Crescent Point ENERGY TRUST

strategicallyfocused

Fourth Quarter 2004 Interim Report
Three Months and Year Ended
December 31, 2004

Crescent Point Energy Trust ("Crescent Point" or the "Trust") is pleased to announce its operating and financial results for the fourth quarter and year ended December 31, 2004.

The Trust commenced operations as an oil and gas income trust on September 5, 2003. This interim report compares financial and operating results for the Trust for the fourth quarter and year ended December 31, 2004 with those of its predecessor organization, Crescent Point Energy Ltd. ("the Corporation") and its subsidiaries, for the period January 1 to September 4, 2003 and with the Trust and its subsidiaries for the period September 5 to December 31, 2003.

The term "units" has been used to identify both the Trust units and exchangeable shares of the Trust issued on or after September 5, 2003 as well as the Class A common shares of the Corporation outstanding prior to the conversion on September 5, 2003. All pre-arrangement comparative share numbers have been adjusted for the consolidation of Class A and Class B shares.

FINANCIAL AND OPERATING HIGHLIGHTS

	Three months ended December 31			Year ended December 31		
($000s except Trust units and per Trust unit amounts)	**2004**	**2003 [4]**	**% Change**	**2004**	**2003 [4]**	**% Change**
Financial						
Gross revenue	47,895	23,297	106	155,299	76,792	102
Cash flow from operations	19,875	11,975	66	69,828	36,626	91
Per unit-diluted	0.64	0.62	3	2.49	1.99	25
Net income	24,409	(626)	3,999	30,659	9,134	236
Per unit-diluted	0.79	(0.03)	2,733	1.09	0.50	118
Cash distributions	14,834	8,897	67	53,877	11,697	361
Per unit	0.51	0.51	-	2.04	0.68	200
Payout ratio (percent) [1]	75	74	1	77	32	45
Per unit-diluted (percent) [1]	80	82	(2)	82	34	48
Capital expenditures and corporate acquisitions, net [2]	21,728	20,071	8	195,354	105,600	85
Net debt [3]	95,360	38,417	148	95,360	38,417	148
Trust units outstanding (MM)						
Units	29.3	19.3	52	29.3	19.3	52
Exchangeable Shares	1.3	1.9	(32)	1.3	1.9	(32)
Weighted average Trust units outstanding (MM)						
Basic (2003 - combined A&B shares)	30.6	19.1	60	27.8	18.4	51
Diluted	31.0	19.3	61	28.1	18.4	53

	Three months ended December 31			Year ended December 31		
	2004	2003	% Change	2004	2003	% Change
Operating						
Average daily production						
Crude oil and NGLs (bbl/d)	8,665	5,773	50	6,815	4,536	50
Natural gas (mcf/d)	16,038	9,349	72	16,733	6,738	148
Barrels of oil equivalent (boe/d)	11,338	7,331	55	9,604	5,659	70
Average product prices						
Crude oil and NGLs ($/bbl)	48.22	34.96	38	46.40	37.05	25
Financial instruments – realized losses ($/bbl)	(7.47)	(1.00)	(647)	(7.42)	(1.48)	(401)
	40.75	33.96	20	38.98	35.57	10
Natural gas ($/mcf)	6.41	5.50	17	6.46	6.28	3
Financial instruments - realized losses ($/mcf)	-	(0.03)	100	(0.06)	(0.11)	45
	6.41	5.47	17	6.40	6.17	4
Netback ($/boe)	23.29	20.31	15	23.00	22.46	2
Wells drilled						
Gross	10.0	8.0	25	38.0	27.0	41
Net	8.4	5.5	53	31.8	19.0	67
Success rate (percent)	100	100	-	95	95	-

1) Crescent Point converted to a trust on September 5, 2003 and began paying distributions effective with the month of September 2003. The Trust's payout ratio for the period September 5, 2003 to December 31, 2003 was 76 percent on an overall basis and 84 percent on a per unit-diluted basis.
2) The capital expenditures and corporate acquisitions include the purchase price of corporate acquisitions (including the working capital deficiency acquired). These amounts differ from the amounts allocated to property, plant and equipment as there were allocations made to goodwill, other assets and liabilities.
3) Net debt is debt net of the working capital deficiency excluding the risk management liability.
4) All pre-arrangement comparative share numbers have been adjusted for the consolidation of Class A and Class B shares.

CORPORATE HIGHLIGHTS

- Crescent Point completed a consolidation acquisition of approximately 370 bbl/d of high netback, light oil production in its core Sounding Lake property for a purchase price of $14 million. The acquisition added approximately 1.0 mmboe proved and 1.1 mmboe proved plus probable reserves.

- The Trust's acquisitions and successful drilling program increased average daily production by 55 percent from 7,331 boe/d in the fourth quarter of 2003, to 11,338 boe/d in the fourth quarter of 2004. Crescent Point exceeded its fourth quarter production target by more than 1,000 boe/d mainly due to its new pool discoveries at Manor-Auburnton and better than expected production performance at Little Bow, John Lake, Tatagwa and Sounding Lake.

- Crescent Point increased its reserves from 18.4 mmboe proved and 24.1 mmboe proved plus probable reserves at the end of 2003, to 25.7 mmboe proved and 34.3 mmboe proved plus probable reserves at the end of 2004, as independently evaluated by Gilbert Laustsen Jung Associates Ltd. ("GLJ") under NI 51-101. This represents an increase of 40 percent for proved reserves and 42 percent for proved plus probable reserves. Crescent Point maintained its reserve life index of 6.8 years proved and 9.1 years proved plus probable, based on the Trust's forecasted 2005 production of 10,350 boe/d.

- Crescent Point drilled 10 gross wells and 8.4 net wells in the fourth quarter with a success rate of 100 percent. Two new pool discoveries at Manor-Auburnton contributed to the record production achieved in the fourth quarter of 2004, with over 1,000 bbl/d of initial flush production.

- The Trust's finding, development and acquisition costs for 2004 excluding future development costs were $17.76 per proved boe and $13.99 per proved plus probable boe of reserves. The Trust's rolling four-year average for finding, development and acquisition costs (excluding future development costs) for proved plus probable reserves was $9.38 per boe. The Trust's finding, development and acquisition costs for 2004 including future development costs were $18.29 per proved boe and $14.39 per proved plus probable boe.

- Crescent Point's cash flow from operations increased by 66 percent from $12.0 million or $0.62 per unit-diluted in the fourth quarter of 2003 to $19.9 million or $0.64 per unit-diluted in the fourth quarter of 2004.

- Crescent Point maintained consistent monthly distributions of $0.17 per unit, totaling $0.51 per unit for the fourth quarter of 2004, representing a diluted payout ratio of 80 percent.

- Crescent Point maintained an excellent balance sheet throughout the quarter which positions the Trust for continued growth in 2005 and beyond. The Trust's credit facility was increased to $135 million and syndicated with two additional Canadian chartered banks.

- The Trust has identified more than 130 low risk infill development drilling locations with more than 5,500 boe/d of risked production additions.

OPERATIONS REVIEW

During the fourth quarter of 2004, Crescent Point continued to aggressively implement management's business strategy of creating sustainable, value added growth in reserves, production and cash flow through acquiring, exploiting and developing high quality, long life, light oil and natural gas properties. Crescent Point's successful fourth quarter drilling results and core area consolidation acquisition have further strengthened the Trust's reserves, production and cash flow.

Based on continued development drilling success at Manor, Tatagwa and Glen Ewen in southeast Saskatchewan and four major acquisitions in the third and fourth quarters of 2004, Crescent Point revised upwards the Trust's average daily production guidance from 8,750 boe/d to 9,150 boe/d for the year ended December 31, 2004 and from 8,750 boe/d to 10,150 boe/d for the fourth quarter of 2004.

Crescent Point exceeded both of these production targets with average daily production of 9,604 boe/d in the year ended December 31, 2004, and 11,338 boe/d in the fourth quarter of 2004. These results are primarily attributable to the drilling success achieved in the Manor-Auburnton area in the fourth quarter and better than expected production performance at Little Bow, John Lake, Tatagwa and Sounding Lake.

DRILLING RESULTS

Crescent Point drilled six (4.7 net) oil wells and four (3.7 net) gas wells in the fourth quarter of 2004, achieving an overall success rate of 100 percent.

The following table summarizes the Trust's drilling results for the quarter:

Three months ended December 31, 2004	Gas	Oil	D&A	Service	Standing	Total	Net	% Success
Southeast Saskatchewan	-	6	-	-	-	6	4.7	100
South/Central Alberta	1	-	-	-	-	1	1.0	100
Northeast BC and West Peace River Arch, Alberta	3	-	-	-	-	3	2.7	100
Total	4	6	-	-	-	10	8.4	100

The following table summarizes the Trust's drilling results for the year ended December 31, 2004:

Year ended December 31, 2004	Gas	Oil	D&A	Service	Standing	Total	Net	% Success
Southeast Saskatchewan	-	24	-	3	-	27	21.8	100
South/Central Alberta	1	-	-	-	-	1	1.0	100
Northeast BC and West Peace River Arch, Alberta	8	-	-	-	2	10	9.0	80
Total	9	24	-	3	2	38	31.8	95

Southeast Saskatchewan

In the fourth quarter of 2004, Crescent Point drilled two (2.0 net) successful horizontal step-out wells in the Manor-Auburnton area, which resulted in two new pool discoveries and added over 1,000 bbl/d of initial flush production. Crescent Point estimates the two new Manor-Auburnton pools have over 4.9 mmbbl of original oil in place.

In addition, Crescent Point successfully drilled two (1.0 net) horizontal development wells at the newly acquired Innes property, one (1.0 net) horizontal development well extending the Manor-Wildwood pool, and one (0.7 net) well at the Tatagwa waterflood property.

Due to the success achieved in the southeast Saskatchewan area, facilities are being constructed to accommodate the increased production in the Manor-Auburnton area which will eliminate trucking costs. In addition, battery modifications at the central Tatagwa facility were completed in the fourth quarter providing additional fluid handling capacity and lower operating costs.

South/Central Alberta

Crescent Point drilled one (1.0 net) well successfully in the Second White Specks zone at the Garden Plains area adding 250 mcf/d of interest production.

Crescent Point continued to exploit and optimize existing properties at Little Bow, Cold Lake and John Lake. Following a successful third quarter recompletion at Little Bow, another previously suspended well was reperforated which added 30 bbl/d of initial production. At Cold Lake, a non-operated recompletion was conducted adding a further 250 mcf/d of interest production. Ongoing field compression configuration continues to sustain production and add value to the John Lake property.

The recently acquired Sounding Lake property provided three workover targets adding 30 bbl/d of production. The waterflood at the Sounding Lake Cummings "A" pool continues to outperform, exceeding 2004 budget forecasts. Additional well completions, waterflood optimization and gas conservation projects are planned in 2005.

Northeast British Columbia and West Peace River Arch, Alberta

During the fourth quarter of 2004, the Trust continued its well testing and pressure survey program at Doe, British Columbia. Based on this program, three (2.7 net) successful wells were drilled in the fourth quarter of 2004. Two of these wells have been tied-in in the first quarter of 2005 and the third well will be tied-in after spring break-up in 2005.

RESERVES AND FINDING, DEVELOPMENT AND ACQUISITION COSTS

All reserves quoted are defined under the new National Instrument 51-101 guidelines. Under NI 51-101's revised reserve definitions and evaluation standards, proved plus probable reserves represent a "best estimate".

Crescent Point entered 2004 with total reserves of 18.4 mmboe proved and 24.1 mmboe proved plus probable as independently evaluated by GLJ. As a result of the Trust's activities in 2004, Crescent Point added 7.3 mmboe proved and 10.2 mmboe proved plus probable reserves, net of 3.5 mmboe of production. The Trust exited 2004 with 25.7 mmboe proved and 34.3 mmboe proved plus probable reserves and reserve life indices of 6.8 years proved and 9.1 years proved plus probable, based on the Trust's 2005 production forecast of 10,350 boe/d.

During 2004, oil and gas capital expenditures net of dispositions (including the purchase price of corporate acquisitions) were $192.6 million. Based on reserve additions of 10.8 mmboe proved and 13.8 mmboe proved plus probable, the Trust had finding, development and acquisition costs excluding future development costs for 2004 of $17.76 per proved boe, and $13.99 per proved plus probable boe. The Trust's rolling four-year average for finding, development and acquisition costs (excluding future development costs) for proved plus probable reserves was $9.38 per boe. Crescent Point's finding, development and acquisition costs for 2004 including future development costs of $5.8 million for proved and $5.5 million for proved plus probable reserves were $18.29 per proved boe and $14.39 per proved plus probable boe.

