UNITHOLDERS

At the time of this writing, the oil and gas industry is in the midst of the most protracted bear market ever experienced in the modern era of the oil business. The price of benchmark West Texas Intermediate (“WTI”) crude oil is in its sixteenth straight month of weakness and averaged only \$14.40 US per barrel (“Bbl”) in 1998, its lowest level since 1977. The average 1998 price was 31 percent lower than the 1997 price of \$20.82 US per Bbl; through the first two months of 1999, the price averaged only \$12.18 US per Bbl. Clearly, the very low price of crude oil is having a dramatic impact on both the conventional oil and gas royalty trust sector as well as the broad oil and gas equities market.

In the context of the highly challenging environment for the oil and gas industry, ARC Energy Trust (the “Trust”) has pursued strategies and initiatives that we believe reaffirm our leadership position in the sector. As a result, the Trust continues to be a top performer on a total return basis. Since inception in mid 1996, the Trust has outperformed the conventional royalty trust index by 13 percent. It is noteworthy that the Trust has also significantly outperformed the TSE Oil and Gas Producers Index on a total return basis by 23 percent. The Trust’s distributions were maintained at \$0.10 per unit per month through the year and were the most stable among all of the royalty trusts. The leadership role which the Trust has developed is consistent with our vision to become the premier conventional oil and gas royalty trust in Canada. Our continued superior results in a weak market confirm that the Trust is delivering on its commitment to be a top performer in the sector.

### Acquisition and Disposition Activity

Management of the Trust’s assets involves both the acquisition and disposition of oil and gas properties to capitalize on opportunities which develop in the market.

During 1998, the oil and gas asset market underwent a dramatic transition from a seller’s market in the first half of the year to a buyer’s market by the end of the year. We were not prepared to pay the prices required to acquire quality assets in the first half of 1998 and instead chose to divest of \$14.5 million of assets of which a significant component was non-producing natural gas reserves. With the shift to a buyer’s market later in the year, a number of attractive acquisition opportunities developed. However, capital market support for the oil and gas industry essentially disappeared in the second half of 1998 which meant that acquisitions had to be debt financed. Again, we were not prepared to debt finance a major acquisition in the prevailing commodity price environment which would have increased our leverage and financial risk to our unitholders. Accordingly, the Trust re-deployed the net proceeds (net of funds applied to distribution stabilization) from the first half dispositions, coupled with a minor debt component, into \$14.8 million of mainly oil acquisitions later in the year. These acquisitions were primarily within existing Trust properties, including our main core area of Pembina.

As a result of the Trust’s acquisition and disposition activity in 1998, 1.1 million barrels of oil equivalent (“Mmboe”) reserves were acquired at a net effective cost of \$0.29 per barrel of oil equivalent (“Boe”). Similarly, the Trust added approximately 309 Boe per day of production at a net effective cost of \$1,027 per Boe per day.

### Reserve Replacement

A successful going concern strategy requires that a trust maintains or grows its reserves and production on a cost-effective basis. In combination with the acquisition and disposition activity described above, the Trust’s drilling and development activities and revisions to its existing

assets replaced 101 percent of production in 1998 at a net total cost of \$2.81 per Boe. We are very pleased with this performance, especially given the difficult market environment which prevailed during 1998.

#### **Financial and Operating Performance**

Production during 1998 was 10,225 Boe per day which was eight percent greater than 1997 production of 9,425 Boe per day. During 1998, oil production increased 21 percent to 4,439 Bbl per day, natural gas production decreased two percent to 37.7 million cubic feet ("Mmcf") per day and natural gas liquids production increased five percent to 2,018 Bbl per day. The decline in natural gas production was the result of the first half disposition of a large gas property.

As a result of weak crude oil and natural gas liquids prices, revenue before royalties for the year decreased nine percent to \$67.1 million. Cash flow during the year declined 20 percent to \$30.0 million. The average commodity prices for the year were \$18.99 per Bbl for oil, \$1.93 per thousand cubic feet ("Mcf") for gas and \$13.17 per Bbl for natural gas liquids. On an oil equivalent basis, the average price was \$17.99 per Boe, which was 16 percent lower than 1997. Despite the significant decline in commodity prices, the Trust's operating netback remained relatively strong at \$10.38 per Boe.

Operating costs for 1998 were \$5.04 per Boe; general and administrative costs net of recoveries and reimbursements were \$0.79 per Boe and management fees were \$0.32 per Boe, resulting in overall costs of \$6.15 per Boe net of the residual one percent royalty reimbursement; this compares to \$6.24 per Boe for 1997.

The Trust incurred a net loss of \$14.1 million for the year which included the impact of a writedown in the book value of the Trust's assets by \$14.7 million (six percent). Earnings prior to the writedown fell to \$0.6 million in 1998 from \$9.2 million in 1997 which is entirely attributable to the decline in oil prices. The low oil price in 1998 (especially the fourth quarter average price for WTI of \$12.83 US per Bbl) and continuing low oil prices in 1999 were the main factors in the writedown of the carrying value of the Trust's assets.

#### **Commodity Price Outlook**

As we begin 1999, oil prices remain very weak and the market sentiment has become extremely negative; there is considerable discussion about a new low price era that could last several years. We strongly disagree with this

view. Our analysis indicates that the world oil market is experiencing a cyclical downturn and we do not see any secular or structural changes to world oil supply or demand fundamentals that would support an environment in which low oil prices prevail long term. The oil market is currently burdened by excess inventories which were created by overproduction relative to demand due to an economic downturn in Asia and several consecutive warmer than normal winters in the northern hemisphere. We believe economic forces are already in motion that will correct this situation. Oil supply outside of OPEC is expected to decline modestly in 1999 and this trend will gain depth and momentum the longer oil prices remain depressed. Oil demand will continue to increase as stability and growth returns to the Asian economies and demand in the rest of the world continues to grow.

Assuming OPEC stands still at current output levels, we see balance returning to the oil market within the next 12 months. This process could be greatly accelerated by further output reductions on the part of OPEC which is a distinct possibility given the mounting financial stress affecting virtually all OPEC members. It is noteworthy that since 1985, the WTI oil price has only been below \$16.00 US per Bbl 20 percent of the time (32 months) during four down cycles, having an average duration of approximately eight months each. During the current price cycle, the price has been below \$16.00 US per Bbl for 13 consecutive months, the longest period yet. WTI has averaged less than \$14.00 US per Bbl only eight percent (11 months) of the time since 1985 during three down cycles, having an average duration of approximately four months each. During the current cycle, the price has been below \$14.00 US per Bbl for six months including the last four straight months (including February 1999). We do not view prices at this level to be sustainable for much longer. As crude oil stocks and refinery inventories return to more normal levels, we expect prices to also return to a more normal level of \$16.00 US to \$20.00 US per Bbl for WTI.

With regard to natural gas, despite another warm winter across North America and the resultant excess storage inventories, we believe the outlook is very positive. Prospects for long-term demand growth are attractive based on the environmental qualities and competitive position of natural gas versus alternative fuels. Supply is tight across North America and should become

substantially tighter later this year because of the constraints on drilling imposed by reduced industry cash flow from continued low oil prices and the absence of financial market support. Given high decline rates and full utilization of existing productive capacity, the upstream sector will have to maintain a very high level of drilling to supply future demand growth. An attractive pricing environment will be necessary to draw the capital needed to finance this activity. Downside risk in prices is mitigated by the fact that, unlike oil, there is no dominant low-cost supplier of natural gas in North America. The outlook for Canadian natural gas is particularly bright because pipeline capacity expansions are likely to lead supply growth for the next three to five years. Surplus pipeline capacity ensures producers have an outlet for their production and creates strong support for Canadian natural gas prices.

Given these positive fundamentals, we are of the view that a plantgate pricing range of \$2.00 to \$2.50 per Mcf is sustainable on a long-term basis for Canadian producers.

#### **1999 Outlook**

Since inception, the Trust has been a top performer in the royalty trust sector through both strong and weak commodity price cycles. The Trust has emerged as a leader in the sector as investors increasingly discriminate on the basis of performance and positive underlying fundamentals. The depressed state of oil prices during 1998 and into 1999 has created many challenges but also significant new opportunities. Our leadership position in the sector was solidified in early 1999 when the Trust took advantage of two such opportunities and entered into business combination agreements with Starcor Energy Royalty Fund ("Starcor") and Orion Energy Trust ("Orion"). With these acquisitions closing on March 12, 1999, the Trust emerged as a leader in the much anticipated and badly needed initial phase of consolidation in the royalty trust sector.

The acquisitions of Starcor and Orion have many benefits for our unitholders, including:

- improved financial efficiency with general and administrative expenses and management fees on a per unit of production basis expected to decline up to 30 percent;

- enhancement of our already high quality asset base;
- increased exposure to natural gas;
- significantly enhanced liquidity, which is expected to attract greater institutional interest and result in improved capital market support; and
- increased size allowing the Trust to develop more in-depth organizational resources to further enhance our strong existing expertise.

Most importantly, the transactions are expected to result in approximately 10 percent accretion to our 1999 unitholder distributions. As a result, we expect to be able to maintain our distributions at \$0.10 per unit per month through 1999 based upon a WTI price of \$14.67 US per Bbl for oil and a natural gas price of \$2.25 Cdn per Mcf. Regardless of the actual oil price in 1999, approximately 10 percent accretion to distributions is anticipated from what otherwise would have occurred.

With the completion of the acquisitions of Starcor and Orion, we will continue to aggressively rationalize our assets in 1999 to further increase efficiencies and strengthen our balance sheet. Broadly, we are confident that the Trust is exceptionally well positioned in both the current market environment as well as in the expected recovery in the oil market to continue to generate superior long-term returns to our unitholders.

Respectfully submitted on behalf  
of the Board of Directors.

Mac H. Van Wielingen (signed)

Director, Vice-Chairman and Chief Executive Officer

John P. Dielwart (signed)

Director and President



As manager of the Trust, ARC Financial Corporation is committed to delivering superior returns and value to unitholders throughout all phases of the sector's business cycle. Our commitment in this regard is evidenced in our continued ability to produce superior growth and performance in a cost-effective manner. The unique financial and technical expertise of ARC Financial Corporation is our competitive advantage.

# commitment, expertise

**BUSINESS COMBINATIONS  
WITH STARCOR AND ORION**

The conventional oil and gas royalty trust sector included 16 separate entities at year-end 1998, of which most performed poorly with consequent wide-spread investor disappointment. It is widely recognized that consolidation in the sector is needed given the extremely low oil prices and the requirement for increased financial efficiency and financial market support. These realities provided the backdrop for the Trust to give serious consideration to pursue the significant acquisitions of Starcor and Orion.

Starcor and Orion were two trusts with a common manager and very attractive assets. In response to a hostile takeover bid by another trust, the Trust, among others, was invited to review confidential information for Starcor and Orion and submit an offer to purchase the trusts. Our offers for both trusts were accepted and we entered into business combination agreements with Orion on January 18, 1999 and Starcor on February 8, 1999.

On March 12, 1999, the Trust completed the business combinations with both Starcor and Orion on the following basis:

	For Each Starcor Unit	For Each Orion Unit
Cash	\$1.50	–
ARC Energy Trust units	0.965	0.875
ARC warrants*	0.193	0.175

\* Full warrant allows purchase of one ARC Energy Trust unit at \$7.25 until June 15, 2000.

After incorporating all transaction costs incurred by the three trusts, the transactions meet and generally exceed all of the Trust's acquisition criteria. The reserves were acquired for \$5.13 per Boe based upon proved plus risked probable reserves.

A very important aspect of the transactions is that the Starcor and Orion properties are highly concentrated, with 13 properties accounting for approximately 90 percent of the reserves and value. The key asset in Starcor is Jenner which is a large, operated, high-quality gas property with meaningful long-term development upside. Jenner is a major strategic acquisition for the Trust and will become the second largest property in our portfolio behind only Pembina.

The Orion properties are generally located west of the fifth meridian in Alberta in close proximity to existing Trust properties. In particular, Orion's Pembina properties are an excellent fit with our existing primary core area where we have experienced considerable success implementing optimization and cost reduction strategies. We have identified similar opportunities on Orion's lands in the area and expect to achieve comparable positive results.

Perhaps the most important benefit of the acquisitions is the estimated 10 percent accretion to unitholder distributions. In the absence of the transactions, maintaining the Trust's distributions at \$0.10 per unit per month would have required average 1999 commodity prices of \$16.00 US per Bbl for WTI crude oil and \$2.25 Cdn per Mcf for natural gas. Pro forma the transactions, the WTI oil price required to maintain distributions at the same gas price is reduced to \$14.67 US per Bbl. This price is consistent with the average 1999 forecast price from three leading Canadian independent engineering consultants and is also consistent with our own internal expectations.

The mergers will have a dramatic impact on the Trust's market capitalization which will increase from approximately \$175 million to \$325 million. This will make the Trust the second largest in the sector based upon market capitalization, which we expect will lead to increased institutional interest and greater access to capital. In addition, the increased size of the Trust will allow us to further develop our organizational resources and enhance our existing strong expertise. More broadly,

the mergers with Starcor and Orion will, we believe, reinforce our leadership position in the sector in terms of management expertise, low cost structure, high-quality assets and successful going concern strategy. This will enhance our ability to continue to generate superior long-term returns for our unitholders.