SUMMARY OF RESERVES AND ECONOMICS

As at December 31, 2004 (1)

	RESERVES (2)								BEFORE TAX PRESENT VALUE - ($000)			
	Oil (mbbl)		Gas (mmcf)		NGLs (mbbl)		Total (mboe)		Discount Rate			
Description	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Undiscounted	10%	12%	15%
Proved producing	18,194	15,782	16,177	13,089	159	132	21,049	18,096	361,975	237,777	225,253	209,535
Proved non-producing	3,528	3,034	6,689	5,482	44	34	4,688	3,982	75,982	46,543	42,862	38,135
Total proved	21,722	18,816	22,866	18,571	203	166	25,737	22,078	437,957	284,320	268,115	247,670
Probable	6,898	6,002	9,646	7,761	65	51	8,570	7,346	163,258	77,827	70,174	61,058
Total proved plus probable	28,620	24,818	32,512	26,332	268	217	34,307	29,424	601,215	362,147	338,289	308,728

(1) Based on GLJ's January 1, 2005 escalated price forecast.

(2) "Gross reserves" are the total Trust's working interest share before deduction of any royalties. "Net reserves" are the total Trust's working interest share after deducting royalties.

RESERVE RECONCILIATION
Gross Reserves [1]
For the year ended December 31, 2004

	CRUDE OIL AND NGLs (mbbl)			NATURAL GAS (mmcf)			BOE (mboe)		
	Proved	Probable	Total	Proved	Probable	Total	Proved	Probable	Total
Opening Balance January 1, 2004	15,732	4,857	20,589	16,067	4,719	20,786	18,409	5,644	24,053
Acquired	5,917	2,047	7,964	14,192	5,259	19,451	8,282	2,923	11,205
Disposed	-	-	-	-	-	-	-	-	-
Production	(2,494)	-	(2,494)	(6,124)	-	(6,124)	(3,515)	-	(3,515)
Development	1,680	246	1,926	237	(22)	215	1,721	240	1,961
Technical Revisions	1,090	(187)	903	(1,506)	(310)	(1,816)	840	(237)	603
Closing Balance December 31, 2004	**21,925**	**6,963**	**28,888**	**22,866**	**9,646**	**32,512**	**25,737**	**8,570**	**34,307**

(1) Based on GLJ's January 1, 2005 escalated price forecast. "Gross reserves" are the Trust's working interest share before deduction of any royalties.

FINDING, DEVELOPMENT AND ACQUISITION COSTS
(Excluding future development costs)
For the year ended December 31, 2004

	CAPITAL EXPENDITURES [1][3]		RESERVES [2]				FINDING, DEVELOPMENT AND ACQUISITION COSTS [1]	
			Total Proved		Proved Plus Probable		Proved	Proved Plus Probable
	$000	%	mboe	%	mboe	%	$/Boe	$/Boe
Development and technical revisions	26,653	14	2,561	24	2,564	19	10.41	10.40
Acquisitions, net of dispositions	165,918	86	8,282	76	11,205	81	20.03	14.81
Total	192,571	100	10,843	100	13,769	100	17.76	13.99

(1) Development and technical revisions exclude the change during the most recent financial year in estimated future development costs relating to proved and proved plus probable reserves. These costs would add $5.8 million and $5.5 million, respectively, to the proved and proved plus probable reserves categories. Including these changes, the proved and proved plus probable finding, development and acquisition costs are $18.29 and $14.39 per boe, respectively.
(2) Gross Trust interest reserves are used in this calculation (working interest reserves, before deduction of any royalties).
(3) The capital expenditures includes the purchase price of corporate acquisitions rather than the amounts allocated to property, plant and equipment for accounting purposes.

ACQUISITIONS

On November 25, 2004, Crescent Point closed an acquisition of approximately 370 bbl/d of high netback, light oil production in its core Sounding Lake property for a purchase price of $14 million. The acquisition added 1.0 mmboe proved and 1.1 mmboe proved plus probable reserves (effective November 1, 2004 and utilizing NI 51-101 reserve definitions). Several recompletion and consolidation opportunities have been identified and the potential to expand onsite crude blending operations and increase recoveries in the Sparky formation through waterflood will be assessed. The acquisition is accretive to Crescent Point on a reserve, production and cash flow per unit basis and was funded through existing credit facilities.

FIRST QUARTER 2005 UPDATE

The Trust plans to drill up to 14 gross (11.8 net) wells, two gross (1.4 net) water injection wells and recomplete up to four gross (4.0 net) wells in the first quarter of 2005. To date, two gross (1.4 net) wells have been drilled at Innes, five gross (4.9 net) wells have been drilled at the Manor area, along with one gross (0.7 net) horizontal well and two injection (1.4 net) wells which have been drilled at the Tatagwa Unit achieving an overall success rate of 100 percent and adding initial production of approximately 525 boe/d of interest production. Construction of a pipeline from the two new pool discoveries at the Manor-Auburnton area to the Queensdale facility has commenced and will be completed by the end of March.

OUTLOOK

Crescent Point has the three key attributes of a successful Trust; a proven management group and Board of Directors, an excellent balance sheet and a high quality reserve base.

The Trust has a high quality, predictable production, reserve and cash flow base focused in large oil and gas in place properties. Each of these properties is characterized by high working interests, is operated by Crescent Point and has significant development upside.

During 2004, Crescent Point continued to expand the Trust's development drilling inventory by completing eight acquisitions and adding more than 30 low risk development locations. Crescent Point now has an inventory of more than 130 low risk development locations in its core areas, which will provide for sustainable production and distributions through 2005 and beyond.

Crescent Point continues to lock in commodity price swaps for 2005 through 2007 at attractive crude oil pricing parameters to reduce risk on distribution levels.

The Trust had an excellent start to 2005 with a successful first quarter drilling program and is projecting average daily production for 2005 of 10,350 boe/d.

Crescent Point has maintained an excellent balance sheet with approximately $40 million of unutilized credit lines and projected net debt of less than 1.0 times projected annual cash flow.

In 2005, Crescent Point is projecting to maintain its 10,350 boe/d of production with capital expenditures of approximately $26 million for drilling, land and seismic. Estimates for 2005 are as follows:

Production	
Oil and NGLs (bbl/d)	7,850
Natural gas (mcf/d)	15,000
Total (boe/d)	10,350
Cash flow ($000s)	82,000
Cash flow per unit-diluted ($)	2.55
Cash distributions per unit ($)	2.04
Payout ratio - per unit-diluted (percent)	80
Capital expenditures ($000s) (1)	26,000
Wells drilled, net	29.0
Pricing	
Crude oil - WTI ($US/bbl)	40.00
Crude oil - Corporate ($Cdn/bbl)	50.00
Natural gas - AECO ($US/GJ)	5.20
Natural gas - Corporate ($Cdn/GJ)	6.50
Exchange rate ($Cdn/$US)	0.80

(1) The projection of capital expenditures excludes acquisitions, which are separately considered and evaluated.

ON BEHALF OF THE BOARD OF DIRECTORS

Scott Saxberg
President and Chief Executive Officer
March 11, 2005

RESULTS OF OPERATIONS

Throughout this discussion and analysis, Crescent Point uses the terms cash flow from operations, cash flow per unit, cash flow per unit-diluted, market value and payout. These terms do not have any standardized meaning as prescribed by Canadian generally accepted accounting principles and therefore they may not be comparable with the calculation of similar measures presented by other issuers. These measures have been described and presented in order to provide unitholders and potential investors with additional information regarding the Trust's liquidity and its ability to generate funds to finance its operations. Management utilizes cash flow from operations as a key measure to assess the ability of the Trust to finance operating activities and capital expenditures. All references to cash flow from operations throughout this report are based on cash flow from operating activities before changes in non-cash working capital.

Forward-Looking Information

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

All tabular amounts are in thousands, except per unit and volume amounts. Certain financial information of the year ended December 31, 2003 has been restated for changes in accounting policies and to conform with the current year presentation.

Plan of Arrangement

During 2003, Crescent Point Energy Ltd. ("Crescent Point Energy" or the "Corporation") completed a strategic merger whereby it acquired Tappit Resources Ltd. ("Tappit") and converted into an oil and gas income trust through a Plan of Arrangement (the "Plan"). In addition, the shareholders of Crescent Point Energy and Tappit received shares in StarPoint Energy Ltd. ("StarPoint"), a separate, publicly listed, exploration and production company. The special meeting of the shareholders approving the Plan was held on August 21, 2003. The effective date for the transaction was September 5, 2003.

The Plan involving conversion to the Trust has been accounted for as a continuity of interests. Accordingly, the consolidated financial statements for the three months and year ended December 31, 2004 reflect the financial position, results of operations and cash flows as if the Trust had always carried on the business formerly carried on by Crescent Point Energy. The comparative information for the three months and year ended December 31, 2003 reflects the results of operations and cash flows of Crescent Point Energy and its subsidiaries up to September 5, 2003, and the results of the Trust and its subsidiaries from September 5 to December 31, 2003.

The term "units" has been used to identify both the Trust units and exchangeable shares of the Trust issued on or after September 5, 2003 as well as the Class A common shares of the Corporation outstanding prior to the conversion on September 5, 2003. All pre-arrangement comparative share numbers have been adjusted for the consolidation of Class A and Class B shares.

Production

Average daily production increased by 70 percent to 9,604 boe/d in 2004 compared to 5,659 boe/d in 2003. This increase is comprised of a 50 percent increase in average crude oil and natural gas liquids ("NGLs") production to 6,815 bbl/d in 2004 from 4,536 bbl/d in 2003, and a 148 percent increase in average natural gas production to 16,733 mcf/d in 2004 from 6,738 mcf/d in 2003. The overall increase in production is attributable to the Plan of Arrangement completed with Tappit on September 5, 2003, the acquisition of Capio Petroleum Corporation ("Capio") on January 6, 2004, the four property acquisitions that closed in the third and fourth quarters of 2004, other minor acquisitions in 2004 and the optimization of existing properties.

Daily Production Volumes	Three months ended December 31			Year ended December 31		
	2004	2003	% Change	2004	2003	% Change
Crude oil and NGLs (bbl/d)	8,665	5,773	50	6,815	4,536	50
Natural gas (mcf/d)	16,038	9,349	72	16,733	6,738	148
Total (boe/d)	11,338	7,331	55	9,604	5,659	70
Crude oil and NGLs	76%	79%	(3)	71%	80%	(9)
Natural gas	24%	21%	3	29%	20%	9
Total	100%	100%	-	100%	100%	-

Marketing and Prices

Crescent Point's average realized crude oil and NGL price increased by 25 percent in 2004 to $46.40 per bbl from $37.05 per bbl in 2003. The increase is mainly attributable to the overall increase in commodity prices in the second half of 2004. For comparison, benchmark Edmonton light sweet oil increased by 22 percent in 2004.

The average realized natural gas price increased three percent in 2004 to $6.46 per mcf from $6.28 per mcf in 2003. In comparison, the AECO monthly index decreased two percent to $6.54 per mcf in 2004 from $6.67 per mcf in 2003.

Average Realized Prices [1]	Three months ended December 31			Year ended December 31		
	2004	2003	% Change	2004	2003	% Change
Crude oil and NGLs ($/bbl)	48.22	34.96	38	46.40	37.05	25
Natural gas ($/mcf)	6.41	5.50	17	6.46	6.28	3
Total ($/boe)	45.92	34.54	33	44.18	37.18	19

1) The average realized prices reported are before realized financial instrument losses and transportation charges.

Benchmark Pricing	Three months ended December 31			Year ended December 31		
	2004	2003	% Change	2004	2003	% Change
Edmonton light sweet oil (Cdn$/bbl)	58.04	39.85	46	52.91	43.23	22
WTI crude oil (US$/bbl)	48.31	31.17	55	41.42	31.14	33
AECO natural gas (Cdn$/mcf)	6.52	5.80	12	6.54	6.67	(2)
Exchange rate – Cdn$/US$	0.82	0.76	8	0.77	0.72	7

Financial Instruments and Risk Management

Management of cash flow variability is an integral component of Crescent Point's business strategy. Changing business conditions are monitored regularly and reviewed with the Board of Directors to establish hedging guidelines used by management in carrying out the Trust's strategic hedging program. The risk exposure inherent in movements in the price of crude oil and natural gas, fluctuations in the Cdn/U.S. dollar exchange rate and interest rate movements on long term debt are all proactively managed by Crescent Point through the use of forward sale financial transactions with reputable, financially sound counterparties. The Trust considers these contracts to be an effective means to manage cash flow.

All of the Trust's financial instruments are in Canadian dollars and referenced to WTI and AECO, unless otherwise noted. These financial instruments allow the Trust to hedge both commodity prices and fluctuations in the Cdn/U.S. exchange rate.

The realized losses on financial instruments in 2004 increased to $18,855,000 or $5.36 per boe from $2,722,000 or $1.32 per boe in 2003. This increase is attributable to the increase in market commodity prices, and an increase in the production volumes hedged.

The following is a summary of the realized financial instrument losses:

Risk Management ($000 except per unit and volume amounts)	Three months ended December 31 2004	2003	% Change	Year ended December 31 2004	2003	% Change
Average crude oil volumes hedged (bbl/d)	2,705	2,555	6	3,019	1,900	59
Crude oil realized financial instrument loss	(5,951)	(533)	(1,017)	(18,507)	(2,458)	(653)
per bbl	(7.47)	(1.00)	(647)	(7.42)	(1.48)	(401)
Average natural gas volumes hedged (GJ/d)	1,516	1,337	13	2,638	1,336	97
Natural gas realized financial instrument loss	-	(26)	100	(348)	(264)	(32)
per mcf	-	(0.03)	100	(0.06)	(0.11)	45
Average barrels of oil equivalent hedged (boe/d)	2,944	2,766	6	3,436	2,111	63
Total realized financial instrument loss	(5,951)	(559)	(965)	(18,855)	(2,722)	(593)
per boe	(5.71)	(0.83)	(588)	(5.36)	(1.32)	(306)

The Trust has not designated any of its risk management activities as accounting hedges under AcG-13 and accordingly has marked-to-market its financial instruments. This resulted in an unrealized financial instrument loss of $7,987,000 for the year ended December 31, 2004. The loss was incurred as a result of higher forward oil prices at December 31, 2004 as compared to the Trust's fixed prices.

Crescent Point currently has the following fixed price oil contracts, costless collar oil contracts and interest rate swaps in place:

Fixed Price Oil Contracts	Weighted average volume (bbl/d)	Weighted average price ($Cdn/bbl)	Index
January 1, 2005 to December 31, 2005	3,701	44.18	WTI
January 1, 2006 to December 31, 2006	3,000	51.89	WTI
January 1, 2007 to March 31, 2007	500	56.54	WTI

Costless Collar Oil Contracts	Weighted average volume (bbl/d)	Floor ($Cdn/bbl)	Ceiling ($Cdn/bbl)	Index
July 1, 2005 to December 31, 2005	250	50.00	57.00	WTI
August 1, 2005 to December 31, 2005	250	50.00	60.00	WTI
January 1, 2006 to December 31, 2006	250	52.00	61.65	WTI
January 1, 2006 to December 31, 2006	250	53.00	66.50	WTI

Interest Rate Swaps	Amount ($000)	Interest rate (%)
January 1, 2005 to February 15, 2005	8,000	4.20
January 1, 2005 to March 4, 2005	12,000	4.03

Revenue

Revenue increased 102 percent to $155,299,000 in 2004 from $76,792,000 in 2003. This increase in revenue consists of an 89 percent increase in crude oil and NGL revenue, and a 156 percent increase in natural gas revenue. Revenue increased by 102 percent due to a combination of increased crude oil and natural gas production from the Trust's increased asset base and higher overall commodity prices.

Revenue [1] ($000)	Three months ended December 31 2004	2003	% Change	Year ended December 31 2004	2003	% Change
Crude oil and NGL sales	38,442	18,568	107	115,732	61,350	89
Natural gas sales	9,453	4,729	100	39,567	15,442	156
Gross revenue	47,895	23,297	106	155,299	76,792	102

1) Revenue is reported before transportation charges.

Transportation Expenses

Effective for fiscal years beginning on or after October 1, 2003, the CICA issued Handbook Section 1100 "Generally Accepted Accounting Principles," which defines the sources of GAAP that companies must use and effectively eliminates industry practice as a source of GAAP. In prior years, it had been industry practice for companies to net transportation charges against revenue rather than showing transportation as a separate expense on the income statement. Beginning January 1, 2004, the Trust recorded revenue gross of transportation charges and a transportation expense on the income

statement. Prior periods have been reclassified for comparative purposes. This adjustment has no impact on net income or cash flow.

The transportation expenses in 2004 were $3,968,000 or $1.13 per boe, as compared with transportation expenses of $2,074,000 or $1.00 per boe in 2003. The transportation expense per boe increased due to higher transportation tariffs on the properties acquired in 2004 as compared to the prior year.

Transportation Expenses	Three months ended December 31			Year ended December 31		
($000)	2004	2003	% Change	2004	2003	% Change
Transportation expenses	1,347	674	100	3,968	2,074	91
Per boe	1.29	1.00	29	1.13	1.00	13

Royalty Expenses

Royalties, net of Alberta Royalty Tax Credit ("ARTC") increased to $28,675,000 in 2004 from $14,044,000 in 2003, representing a 104 percent increase. The increase is consistent with the 102 percent increase in gross revenue which resulted from increased production and higher commodity prices. Royalties as a percentage of oil and gas sales remained stable at 18 percent.

Royalties	Three months ended December 31			Year ended December 31		
($000)	2004	2003	% Change	2004	2003	% Change
Total royalties, net of ARTC	8,482	4,384	93	28,675	14,044	104
As a % of oil and gas sales	18%	19%	(1)	18%	18%	-
Per boe	8.13	6.50	25	8.16	6.80	20

Operating Expenses

Operating expenses increased 17 percent to $6.53 per boe in 2004, from $5.60 per boe in 2003. This increase is due to the higher operating costs associated with the three properties acquired in the third quarter of 2004, along with general increases in the industry, offset by optimizations realized on existing properties.

Operating Expenses	Three months ended December 31			Year ended December 31		
($000)	2004	2003	% Change	2004	2003	% Change
Operating expenses	7,827	3,982	97	22,941	11,561	98
Per boe	7.50	5.90	27	6.53	5.60	17

Netbacks

Note: The following discussion of netbacks refers to netbacks after realized financial instrument losses.

In 2004, Crescent Point received an average crude oil and NGL netback of $22.56 per bbl as compared to $22.95 per bbl in 2003, and a natural gas netback of $4.02 per mcf as compared to $3.41 per mcf in 2003. On a total commodity basis, the Trust received a netback of $23.00 per boe in 2004, as compared to $22.46 per boe in 2003. The Trust's overall netback increased by $0.54 per boe or two percent primarily due to higher average realized commodity prices in 2004 as compared to 2003.

Netbacks	Three months ended December 31			Year ended December 31		
	2004	2003	% Change	2004	2003	% Change
Crude oil and NGLs ($/bbl)						
Production (bbl/d)	8,665	5,773	50	6,815	4,536	50
Price	48.22	34.96	38	46.40	37.05	25
Transportation expenses	(1.06)	(0.92)	15	(1.09)	(1.01)	8
Financial instruments – realized loss	(7.47)	(1.00)	(647)	(7.42)	(1.48)	(401)
Royalty expenses, net	(7.91)	(6.55)	21	(8.23)	(6.41)	28
Operating expenses	(8.32)	(5.56)	50	(7.10)	(5.20)	37
Netback	23.46	20.93	12	22.56	22.95	(2)
Natural gas ($/mcf)						
Production (mcf/d)	16,038	9,349	72	16,733	6,738	148
Price	6.41	5.50	17	6.46	6.28	3
Transportation expenses	(0.34)	(0.22)	55	(0.20)	(0.17)	18
Financial instruments – realized loss	-	(0.03)	100	(0.06)	(0.11)	45
Royalty expenses, net	(1.48)	(1.05)	41	(1.33)	(1.39)	(4)
Operating expenses	(0.81)	(1.20)	(33)	(0.85)	(1.20)	(29)
Netback	3.78	3.00	26	4.02	3.41	18
Total ($/boe)						
Production (boe/d)	11,338	7,331	55	9,604	5,659	70
Price	45.92	34.54	33	44.18	37.18	19
Transportation expenses	(1.29)	(1.00)	29	(1.13)	(1.00)	13
Financial instruments – realized loss	(5.71)	(0.83)	(588)	(5.36)	(1.32)	(306)
Royalty expenses, net	(8.13)	(6.50)	25	(8.16)	(6.80)	20
Operating expenses	(7.50)	(5.90)	27	(6.53)	(5.60)	17
Netback	23.29	20.31	15	23.00	22.46	2

General and Administrative Expenses

General and administrative costs incurred by the Trust in 2004 were $5,775,000. Of this, $1,048,000 was capitalized as part of the Trust's drilling and development program, resulting in net administrative expenses of $4,727,000 or $1.34 per boe. This compares with general and administrative costs in 2003 of $3,612,000 of which $1,472,000 was capitalized, resulting in net administrative expenses of $2,140,000 or $1.04 per boe. The 29 percent increase in general and administrative expenses on a per boe basis relates to higher compensation costs in the year as a result of the successful results achieved by the Trust in 2004.

General and Administrative Expenses	Three months ended December 31			Year ended December 31		
($000, except per unit and volume amounts)	2004	2003	% Change	2004	2003	% Change
General and administrative costs	2,472	755	227	5,775	3,612	60
Capitalized	(343)	(108)	218	(1,048)	(1,472)	(29)
General and Administrative Expense	2,129	647	229	4,727	2,140	121
Per boe	2.04	0.96	113	1.34	1.04	29

Interest Expense

Interest expense for the year ended December 31, 2004 amounted to $3,398,000 compared with $1,640,000 in 2003. The increase in interest expense in 2004 is due to the growth of the Trust's overall asset base and corresponding capital structure, which resulted in higher average debt levels in the year.

Interest Expense	Three months ended December 31			Year ended December 31		
($000, except per unit and volume amounts)	2004	2003	% Change	2004	2003	% Change
Interest Expense	1,135	624	82	3,398	1,640	107
Per boe	1.09	0.93	17	0.97	0.79	23

Depletion, Depreciation and Amortization ("DD&A")

Crescent Point's depletion, depreciation and amortization for the year ended December 31, 2004 was $40,157,000 or $11.42 per boe, as compared to depletion of $19,187,000 or $9.29 per boe in 2003. The higher DD&A rate is due to the acquisitions completed in 2004 which carried a higher cost per barrel of reserves as compared to the Trust's existing properties, a trend observed throughout the entire oil and gas industry.

Depletion, Depreciation and Amortization	Three months ended December 31			Year ended December 31		
($000)	2004	2003	% Change	2004	2003	% Change
Depletion, Depreciation and Amortization	12,194	7,546	62	40,157	19,187	109
Per boe	11.69	11.19	4	11.42	9.29	23

Taxes

Capital and other taxes paid or payable were $2,854,000 in 2004 as compared with $770,000 in 2003. The increase in capital taxes is due to higher levels of debt and equity, resulting mainly from the acquisitions completed in 2004.

Future income taxes arise from differences between the accounting and tax bases of the operating companies' assets and liabilities. In the Trust structure, payments are made between the operating companies and the Trust transferring both the income and tax liability to the unitholders. It is therefore expected the Trust will not incur any cash income taxes in the future, and as such the future tax liability recorded on the balance sheet will be recovered through future earnings.

In the first quarter of 2004, the Alberta government passed legislation to reduce provincial corporate income tax rates to 11.5 percent from 12.5 percent, effective April 1, 2004. Crescent Point's expected future income tax rate incorporating this rate reduction is approximately 35 percent as compared to 36 percent in 2003.

The future income tax recovery for 2004 was ($12,014,000), as compared to the future income tax expense for 2003 of $8,101,000. The increase in the future income tax recovery is primarily attributable to the increase in the net income of the mutual fund trust.

Taxes	Three months ended December 31			Year ended December 31		
($000)	2004	2003	% Change	2004	2003	% Change
Capital and other tax expense	1,149	191	502	2,854	770	271
Future income expense (recovery)	(3,370)	4,670	(172)	(12,014)	8,101	(248)

Cash Flow and Net Income

Note - all per unit amounts discussed in this section represent per unit-diluted amounts.

Crescent Point generated cash flow from operations for 2004 of $69,828,000 or $2.49 per unit as compared to $36,626,000 or $1.99 per unit in 2003. Normalizing cash flow in 2003 by excluding $5,215,000 of non-recurring expenses relating to the corporate reorganization results in cash flow of $41,841,000 or $2.27 per unit. The $0.22 per unit increase in the normalized cash flow in 2004 relates to the accretive acquisitions completed in the year, increased production on existing properties and higher corporate netbacks.

Crescent Point's net income for 2004 was $30,659,000 or $1.09 per unit as compared to $9,134,000 or $0.50 per unit in 2003. The increase in net income also relates to a combination of the overall growth in the Trust's asset base resulting in increased production and to higher corporate netbacks.