The following table summarizes the impact the acquisitions will have on the Trust's reserves and operations:

	Existing	Pro Forma
1. Increases the Trust's already long reserve life		
Risky reserve life index (years)	11.6	12.2
2. Increases established reserves 91 percent		
Reserves at December 31, 1998 (Mmboe)	47.2	90.1
3. Increases natural gas component of commodity split		
Natural gas share of established reserves	26%	32%
Natural gas share of production	34%	39%
4. Significantly increases production		
Average 1999 rate (Boe/d)	10,300	17,000
Exit 1999 rate (Boe/d)	10,000	18,500
5. Increases Pembina core area production		
Daily production (Boe/d)	2,441	3,240
6. Increases operated component of production		
Percent operated	20%	33%

#### LOCATION OF PRINCIPAL PROPERTIES





operations review

## OPERATIONS REVIEW

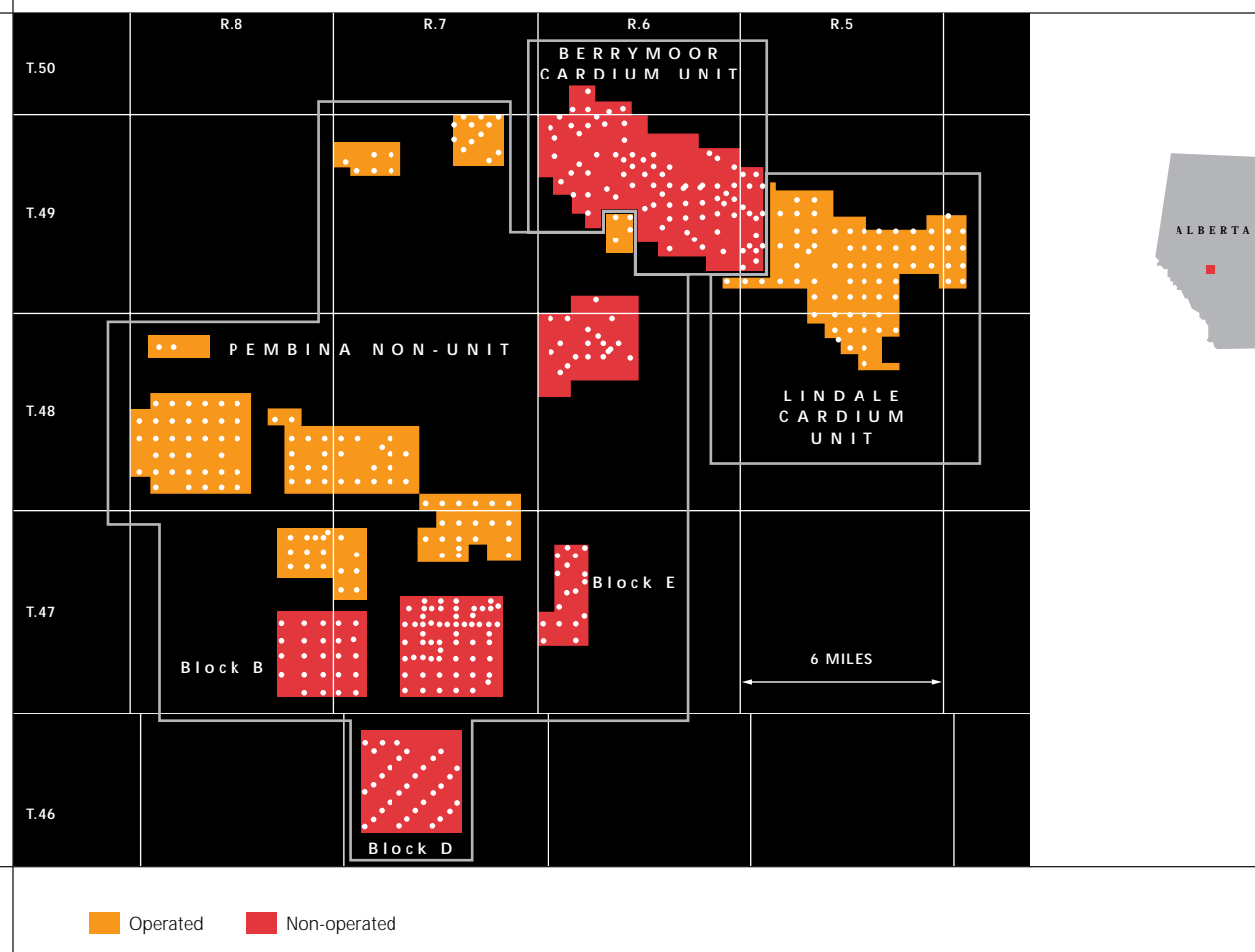
During 1998, production volumes were augmented as a result of development and acquisition/disposition activities. The 1998 average production rate was 10,225 Boe per day, compared to 9,425 Boe per day in 1997.

Over the year, natural gas sales averaged 37.7 Mmcf per day, oil production averaged 4,439 Bbl per day and condensate and natural gas liquids volumes averaged 2,018 Bbl per day. Operating costs, net of processing income, averaged \$5.04 per Boe for the year, down from \$5.16 per Boe in 1997.

In 1998, capital expenditures of \$10.6 million were undertaken to increase production and reserves and maintain existing facilities, thereby strengthening unitholder distributions. Numerous initiatives involving drilling, completions, tie-ins, facility modifications and production optimization were undertaken on many of our properties; notably Caroline, Pembina, Progress, Buick Creek, Marten Hills, Meekwap, Minnehik Buck Lake, Medicine River, House Mountain, Midale, Niton and Innisfail.

<b>Production by Area</b>	Oil (Bbl/d)	Gas (Mcf/d)	NGLs (Bbl/d)	Total (Boe/d)
Pembina area	2,040	2,341	165	2,441
Caroline	–	2,561	1,186	1,442
Progress	–	3,599	51	411
House Mountain	320	37	17	341
Medicine River	174	1,294	26	329
Buick Creek	–	2,707	30	301
Meekwap	264	159	17	297
Midale	283	29	2	288
Mitsue	228	278	29	285
Innisfail	194	359	30	260
Minnehik Buck Lake	–	1,722	78	250
Marten Hills	–	2,393	1	240
Niton	77	1,265	36	238
Inga	–	2,033	32	235
Sylvan Lake	14	1,278	55	197
Harmattan Elkton	26	1,189	37	182
Pouce Coupe	161	91	8	178
Other areas	658	14,346	218	2,310
<b>Total</b>	<b>4,439</b>	<b>37,681</b>	<b>2,018</b>	<b>10,225</b>

## Pembina



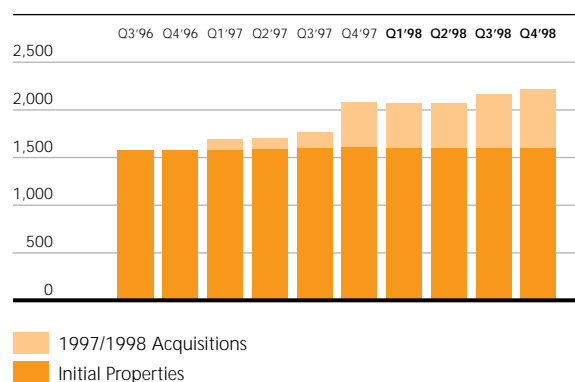
### 1998 Highlights

- Implemented further cost cutting initiatives in operated areas, reducing operating costs by 9 percent
- Optimized a large portion of the MIPA Block's waterflood
- Observed oil production increases as a result of reallocating injection water
- Acquired additional Pembina Cardium interests
- Invested capital to ensure long-term integrity of the injection system

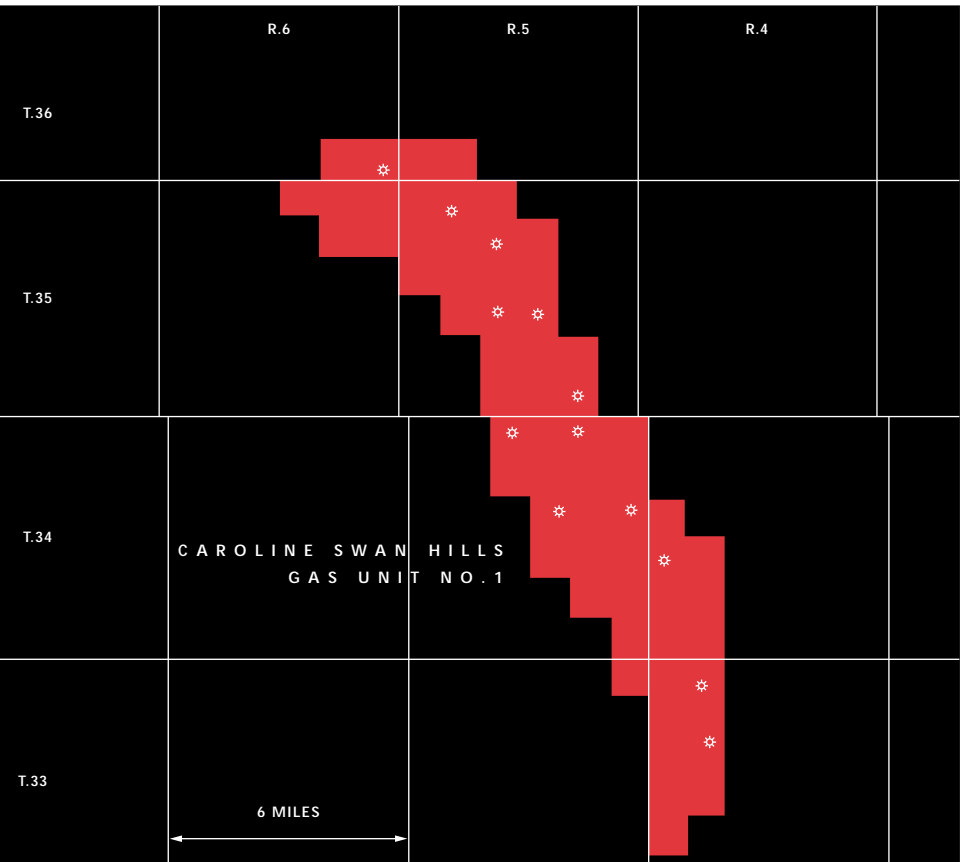
### 1999 Program

- Continue to implement cost cutting initiatives
- Complete the optimization of the MIPA waterflood
- Continue to optimize oil production from individual wells
- Pursue infill drilling opportunities
- Acquire additional working interests in operated properties

### Production (Bbl/d)



# Caroline



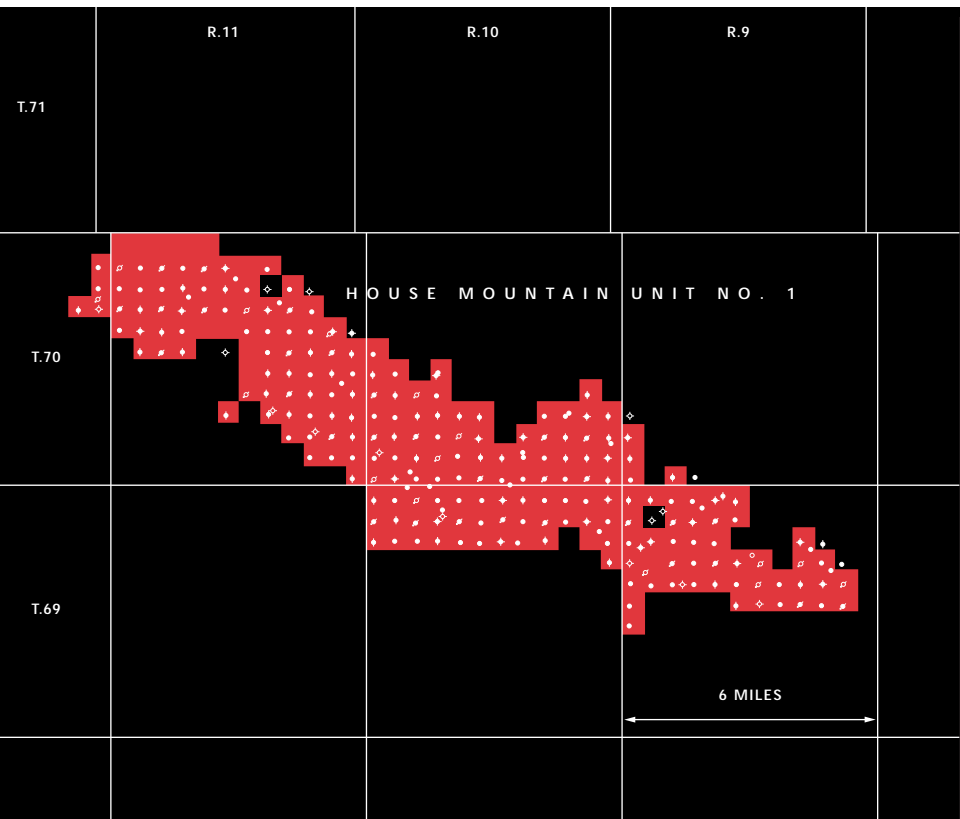
## 1998 Highlights

- Worked over four wells to increase unit production capability
- Continued to maintain throughput levels significantly above original plant capacity
- Tested potential outside gas stream for future custom processing revenues

## 1999 Program

- Maintain full expanded plant throughput utilizing unit gas production
- Workover one well

# House Mountain



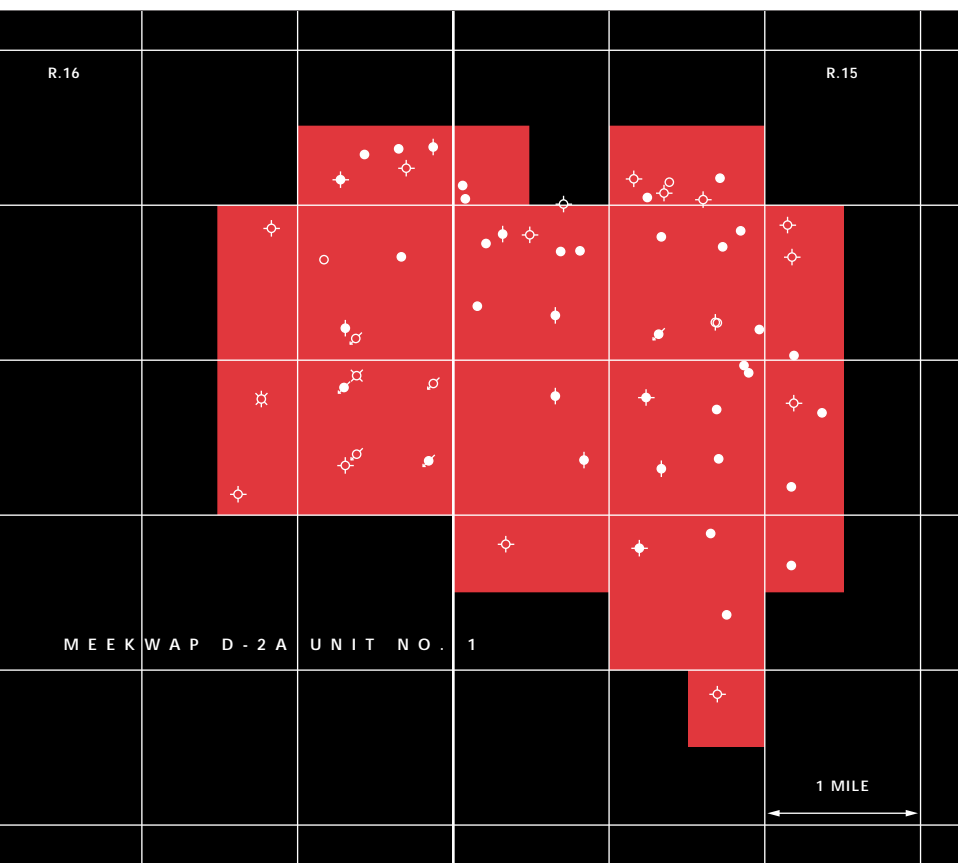
## 1998 Highlights

- Drilled two successful horizontal re-entries
- Increased proved and established oil reserves by 30 percent