Cash Flow and Net Income	Three months ended December 31			Year ended December 31		
($000, except per unit amounts)	2004	2003	% Change	2004	2003	% Change
Cash flow from operations	19,875	11,975	66	69,828	36,626	91
Cash flow from operations per unit-diluted	0.64	0.62	3	2.49	1.99	25
Net income	24,409	(626)	3,999	30,659	9,134	236
Net income per unit-diluted	0.79	(0.03)	2,733	1.09	0.50	118

Cash Distributions

Crescent Point's distributions to unitholders are paid monthly and are dependent upon commodity prices, production levels and the amount of capital expenditures to be funded from cash flow. The Trust contributes part of its cash flow towards the capital program to provide for more sustainable distributions in the future. The actual amount of the distributions are at the discretion of the Board of Directors. In the event that commodity prices are higher than anticipated and a cash surplus develops during a quarter, the surplus may be used to increase distributions, reduce debt, and/or increase the capital program.

Cash distributions of $2.04 per Trust unit were declared in 2004. Of this amount, $1.87 per unit was paid in 2004, and $0.17 per unit was paid on January 17, 2005. Cash flow from operations for the period ending December 31, 2004 was $2.49 per unit representing a payout ratio of 82 percent on a per unit-diluted basis (including the exchangeable shares and restricted units). The payout ratio of 82 percent per unit-diluted in 2004 represents a two percent reduction from the September 5, 2003 to December 31, 2003 payout ratio of 84 percent. The payout ratio excluding exchangeable shares and restricted units (which do not receive cash distributions) was 77 percent for 2004, as compared to 75 percent for the period September 5, 2003 to December 31, 2003.

The Trust has maintained monthly distributions of $0.17 per unit since its inception on September 5, 2003, providing total accumulated distributions to unitholders of $2.72 per unit.

Taxation of Cash Distributions

Cash distributions are comprised of a return on capital portion (taxable) and a return of capital portion (tax deferred). For cash distributions received by a Canadian resident, outside of a registered pension or retirement plan in the 2004 taxation year, the breakdown is 71.8 percent taxable with the remaining 28.2 percent being tax deferred.

For 2005, Crescent Point estimates that 75 percent of cash distributions will be taxable, and 25 percent will be a return of capital and used to reduce the unitholder's adjusted cost base. Actual taxable amounts will be dependent on actual distributions paid, commodity prices realized throughout the year and additions to the tax pools resulting from capital spending.

The following is a breakdown of the cash distributions per unit paid or payable by the Trust with respect to the record dates from January 31, 2004 to December 31, 2004 for Canadian tax purposes:

Record Date	Payment Date	Taxable Amount (Box 26 Other Income)	Tax Deferred Amount (Box 42 Return of Capital)	Total Cash Distribution
January 31, 2004	February 16, 2004	$0.12206	$0.04794	$0.17
February 29, 2004	March 15, 2004	$0.12206	$0.04794	$0.17
March 31, 2004	April 15, 2004	$0.12206	$0.04794	$0.17
April 30, 2004	May 17, 2004	$0.12206	$0.04794	$0.17
May 31, 2004	June 15, 2004	$0.12206	$0.04794	$0.17
June 30, 2004	July 15, 2004	$0.12206	$0.04794	$0.17
July 31, 2004	August 16, 2004	$0.12206	$0.04794	$0.17
August 31, 2004	September 15, 2004	$0.12206	$0.04794	$0.17
September 30, 2004	October 15, 2004	$0.12206	$0.04794	$0.17
October 31, 2004	November 15, 2004	$0.12206	$0.04794	$0.17
November 30, 2004	December 15, 2004	$0.12206	$0.04794	$0.17
December 31, 2004	January 17, 2005	$0.12206	$0.04794	$0.17
TOTAL PER UNIT		**$1.46472**	**$0.57528**	**$2.04**

For more details, please visit our website at www.crescentpointenergy.com

Capital Expenditures

In 2004, capital expenditures (net of dispositions) totaled $174,335,000 as compared to $124,464,000 in 2003. The capital expenditures are summarized as follows:

Capital Expenditures (net) [1]	Three months ended December 31			Year ended December 31		
($000)	2004	2003	% Change	2004	2003	% Change
Property acquisitions[2]	14,369	14,700	(2)	145,152	99,675	46
Drilling and development	6,650	7,538	(12)	26,868	22,488	19
Capitalized administration	343	108	218	1,048	1,472	(29)
Other	366	238	54	1,267	829	53
Total	21,728	22,584	(4)	174,335	124,464	40

1) The capital expenditures do not include the amounts recorded to property, plant and equipment in respect of asset retirement obligations.
2) The property acquisitions for the year ended December 31, 2003 are net of the transfer of exploration assets with a net book value of $10,055,000 to StarPoint.

The Trust closed eight acquisitions in 2004. These include Capio Petroleum Corporation for approximately $82,707,000 ($61,688,000 was allocated to property, plant and equipment), three property acquisitions in the Trust's main operating area of southeast Saskatchewan for $64,742,000, a property acquisition at Sounding Lake for $14,189,000 and a property acquisition at Killam for $3,528,000. There were other minor acquisitions and dispositions in 2004 totaling $1,005,000.

The Trust's 2005 capital program excluding acquisitions is budgeted to be approximately $26,000,000. The program is expected to be financed by residual cash flow after distribution payments and the distribution reinvestment programs.

The Trust does not set a budget for acquisitions. The Trust searches for opportunities that align with strategic parameters and evaluates each prospect on a case-by-case basis. The Trust's acquisitions are expected to be financed through bank debt, the distribution reinvestment programs and new equity issuances.

Goodwill

The Trust's goodwill is comprised of $21,171,000 which arose on the 2003 acquisition of Tappit and $36,976,000 which arose on the 2004 acquisition of Capio. The Trust performed a goodwill test as at December 31, 2004 and no impairment of goodwill exists.

Asset Retirement Obligation

Effective January 1, 2004, the Trust retroactively adopted the new accounting standard CICA Handbook section 3110 "Asset Retirement Obligations." Upon adoption, all prior periods have been restated for the change in the accounting policy. At January 1, 2004, this resulted in an increase to the asset retirement obligation of $5,195,000, an increase to property, plant and equipment of $3,443,000, an increase in accumulated earnings of $139,000, a decrease in the site restoration liability of $1,972,000 and an increase to the future tax liability of $81,000.

The asset retirement obligation increased by $16,208,000 during 2004 for three main reasons. There were liabilities of $9,482,000 recorded in respect of the acquisitions and wells drilled during the year. Secondly, there were additional liabilities of $6,242,000 recorded due to changes in estimates of prior periods. The Trust bases its asset retirement obligation cost estimates on information published by the Alberta Energy Utilities Board ("AEUB") for their liability ratings. During the year, the AEUB published a new directive outlining estimates for abandonment and reclamation costs. Crescent Point increased its asset retirement cost estimates to ensure consistency with the estimates published by the AEUB. Lastly, there was accretion expense of $798,000 recorded in 2004, which was partially offset by actual retirement expenditures of $314,000.

Reclamation Fund

During the third quarter of 2004, the Trust implemented a reclamation fund to provide for future asset retirement costs. Effective July 1, 2004, the Trust began contributing $0.15 per barrel of production to the reclamation fund which results in minimum annual contributions of approximately $550,000 based upon properties owned at December 31, 2004. Additional contributions are made at the discretion of the Board of Directors. Contributions to the fund during 2004 were $539,000 of which $314,000 was used in asset retirement activities during the year.

Liquidity and Capital Resources

In the fourth quarter of 2004, the Trust's credit facility was increased from $105,000,000 to $135,000,000 and syndicated with two additional Canadian chartered banks. As at December 31, 2004, the Trust had net debt of $95,360,000 compared with $38,417,000 as at December 31, 2003. The amount drawn under the credit facility by the Trust at December 31, 2004 was $92,720,000 providing in excess of $42,000,000 of unutilized credit capacity. Given the significant amount available but unutilized under the credit facility at December 31, 2004 and the success raising new equity during the year (see Unitholders' Equity discussion below), the Trust believes it has sufficient capital resources to meet obligations and achieve excellent financial results going forward.

At the end of 2004, Crescent Point was capitalized with 15 percent debt and 85 percent equity, as compared with 12 percent debt and 88 percent equity at the end of 2003 (based on year-end market capitalization). The Trust's net debt to cash flow ratio was 1.4 times at the end of 2004 (using the annual cash flows for 2004), as compared with 1.0 times at the end of 2003. Crescent Point's net debt to cash flow ratio increased in 2004 due to funding the Sounding Lake property acquisition of $14,189,000 in the fourth quarter of 2004 through the existing credit line. The Trust's projected annual cash flow will result in a net debt to cash flow ratio below 1.0 times in 2005.

Capitalization Table ($000 except unit and per unit amounts)	December 31, 2004	December 31, 2003
Bank debt	92,720	40,220
Less: working capital (deficiency) [1]	2,640	(1,803)
Net debt [1]	95,360	38,417
Units outstanding and issuable for exchangeable shares	30,906,277	21,265,233
Market price at end of year (per unit)	16.85	13.39
Market capitalization	520,771	284,741
Total capitalization [2]	616,131	323,158
Net debt as a percentage of total capitalization	15%	12%
Cash flow	69,828	36,626
Net debt to cash flow	1.4	1.0

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

Unitholders' Equity

Crescent Point's total capitalization increased 91 percent to $616,131,000 at December 31, 2004 with the market value of Trust units representing 85 percent of total capitalization. This compares with the total capitalization of $323,158,000 at December 31, 2003, with the market value of Trust units representing 88 percent of total capitalization.

On January 6, 2004, the Trust closed a bought deal equity financing of 5,150,000 units for gross proceeds of $65,662,500 ($12.75 per Trust unit). The proceeds from this financing were used to fund the acquisition of Capio.

On September 9, 2004, the Trust closed a bought deal equity financing pursuant to which 3,000,000 units were sold for proceeds of $45,000,000 ($15.00 per Trust unit). The proceeds from this financing were used to fund three separate property acquisitions totaling $64,742,000.

During the year ended December 31, 2004, the units traded in the ranges of $13.00 to $18.25, with an average daily trading volume of 105,000 units.

For the year ended December 31, 2004, the distribution reinvestment and premium distribution reinvestment plans resulted in an additional 1,208,002 units being issued at an average price of $14.62, raising a total of $17,657,000. Participation levels in these plans is currently in excess of 30 percent. The cash raised through these alternative equity programs is used for general corporate purposes. Crescent Point will continue to monitor participation levels and utilize these funds in the most effective manner.

The Trust established the Restricted Unit Bonus Plan on September 5, 2003. Under the terms of the Restricted Unit Bonus Plan, the Trust may grant restricted units to directors, officers, employees and consultants. Restricted units vest at 33 ⅓ percent on each of the first, second and third anniversaries of the grant date. Restricted unitholders are eligible for the first third of their monthly distributions for the first year, immediately upon grant. On the date the other two thirds of the restricted units vest, the restricted unitholders are entitled to the accrued distributions from the date of grant.

The unitholders have approved a maximum number of units allowable under the Restricted Unit Bonus Plan of 935,000 units. The Trust had 400,559 restricted units outstanding at December 31, 2004 compared with 180,200 restricted units outstanding at December 31, 2003. The Trust recorded compensation expense and contributed surplus of $2,294,000 in the year ended December 31, 2004 based on the estimated fair value of the units on the date of grant.

Contractual Obligations and Commitments

The Trust has assumed various contractual obligations and commitments in the normal course of operations. The following table summarizes the Trust's contractual obligations and commitments as at December 31, 2004:

Contractual Obligations - Summary ($000)	Expected Payout Date				
	Total	2005	2006-2007	2008-2009	After 2009
Operating Leases [1]	1,196	470	726	-	-

1) Operating leases includes leases for office space and equipment.

Critical Accounting Estimates

The preparation of the Trust's financial statements requires management to adopt accounting policies that involve the use of significant estimates and assumptions. These estimates and assumptions are developed based on the best available information and are believed by management to be reasonable under the existing circumstances. New events or additional information may result in the revision of these estimates over time. A summary of the significant accounting policies used by Crescent Point can be found in Note 2 to the December 31, 2004 consolidated financial statements. The following discussion outlines what management believes to be the most critical accounting policies involving the use of estimates or assumptions.