## 1999 Program

- Drill four horizontal wells
- Optimize waterflood injection via conversion and workovers

## Meekwap



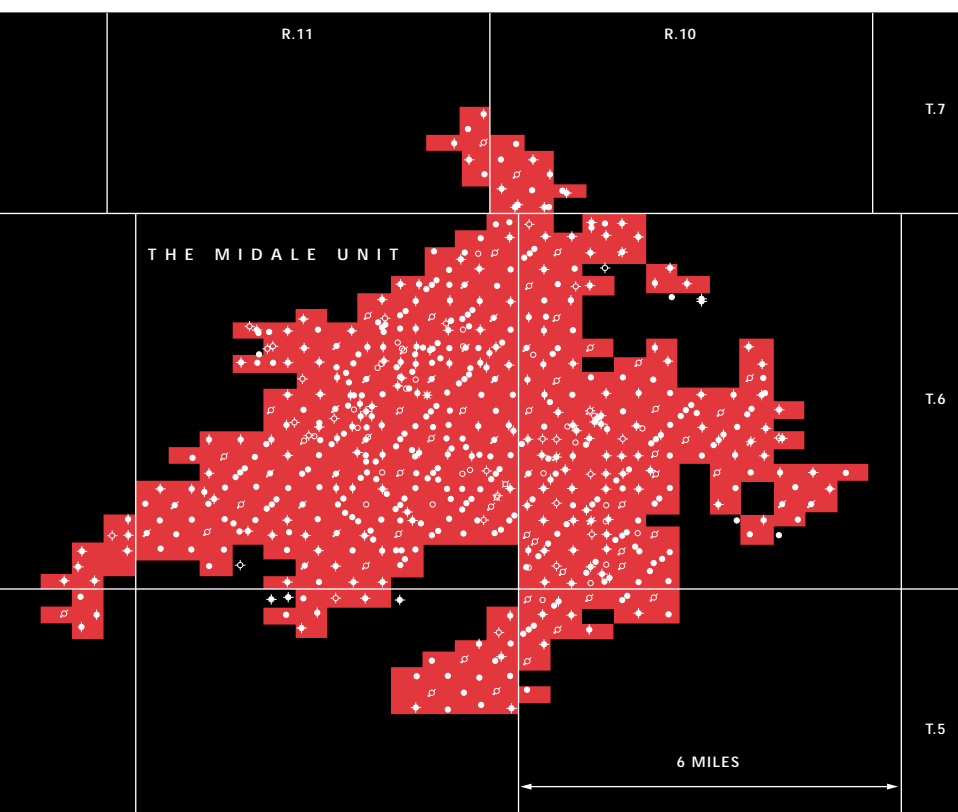
### 1998 Highlights

- Drilled one non-unit and two unit wells
- Production over the year increased 35 percent on average compared to 1997 exit volume
- Oil reserves increased 55 percent on a proved basis and 75 percent on an established basis

### 1999 Program

- Continue to pursue infill drilling opportunities

## Midale



### 1998 Highlights

- Drilled 11 horizontal wells including one injector and 10 multi-legged producers in the Midale Unit
- Drilled one vertical well in the non-unit Frobisher
- Added 0.66 Mmbbl of proved oil reserves and 1.40 Mmbbl of established oil reserves
- Acquired initial Frobisher 100 percent non-unit interest and additional 7.8 percent in Midale Unit interests

### 1999 Program

- Drill at least one horizontal non-unit Frobisher well
- Optimize the waterflood and line drive in the Midale Unit; delay further infill drilling until prices improve



# performance

Since inception, the Trust has demonstrated strong performance in terms of both financial returns to unitholders and growth of our asset base. The Trust continues to be a top performer among all conventional oil and gas royalty trusts on the basis of total returns. The Trust

increased oil equivalent production by eight percent during 1998 and replaced 101 percent of production at a net effective cost of \$2.81 per Boe. The Trust's average reserve acquisition cost since inception is among the lowest in the sector.

## ACQUISITIONS AND DIVESTMENTS

Management of the Trust's assets involves both the acquisition and disposition of oil and gas assets to capitalize on opportunities which develop in the market. ARC Resources Ltd. ("ARC Resources") was moderately active on behalf of the Trust during 1998, completing a number of acquisitions as well as several dispositions.

Total acquisitions added 3.5 Mmboe at an average price of \$4.20 per Boe which is well below the industry average acquisition price. The acquired assets were high quality and had an average reserve life index of 16.8 years. Total dispositions resulted in the sale of 2.4 Mmboe at an average price of \$5.97 per Boe. Net acquisitions of \$0.3 million were at an average price of \$0.29 per Boe of reserves and \$1,027 per Boe per day of production. The net acquisitions replaced 29 percent of the Trust's 1998 production and increased the Trust's reserves by two percent and production by approximately three percent.

The acquired assets consisted of incremental interests in the Midale Unit in Saskatchewan as well as additional unit and non-unit interests in the Trust's main core area of Pembina.

## RESERVES

Based upon independent engineering evaluations conducted by Sproule Associates Limited ("Sproule") and Gilbert Laustsen Jung Associates Ltd. ("GLJ") effective December 31, 1998, ARC Resources had proved plus risked probable reserves of 121.9 billion

cubic feet ("Bcf") of natural gas and 35.0 million barrels ("Mmbbl") of crude oil and natural gas liquids. On an oil equivalent basis, reserves at December 31, 1998 were 47.22 Mmbbl which was slightly greater than the 47.19 Mmbbl as at December 31, 1997. Approximately 74 percent of ARC Resources' reserves are crude oil and natural gas liquids and 26 percent are natural gas on a 10:1 barrel of oil equivalent basis.

The following tables summarize reserves of natural gas, crude oil and natural gas liquids as evaluated by Sproule and GLJ. Reserves are company interest before royalties and probable reserves have been risked 50 percent to calculate the established reserves. All estimates of future net cash flow in these tables are calculated without any provision for income taxes, general and administrative costs or management fees but include provisions for future abandonment liabilities.

Reserve Life Index ("RLI") is calculated by dividing the reserves by annual production (either current year annual production or the independent evaluator's forecast of the first year's production). This provides a simplified representation of how many years of reserves remain if production remained constant at that rate. The actual productive life of the reserves is significantly longer than this value due to a declining production rate over time. Due to the impact and timing of acquisition and divestment activity, the following tables use the independent evaluator's forecast of the first year's production in determining RLI, as this results in a more consistent representation of RLI over time.

### Acquisition/Disposition Summary

	Purchase Price (\$ millions)	Risked Reserves (Mboe)	Reserve Purchase Price (\$/Boe)	Production Rate (Boe/d)	Production Purchase Price (\$/Boe/d)	Reserve Life Index (years)
Acquisitions	14.8	3,533	4.20	577	25,734	16.8
Dispositions	(14.5)	(2,435)	5.97	(268)	54,204	24.9
Net acquisitions	0.3	1,098	0.29	309	1,027	9.7

## Reserve Summary and Reserve Life Index

	1998	1997	1996
<b>Crude Oil</b>			
Proved producing (Mbbbl)	20,090	18,554	10,729
Proved non-producing (Mbbbl)	2,677	394	–
Total proved (Mbbbl)	22,767	18,948	10,729
Proved reserve life index (years) <sup>(1)</sup>	12.1	11.3	10.5
Established (Mbbbl) <sup>(2)</sup>	27,896	24,155	14,147
Established reserve life index (years) <sup>(1)</sup>	14.8	14.5	13.9
<b>Natural Gas Liquids</b>			
Proved producing (Mbbbl)	6,066	6,956	6,868
Proved non-producing (Mbbbl)	475	500	819
Total proved (Mbbbl)	6,542	7,459	7,687
Proved reserve life index (years) <sup>(1)</sup>	8.7	8.8	12.0
Established (Mbbbl) <sup>(2)</sup>	7,138	8,218	8,367
Established reserve life index (years) <sup>(1)</sup>	9.5	9.7	13.1
<b>Natural Gas</b>			
Proved producing (Bcf)	83.9	97.9	76.5
Proved non-producing (Bcf)	19.7	29.8	24.0
Total proved (Bcf)	103.6	127.7	100.5
Proved reserve life index (years) <sup>(1)</sup>	7.2	7.4	9.2
Established (Bcf) <sup>(2)</sup>	121.9	148.2	112.0
Established reserve life index (years) <sup>(1)</sup>	8.5	8.6	10.3
<b>Oil Equivalent</b>			
Proved producing (Mbbbl)	34,543	35,299	25,249
Proved non-producing (Mbbbl)	5,121	3,875	3,214
Total proved (Mbbbl)	39,665	39,175	28,463
Proved reserve life index (years) <sup>(1)</sup>	9.8	9.2	10.4
Established (Mbbbl) <sup>(2)</sup>	47,226	47,190	33,710
Established reserve life index (years) <sup>(1)</sup>	11.6	11.1	12.3

(1) RLI calculated using independent evaluator's forecast of production

(2) Established = Proved plus risked probable (risked at 50%)

## Reserves Reconciliation

	Crude Oil (Mbbbl)		Natural Gas (Bcf)		Natural Gas Liquids (Mbbbl)		Total (Mboe)	
	Proved	Risked Probable	Proved	Risked Probable	Proved	Risked Probable	Proved	Risked Probable
Reserves at December 31, 1996	10,729	3,418	100.5	11.5	7,687	680	28,463	5,247
Acquisitions and divestments	7,961	1,552	38.8	10.3	1,104	232	12,943	2,809
Drilling and development	176	13	4.7	0.3	49	5	695	46
Production	(1,334)	–	(14.0)	–	(704)	–	(3,440)	–
Revisions	1,416	224	(2.3)	(1.6)	(677)	(158)	514	(87)
Reserves at December 31, 1997	18,948	5,207	127.7	20.5	7,459	759	39,175	8,015
Acquisitions and divestments <sup>(1)</sup>	2,465	648	(15.1)	(2.7)	(195)	(36)	759	338
Drilling and development	981	844	4.0	1.2	7	(104)	1,388	860
Production	(1,620)	–	(13.8)	–	(737)	–	(3,732)	–
Revisions <sup>(2)</sup>	1,993	(1,570)	0.8	(0.6)	8	(23)	2,080	(1,653)
Reserves at December 31, 1998	22,767	5,129	103.6	18.4	6,542	596	39,665	7,560

(1) As evaluated by GLJ/Sproule at the time of the acquisition/divestment

(2) Revisions and production adjustment

## Present Value of Reserves

(\$ thousands before income taxes)	1998			1997			1996		
	10%	12%	15%	10%	12%	15%	10%	12%	15%
Discount factor									
Proved producing	<b>209,733</b>	<b>193,488</b>	<b>173,600</b>	258,290	236,639	210,767	192,352	173,207	151,036
Proved non-producing	<b>29,643</b>	<b>26,330</b>	<b>22,295</b>	27,670	24,945	21,523	24,921	22,389	19,285
Total proved	<b>239,376</b>	<b>219,818</b>	<b>195,895</b>	285,960	261,584	232,290	217,273	195,590	170,321
Risked probable	<b>38,977</b>	<b>33,711</b>	<b>27,627</b>	34,063	28,656	22,845	21,999	18,068	14,156
Established	<b>278,353</b>	<b>253,529</b>	<b>223,522</b>	320,024	290,240	255,136	239,272	213,658	184,478

## Net Asset Value

	December 31, 1998		December 31, 1997		December 31, 1996	
(\$ thousands, except per unit)	10%	12%	10%	12%	10%	12%
Value of established oil and gas reserves	<b>278,353</b>	<b>253,529</b>	320,024	290,240	239,272	213,658
Add: Undeveloped lands	<b>2,655</b>	<b>2,655</b>	1,500	1,500	1,800	1,800
Working capital	<b>(1,688)</b>	<b>(1,688)</b>	4,647	4,647	1,647	1,647
Reclamation fund	<b>4,504</b>	<b>4,504</b>	3,016	3,016	908	908
Deduct: Debt	<b>(72,499)</b>	<b>(72,499)</b>	(65,955)	(65,955)	(37,998)	(37,998)
Net asset value	<b>211,325</b>	<b>186,501</b>	262,232	233,448	205,629	180,015
Units outstanding (thousands)	<b>25,604</b>	<b>25,604</b>	25,604	25,604	18,000	18,000
Per unit	<b>\$8.25</b>	<b>\$7.28</b>	\$10.24	\$9.12	\$11.42	\$10.00

The declines in net asset value are directly related to the reduced price forecasts detailed below. The 1998 industry consensus pricing assumptions for WTI Crude Oil have declined by a range of approximately \$6.00 per Bbl in the early years to \$13.00 per Bbl in later years.

## Pricing Assumptions – Industry Consensus<sup>(1)</sup>

	WTI Crude Oil (\$ US/Bbl)			Edmonton Crude Oil <sup>(2)</sup> (\$ Cdn/Bbl)			Natural Gas <sup>(3)</sup> (\$ Cdn/MmBtu)		
Year	1998	1997	1996	1998	1997	1996	1998	1997	1996
1997	–	–	20.00	–	–	26.58	–	–	1.63
1998	–	20.31	20.39	–	26.71	26.85	–	1.83	1.77
1999	<b>14.67</b>	20.85	21.27	<b>21.06</b>	27.15	27.77	<b>2.25</b>	1.97	2.06
2000	<b>16.61</b>	21.44	22.18	<b>23.07</b>	27.79	29.00	<b>2.28</b>	2.11	2.17
2001	<b>18.57</b>	22.06	23.13	<b>24.98</b>	28.60	30.28	<b>2.31</b>	2.21	2.30
2002	<b>20.05</b>	22.72	24.12	<b>26.37</b>	29.41	31.61	<b>2.37</b>	2.31	2.42
2003	<b>20.69</b>	23.38	25.16	<b>27.18</b>	30.26	33.01	<b>2.45</b>	2.42	2.56
2004	<b>21.13</b>	24.09	26.23	<b>27.70</b>	31.10	34.46	<b>2.53</b>	2.52	2.70
2005	<b>21.57</b>	24.83	27.36	<b>28.25</b>	32.10	35.98	<b>2.61</b>	2.64	2.84
2006	<b>22.01</b>	25.61	28.53	<b>28.86</b>	33.08	37.56	<b>2.66</b>	2.73	2.94
2007	<b>22.45</b>	26.39	29.75	<b>29.47</b>	34.13	39.21	<b>2.72</b>	2.82	3.05
2008	<b>22.85</b>	27.22	31.03	<b>30.07</b>	35.22	40.93	<b>2.78</b>	2.92	3.15
2009	<b>23.34</b>	28.08	32.26	<b>30.67</b>	36.38	42.73	<b>2.84</b>	3.03	3.26
2010	<b>23.82</b>	28.95	33.75	<b>31.25</b>	37.55	44.60	<b>2.89</b>	3.13	3.37
2011	<b>24.32</b>	29.86	34.76	<b>31.86</b>	38.75	45.94	<b>2.96</b>	3.24	3.47
2012	<b>24.81</b>	30.78	35.81	<b>32.47</b>	40.00	47.32	<b>3.01</b>	3.32	3.58
2013	<b>25.31</b>	31.73	36.88	<b>33.13</b>	41.25	48.74	<b>3.07</b>	3.42	3.68
2014	<b>25.81</b>	32.73	38.00	<b>33.84</b>	42.58	50.20	<b>3.12</b>	3.54	3.79
2015	<b>26.31</b>	33.16	39.13	<b>34.54</b>	43.13	51.70	<b>3.18</b>	3.59	3.91
Thereafter	<b>1.3%/yr</b>	1.3%/yr	3%/yr	<b>1.3%/yr</b>	1.3%/yr	3%/yr	<b>1.3%/yr</b>	1.3%/yr	3%/yr

(1) Average of GLJ, Sproule and McDaniel & Associates Consultants Ltd. then current price forecasts

(2) Edmonton Refinery Postings for 40° API, 0.4 percent sulphur content crude

(3) Average Alberta plantgate price

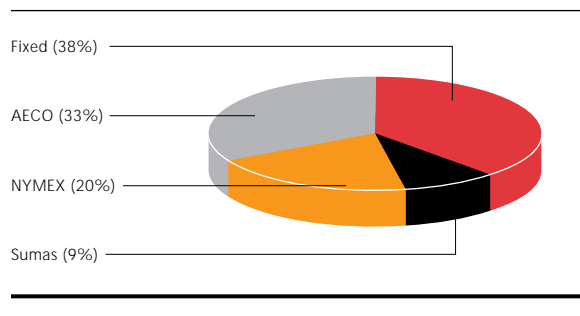
## MARKETING

### Natural Gas

During 1998, ARC Resources continued its marketing strategy to diversify its sales and transportation portfolio and increase the level of direct control over the marketing of its natural gas production. The diversity provides the combination of control and risk-management required to maximize production netbacks.

The average natural gas price received during 1998 was \$1.93 per Mcf as compared to \$1.82 for 1997. This price was achieved with a portfolio mix that on average through the year received fixed pricing for 38 percent of total production, AECO pricing for 33 percent, NYMEX pricing for 20 percent and Sumas pricing for the remaining nine percent of production.

### Natural Gas Portfolio



To manage natural gas price volatility and to stabilize the revenue stream, the natural gas portfolio is directed towards maintaining:

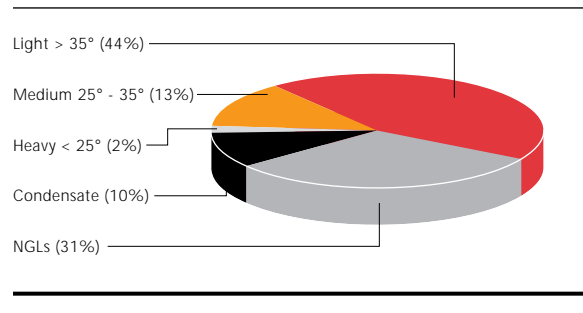
1. a balanced exposure to both U.S., Canadian and fixed price markets;
2. market-sensitive and hedgable pricing terms and contract flexibility; and
3. a high utilization of contracted pipeline and processing capacity.

During 1998, ARC Resources selectively entered into several short (one year) and mid-term (two to three year) fixed price natural gas contracts, which in aggregate outperformed the market indices for the corresponding period.

### Crude Oil and Natural Gas Liquids

Liquids production in 1998 was comprised of 44 percent light gravity (>35° API) oil, 13 percent medium gravity (25° to 35° API) oil, 10 percent condensate and 31 percent natural gas liquids. Heavier gravity (<25° API) crude oil accounted for only two percent of production.

### Liquid Sales Volumes



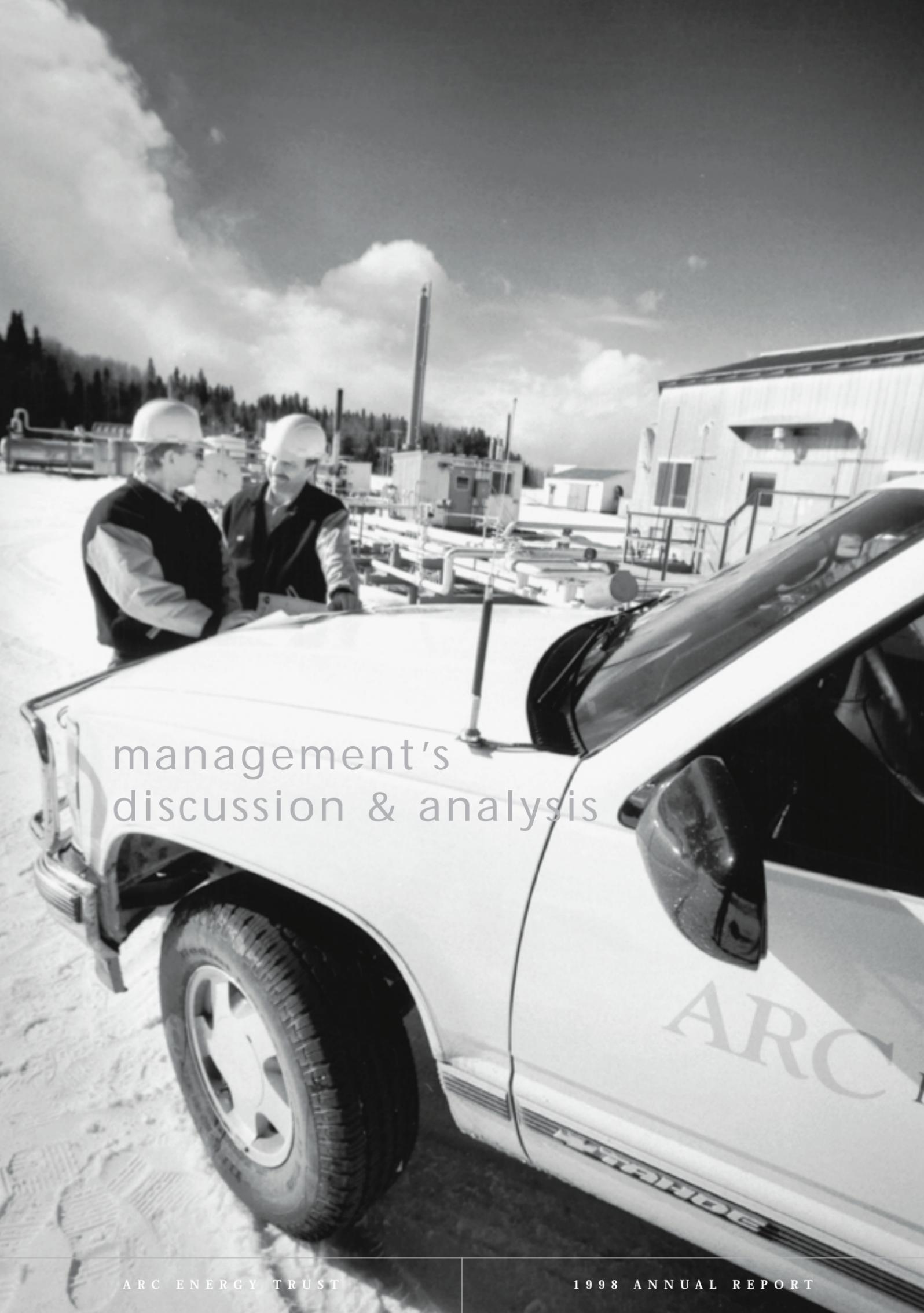
During 1998, average sales prices were \$18.99 per Bbl for oil and \$13.17 per Bbl for natural gas liquids; these prices compare to 1997 prices of \$26.35 per Bbl for oil and \$18.27 per Bbl for natural gas liquids. Crude oil is sold under 30-day evergreen contracts while natural gas liquids are sold under annual arrangements. Industry pricing benchmarks for crude oil and natural gas liquids are continuously monitored to ensure optimal netbacks.

ARC Resources has not entered into any long-term contractual arrangements for any of its crude oil or natural gas liquids production.

## ENVIRONMENT AND SAFETY

ARC Resources is firmly committed to conducting its operations in a safe and environmentally responsible manner. Management, staff and contractors are responsible for ensuring that operations are conducted in accordance with all current environmental and occupational health and safety laws and regulations and *ARC Resources' Operations Safety and Environment Policies and Guidelines*. During 1998, all ARC Resources' personnel conducted safe operations with no lost-time accidents.

A reclamation fund (the "Fund") has been established to ensure that the necessary funds are available for future reclamation and abandonment of all wells, plants and facilities. Total funding during the year net of actual abandonment expenditures amounted to \$1.5 million, increasing the balance in the Fund at December 31, 1998 to \$4.5 million. ARC Resources has a continuing program of well-site abandonment, cleanup and restoration to reduce future environmental liabilities.



management's  
discussion & analysis

## MANAGEMENT'S DISCUSSION AND ANALYSIS

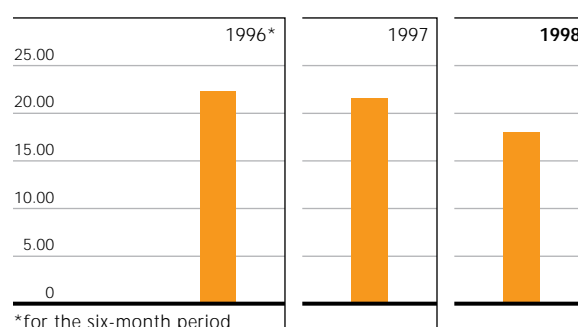
### Highlights

ARC Energy Trust's (the "Trust") 1998 financial results were significantly impacted by weak oil prices which were at a 21-year low. The Manager of the Trust remained focused on all of the key factors which are under its control. Accordingly, production volumes, operating costs and general and administrative costs were all in line with expectations. Production volumes were eight percent above 1997 levels and operating costs at \$5.04 per Boe were two percent lower than the 1997 level of \$5.16 per Boe. Combined operating costs, general and administrative expenses and management fees were \$6.15 per Boe versus \$6.24 per Boe in 1997. These costs remain among the lowest for all conventional oil and gas royalty trusts.

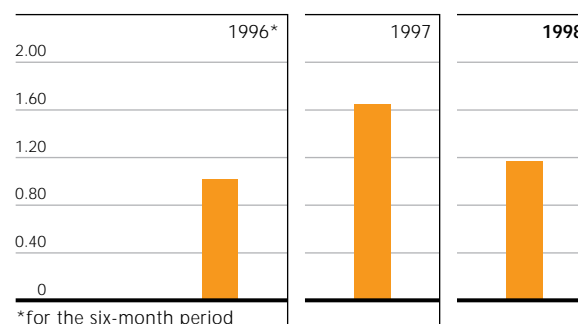
The Trust incurred a net loss of \$14.1 million for the year which included the impact of a writedown in the book value of the Trust's assets by \$14.7 million (six percent). Earnings prior to the writedown fell to \$0.6 million in 1998 from \$9.2 million in 1997 which is entirely attributable to the decline in oil prices. The low oil price in 1998 (especially the fourth quarter average price for WTI of \$12.83 US per Bbl) and continuing low oil prices in 1999 were the main factors in the writedown of the carrying value of the Trust's assets.

The Trust's reserve life index at year-end 1998 was 11.6 years. The actual productive life of the Trust's wells varies from property to property with a typical productive life ranging from 20 to 50 years. The long life nature of the Trust's assets is critical since it ensures the Trust can endure the inevitable commodity price cycles and participate fully in the expected recovery in the price of oil.

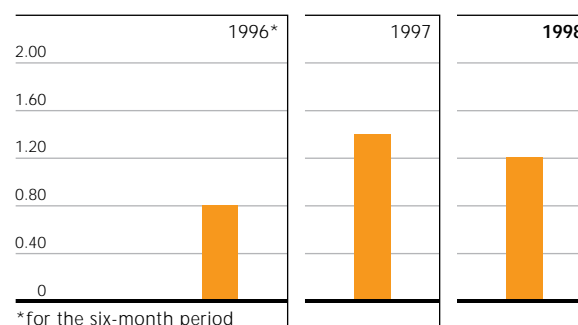
Sales Price (\$/Boe)



Cash Flow (\$/unit)



Distributions (\$/unit)



The Trust's diverse, high-quality property mix contributed to reserve additions which replaced 72 percent of 1998 production through drilling programs in a number of areas including:

1. company-operated (100 percent working interest) oil development program at Midale Non-Unit;
2. infill drilling in the Midale Unit;
3. a gas development program at Minnehik Buck Lake;
4. infill drilling program at House Mountain Unit No. 1; and
5. a step-out oil development drilling program in the Meekwap Unit.

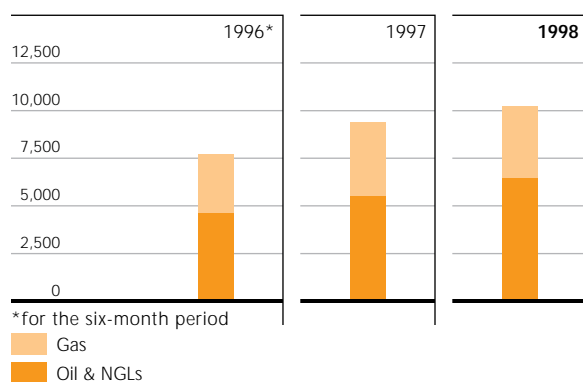
The Trust's net acquisition and divestment activity during 1998 also replaced 29 percent of 1998 production for total reserve additions replacing 101 percent of 1998 production.