Depletion, Depreciation and Amortization ("DD&A")

Crescent Point follows the Canadian Institute of Chartered Accountant's (the "CICA") Accounting Guideline AcG-16 on full cost accounting in the oil and gas industry to account for oil and gas properties. Under this method, all costs associated with the acquisition of, exploration for, and the development of natural gas and crude oil reserves are capitalized and costs associated with production are expensed. The capitalized costs are depleted using the unit-of-production method based on estimated proved reserves using management's best estimate of future prices (see Oil and Gas Reserves discussion below). Reserve estimates can have a significant impact on earnings, as they are a key component in the calculation of depletion. A downward revision in a reserve estimate could result in a higher DD&A charge to earnings. In addition, if net capitalized costs are determined to be in excess of the calculated ceiling, which is based largely on reserve estimates (see Asset Impairment discussion below), the excess must be written off as an expense charged against earnings. In the event of a property disposition, proceeds are normally deducted from the full cost pool without recognition of a gain or loss unless there is a change in the DD&A rate of 20 percent or greater.

Asset Retirement Obligation

Upon retirement of its oil and gas assets, the Trust anticipates incurring substantial costs associated with asset retirement activities. Estimates of the associated costs are subject to uncertainty associated with the method, timing and extent of future retirement activities. A liability for these costs and a related asset are recorded using the discounted asset retirement costs and the capitalized costs are depleted on a unit-of-production basis over the associated reserve life. Accordingly, the liability, the related asset and the expense are impacted by changes in the estimates and timing of the expected costs and reserves (see Oil and Gas Reserves discussion below).

Asset Impairment

Producing properties and unproved properties are assessed annually, or as economic events dictate, for potential impairment. Impairment is assessed by comparing the estimated undiscounted future cash flows to the carrying value of the asset. The cash flows used in the impairment assessment require management to make assumptions and estimates about recoverable reserves (see Oil and Gas Reserves discussion below), future commodity prices and operating costs. Changes in any of the assumptions, such as a downward revision in reserves, a decrease in future commodity prices, or an increase in operating costs could result in an impairment of an asset's carrying value.

Purchase Price Allocation

Business acquisitions are accounted for by the purchase method of accounting. Under this method, the purchase price is allocated to the assets acquired and the liabilities assumed based on the fair value at the time of acquisition. The excess purchase price over the fair value of identifiable assets and liabilities acquired is goodwill. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of property, plant and equipment acquired generally require the most judgment and include estimates of reserves acquired (see Oil and Gas Reserves discussion below), future commodity prices, and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities, and goodwill in the purchase price allocation. Future net earnings can be affected as a result of changes in future depletion and depreciation, asset impairment or goodwill impairment.

Goodwill Impairment

Goodwill is subject to impairment tests annually, or as economic events dictate, by comparing the fair value of the reporting entity to its carrying value, including goodwill. If the fair value of the reporting entity is less than its carrying value, a goodwill impairment loss is recognized as the excess of the carrying value of the goodwill over the implied value of the goodwill. The determination of fair value requires management to make assumptions and estimates about recoverable reserves (see Oil and Gas Reserves discussion below), future commodity prices, operating costs, production profiles, and discount rates. Changes in any of these assumptions, such as a downward revision in reserves, a decrease in future commodity prices, an increase in operating costs or an increase in discount rates could result in an impairment of all or a portion of the goodwill carrying value in future periods.

Oil and Gas Reserves

Reserves estimates, although not reported as part of the Trust's financial statements, can have a significant effect on net earnings as a result of their impact on depletion and depreciation rates, asset retirement provisions, asset impairments, purchase price allocations, and goodwill impairment (see discussion of these items above). Independent petroleum reservoir engineering consultants perform evaluations of the Trust's oil and gas reserves on an annual basis. However, the estimation of reserves is an inherently complex process requiring significant judgment. Estimates of economically recoverable oil and gas reserves are based upon a number of variables and assumptions such as geoscientific interpretation, commodity prices, operating and capital costs and production forecasts, all of which may vary considerably from actual results. These estimates are expected to be revised upward or downward over time, as additional information such as reservoir performance becomes available, or as economic conditions change.

New Accounting Pronouncements

ACCOUNTING CHANGES IN THE CURRENT YEAR

Full Cost Accounting

Effective January 1, 2004, the Trust adopted the new CICA accounting guideline AcG-16 "Oil and Gas Accounting – Full Cost." The new guideline modifies how the ceiling test is performed, and requires cost centres to be tested for impairment using undiscounted future cash flows which are determined using management's estimate of future prices applied to proved reserves. If the carrying value exceeds the undiscounted cash flows, an impairment loss would be recorded in income. The impairment is measured as the amount by which the carrying amount of property, plant and equipment exceeds the discounted cash flows from proved and probable reserves.

There was no impact on the Trust's carrying amount for property, plant and equipment or to net income as a result of adopting this guideline.

Asset Retirement Obligations

Effective January 1, 2004, the Trust retroactively adopted the new accounting standard CICA Handbook section 3110 "Asset Retirement Obligations." This new section changes the method of accruing for costs associated with the retirement of property, plant and equipment, which an entity is legally obligated to incur. Previously, asset retirement obligations were accrued on an undiscounted unit-of-production basis over the entire life of the asset. The new accounting standard requires that companies record the fair value of legal obligations associated with the retirement of tangible long-lived assets. The obligations are recorded as liabilities on a discounted basis when incurred, with a corresponding increase to the carrying amount of the related asset. Over time the liabilities are accreted for the change in their present value and the capitalized costs are depleted on a unit-of-production basis over the life of the reserves. Revisions to the estimated timing of cash flows or the original estimated undiscounted cost would also result in an increase or decrease to the obligation and related asset.

Upon adoption, all prior periods have been restated for the change in the accounting policy. At January 1, 2004, this resulted in an increase to the asset retirement obligation of $5,195,000, an increase to property, plant and equipment of $3,443,000, an increase in accumulated earnings of $139,000, a decrease in the site restoration liability of $1,972,000 and an increase to the future tax liability of $81,000.

The previously reported 2003 amounts have been restated due to the retroactive application of this new standard. At January 1, 2003, this resulted in an increase to the asset retirement obligation of $2,224,000, an increase to property, plant and equipment of $1,902,000, an increase in accumulated earnings of $24,000, a decrease in the site restoration liability of $363,000 and an increase to the future tax liability of $17,000. Net income for the year ended December 31, 2003 increased by $115,000 as a result of the retroactive application of the accounting standard.

There was no impact on the Trust's cash flow or liquidity as a result of adopting this new accounting standard.

Hedging Relationships

Effective January 1, 2004, the Trust adopted the new CICA accounting guideline AcG-13 "Hedging Relationships." Financial instruments that are not designated as hedges under the guideline are recorded on the balance sheet as either an asset or liability with the change in fair value recognized in net earnings. The Trust has not designated any of its risk management activities as accounting hedges under AcG-13, and accordingly has marked-to-market its financial instruments.

The impact on the Trust's financial statements as at January 1, 2004 was the recognition of a risk management liability and a deferred financial instrument loss (net) of $3,209,000. The deferred financial instrument loss is being recognized in earnings as the contracts expire.

Transportation Expenses

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

FUTURE ACCOUNTING CHANGES

Exchangeable Share Accounting

The CICA issued EIC-151, "Exchangeable Securities Issued by Subsidiaries of Income Trusts" in January 2005. The EIC requires that exchangeable shares be presented as either non-controlling interest or debt unless certain criteria are met. The EIC is effective for financial statements issued after July 1, 2005, and is to be applied retroactively with restatement of prior periods. Crescent Point is currently assessing the impact of this EIC on its financial statements and cannot reasonably estimate the impact at this time.

Variable Interest Entities

The CICA issued Accounting Guideline AcG-15, "Consolidation of Variable Interest Entities" in June 2003. The EIC provides guidance regarding the entities which should be included in consolidated financial statements. The EIC is effective for the Trust's fiscal year beginning January 1, 2005. The Trust has not assessed the impact of this EIC on its financial statements.

Financial Instruments

The CICA issued a new accounting standard, CICA Accounting Standard Handbook section 3855, "Financial Instruments Recognition and Measurement". This standard prescribes how and at what amount financial assets, financial liabilities and non-financial derivatives are to be recognized on the balance sheet. The standard prescribes fair value in some cases while cost-based measures are prescribed in other cases. It also specifies how financial instrument gains and losses are to be presented. The new standard is effective for fiscal years beginning on or after October 1, 2006. The Trust has not assessed the impact of this standard on its financial statements.

Outstanding Trust Unit Data

As at March 3, 2005, the Trust had 29,558,864 Trust units outstanding and 1,217,012 exchangeable shares outstanding. The number of Trust units issuable upon conversion of the exchangeable shares is 1,479,680 Trust units, using the exchange ratio in effect at March 3, 2005.

Selected Annual Information

Annual Financial Results[1]

($000 except per unit amounts)	2004	2003 (restated [2])	2002 (restated [2])
Total revenue [3]	151,331	74,718	24,655
Net income [4]	30,659	9,134	3,341
Net income per unit [4]	1.10	0.50	0.32
Net income per unit-diluted [4]	1.09	0.50	0.30
Cash flow from operations	69,828	36,626	11,893
Cash flow from operations per unit	2.52	1.99	1.12
Cash flow from operations per unit-diluted	2.49	1.99	1.07
Total assets	397,318	208,855	76,572
Total long-term financial liabilities	-	-	-
Cash distributions	53,877	11,697	-
Cash distributions/dividends per unit/share	2.04	0.68	-

1) The financial information has been prepared in accordance with Canadian generally accepted accounting principles, and is measured and reported in Canadian dollars.
2) The comparative annual results have been restated for the retroactive impact of adopting the accounting standard asset retirement obligations.
3) Total revenue reported is net of transportation expenses.
4) Net income and net income before discontinued operations and extraordinary items are the same.

Crescent Point's revenue, net income, cash flow and assets have increased substantially from the year ended December 31, 2002 through the year ended December 31, 2004 due to several corporate and property acquisitions and successful drilling and development programs.

Summary of Quarterly Results

	2004				2003 (Restated [3])			
($000, except per unit amounts)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Total revenue [1]	46,548	39,830	34,130	30,823	22,623	18,671	15,827	17,597
Net income (loss) [2]	24,409	3,058	2,754	438	(626)	1,376	5,125	3,259
Net income (loss) per unit [2]	0.80	0.11	0.10	0.02	(0.03)	0.09	0.37	0.24
Net income (loss) per unit-diluted [2]	0.79	0.11	0.10	0.02	(0.03)	0.09	0.36	0.23
Cash flow from operations	19,875	18,096	16,348	15,509	11,975	6,084	9,368	9,199
Cash flow from operations per unit	0.65	0.65	0.61	0.60	0.63	0.40	0.68	0.67
Cash flow from operations per unit-diluted	0.64	0.64	0.60	0.59	0.62	0.40	0.66	0.64
Capital expenditures	21,728	74,948	8,875	68,784	22,584	66,102	5,676	30,102
Cash distributions	14,834	13,490	12,929	12,624	8,897	2,800	-	-
Cash distributions per unit	0.51	0.51	0.51	0.51	0.51	0.17	-	-

1) Total revenue reported is net of transportation expenses.
2) Net income and net income before discontinued operations and extraordinary items are the same.
3) The comparative quarterly results have been restated for the retroactive impact of adopting the accounting standard Asset Retirement Obligations.

Crescent Point's revenue has increased significantly through the previous eight quarters primarily due to the corporate acquisitions of Tappit Resources Ltd. in September 2003 and Capio Petroleum Corporation in January 2004, several property acquisitions over the past two years and the Trust's successful drilling programs. The overall growth in the Trust's asset base also contributed to the general increase in cash flow from operations and net income. Capital expenditures fluctuated throughout this period as a result of the timing of acquisitions. The general increase in cash flows throughout the last eight quarters has allowed the Trust to maintain stable monthly cash distributions of $0.17 per unit.