The Trust implemented a distribution stabilization program in 1998 whereby a portion of the proceeds of dispositions of certain non-core assets were distributed to unitholders, allowing the Trust to maintain distributions at \$0.10 per month through the year. Total distributions in 1998 were \$1.20 per unit of which 90 percent were tax deferred. Total distributions since inception of the Trust in July 1996 exceeded \$78 million at December 31, 1998 or \$3.41 per unit. This has resulted in the Trust being a top quartile performer in terms of total returns to unitholders among all conventional oil and gas royalty trusts.

### Production

Production volumes for 1998 averaged 10,225 Boe per day up eight percent from the 1997 average of 9,425 Boe per day. This increase was the result of

**Production (Boe/d)**



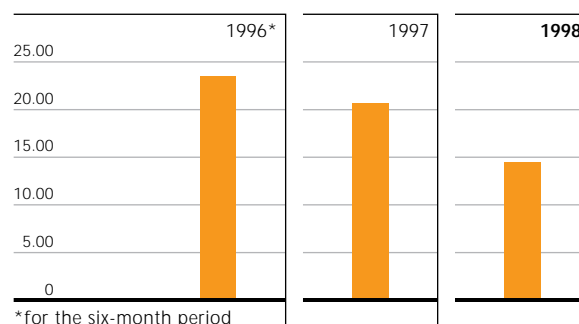
acquisitions completed in the second half of 1997 as well as ongoing development activities on the Trust's properties. Crude oil and natural gas liquids production as a percentage of total production increased to 63 percent in 1998 from 59 percent in 1997.

The Trust's two core areas, Pembina and Caroline, accounted for 39 percent of total production. Production at Pembina increased 27 percent to 2,441 Bbl per day up from 1,923 Bbl per day in 1997. A major planned turnaround at Caroline in June 1998 reduced production rates. However, actual 1998 Caroline production averaged 1,442 Boe per day which is within one percent of 1997 production of 1,475 Boe per day.

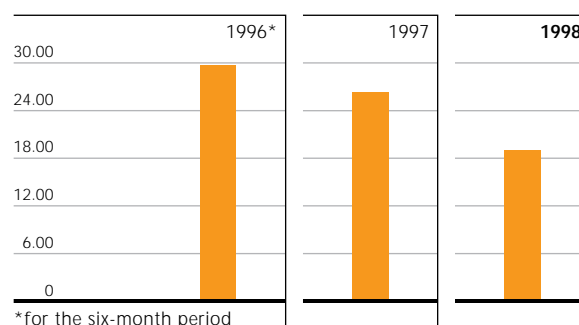
### Prices

The Trust's average oil prices declined 28 percent in 1998 as compared to 1997 average prices. In US dollar terms, the benchmark WTI averaged \$14.40 US per Bbl which was well below the normal trading range over the past decade. A combination of factors including the economic downturn in Asia which reduced the demand for crude oil, several consecutive warm winters in North America and the resumption

**West Texas Intermediate (\$ US/Bbl)**



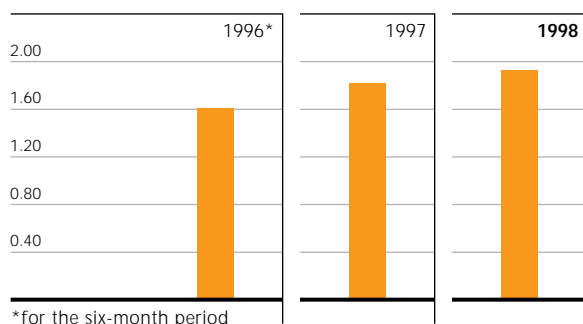
**Oil Sales Price (\$ Cdn/Bbl)**



of oil exports from Iraq resulted in the current excess inventory of crude oil and refined products. We believe economic forces are already in motion which will result in the decline of this inventory and the return of oil prices to the normal range of \$16.00 US to \$20.00 US per Bbl either late in 1999 or early in the year 2000. Concerted action by OPEC to reduce production would accelerate this timeline for price recovery.

Conversely, gas prices have been strong, reflecting pipeline expansions that have occurred which allow improved access for Canadian gas to US markets. The Trust's 1998 average gas price increased by six percent over 1997 to \$1.93 per Mcf at the wellhead.

#### Gas Sales Price (\$ Cdn/Mcf)



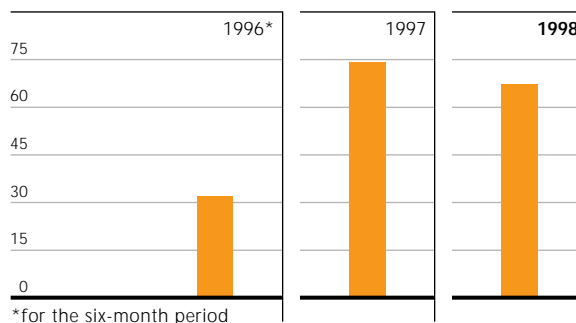
The decline in the Canadian dollar versus the US dollar in 1998 from a \$0.70 US to \$0.65 US range had a positive impact on both the Canadian oil and natural gas product prices. As virtually all of our supplies are purchased from Canadian suppliers, the decline in the Canadian dollar has not increased our operating and capital costs.

The Trust has not entered into any financial hedges in respect of commodities or currency, although hedging alternatives and opportunities are periodically reviewed.

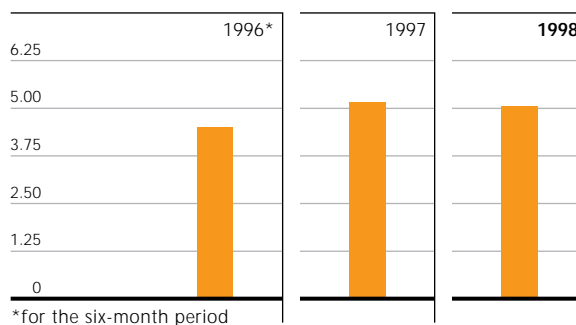
#### Revenue and Cash Flow

1998 revenues decreased to \$67.1 million compared to \$74.1 million in 1997 with the 28 percent decline in oil prices more than offsetting higher production and natural gas prices. Royalties decreased to 14.3 percent of revenues from 16.5 percent in 1997, due primarily to a larger Alberta Royalty Tax Credit ("ARTC") claim arising from the acquisition of properties eligible for ARTC and lower oil royalty rates. Operating costs in 1998 totalled \$18.8 million, compared to \$17.8 million

#### Revenue (\$ millions)



#### Operating Costs (\$/Boe)



in 1997. At \$5.04 per Boe, 1998 operating costs are consistent with industry average operating costs and were two percent lower than 1997 operating costs of \$5.16 per Boe.

#### Netbacks

Operating netbacks of \$10.38 per Boe were realized in 1998 which compares to \$12.82 per Boe in 1997.

Netbacks declined 33 percent on oil production to \$10.25 per Boe with oil prices declining 28 percent. Oil operating costs remained constant between 1997 and 1998 with the 21 percent higher oil production volumes contributing to the per unit decline in oil operating costs.

Natural gas liquids prices declined 28 percent in 1998 in line with the decline in oil prices. NGL netbacks declined to \$7.13 per Boe with operating costs up modestly by 14 percent in 1998.

Natural gas netbacks increased 15 percent to \$1.23 per Mcf with higher gas prices in 1998 over 1997. The percentage of gas production on properties eligible for ARTC increased in 1998, resulting in lower royalties.

Operating netbacks in 1998 over 1997 declined for oil and NGLs and increased for natural gas as shown below:

(\$/Bbl)	1998	1997	1996
Selling price	<b>17.99</b>	21.54	22.31
Royalties	<b>(2.57)</b>	(3.56)	(3.61)
Operating costs	<b>(5.04)</b>	(5.16)	(4.49)
Netback	<b>10.38</b>	12.82	14.21

#### Netbacks by Product

Oil (\$/Bbl)	1998	1997	1996
Selling price	<b>18.99</b>	26.35	29.76
Royalties	<b>(2.17)</b>	(3.37)	(4.89)
Operating costs	<b>(6.57)</b>	(7.69)	(5.81)
Netback	<b>10.25</b>	15.29	19.06

NGLs (\$/Bbl)	1998	1997	1996
Selling price	<b>13.17</b>	18.27	20.31
Royalties	<b>(2.73)</b>	(3.66)	(4.50)
Operating costs	<b>(3.31)</b>	(2.91)	(4.37)
Netback	<b>7.13</b>	11.70	11.44

Natural Gas (\$/Mcf)	1998	1997	1996
Selling price	<b>1.93</b>	1.82	1.61
Royalties	<b>(0.31)</b>	(0.36)	(0.18)
Operating costs	<b>(0.39)</b>	(0.39)	(0.32)
Netback	<b>1.23</b>	1.07	1.11

#### General and Administrative Expenses

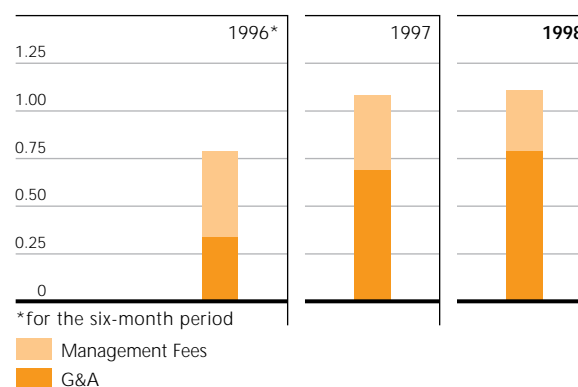
General and administrative expenses, after deduction of the residual one percent royalty reimbursement, increased in 1998 to \$0.79 per Boe from \$0.69 per Boe in 1997 due to additional technical staff being hired to enhance the production and value of properties owned by the Trust. No amounts were capitalized for accounting purposes in respect of general and administrative expenses in the financial statements.

(\$ thousands, except per Boe amounts)	1998	1997	1996
General and administrative expenses	<b>3,246</b>	2,735	652
Residual 1% of income retained by the Trust	<b>(300)</b>	(377)	(184)
Net general and administrative expenses	<b>2,946</b>	2,358	468
Per Boe	<b>0.79</b>	0.69	0.34

#### Management Fees

ARC Financial Corporation (the "Manager"), manager of the Trust, receives a management fee of three percent of net operating revenue which equalled \$1.2 million or \$0.32 per Boe in 1998 bringing the total general and administrative expenses and management fee costs for 1998 to \$1.11 per Boe which compares to \$1.08 in 1997. In 1997, management fees were \$1.4 million or \$0.39 per Boe.

#### G&A and Management Fees (\$/Boe)



#### Interest Expense

Interest expense increased to \$4.1 million in 1998 from \$2.1 million in 1997 with average debt balances increasing year over year. Interest expense was minimized over the course of the year by the issuance of bankers' acceptances which were issued at a discount to the prevailing bank prime interest rates at the time.

#### Taxes

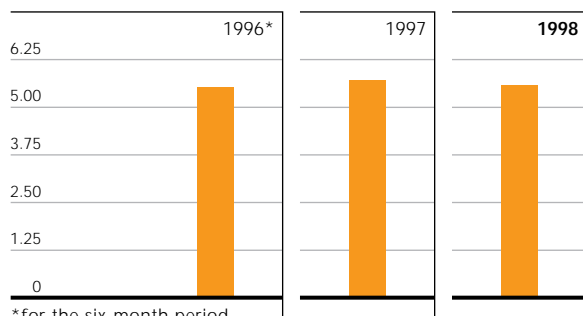
Capital taxes, paid by ARC Resources based on debt and equity levels at the end of the year, equalled \$150,000 in 1998 versus \$137,000 in 1997.

#### Depletion, Depreciation and

#### Future Site Reclamation Expenses

The 1998 and 1997 depletion and depreciation rates were \$5.58 and \$5.70 per Boe, respectively, based on a 6:1 energy equivalent factor. The calculation of the 1998 rate includes an estimated \$30 million for future development costs of proved undeveloped reserves and excluded \$3.2 million for future net realizable salvage value of existing production facilities and \$2.6 million for undeveloped land. The provision for future site

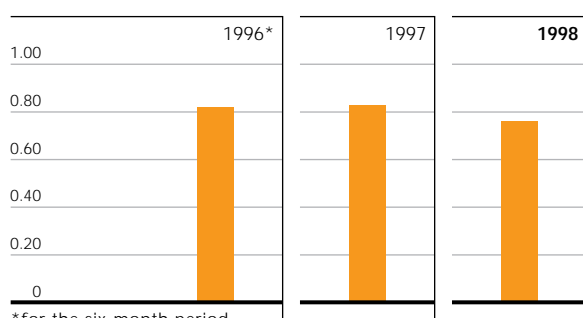
### Depletion, Depreciation and Amortization (\$/Boe)



\*for the six-month period

(based upon a 6:1 energy equivalent factor)

### Reclamation and Abandonment (\$/Boe)



\*for the six-month period

(based upon a 6:1 energy equivalent factor)

reclamation and abandonment equalled \$0.76 per Boe in 1998 compared to \$0.83 per Boe in 1997. A ceiling test writedown of \$14.7 million was charged to earnings as additional depletion, depreciation and amortization in 1998. The ceiling test estimated future net revenues over the Trust's reserves using constant 1998 average prices received by the Trust of \$18.99 per Bbl for oil, \$13.17 per Bbl for natural gas liquids and \$1.93 per Mcf for natural gas, net of all future costs of production, abandonment, general and administrative, management fees, interest expense and taxes.

### Capital Expenditures

ARC Resources completed a number of minor acquisitions and divestments in 1998 which increased reserves and enhanced our asset base. Also, in 1998, development drilling occurred on a number of properties to maintain or increase production. Plant expenditures were concentrated in Caroline to increase throughput and processing capacity at the plant. Total reserve replacement costs for 1998 were \$2.81 per Boe. Capital expenditures were also incurred on company operated properties in the Pembina area on battery and flowline improvements which will decrease future operating costs.

(\$ thousands)	1998	1997	1996
Lease rentals and acquisition	593	857	109
Geological and geophysical expenditures	339	74	—
Development drilling	6,967	7,362	116
Plant and facilities	2,636	462	977
Producing property net acquisitions (net of post-closing adjustments)	60	93,962	206,231
Total capital	10,595	102,717	207,433

Capital expenditures were financed by debt and cash flow, thereby reducing cash otherwise available for distribution to unitholders by approximately 10 percent.