CONSOLIDATED BALANCE SHEET

(UNAUDITED) ($000)	As at December 31, 2004	December 31, 2003
		Restated (Note 3(b))
ASSETS		
Current assets		
Cash	44	82
Accounts receivable	20,645	17,505
Investments in marketable securities	-	188
Prepaids and deposits	339	318
	21,028	18,093
Deposits on property, plant and equipment	-	1,000
Reclamation fund (Note 8)	225	-
Property, plant and equipment (Note 7)	317,918	168,591
Goodwill (Note 6)	58,147	21,171
	397,318	208,855
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	20,322	13,945
Cash distributions payable	3,346	2,345
Bank indebtedness (Note 9)	92,720	40,220
Risk management liability (Note 14)	7,898	-
	124,286	56,510
Asset retirement obligation (Note 10)	21,403	5,195
Future income taxes (Note 12)	33,081	29,713
	178,770	91,418
Unitholders' equity		
Unitholders' capital (Note 11(b))	240,006	113,880
Exchangeable shares (Note 11(b))	7,406	10,782
Contributed surplus (Note 11(d))	1,918	339
Accumulated earnings	34,792	4,133
Accumulated cash distributions (Note 5)	(65,574)	(11,697)
	218,548	117,437
	397,318	208,855

Commitments (Note 15)

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENT OF OPERATIONS AND ACCUMULATED EARNINGS

(UNAUDITED) ($000 except per unit amounts)	Three months ended December 31, 2004	Three months ended December 31, 2003	Year ended December 31, 2004	Year ended December 31, 2003
		Restated (Note 3(b)&(d))		*Restated (Note 3(b)&(d))*
REVENUE				
Oil and gas sales	47,895	23,297	155,299	76,792
Transportation expenses (Note 3(d))	(1,347)	(674)	(3,968)	(2,074)
Royalties, net of ARTC	(8,482)	(4,384)	(28,675)	(14,044)
Financial instruments				
Realized losses	(5,951)	(559)	(18,855)	(2,722)
Unrealized gains (losses) (Note 14)	14,537	-	(7,987)	-
	46,652	17,680	95,814	57,952
EXPENSES				
Operating	7,827	3,982	22,941	11,561
General and administrative	2,129	647	4,727	2,140
Unit-based compensation (Note 11(d))	774	339	2,294	339
Interest on bank indebtedness	1,135	624	3,398	1,640
Depletion, depreciation and amortization	12,194	7,546	40,157	19,187
Accretion on asset retirement obligation (Note 10)	405	46	798	178
Capital and other taxes	1,149	191	2,854	770
Reorganization costs	-	261	-	5,215
Gain on sale of investment (Note 4)	-	-	-	(313)
	25,613	13,636	77,169	40,717
Income before future income tax	21,039	4,044	18,645	17,235
Future income tax expense (recovery)	(3,370)	4,670	(12,014)	8,101
Net income (loss) for the period	24,409	(626)	30,659	9,134
Accumulated earnings, beginning of the period	10,383	3,945	3,994	3,117
Retroactive application of change in accounting policy (Note 3(b))	-	101	139	24
Transfer of assets pursuant to Plan of Arrangement (Note 6(c))	-	713	-	(8,142)
Accumulated earnings, end of the period	34,792	4,133	34,792	4,133
Net income per unit (Note 13)				
Basic	0.80	(0.03)	1.10	0.50
Diluted	0.79	(0.03)	1.09	0.50

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENT OF CASH FLOWS

(UNAUDITED) ($000)	Three months ended December 31, 2004	Three months ended December 31, 2003	Year ended December 31, 2004	Year ended December 31, 2003
		Restated (Note 3(b))		*Restated (Note 3(b))*
Cash provided by (used in)				
Operating activities				
Net income (loss) for the period	24,409	(626)	30,659	9,134
Items not affecting cash				
Future income taxes	(3,370)	4,670	(12,014)	8,101
Unit-based compensation (Note 11(d))	774	339	2,294	339
Depletion, depreciation and amortization	12,194	7,546	40,157	19,187
Accretion on asset retirement obligation (Note 10)	405	46	798	178
Gain on sale of investment (Note 4)	-	-	(53)	(313)
Unrealized (gains) losses on financial instruments (Note 14)	(14,537)	-	7,987	-
Cash flow from operations	19,875	11,975	69,828	36,626
Asset retirement expenditures (Note 10)	(197)	-	(314)	-
Change in non-cash working capital				
Accounts receivable	9,495	2,434	(959)	1,583
Prepaid expenses and deposits	3	(138)	194	(219)
Accounts payable	975	(375)	(1,682)	(5,060)
	30,151	13,896	67,067	32,930
Investing activities				
Expenditures on petroleum and natural gas properties	(21,728)	(20,349)	(112,647)	(61,297)
Acquisition of Tappit Resources Ltd. (Note 6(b))	-	278	-	(7,714)
Acquisition of Capio Petroleum Corporation (Note 6(a))	-	-	(76,845)	-
Petroleum and natural gas deposits	-	(1,000)	1,000	2,225
Reclamation fund net contributions (Note 8)	(210)	-	(225)	-
Proceeds on sale of investments (Note 4)	-	-	241	741
Change in non-cash working capital				
Accounts receivable	160	(2,646)	275	(770)
Accounts payable	(9,595)	(807)	42	(1,972)
	(31,373)	(24,524)	(188,159)	(68,787)
Financing activities				
Issue of trust units, net of issue costs	4,517	31,419	122,037	42,685
Increase in bank indebtedness	11,400	(11,417)	51,893	2,521
Cash distributions (including DRIP)	(14,834)	(8,897)	(53,877)	(11,697)
Change in non-cash working capital				
Cash distributions payable	113	(455)	1,001	2,345
	1,196	10,650	121,054	35,854
Increase (decrease) in cash	(26)	22	(38)	(3)
Cash at beginning of period	70	60	82	85
Cash at end of period	44	82	44	82

See accompanying notes to the consolidated financial statements

1. CORPORATE REORGANIZATION AND BASIS OF PRESENTATION

Crescent Point Energy Trust (the "Trust") is an open-ended unincorporated investment trust created pursuant to a Declaration of Trust and operating under the laws of the Province of Alberta. The Trust was established as part of a Plan of Arrangement (the "Arrangement") that became effective on September 5, 2003.

The Arrangement gave effect to the transactions contemplated by the agreement entered into on May 26, 2003 by Crescent Point Energy Ltd. ("old Crescent Point" or the "Corporation") and Tappit Resources Ltd. ("Tappit"). The reorganization resulted in the shareholders of old Crescent Point and Tappit receiving trust units in the Trust, a new oil and natural gas energy trust that owns subsidiaries which own all of old Crescent Point's and Tappit's producing assets. In addition, the shareholders of old Crescent Point and Tappit received shares in a separate, publicly-listed, growth and exploration focused producer StarPoint Energy Ltd. ("StarPoint").

Pursuant to the Arrangement, shareholders of both old Crescent Point and Tappit received shares of StarPoint, and at their election, either units of the Trust, which will pay monthly cash distributions, or exchangeable shares which may be exchanged into units of the Trust. The Arrangement also resulted in a share consolidation of the outstanding shares of old Crescent Point.

For each old Crescent Point Class A share owned, shareholders received at their election:
a) 0.5 units of the Trust and 0.5 shares of StarPoint, or
b) 0.5 exchangeable shares and 0.5 shares of StarPoint.

For each old Crescent Point Class B share owned, shareholders received at their election:
a) 0.75 units of the Trust and 0.75 shares of StarPoint, or
b) 0.75 exchangeable shares and 0.75 shares of StarPoint.

For each Tappit common share owned, shareholders received at their election:
a) 0.19 units of the Trust, $0.36 cash and 0.1 shares of StarPoint, or
b) 0.19 exchangeable shares, $0.36 cash and 0.1 shares of StarPoint.

Upon completion of the Arrangement, 16,433,734 Trust units and 2,000,000 exchangeable shares were outstanding. In addition, the Trust can issue up to 935,000 restricted units under the Restricted Unit Bonus Plan (see note 11(d)).

The Arrangement involving conversion to the Trust has been accounted for as a continuity of interests. Accordingly, these consolidated financial statements reflect the financial position, results of operations and cash flows as if the trust had always carried on the businesses formerly carried on by old Crescent Point. All assets and liabilities are recorded at historical cost. The three months and year ended December 31, 2003 reflect the results of operations and cash flows of old Crescent Point and its subsidiaries up to September 5, 2003, and the results of the Trust and its subsidiaries from September 5 to December 31, 2003.

The term "units" has been used in these financial statements to identify both the Trust units and exchangeable shares of the Trust issued on or after September 5, 2003 as well as the Class A common shares of the Corporation outstanding prior to the conversion on September 5, 2003. All pre-arrangement comparative share numbers have been adjusted for the consolidation of Class A and Class B shares.

2. SIGNIFICANT ACCOUNTING POLICIES

a) Principles of Consolidation

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

b) Joint Ventures

Certain of the Trust's exploration and production activities are conducted jointly with others through unincorporated joint ventures. The accounts of the Trust reflect its proportionate interest in such activities.

c) Property, Plant and Equipment

The Trust follows the full cost method of accounting for petroleum and natural gas properties and equipment, whereby all costs of acquiring petroleum and natural gas properties and related development costs are capitalized and accumulated in one cost centre. Such costs include lease acquisition costs, geological and geophysical expenditures, costs of drilling both productive and non-productive wells, related plant and production equipment costs and related overhead charges. Maintenance and repairs are charged against income, and renewals and enhancements which extend the economic life of the properties and equipment are capitalized.

Gains and losses are not recognized upon disposition of petroleum and natural gas properties unless such a disposition would alter the rate of depletion by 20 percent or more.

Depletion, Depreciation and Amortization

Depletion of petroleum and natural gas properties is calculated using the unit-of-production method based on the estimated proved reserves before royalties, as determined by independent engineers. Natural gas reserves and production are converted to equivalent barrels of oil based upon the relevant energy content (6:1). The depletion base includes capitalized costs, plus future costs to be incurred in developing proven reserves and excludes the unimpaired cost of undeveloped land. Costs associated with unproved properties are not subject to depletion and are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned or the value of the unproved property is considered to be impaired, the cost of the unproved property or the amount of impairment is added to costs subject to depletion.

Tangible production equipment is depreciated on a straight-line basis over its estimated useful life of 15 years. Office furniture, equipment and motor vehicles are depreciated on a declining balance basis at rates ranging from 10 percent to 30 percent.

Ceiling Test

A limit is placed on the aggregate carrying value of property, plant and equipment, which may be amortized against revenues of future periods (the "ceiling test"). The ceiling test is an impairment test whereby the carrying amount of property, plant and equipment is compared to the undiscounted cash flows from proved reserves using management's best estimate of future prices. If the carrying value exceeds the undiscounted cash flows, an impairment loss would be recorded in income. The impairment is measured as the amount by which the carrying amount of property, plant and equipment exceeds the discounted cash flows from proved and probable reserves.

d) Asset Retirement Obligation

The Trust recognizes the fair value of an asset retirement obligation in the period in which it is incurred. The obligation is recorded as a liability on a discounted basis when incurred, with a corresponding increase to the carrying amount of the related asset. Over time the liabilities are accreted for the change in their present value and the capitalized costs are depleted on a unit-of-production basis over the life of the reserves. Revisions to the estimated timing of cash flows or the original estimated undiscounted cost would also result in an increase or decrease to the obligation and related asset.

e) Goodwill

The Trust must record goodwill relating to a corporate acquisition when the total purchase price exceeds the fair value for accounting purposes of the net identifiable assets and liabilities of the acquired company. The goodwill balance is assessed for impairment annually at year-end or as events occur that could result in an impairment. Impairment is recognized based on the fair value of the reporting entity ("consolidated Trust") compared to the book value of the reporting entity. If the fair value of the consolidated Trust is less than the book value, impairment is measured by allocating the fair value of the consolidated Trust to the identifiable assets and liabilities as if the Trust has been acquired in a business combination for a purchase price equal to its fair value. The excess of the fair value of the consolidated Trust over the amounts assigned to the identifiable assets and liabilities is the implied value of the goodwill. Any excess of the book value of goodwill over the implied value of goodwill is the impairment amount. Impairment is charged to earnings and is not tax effected, in the period in which it occurs. Goodwill is stated at cost less impairment and is not amortized.

f) Unit-based Compensation

The Trust established a Restricted Unit Bonus Plan on September 5, 2003. Prior to the Arrangement on September 5, 2003, the Corporation had a stock-based compensation plan.

The fair value based method of accounting is used to account for the stock options granted during the year ended December 31, 2003 and the restricted units granted under the Restricted Unit Bonus Plan. Compensation expense is determined based on the estimated fair value of stock options or trust units on the date of grant. The compensation expense is recognized over the vesting period, with a corresponding increase to contributed surplus. At the time the options or restricted units vest, the issuance of shares or units is recorded with a corresponding decrease to contributed surplus.

g) Income Taxes

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

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

h) Financial Instruments

The Trust uses financial instruments and physical delivery commodity contracts from time to time to reduce its exposure to fluctuations in commodity prices, foreign exchange rates and interest rates. Financial instruments that are not designated as hedges under CICA accounting guideline AcG-13 "Hedging Relationships" are recorded on the balance sheet as either an asset or a liability with the change in fair value from the prior period recognized in net earnings. The Trust has not designated any of its risk management activities as accounting hedges under AcG-13, and accordingly has marked-to-market its financial instruments.

i) Revenue Recognition

Revenues associated with sales of crude oil, natural gas and natural gas liquids are recognized when title passes to the purchaser.

j) Cash and Cash Equivalents

Cash and cash equivalents include short-term investments with a maturity of three months or less when purchased.

k) Measurement Uncertainty

Certain items recognized in the financial statements are subject to measurement uncertainty. The recognized amounts of such items are based on the Trust's best information and judgement. Such amounts are not expected to change materially in the near term. They include the amounts recorded for depletion, depreciation and asset retirement costs which depend on estimates of oil and gas reserves or the economic lives and future cash flows from related assets.

3. CHANGES IN ACCOUNTING POLICIES

a) Full Cost Accounting

Effective January 1, 2004, the Trust adopted the new CICA accounting guideline AcG-16 "Oil and Gas Accounting – Full Cost." The new guideline modifies how the ceiling test is performed, and requires cost centres to be tested for impairment using undiscounted future cash flows which are determined using management's estimate of future prices applied to proved reserves. If the carrying value exceeds the undiscounted cash flows, an impairment loss would be recorded in income. The impairment is measured as the amount by which the carrying amount of property, plant and equipment exceeds the discounted cash flows from proved and probable reserves.

There was no impact on the Trust's carrying amount for property, plant and equipment or to net income as a result of adopting this guideline. See Note 7 for additional information regarding the ceiling test.

b) Asset Retirement Obligation

Effective January 1, 2004, the Trust retroactively adopted the new accounting standard CICA Handbook section 3110 "Asset Retirement Obligations." This new section changes the method of accruing for costs associated with the retirement of fixed assets which an entity is legally obligated to incur. Previously, asset retirement obligations were accrued on an undiscounted unit-of-production basis over the entire life of the asset. The new accounting standard requires that companies record the fair value of legal obligations associated with the retirement of tangible long-lived assets. The obligations are recorded as liabilities on a discounted basis when incurred, with a corresponding increase to the carrying amount of the related asset. Over time the liabilities are accreted for the change in their present value and the capitalized costs are depleted on a unit-of-production basis over the life of the reserves. Revisions to the estimated timing of cash flows or the original estimated undiscounted cost would also result in an increase or decrease to the obligation and related asset.

Upon adoption, all prior periods have been restated for the change in the accounting policy. At January 1, 2004, this resulted in an increase to the asset retirement obligation of $5,195,000, an increase to property, plant and equipment of $3,443,000, an increase in accumulated earnings of $139,000, a decrease in the site restoration liability of $1,972,000 and an increase to the future tax liability of $81,000.

The previously reported 2003 amounts have been restated due to the retroactive application of this new standard. At January 1, 2003, this resulted in an increase to the asset retirement obligation of $2,224,000, an increase to property, plant and equipment of $1,902,000, an increase in accumulated earnings of $24,000, a decrease in the site restoration liability of $363,000 and an increase to the future tax liability of $17,000. Net income for the year ended December 31, 2003 increased by $115,000 as a result of the retroactive application of the accounting standard.

There is no impact on the Trust's cash flow or liquidity as a result of adopting this new accounting standard. See Note 10 for additional information regarding the asset retirement obligation and impact on the consolidated financial statements.

c) Financial Instruments

Effective January 1, 2004, the Trust adopted the new CICA accounting guideline AcG-13 "Hedging Relationships." Financial instruments that are not designated as hedges under the guideline are recorded on the balance sheet as either an asset or liability with the change in fair value recognized in net earnings. The Trust has not designated any of its risk management activities as accounting hedges under AcG-13, and accordingly has marked-to-market its financial instruments.

The impact on the Trust's financial statements as at January 1, 2004 was the recognition of a risk management liability and a deferred financial instrument loss (net) of $3,209,000. The deferred financial instrument loss is being recognized in earnings as the contracts expire. See Note 14 for additional information regarding the financial instruments and risk management.

d) Transportation Expenses

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

4. INVESTMENTS IN MARKETABLE SECURITIES

In July 2003, the Corporation divested its entire investment of 2.15 million common shares in Rise Energy Ltd. ("Rise") subsequent to DT Energy Ltd. purchasing Rise. The carrying value had been written down to $0.20 per share in 2002. Net proceeds from the disposition amounted to $741,000.

5. RECONCILIATION OF CASH FLOW AND DISTRIBUTIONS

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

	Three months ended December 31		Year ended December 31	
($000, except per unit amounts)	2004	2003	2004	2003
Cash flow from operations before changes in non-cash working capital	19,875	11,975	69,828	36,626
Deduct				
Cash flow from operations before changes in non-cash working capital for January 1, 2003 to September 4, 2003	-	-	-	(21,221)
	19,875	11,975	69,828	15,405
Add (deduct)				
Cash withheld to fund current period capital expenditures	(4,634)	(3,078)	(15,412)	(3,708)
Reclamation fund contributions and interest earned on fund [1]	(407)	-	(539)	-
Cash distributions declared to unitholders	14,834	8,897	53,877	11,697
Accumulated cash distributions – beginning of period	50,740	2,800	11,697	-
Accumulated cash distributions – end of period	65,574	11,697	65,574	11,697
Cash distributions per unit [2]	0.51	0.51	2.04	0.68
Accumulated cash distributions per unit – beginning of period	2.21	0.17	0.68	-
Accumulated cash distributions per unit – end of period	2.72	0.68	2.72	0.68

1) The trust implemented a reclamation fund effective July 1, 2004.
2) Cash distributions per trust unit reflect the sum of the per unit amounts declared monthly to unitholders.

6. ACQUISITIONS AND DISPOSITIONS

a) Acquisition of Capio Petroleum Corporation

On January 6, 2004, the Trust purchased all of the issued and outstanding shares of Capio Petroleum Corporation, a private oil and gas company. The purchase was paid for with cash and accounted for using the purchase method of accounting. The net assets acquired and consideration is allocated as follows:

	($000)
Net assets acquired	
Cash	56
Property, plant and equipment	61,688
Goodwill	36,976
Working capital deficiency	(5,862)
Asset retirement obligation	(575)
Future income taxes	(15,382)
Total net assets acquired	76,901
Consideration	
Cash	76,488
Acquisition costs (net of option proceeds of $2,580,000)	413
Total purchase price	76,901

b) Acquisition of Tappit Resources Ltd.

On September 5, 2003, old Crescent Point purchased all of the issued and outstanding shares of Tappit Resources Ltd., a public oil and gas company. The results of Tappit have been included in these financial statements from the date of acquisition. The transaction was accounted for as a business combination with net assets acquired and consideration allocated as follows:

	($000)
Net assets acquired	
Property, plant and equipment	73,223
Goodwill	21,171
Working capital deficiency	(1,948)
Bank debt	(23,699)
Asset retirement obligation	(830)
Future income taxes	(15,506)
Total net assets acquired	52,411
Consideration	
Cash	7,303
Units issued	44,698
Acquisition costs (net of option proceeds of $1,217,000)	410
Total purchase price	52,411

c) Assets transferred to StarPoint Energy Ltd.

Under the Arrangement on September 5, 2003, old Crescent Point transferred to StarPoint Energy Ltd. its existing interests in its British Columbia exploration area. A future tax liability has been recorded by the Trust as a result of transferring tax pools of $14,481,000, which were in excess of the net book value of $10,055,000. The details are as follows:

	($000)
Petroleum and natural gas properties and equipment	10,055
Future tax asset	1,587
Total assets transferred	11,642
Bank indebtedness assumed	3,500
Net assets transferred and reduction in accumulated earnings	8,142

7. PROPERTY, PLANT AND EQUIPMENT

December 31, 2004 ($000)	Cost	Accumulated depletion, depreciation and amortization	Net
Petroleum and natural gas properties	305,955	57,169	248,786
Production equipment	74,752	7,216	67,536
Office furniture and equipment	2,662	1,066	1,596
	383,369	65,451	317,918

December 31, 2003 ($000)	Cost	Accumulated depletion, depreciation and amortization	Net
Petroleum and natural gas properties	155,091	21,754	133,337
Production equipment	37,399	3,070	34,329
Office furniture and equipment	1,395	470	925
	193,885	25,294	168,591

At December 31, 2004, unproved land costs of $8,378,000 (2003 – $3,797,000) have been excluded from costs subject to depletion.

General and administrative expenses capitalized by the Trust during the year were $1,048,000 (2003 – $1,472,000).

The ceiling test calculation at December 31, 2004 indicated that the net recoverable amount from proved reserves exceeded the net carrying value of the petroleum and natural gas properties and equipment. The following are the prices that were used in the December 31, 2004 ceiling test:

	Average Price Forecast									
	2005	2006	2007	2008	2009	2010- 2012	2013	2014	2015	2016+[1]
WTI ($US/bbl)	42.00	40.00	38.00	36.00	34.00	33.00	33.50	34.00	34.50	2.0%
Exchange Rate	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	-
WTI ($Cdn/bbl)	51.22	48.78	46.34	43.90	41.46	40.24	40.85	41.46	42.07	2.0%
AECO ($Cdn/mcf)	6.60	6.35	6.15	6.00	6.00	6.00	6.10	6.20	6.30	2.0%

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

8. RECLAMATION FUND

A reclamation fund was established effective July 1, 2004 to fund future asset retirement obligation costs. The Board of Directors has approved contributions of $0.15 per barrel of production which results in minimum annual contributions of approximately $550,000 based upon properties owned at December 31, 2004. Additional contributions are made at the discretion of the Board of Directors. Contributions to the reclamation fund and interest earned on the reclamation fund balance have been deducted from the cash distributions to the unitholders and cash withheld to fund current period capital expenditures. The following table reconciles the reclamation fund:

	2004 ($000)
Balance, beginning of year	-
Contributions	539
Actual expenditures	(314)
Interest earned on fund	-
Balance, end of year	225

9. BANK INDEBTEDNESS

On January 6, 2004, the Trust's revolving term demand bank loan facility was increased to $105,000,000. The amount available under the banking facility was temporarily increased to $117,000,000 for the period August 16 to October 7, 2004 in connection with the financing of three acquisitions. On October 7, 2004, the Trust's credit facility was increased to $135,000,000 and on November 1, 2004 the Trust's credit facility was restructured into a syndicated facility and two additional Canadian chartered banks were welcomed into the syndicate.

The interest charged on the facility is calculated based on a sliding scale ratio of the Trust's debt to cash flows. The effective interest rate for 2004 is 4.71% (2003 - 4.76%)

10. ASSET RETIREMENT OBLIGATION

The total future asset retirement obligation was estimated by management based on the Trust's net ownership in all wells and facilities. This includes all estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. The Trust has estimated the net present value of its total asset retirement obligation to be $21,403,000 at December 31, 2004 (December 31, 2003 - $5,195,000) based on total estimated undiscounted cash flows to settle the obligation of $47,448,000 (December 31, 2003 - $13,532,000). The expected period until settlement ranges from a minimum of two years to a maximum of 42 years, with the costs expected to be paid over an average of 20 years. The estimated cash flows have been discounted using a credit-adjusted risk-free rate of eight percent and an inflation rate of two percent.

The following table reconciles the asset retirement obligation:

($000)	2004	2003
Asset retirement obligation, beginning of year	5,195	2,224
Liabilities acquired through corporate acquisitions	575	830
Liabilities incurred	8,907	1,963
Liabilities settled	(314)	-
Changes in prior period estimates	6,242	-
Accretion expense	798	178
Asset retirement obligation, end of year	21,403	5,195

On July 1, 2004, the Trust implemented a reclamation fund. See Note 8 for information regarding the reclamation fund.

11. UNITHOLDERS' EQUITY

a) Authorized

Unlimited number of voting Trust units
2,000,000 exchangeable shares

b) Issued and outstanding

Refer to Note 1 – Corporate reorganization which discusses the Arrangement including old Crescent Point's share to unit reorganization.

The exchangeable shares can be converted at the option of the holder into Trust units at any time before September 5, 2013. Any exchangeable shares which have not been converted into Trust units by September 5, 2013 will automatically be converted into Trust units at that time. If the number of exchangeable shares outstanding reaches 1,000,000, the Trust can elect to redeem the exchangeable shares for Trust units. The number of Trust units issued upon conversion is based on the exchange ratio in effect on the date of conversion. The exchange ratio is calculated monthly based on the distributions declared and the ten day weighted average Trust unit trading price preceding the monthly effective date. The exchangeable shares are not eligible for distributions, and are not publicly traded.