### Abandonments

ARC Resources has an interest in approximately 4,936 (467 net) wells at year end. The abandonment of these wells is being incurred on an ongoing basis as required. In 1998, five net wells were abandoned at a cost of \$112,500. In addition, underground storage tanks at Pembina were removed and the site restored. The Trust in conjunction with ARC Resources has established a reclamation fund (the "Fund") into which \$1.5 million was contributed in 1998 bringing the balance in the Fund to \$4.5 million as at December 31, 1998. The Fund is invested in short-term market instruments to provide for future abandonment liabilities. Future contributions to the Fund are currently set at \$1.45 million per year in order to fund the total estimated future abandonment and site reclamation over a 20-year period.

### Equity and Financial Resources

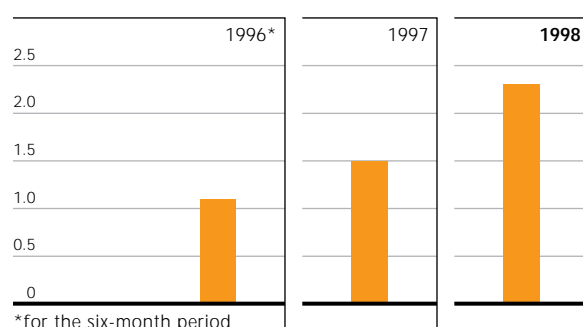
Working capital at December 31, 1998 decreased to a deficit of \$1.7 million after year-end accruals. Bank debt stood at \$72.5 million with \$27.5 million of unutilized line of credit available to ARC Resources based on a total \$100 million credit facility in place with a major Canadian financial institution. As a result of completing the acquisitions of Starcor Energy Royalty Fund ("Starcor") and Orion Energy Trust ("Orion"), the credit facility has been increased to \$190 million with approximately \$157 million drawn at closing on March 12, 1999.

The debt is supported by the Trust's diverse, mature, high-quality, long-life assets.

End-of-year debt to total capitalization was approximately 31 percent and debt/cash flow payout was approximately 2.3 years. Both of these ratios are in line with averages for the oil and gas trust sector.

(\$ thousands, except market price amounts)	1998	1997	1996
Bank debt	<b>72,499</b>	65,955	37,998
Less: Working capital	<b>(1,688)</b>	4,647	1,647
Reclamation fund	<b>4,504</b>	3,016	908
Net debt obligations	<b>69,683</b>	58,292	35,443
Outstanding units	<b>25,604</b>	25,604	18,000
Market price at end of period	<b>\$6.15</b>	\$10.45	\$12.25
Total Trust capitalization	<b>227,148</b>	325,854	255,943
Debt as a percentage of total capitalization	<b>30.7%</b>	17.9%	13.8%

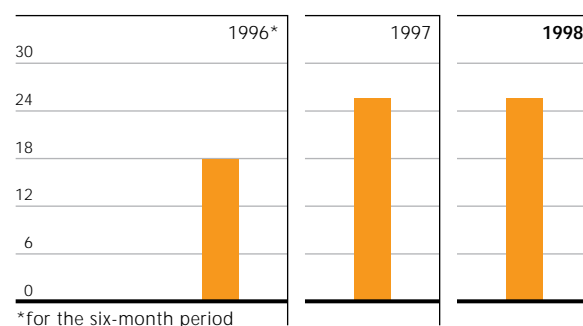
#### Debt as a Multiple of Annual Cash Flow



#### Unitholder Equity

No new equity was raised in 1998 and therefore the number of units outstanding equalled 25,604,000 as at December 31, 1998 and 1997. In the first quarter of 1999, an additional 22 million units were issued in conjunction with the Starcor and Orion acquisitions.

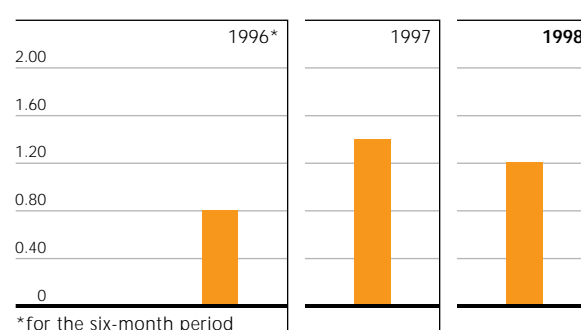
#### Outstanding Units (millions)



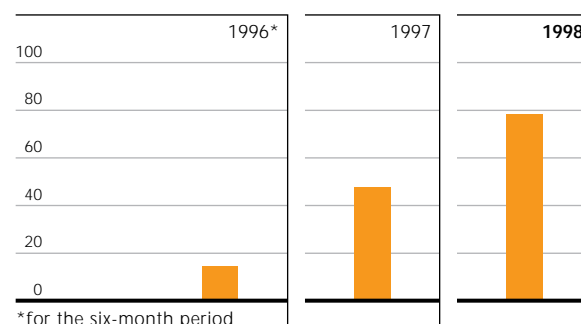
#### Cash Distributions

Cash distributions of \$0.10 per unit per month totalled \$1.20 per unit in 1998 (\$1.40 in 1997) for total cumulative distributions since inception of \$78.5 million (\$3.41 per unit). The Trust changed from quarterly to monthly distributions effective July 1, 1997 and declared a regular distribution of \$0.10 per unit per month which will be subject to change from time to time depending on the business environment. Actual cash available for distribution will be reviewed each quarter and, to the extent excess undistributed cash is available, it will be distributed to unitholders as an extra distribution.

#### Distributions (\$/unit)



#### Cumulative Distributions (\$ millions)



In 1998, the Manager initiated a cash distribution stabilization policy under which \$4.2 million of proceeds from minor property sales were utilized to maintain the distributions at \$0.10 per unit per month.

The managers of royalty trusts have flexibility in the deductions that can be made from unitholder distributions. We have developed policies which have been reviewed by the Board of Directors under which we have deliberately reduced distributions to make reclamation fund contributions and pay for a portion of capital expenditures incurred in the period. In our internal benchmarking process, where we compare our results to other royalty trusts, we found that our policies are the most stringent in the sector, in that unitholder distributions are reduced by a greater amount than other trusts. We continue to believe that our policy of contributing annually to the reclamation fund and deducting up to 10 percent of funds otherwise available for distribution for capital expenditures will be the most prudent policies in the long term, and be more equitable for all unitholders over the life of the Trust.

(\$ thousands, except per unit amounts)	1998	1997	1996
Cash flow from operations	30,040	37,757	18,315
Add:			
Property dispositions, net of discretionary debt repayments and working capital	5,356	952	(1,615)
Less:			
Reclamation fund contributions and actual costs	(1,600)	(2,143)	(954)
Deductions to fund capital expenditures	(3,072)	(3,324)	(1,166)
Royalty distributions	30,724	33,242	14,580
Royalty distributions per unit (\$)	1.20	1.40	0.81

In 1998, 10 percent of distributions were taxable with the remaining 90 percent being tax deferred for Canadian investors holding the units outside a registered pension plan. The taxable portion of distributions was down from 22 percent in 1997 due to the decline in oil prices and resulting decrease to taxable income. Based upon our 1999 budget, which contains an oil price forecast of \$14.67 average for the year, we expect 1999 distributions to again be 10 percent taxable and 90 percent tax deferred.

## Risk Assessment

### Business Risks

The oil and gas business is subject to numerous risks, including, but not limited to, the following: (a) operational risk associated with the production of oil and natural gas; (b) reserve risk in respect to the quantity and quality of recoverable reserves; (c) market risk relating to the availability of transportation systems to move the product to market; (d) commodity risk as oil and natural gas prices fluctuate due to market forces; (e) financial risks such as the \$Canadian/\$US exchange rate, interest rates and debt service obligations; (f) environmental and safety risks associated with well and production facilities; and (g) changing government royalty legislation, income tax laws and incentive programs relating to the oil and gas industry.

The Trust's policies and procedures to mitigate these risks are as follows: (a) acquire mature production to reduce technical risks; (b) acquire long life reserves to ensure relatively stable production and to reduce the economic risks associated with commodity price cycles; (c) maintain a low-cost structure to maximize product netbacks; (d) diversify properties to mitigate individual property risk; (e) seek to maintain a relatively balanced commodity exposure; (f) subject all property acquisitions to rigorous review; (g) closely monitor pricing trends and develop a mix of contractual arrangements for the marketing of products; (h) implement a diversified strategy of managing foreign currency and interest rate transactions; (i) continuously obtain the services of technical experts when required; (j) ensure strong third-party operators for non-operated properties; (k) adhere to the Trust's safety program and keep abreast of current operating practices; (l) carry insurance to cover losses and business interruption; and (m) establish and build cash resources to pay for future abandonment and site restoration costs.

### Year 2000 Plan

The Year 2000 issue is a general term used to refer to certain business implications associated with the arrival of the Year 2000. These implications arise because it has been normal practice for computer hardware and software to use only two digits rather than four to record the year in date fields. On January 1, 2000, when the year is designated as "00", many computer systems could either fail completely or create erroneous data as a result of misinterpretation of the year. The results of failures may range from relatively minor processing inaccuracies to complete system malfunctions. Failures may not only affect hardware and software used to process everyday business information but also the embedded computers that control plant machinery, office equipment and security systems. There can be no assurance that third parties on which the Trust is dependent, including pipeline companies, suppliers, customers, joint venture participants and operators of jointly owned facilities, will all be Year 2000 compliant.

The Manager has undertaken a review of the extent of potential Year 2000 problems for the Trust by identifying information systems issues and the extent to which such systems may require remedial action. The Manager's policy is to acquire known technology rather than developing its own technology in relation to the Trust's business systems. The Manager has been in contact with the suppliers of the critical computer systems to ensure they are Year 2000 compliant. The outcome of this process is the upgrading of one major computer application and the replacement of two computer applications with programs that are Year 2000 compliant. Although the Manager believes that the Trust has minimal risk with the Year 2000 compliance issue within its own administrative and field operations, it is susceptible to third-party vendors including outside operators of facilities.

The Manager has a Year 2000 plan in place to assess and act on issues in order to ensure Year 2000 compliance. The Manager expects internal Year 2000 compliance issues will be identified and addressed by June 1999. As the Manager and the Trust use new technology, minimal costs have been incurred to date and few future costs are foreseen to ensure compliance.

### Outlook

The outlook for 1999 is positive and definitively growth oriented with the Trust acquiring the Starcor and Orion trusts. These business combinations, which will be accounted for as acquisitions by the Trust, will increase production and reserves by approximately 85 and 90 percent, respectively. Total assets will grow to approximately \$509 million. Debt will increase to approximately \$157 million and the market capitalization will exceed \$325 million with units outstanding of approximately 48 million.

The following table sets out supplementary pro forma combined financial information, incorporating the effect of the acquisitions as if they had occurred on December 31, 1998.

(\$ thousands)	
Working capital deficiency	(3,227)
Reclamation fund	5,960
Total assets*	520,873
Long-term debt*	168,318
Unitholders' equity	321,995

\* After December 31, 1998, long-term debt was reduced by \$11.7 million of proceeds from a disposition by Starcor.

These acquisitions have a number of benefits. A major financial benefit is improved access to new capital in the future. A larger trust will be better positioned to attract both individual and institutional investors with a larger, more diverse property base, larger market capitalization and corresponding increased liquidity.

Fiscal 1999 has started with a very challenging business environment with oil prices at extremely low levels. This low price environment has constrained the oil and gas industry as a whole from raising new equity to finance capital programs. With the Starcor and Orion acquisitions, the Trust is in the enviable position of having a number of development drilling programs which will allow for continuing growth. In all properties, cost cutting programs are being re-examined to increase profitability and financial returns to the Trust unitholders.

## MANAGEMENT'S RESPONSIBILITY

ARC Financial Corporation (the "Manager"), as manager of ARC Energy Trust and ARC Resources Ltd., is responsible for the preparation of the accompanying combined financial statements and for the consistency therewith of all other financial and operating data presented in this annual report. The statements have been prepared in accordance with the accounting policies detailed in the accounting policies note to the combined financial statements. In the Manager's opinion the combined financial statements are in accordance with generally accepted accounting principles, have been prepared with 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.

Arthur Andersen LLP, independent auditors appointed by the Trustee, have examined the combined financial statements of the Trust. The Audit Committee, consisting of the independent directors of ARC Resources Ltd., has reviewed these statements with management and the auditors, and has recommended them to the Board of Directors for approval. The Board has approved the combined financial statements of the Trust.

Calgary, Alberta,  
February 8, 1999.

John P. Dielwart (signed)  
President and Director

Steven W. Sinclair (signed)  
Vice-President Finance

## AUDITORS' REPORT

To the Unitholders of ARC Energy Trust:

We have audited the combined balance sheet of ARC Energy Trust as at December 31, 1998 and 1997 and the combined statements of income (loss) and accumulated earnings, royalty distributions and accumulated royalty distributions and changes in financial position 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 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 combined financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 1998 and 1997 and the results of its operations and the changes in its financial position for the years then ended in accordance with generally accepted accounting principles.

Calgary, Alberta,  
February 8, 1999.

Arthur Andersen LLP (signed)  
Chartered Accountants

# ARC ENERGY TRUST

## COMBINED BALANCE SHEET

As at December 31, 1998 and 1997  
(\$ thousands)

	1998	1997
<b>Assets</b>		
Current assets		
Cash	\$ 1,390	\$ 2,983
Accounts receivable	7,747	12,767
	9,137	15,750
Reclamation fund (Note 3)	4,504	3,016
Property, plant and equipment (Notes 2 and 4)	245,374	275,402
<b>Total assets</b>	<b>\$ 259,015</b>	<b>\$ 294,168</b>
<b>Liabilities</b>		
Current liabilities		
Accounts payable and accrued liabilities	\$ 7,535	\$ 8,015
Royalty distributions payable	2,560	2,560
Payable to the Manager (Note 9)	730	528
	10,825	11,103
Long-term debt (Note 5)	72,499	65,955
Future site reclamation and abandonment	8,368	4,970
<b>Total liabilities</b>	<b>91,692</b>	<b>82,028</b>
<b>Unitholders' Equity</b>		
Unitholders' capital (Note 6)	243,689	243,689
Accumulated earnings	2,180	16,273
Accumulated royalty distributions	(78,546)	(47,822)
<b>Total unitholders' equity</b>	<b>167,323</b>	<b>212,140</b>
<b>Total liabilities and unitholders' equity</b>	<b>\$ 259,015</b>	<b>\$ 294,168</b>

Approved on behalf of the Board:

Mac H. Van Wielingen (signed)  
Director

John P. Dielwart (signed)  
Director

## COMBINED STATEMENT OF INCOME (LOSS) AND ACCUMULATED EARNINGS

For the years ended December 31, 1998 and 1997  
(\$ thousands)

	1998	1997
<b>Revenue</b>		
Oil, natural gas, natural gas liquids and sulphur sales	\$ 67,124	\$ 74,103
Royalties	(9,595)	(12,254)
	57,529	61,849
<b>Expenses</b>		
Operating	18,803	17,760
General and administrative (Note 9), net of recoveries	3,246	2,735
Management fee (Note 9)	1,187	1,351
Interest on long-term debt	4,103	2,109
Capital taxes (Note 8)	150	137
Depletion, depreciation and amortization (Note 2)	44,133	28,592
	71,622	52,684
<b>Net income (loss)</b>	<b>(14,093)</b>	<b>9,165</b>
<b>Accumulated earnings, beginning of the year</b>	<b>16,273</b>	<b>7,108</b>
<b>Accumulated earnings, end of the year</b>	<b>\$ 2,180</b>	<b>\$ 16,273</b>

## COMBINED STATEMENT OF CHANGES IN FINANCIAL POSITION

For the years ended December 31, 1998 and 1997  
(\$ thousands)

	1998	1997
<b>Operating activities</b>		
Net income (loss)	\$ (14,093)	\$ 9,165
Add items not involving cash:		
Depletion, depreciation and amortization	44,133	28,592
	30,040	37,757
(Increase) decrease in non-cash working capital accounts	4,742	(8,149)
	34,782	29,608
<b>Financing activities</b>		
Issue of Trust units, net of expenses	–	75,383
Increase in long-term debt, net	6,544	27,957
Royalty distributions	(30,724)	(33,242)
	(24,180)	70,098
<b>Investing activities</b>		
Acquisition of properties, net of dispositions	(60)	(93,962)
Reclamation fund contributions and actual costs incurred	(1,600)	(2,138)
Purchase of capital assets	(10,535)	(8,755)
	(12,195)	(104,855)
<b>Decrease in cash</b>	<b>(1,593)</b>	<b>(5,149)</b>
<b>Cash, beginning of the year</b>	<b>2,983</b>	<b>8,132</b>
<b>Cash, end of the year</b>	<b>\$ 1,390</b>	<b>\$ 2,983</b>

## COMBINED STATEMENT OF ROYALTY DISTRIBUTIONS AND ACCUMULATED ROYALTY DISTRIBUTIONS

For the years ended December 31, 1998 and 1997  
(\$ thousands, except per unit amounts)

	1998	1997
<b>Net income (loss)</b>	<b>\$ (14,093)</b>	<b>\$ 9,165</b>
Depletion, depreciation and amortization	44,133	28,592
<b>Cash from operations</b>	<b>\$ 30,040</b>	<b>\$ 37,757</b>
<b>Cash from operations (99 percent)</b>	<b>\$ 29,740</b>	<b>\$ 37,380</b>
Add (deduct):		
General and administrative expense reimbursement (residual 1 percent)	300	377
Disposition of royalty interests	11,634	10,074
Capital expenditures	(3,072)	(3,324)
Discretionary debt repayment	(11,020)	(6,513)
Reclamation fund contributions and actual reclamation costs incurred	(1,600)	(2,143)
Current period accruals	4,742	(2,609)
<b>Royalty distributions</b>	<b>30,724</b>	<b>33,242</b>
<b>Accumulated royalty distributions, beginning of the year</b>	<b>47,822</b>	<b>14,580</b>
<b>Accumulated royalty distributions, end of the year</b>	<b>\$ 78,546</b>	<b>\$ 47,822</b>
<b>Royalty distributions per unit (Note 7)</b>	<b>\$ 1.20</b>	<b>\$ 1.40</b>

## **NOTES TO THE COMBINED FINANCIAL STATEMENTS**

December 31, 1998 and 1997  
(all tabular amounts in thousands, except per unit amounts)

### **1. Structure of the Trust**

ARC Energy Trust ("the Trust") is a closed-end investment trust formed under the laws of the Province of Alberta pursuant to a trust indenture (the "Trust Indenture") dated May 7, 1996 between the Trust and Montreal Trust Company of Canada (the "Trustee"). The beneficiaries of the Trust, which commenced operations on July 11, 1996, are the holders of the trust units (the "Unitholders"). Operations of the Trust consist of acquiring and holding, as the Trust's principal asset, a royalty in the properties of ARC Resources Ltd. ("ARC Resources").

ARC Resources acquires oil and gas properties and grants a royalty to the Trust. The royalty in producing oil and gas properties acquired from ARC Resources effectively transfers the economic interest in the properties acquired by ARC Resources to the Trust. The royalty constitutes a contractual interest in revenues from the oil and gas properties owned by ARC Resources but does not confer ownership in the underlying resource properties.

### **2. Summary of Accounting Policies**

The Trust's financial statements have been prepared following accounting policies generally accepted in Canada. The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the combined 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 site restoration and abandonment are based on estimates of reserves and future costs. By their nature, these estimates, and those related to the 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.

The following significant accounting policies are presented to assist the reader in evaluating these statements.

### **BASIS OF ACCOUNTING**

The Trust's combined financial statements include the accounts of the Trust and the accounts of ARC Resources. All inter-entity transactions have been eliminated.

### **FINANCIAL INSTRUMENTS**

Financial instruments of the Trust consist mainly of the accounts receivable, reclamation fund investments, accounts payable and accrued liabilities and the long-term debt. As at December 31, 1998 and 1997, there were no significant differences between the carrying values of these amounts and their estimated market values.

### **CREDIT RISK**

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

### **PROPERTY, PLANT AND EQUIPMENT**

The Trust follows the full cost method of accounting. All costs of acquiring oil and natural gas properties and related development costs are capitalized and accumulated in one cost centre. Maintenance and repairs are charged against earnings, and renewals and enhancements which extend the economic life of the property, plant and equipment are capitalized. Gains and losses are not recognized upon disposition of oil and natural gas properties unless such a disposition would alter the rate of depletion by 20% or more.

### **DEPLETION, DEPRECIATION AND AMORTIZATION**

Depletion of petroleum and natural gas properties and depreciation of production equipment, except for major gas plant facilities which are depreciated on a straight-line basis over their estimated useful life, are calculated on the unit-of-production method based on:

- a) total estimated proved developed and undeveloped reserves net of royalties;
- b) total capitalized costs plus estimated future development costs of proved undeveloped reserves less estimated salvage value of production equipment and facilities after the proved reserves are fully produced; and

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

Future site restoration and abandonment provisions are calculated on the unit-of-production method. Actual site restoration costs are charged against the future site restoration and abandonment liability.

#### CEILING TEST

The Trust places a limit on the aggregate cost of property, plant and equipment which may be carried forward for amortization against revenues of future periods (the "ceiling test"). The ceiling test is a cost recovery test whereby the capitalized costs less accumulated depletion, depreciation and site restoration are limited to an amount equal to estimated undiscounted future net revenues from proved reserves less recurring general and administrative expenses, site restoration, management fees, future financing costs and income taxes. As a result of using 1998 average prices received by the Trust of \$18.99 per barrel of oil and of \$1.93 per Mcf of natural gas field prices, a writedown of \$14.7 million was charged to earnings as additional depletion, depreciation and amortization in 1998. Alternatively, if the ceiling test had been calculated using year-end prices of \$16.98 per barrel of oil and \$2.39 per Mcf of natural gas, a writedown of approximately \$28 million would have been charged to earnings in 1998.

#### INCOME TAXES

The *Income Tax Act* (Canada) requires the Trust compute its income or loss for a taxation year as though it were an individual. The taxation year of the Trust is the calendar year. Each year the Trustee has agreed to designate the full amount of taxable income to the Unitholders (less any amount the Trust may want to bring into income to utilize available deductions and loss carryforwards). As such, no accounting for deferred income taxes is provided in these combined financial statements as future tax liabilities will be borne by the Unitholders.

Periodically, current taxes may arise in ARC Resources depending on the timing of income tax deductions and the timing of debt repayments. Should such taxes prove to be unrecoverable, they will be deducted from royalty distributions in accordance with the Royalty Agreement.

### 3. Reclamation Fund

	1998	1997
Opening balance	\$ 3,016	\$ 908
Contributions, net of		
actual expenditures	1,338	2,081
Interest income on fund	150	27
Ending balance	\$ 4,504	\$ 3,016

A reclamation fund was established solely to fund future site restoration and abandonment costs. The Board has approved

contributions over a 20 year period which results in annual contributions of \$1.45 million per year based upon properties owned as at December 31, 1998. Contributions to the reclamation fund have been deducted from cash distributions to the Unitholders. During the year \$112,000 (1997 – \$57,000) of actual expenditures were charged against the Trust.

### 4. Property, Plant and Equipment

	1998	1997
Property, plant and equipment		
at cost	\$ 320,745	\$ 310,150
Accumulated depletion and		
depreciation	(75,371)	(34,748)
Property, plant and equipment, net	\$ 245,374	\$ 275,402

The calculation of 1998 depletion and depreciation included an estimated \$30.0 million (\$18.3 million in 1997) for future development costs of proved undeveloped reserves and excluded \$3.2 million (\$7.8 million in 1997) for future net realizable value of production equipment and facilities and \$2.6 million (\$1.5 million in 1997) for unevaluated petroleum and natural gas properties.

### 5. Long-term Debt

Long-term debt consists of a demand revolving credit facility to a maximum of \$100 million. The lender reviews the credit facility by July 1 each year and determines whether it will extend the revolving period for another year. In the event that the revolving period is not extended the principal becomes repayable over five years in equal quarterly instalments.

The loan bears interest at bank prime (6.75% at December 31, 1998, 6.0% at December 31, 1997) or at the ARC Resources' option, bankers acceptance plus 6/10 of 1%.

The loan is the legal obligation of ARC Resources which has granted security in the form of a floating charge on all lands and an assignment and negative pledge on specific oil and gas properties. The Unitholders have no direct liability to ARC Resources should the properties securing this debt generate insufficient revenue to repay the outstanding balance.

The payment of the principal and interest are allowable deductions in the calculation of the royalty available for distribution to the Unitholders.

### 6. Unitholders' Capital

During 1997, the Trust issued 1.1 million special warrants at \$11.00 per warrant, which were converted into trust units for no additional consideration under a private placement and closed a public issue of 6.5 million trust units at \$10.45 per unit for net proceeds under both offerings of \$75.3 million after issue costs. No trust units were issued in 1998.

## Number of Trust Units

	Number of Trust Units	\$
Initial public offering and balance		
as at December 31, 1996	18,000	\$ 168,306
Private Placement of Special Warrants	1,100	11,466
Public offering	6,500	63,877
Exercise of Directors' options	4	40
Balance as at December 31, 1997		
and December 31, 1998	25,604	\$ 243,689

As at December 31, 1998 and 1997, 921,000 options to purchase trust units were issued and outstanding. The options are exercisable at \$10.00 per unit and expire on July 10, 2001.

## 7. Net Income (Loss) and Cash Flow From Operations per Unit

	1998	1997
Net income (loss) – basic and fully diluted	\$ (0.55)	\$ 0.40
Cash flow from operations <sup>(1)</sup>		
– basic	1.17	1.65
– fully diluted	1.15	1.62

(1) Calculated by adding depletion, depreciation and amortization back to net income (loss) and dividing by the number of trust units.

Fully diluted per unit calculations include imputed interest at 5% per annum on the proceeds from the exercise of trust unit options.

Royalty distributions per unit reflect the amounts paid quarterly up to July 1997 and amounts paid monthly thereafter to unitholders.

## 8. Taxes

ARC Resources is subject to both the large corporations tax and income taxes. No current income taxes were payable in 1998 or 1997 but \$150,000 (1997 – \$137,000) of large corporations tax was paid or payable at year end, charged to operations, and deducted from royalty distributions.

## 9. Related Party Transactions

A management agreement was signed on July 11, 1996 with ARC Financial Corporation ("the Manager") to provide management, advisory and administrative services. The fees payable to the Manager include a fee equal to 3% of net production revenue; and fees of 1.5%, and 1.25% of the purchase price of acquisitions and selling price of dispositions, respectively. In 1998, total acquisition and disposition fees paid to the Manager were \$375,000 (\$1,639,000 in 1997).

During 1998, the Manager was reimbursed \$3,385,000 (\$2,578,000 in 1997) for general and administrative expenses incurred on behalf of the Trust.

During 1997, in connection with the acquisition of oil and gas properties, a company under common control with the Manager sold its 10.5% interest in certain properties to the Trust for

\$3.6 million. The acquisition price to the Trust was based on the same reserve value, and on the same terms and conditions, as agreed to with the independent owner of the remaining working interest in the properties.

## 10. Year 2000 Uncertainty

Most entities depend on computerized systems and therefore are exposed to Year 2000 conversion risk, which, if not properly addressed, could affect an entity's ability to conduct normal business operations. Management is addressing this issue, however, given the nature of this risk, it is not possible to be certain that all aspects of the Year 2000 issue affecting the Trust and those with whom it deals will be fully resolved without adverse impact on the Trust's operations.

## 11. Events Subsequent to December 31, 1998

The Trust has agreed, in separate transactions, to acquire all of the net assets of two royalty trusts unrelated to the Trust, Starcor Energy Royalty Fund ("Starcor") and Orion Energy Trust ("Orion"), with the combined entity to be managed by the Manager.

Under the terms of the agreement between the Trust and Starcor, as amended, the Trust will acquire the net assets of Starcor and each unit of Starcor is to be exchanged for \$1.50 in cash, 0.965 of a trust unit and 0.193 of a warrant to purchase a trust unit at a price of \$7.25 until June 15, 2000.

Under the terms of the agreement between the Trust and Orion, the Trust will acquire the net assets of Orion and each unit of Orion is to be exchanged for 0.875 of a trust unit and 0.175 of a warrant to purchase a trust unit at a price of \$7.25 until June 15, 2000.

The transaction will result in a termination fee payable to the existing manager of Starcor and Orion of \$7.8 million as well as the normal acquisition fee of 1.5% to the Manager. Employee severance costs and lease termination fees totalling \$2.2 million will also be paid by the Trust.

The completion of each proposed acquisition is subject to satisfaction of all regulatory requirements and receiving approval by each of Starcor's and Orion's unitholders for their respective transactions.