Effective with the November 2003 distribution, the Trust initiated a distribution reinvestment plan (the "Regular DRIP") and a premium distribution reinvestment plan (the "Premium DRIP"). The Regular DRIP permits eligible unitholders to direct their distributions to the purchase of additional units at 95 percent of the average market price, as defined in the plan. The Premium DRIP permits eligible unitholders to elect to receive 102 percent of the cash the unitholder would otherwise have received on the distribution date. The additional cash distributed to the Premium DRIP unitholders is funded through the issuance of additional Trust units in the open market. Participation in the Regular and Premium DRIP is subject to proration by the Trust. Unitholders who participate in either the Regular DRIP or the Premium DRIP are also eligible to participate in the optional unit purchase plan as defined in the plan.

Unitholders' Equity	2004 Number of shares/ Trust units	2004 Amount ($000)	2003 Number of shares/ Trust units	2003 Amount ($000)
Class A Shares				
Balance – January 1	-	-	23,978,092	34,335
Issued under the private placement	-	-	2,360,000	10,030
Issued to acquire properties	-	-	-	-
Issued under stock option exercise	-	-	1,607,499	2,049
Shares exchanged for Trust units	-	-	(25,130,464)	(41,738)
Shares exchanged for exchangeable shares	-	-	(2,815,127)	(4,676)
Balance – December 31	-	-	-	-
Class B Shares				
Balance – January 1	-	-	808,830	4,641
Shares exchanged for Trust units	-	-	(736,604)	(4,227)
Shares exchanged for exchangeable shares	-	-	(72,226)	(414)
Balance – December 31	-	-	-	-
Trust Units				
Balance – January 1	19,282,049	118,038	-	-
Units issued for Class A shares	-	-	12,565,232	41,739
Units issued for Class B shares	-	-	552,453	4,227
Units issued to Tappit shareholders	-	-	3,316,049	38,456
Issued for cash	8,150,000	110,663	2,650,000	31,800
Issued on conversion of exchangeable shares	661,727	3,376	98,598	550
Issued on vesting of restricted units [1]	45,630	487	-	-
Issued pursuant to the distribution reinvestment plans	1,109,335	16,031	26,616	318
To be issued pursuant to the distribution reinvestment plans	98,667	1,626	73,101	948
Balance – December 31	29,347,408	250,221	19,282,049	118,038
Cumulative unit issue costs	-	(10,215)	-	(4,158)
Total Unitholders' capital – December 31	**29,347,408**	**240,006**	**19,282,049**	**113,880**
Exchangeable Shares				
Balance – January 1	1,902,901	10,782	-	-
Units issued for Class A shares	-	-	1,407,563	4,676
Units issued for Class B shares	-	-	54,169	414
Units issued to Tappit shareholders	-	-	538,268	6,242
Exchanged for Trust units	(595,761)	(3,376)	(97,099)	(550)
Balance – December 31	1,307,140	7,406	1,902,901	10,782
Exchange ratio – December 31	1.19258	-	1.04219	-
Trust units issuable upon conversion – December 31	**1,558,869**	**7,406**	**1,983,184**	**10,782**

1) The amount of Trust units issued on vesting of restricted units is net of employee withholding taxes.

c) Stock options

Prior to the Arrangement, in accordance with the rules and policies of the TSX Exchange Inc. ("TSX"), the directors, management, employees and consultants of the Corporation could be granted options to acquire shares of the Corporation. The exercise price and vesting terms of any options granted were fixed by the Board of Directors of the Corporation at the time of grant, subject to the limitations of the TSX.

During 2003, there were 2,107,000 stock options outstanding, of which 1,607,499 options were exercised, 5,001 options were forfeited and 494,500 options were cancelled. There were 494,500 options cancelled as these options were granted subject to the approval of the Toronto Stock Exchange. The Corporation made a cash payment to the holders of the cancelled stock options equivalent to the difference between the share trading price and the option price. The total payment was $1,941,000, of which $1,417,000 was expensed and $524,000 was capitalized. The stock option plan has been replaced by the Restricted Unit Bonus Plan (see note 11(d)). As a result of the change in the stock-based compensation plans, there were no stock options outstanding at December 31, 2003.

If the Corporation had used the fair value based method for stock options granted in the year ended December 31, 2002, an additional $588,000 of compensation costs would have been expensed in 2003, which would have reduced the Corporation's pro forma basic and diluted net income per unit to $0.46 in 2003.

d) Restricted Unit Bonus Plan

The Trust established the Restricted Unit Bonus Plan on September 5, 2003. Under the terms of the Restricted Unit Bonus Plan, the Trust may grant restricted units to directors, officers, employees and consultants. Restricted units vest at 33 1/3 percent on each of the first, second and third anniversaries of the grant date. Restricted unitholders are eligible for the first third of their monthly distributions for the first year, immediately upon grant. On the date the other two thirds of the restricted units vest, the restricted unitholders are entitled to the accrued distributions from the date of grant.

The unitholders have approved a maximum number of units allowable under the Restricted Unit Bonus Plan of 935,000 units. A summary of the changes in the restricted units outstanding under the plan is as follows:

	2004	2003
Restricted units, beginning of year	180,200	-
Granted	318,083	180,200
Exercised	(60,447)	-
Cancelled	(37,277)	-
Restricted units, end of year	400,559	180,200

The Trust recorded compensation expense and contributed surplus of $774,000 in the three-month period ended December 31, 2004 and $2,294,000 for the year ended December 31, 2004, based on the fair value of the units on the date of the grant.

12. INCOME TAXES

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

In 2003, Royal Assent was received, thereby legislating certain federal reductions in corporate income tax rates. The rate reductions are to be phased in over five years commencing in 2003. The rate changes incorporate a reduction in the applicable federal tax rate on resource income from 28 percent to 21 percent, provide for the deduction of crown royalties and eliminate the deduction for resource allowance. As a result of the rate changes, the Trust's future income tax rate decreased to approximately 35 percent in 2004 (36 percent in 2003) compared to the tax rate of 41 percent applicable for the 2004 income tax year.

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

($000)	2004	2003
Income before income taxes	18,645	17,235
Statutory income tax rate	40.70%	41.86%
Expected provision for income taxes	7,589	7,215
Effect of change in corporate tax rates	(465)	(1,335)
Non-deductible crown charges	2,077	2,160
Resource allowance	(5,275)	(4,222)
Net income of the Trust and other	(15,940)	2,100
Non-deductible reorganization costs	-	2,183
Future income tax expense (recovery)	(12,014)	8,101

b) The net future income tax liability is comprised of:

($000)	2004	2003
Property, plant and equipment net book value in excess of tax value	29,972	18,628
Asset retirement obligation	(4,855)	(1,738)
Financial instruments	(2,564)	-
Partnership deferral	18,171	14,813
Unit issue costs	(677)	(934)
Loss carryforward	(6,359)	(1,029)
Attributed Canadian royalty income	(607)	(27)
Future income tax liability	33,081	29,713

c) The following tax pools are available for future use as deductions from taxable income:

	2004			2003		
($000)	The Trust	Other Entities	Total	The Trust	Other Entities	Total
Intangible resource pools	25,701	155,968	181,669	24,815	54,838	79,653
Undepreciated capital cost	-	55,790	55,790	-	34,835	34,835
Loss carryforward (expire through 2009)	-	18,195	18,195	-	2,893	2,893
Unit issue costs	6,748	1,938	8,686	1,716	2,623	4,339
Attributed Canadian royalty income	13,686	5,278	18,964	3,388	214	3,602
Total tax pools	46,135	237,169	283,304	29,919	95,403	125,322

13. PER TRUST UNIT AMOUNTS

The following table summarizes the weighted average Trust units used in calculating net income per Trust unit:

	Three months ended		Year ended	
	December 31, 2004	December 31, 2003[2]	December 31, 2004	December 31, 2003[2]
Weighted average Trust units/shares	29,010,500	17,137,197	26,204,295	16,413,279
Trust units issuable on conversion of exchangeable shares [1]	1,558,869	1,983,184	1,558,869	1,983,184
Weighted average Trust units/shares and exchangeable shares	30,569,369	19,120,381	27,763,164	18,396,463
Dilutive impact of restricted units/stock options	405,430	187,950	320,446	47,373
Dilutive Trust units/shares and exchangeable shares	30,974,799	19,308,331	28,083,610	18,443,836

1) The Trust units issuable on conversion of the exchangeable shares reflects the exchangeable shares outstanding at the end of the period converted at the exchange ratio in effect at the end of the period.
2) All pre-arrangement comparative share numbers have been adjusted for the consolidation of Class A and Class B shares.

14. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The financial instruments of the Trust that are included on the balance sheet are comprised of cash, accounts receivable, the reclamation fund and current liabilities.

a) Fair values of financial assets and liabilities

The fair values of financial instruments approximate their carrying amount.

b) Credit risk

A substantial portion of the Trust's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks.

c) Risk management

The Trust has entered into fixed price oil contracts and interest rate swaps to manage its exposure to fluctuations in the price of crude oil and interest rates on debt.

The following is a summary of all financial instrument contracts in place at December 31, 2004:

Fixed Price Oil Contracts	Weighted average volume (bbl/d)	Weighted average price ($Cdn/bbl)	Index
January 1, 2005 to December 31, 2005	3,450	43.37	WTI
January 1, 2006 to December 31, 2006	2,062	51.20	WTI

Interest Rate Swaps	Amount ($000)	Interest rate %
January 1, 2005 to February 15, 2005	8,000	4.20
January 1, 2005 to March 4, 2005	12,000	4.03

None of the Trust's commodity or interest rate contracts have been designated as effective accounting hedges. Accordingly, all commodity and interest rate contracts have been recorded on the balance sheet as assets and liabilities based on their fair values. The following table reconciles the movement in the fair value of the Trust's commodity and interest rate contracts for the year ended December 31, 2004:

	($000)
Risk management liability (net), January 1, 2004	3,209
Change in mark-to-market unrealized loss	4,689
Risk management liability (net), December 31, 2004	7,898

Upon implementation of the new hedge accounting guideline on January 1, 2004, the Trust recorded a deferred financial instrument loss of $3,407,000 and a deferred financial instrument gain of $198,000. The opening deferred financial instrument loss and gain are being amortized into income as the contracts are settled. At December 31, 2004, $3,369,000 of the deferred loss and $71,000 of the deferred gain have been amortized into income.

15. COMMITMENTS

At December 31, 2004, the Trust had contractual obligations and commitments for office space and equipment:

	($000)
2005	470
2006	484
2007	242
2008	-
2009	-

16. COMPARATIVE INFORMATION

Certain information provided for the previous period has been restated to conform to the current period presentation.

CORPORATE INFORMATION

DIRECTORS:
Scott Saxberg (4)
Paul Colborne, Chairman (2)(4)
Hugh Gillard (1)(2)
Peter Bannister (1)(3)
Ken Cugnet (3)(4)
Greg Turnbull (2)
Gerald Romanzin (1)(3)

1. Member of the Audit Committee of the Board of Directors
2. Member of the Compensation Committee of the Board of Directors
3. Member of the Reserves Committee of the Board of Directors
4. Member of the Health, Safety and Environment Committee of the Board of Directors

OFFICERS:
Scott Saxberg, President and Chief Executive Officer
C. Neil Smith, Vice President, Engineering and Business Development
Greg Tisdale, Chief Financial Officer
Dave Balutis, Vice President, Geosciences

Head Office:	Suite 1800, 500 – 4 Avenue SW, Calgary, Alberta T2P 2V6 Tel: (403) 693-0020; Fax: (403) 693-0070
Banker:	The Bank of Nova Scotia, Calgary, Alberta
Auditor:	PricewaterhouseCoopers LLP, Calgary, Alberta
Legal Counsel:	McCarthy Tétrault LLP, Calgary, Alberta
Evaluation Engineers:	Gilbert Laustsen Jung Associates Ltd., Calgary, Alberta

INVESTOR RELATIONS:

Registrar and Transfer Agent:	Investors are encouraged to contact Crescent Point's Registrar and Transfer Agent for information regarding their security holdings: Olympia Trust Company 2300, 125 - 9 Avenue SE, Calgary, Alberta T2G 0P6 Tel: (403) 261-0900
Stock Exchange:	Toronto Stock Exchange - TSX
Stock Symbols:	CPG.UN
Investor Contacts:	Scott Saxberg, President and Chief Executive Officer, (403) 693-0020 Greg Tisdale, Chief Financial Officer, (403) 693-0020

Crescent Point
ENERGY TRUST

Suite 1800, 500 - 4th Avenue SW
Calgary, Alberta T2P 2V6
Tel: (403) 693-0020
Fax: (403) 693-0070

www.crescentpointenergy.com