If both mergers occur, the transactions will be accounted for in 1999 by the Trust under the purchase method of accounting.

The following table sets out supplementary pro forma combined financial information, incorporating the effect of the potential acquisitions as if they had occurred on December 31, 1998.

	(unaudited)
Working capital deficiency	\$ (3,227)
Reclamation fund	\$ 5,960
Total assets	\$ 520,873
Long-term debt	\$ 168,318
Unitholders' equity	\$ 321,995

## FACTS AND STRUCTURE

ARC Energy Trust is a closed-end investment trust which offers investors indirect ownership in cash-generating assets plus the market liquidity of a publicly-traded security. The royalty trust structure allows net cash flow from oil and gas properties to flow directly to unitholders in a tax-efficient manner. Business risk is minimized through the avoidance of exploration and related high-risk reinvestment activities and through property and commodity diversification.

ARC Resources was formed to acquire oil and natural gas producing properties and to grant a royalty to the Trust. The royalty paid to unitholders consists of 99 percent of the net cash flow generated by the properties acquired by ARC Resources. Net cash flow is production revenue less operating costs, royalties, general and administrative expenses, management fees, interest charges and any taxes payable by ARC Resources. The residual one percent income from ARC Resources also accrues to the benefit of the Trust as it is used by ARC Resources to defray general and administrative costs and management fees.

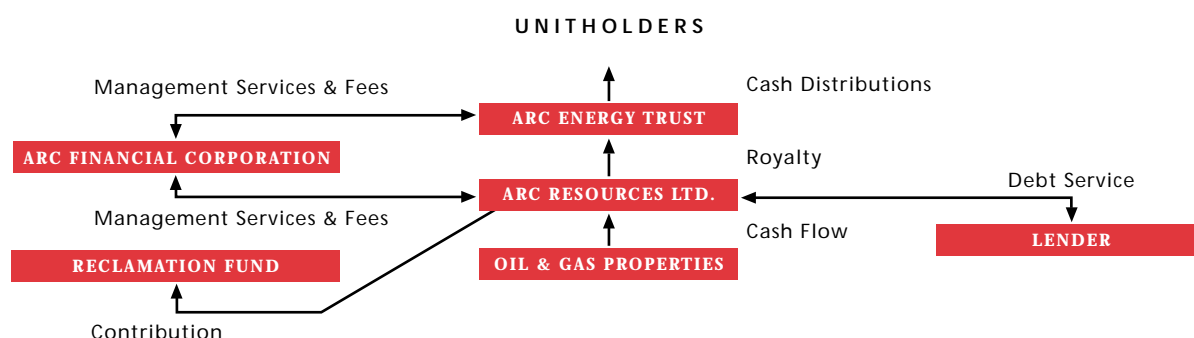
### Manager and Trustee

ARC Financial Corporation is Manager of ARC Energy Trust and ARC Resources Ltd., providing both advisory and management services. Montreal Trust Company of Canada (the "Trustee") is Trustee of the Trust.

### Cash Distributions

Cash distributions of royalty income are paid to unitholders after deductions for debt principal repayments, capital expenditures and reclamation fund contributions. Cash distributions are made on a monthly basis on the 15th of the month to unitholders of record on the last day of the previous month. To be a unitholder of record on the last day of a month, new unitholders should take into account the normal three-day settlement period.

A direct deposit plan has been established for the Trust to provide unitholders who have Canadian bank accounts with a method of receiving cash distributions as a direct deposit into their bank account. In addition, cash distributions can be made by the Trustee in US funds, with the amount of US dollar distributions reflecting the current Canada/US exchange rate.



**Capital Expenditures**

Under the terms of the royalty agreement, capital expenditure deductions will not exceed 10 percent of annual net cash flow from the oil and gas properties; capital requirements in excess of this level will be financed with bank debt or through the issuance of additional Trust units. Capital expenditures are generally directed towards maintaining or improving production from the oil and gas properties and development drilling upon existing proven oil and gas fields. ARC Resources does not initiate any exploratory drilling, nor does it directly participate in exploration activities initiated by other operators.

**Borrowing**

ARC Resources may borrow funds to purchase additional oil and gas properties or for capital expenditures on existing assets. The Trust had a \$100 million revolving credit facility at December 31, 1998. The credit facility permits borrowing at the bank's prime rate or at bankers' acceptance rates plus 60 basis points. ARC Resources intends to repay this debt from time to time through cash flow and the issuance of additional Trust units in conjunction with the financing of new acquisitions.

**Reclamation Fund**

ARC Resources established a reclamation fund to which it currently makes annual contributions of \$1.45 million, less current year site reclamation and abandonment costs. The intent of the fund is to ensure that estimated future environmental and reclamation obligations associated with ARC Resources' properties are funded over 20 years. Contributions to the fund may be adjusted from time to time based on revised assessments of the environmental obligations or as a result of new acquisitions.

**Tax Considerations for ARC Energy Trust**

Under the *Income Tax Act* of Canada, the Trust is entitled to claim various tax deductions such as Canadian Oil and Gas Property Expense, resource allowance and issue expenses. These deductions will be used to shelter most of the Trust's income. Any remaining taxable income is allocated to unitholders on a pro rata basis such that the Trust does not pay income taxes.

**Tax Considerations for Unitholders**

The Trust's 1998 cash distributions were 90 percent tax deferred. Unitholders holding the units outside of a registered pension plan are required to report the remaining 10 percent of 1998 cash distributions as taxable income on their 1998 income tax returns.

At this time, it is anticipated that the majority of 1999 cash distributions will also be tax deferred, with approximately 10 percent expected to be taxable for unitholders.

**Disposition of ARC Energy Trust Units**

The tax deferred or non-taxable portion of cash distributions received by a unitholder is considered a return of capital. The adjusted cost base of a Trust unit is calculated by deducting all tax deferred distributions received by the unitholder from the original cost of the unit. Capital gains or losses relative to this adjusted cost base will be realized by the unitholder holding the units outside of a registered pension plan, upon the actual sale or deemed disposition of the Trust unit.

**Distribution Reinvestment Plan and Cash Investment Program**

Unitholders may elect to participate in a cash distribution reinvestment plan that will automatically reinvest all or part of the distributions from the Trust in additional Trust units. An optional cash investment program is also available to allow cash payments of up to \$3,000 per distribution. Both plans facilitate investment in additional Trust units at prevailing market prices with no brokerage commission or Trust fees.

An application form for this purpose and a brochure detailing the terms of these programs are available from the Trustee in Calgary, Alberta. Unitholders who are interested in these plans should complete the form and return it directly to the Trustee.

**HISTORICAL REVIEW**

(\$ thousands, except per unit amounts)	Year Ended December 31, 1998	Year Ended December 31, 1997	Six Months Ended December 31, 1996
<b>Financial</b>			
Revenue before royalties	67,124	74,103	31,908
Per unit	2.62	3.24	1.77
Cash flow	30,040	37,757	18,315
Per unit	1.17	1.65	1.02
Net income	(14,093)	9,165	7,108
Per unit	(0.55)	0.40	0.39
Cash distributions	30,724	33,242	14,580
Per unit*	1.20	1.40	0.81
Working capital	(1,688)	4,647	1,647
Long-term debt	72,499	65,955	37,998
Unitholders' equity	167,323	212,140	160,834
Weighted average units (thousands)	25,604	22,837	18,000
Units outstanding at year end (thousands)	25,604	25,604	18,000

\* Based on the number of units outstanding at each cash distribution date

**Operating**

Production			
Crude oil (Bbl/d)	4,439	3,656	2,922
Natural gas (Mmc/d)	37.68	38.40	29.47
Natural gas liquids (Bbl/d)	2,018	1,929	1,732
Total (Boe/d)	10,225	9,425	7,600
Average prices			
Crude oil (\$/Bbl)	18.99	26.35	29.76
Natural gas (\$/Mcf)	1.93	1.82	1.61
Natural gas liquids (\$/Bbl)	13.17	18.27	20.31
Oil equivalent (\$/Boe)	17.99	21.54	22.31
Proved plus probable reserves			
Crude oil and NGL (Mbbbl)	35,034	32,373	22,514
Natural gas (Bcf)	121.9	148.2	112.0
Total (Mboe)	47,224	47,190	33,710

	1998	1997	1996
<b>Trust Unit Trading</b>			
Prices (\$)			
High	11.40	13.00	12.85
Low	6.10	10.15	9.90
Close	6.15	10.45	12.25
Average daily volume (thousands)	32	55	98

**QUARTERLY REVIEW**

	1998	1998	1998	1998	1997	1997	1997	1997
(\$ thousands, except per unit amounts)	4Q	3Q	2Q	1Q	4Q	3Q	2Q	1Q
<b>Financial</b>								
Revenue before royalties	16,767	16,362	16,474	17,521	23,056	19,122	15,593	16,332
Per unit	0.65	0.64	0.64	0.68	0.90	0.75	0.71	0.90
Cash flow	7,693	6,294	7,801	8,252	11,593	9,372	7,739	9,053
Per unit	0.30	0.25	0.30	0.32	0.45	0.37	0.35	0.50
Net income	(14,563)	(253)	287	436	3,110	1,589	753	3,713
Per unit	(0.57)	(0.01)	0.01	0.02	0.15	0.06	0.03	0.21
Cash distributions	7,681	7,681	7,681	7,681	9,730	7,680	8,192	7,640
Per unit*	0.30	0.30	0.30	0.30	0.38	0.30	0.32	0.40
Working capital	(1,688)	3,968	8,389	5,382	4,647	5,370	3,080	(1,402)
Long-term debt	72,499	63,633	63,296	69,550	65,955	67,161	26,173	26,308
Unitholders' equity	167,323	189,566	197,501	204,895	212,140	218,720	224,817	168,932
Weighted average units (thousands)	25,604	25,604	25,604	25,604	25,604	25,600	21,957	18,085
Units outstanding at quarter end (thousands)	25,604	25,604	25,604	25,604	25,604	25,600	25,600	19,100

\* Based on the number of units outstanding at each cash distribution date

**Operating**

<b>Production</b>								
Crude oil (Bbl/d)	4,420	4,498	4,472	4,365	4,461	3,961	3,472	2,707
Natural gas (Mmc/d)	34.83	36.18	38.74	41.05	47.60	44.34	32.96	28.42
Natural gas liquids (Bbl/d)	2,085	2,041	1,834	2,113	2,080	2,058	1,797	1,775
Total (Boe/d)	9,988	10,157	10,180	10,583	11,302	10,453	8,564	7,324
<b>Average prices</b>								
Crude oil (\$/Bbl)	18.42	18.61	18.85	20.13	25.00	25.37	26.10	29.41
Natural gas (\$/Mcf)	2.12	1.92	1.88	1.83	1.91	1.62	1.46	2.24
Natural gas liquids (\$/Bbl)	13.16	11.65	13.09	14.75	17.31	17.55	16.84	21.24
Oil equivalent (\$/Boe)	18.25	17.51	17.78	18.40	22.17	19.88	20.01	24.78

	1998	1998	1998	1998	1997	1997	1997	1997
(based on daily closing price)	4Q	3Q	2Q	1Q	4Q	3Q	2Q	1Q

**Trust Unit Trading**

<b>Prices (\$)</b>								
High	8.65	9.25	10.50	11.40	12.95	13.00	12.00	12.30
Low	6.10	7.00	8.85	9.40	10.15	11.95	10.35	10.60
Close	6.15	8.95	9.25	10.25	10.45	13.00	11.95	10.90
Average daily volume (thousands)	35	25	33	35	48	63	61	47

## CORPORATE INFORMATION



**Mac H. Van Wielingen**  
Director, Vice-Chairman  
and Chief Executive  
Officer



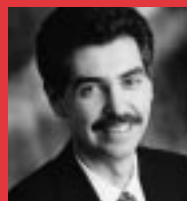
**John P. Dielwart**  
Director and President



**Nancy V. Lever**  
Vice-President, Planning



**Doug J. Bonner**  
Vice-President,  
Engineering



**Steven W. Sinclair**  
Vice-President, Finance



**Myron M. Stadnyk**  
Manager, Operations



**Susan D. Healy**  
Manager, Land

### Directors, Officers and Senior Personnel of ARC Resources Ltd.

Walter DeBoni<sup>(1)(2)</sup>  
Chairman

Mac H. Van Wielingen  
Director, Vice-Chairman and  
Chief Executive Officer

John P. Dielwart  
Director and President

John M. Beddome<sup>(1)(2)</sup>  
Director

Frederic C. Coles<sup>(1)(2)</sup>  
Director

Michael M. Kanovsky<sup>(1)(2)</sup>  
Director

John M. Stewart  
Director

Allan R. Twa  
Secretary

Nancy V. Lever  
Vice-President, Planning

Doug J. Bonner  
Vice-President, Engineering

Steven W. Sinclair  
Vice-President, Finance

Myron M. Stadnyk  
Manager, Operations

Susan D. Healy  
Manager, Land

(1) Member of Audit Committee

(2) Member of Reserve Audit Committee

### Trustee

Montreal Trust Company of Canada  
Corporate Trust Department  
600, 530 - 8th Avenue S.W.  
Calgary, Alberta  
T2P 3S8

### Bankers

Royal Bank of Canada  
Calgary, Alberta

### Auditors

Arthur Andersen LLP  
Calgary, Alberta

### Engineering Consultants

Gilbert Laustsen Jung Associates Ltd.  
Calgary, Alberta

Sproule Associates Limited  
Calgary, Alberta

### Legal Counsel

Burnet, Duckworth & Palmer  
Calgary, Alberta

### Stock Exchange Listing

The Toronto Stock Exchange  
Trading Symbol: AET.UN

### Executive Office

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1-888-272-4900  
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Web Site: [www.arcfinancial.com](http://www.arcfinancial.com)  
E-Mail Address:  
[arc\\_energy\\_trust@arcfinancial.com](mailto:arc_energy_trust@arcfinancial.com)

### For Investor Information Contact:

Steven W. Sinclair  
Vice-President, Finance

### Abbreviations

ARTC	Alberta Royalty Tax Credit
Bbl	barrels
Bcf	billion cubic feet
Boe	barrels of oil equivalent
Mboe	thousand barrels of oil equivalent
Mcf	thousand cubic feet
Mmbbl	million barrels
Mmboe	million barrels of oil equivalent
MmBtu	million British thermal units
Mmcf	million cubic feet
/d	per day
WTI	West Texas Intermediate
Barrel of oil equivalence	10 Mcf = 1 Bbl



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