Crescent Point Energy Trust

PRESS RELEASE

MARCH 24, 2004
Calgary, Alberta

CRESCENT POINT ENERGY TRUST ANNOUNCES 2003 YEAR END AND FOURTH QUARTER RESULTS

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, 2003.

Crescent Point's business plan is to create sustainable growth in reserves, production and cash flow through the execution of management's integrated growth strategy of acquiring, exploiting and developing high quality, long life, light oil and natural gas properties. In 2003, Crescent Point continued to implement management's business plan by successfully merging with Tappit Resources Ltd. ("Tappit"), converting to a royalty trust and divesting of its northeast B.C. exploration assets through a Plan of Arrangement (the "Plan") to a newly created, publicly listed, exploration and production company, StarPoint Energy Ltd. ("StarPoint").

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.

All reserves quoted are defined under the new National Instrument 51-101 ("NI 51-101") guidelines. Under NI 51-101's revised reserve definitions and evaluation standards, proved plus probable reserves represent a "best estimate" and are compared to prior years "established" reserves which were defined as proved plus 50 percent probable.

2003 YEAR END HIGHLIGHTS

- Completed a strategic merger whereby Crescent Point acquired Tappit and converted into an oil and gas royalty trust through the Plan. In addition, the shareholders of Crescent Point Energy and Tappit received shares in StarPoint, a separate, publicly listed, exploration and production company. The special meeting of the shareholders approving the transaction was held on August 21, 2003. The effective date for the transaction was September 5, 2003.

- Increased the Trusts reserves from 9.1 million boe ("mmboe") proved, and 10.8 mmboe of proved plus probable (established) reserves at the end of 2002, to 18.4 mmboe proved and 24.1 mmboe of proved plus probable reserves at the end of 2003, as independently engineered by Gilbert Laustsen Jung Associates Ltd ("GLJ") under NI 51-101 (natural gas reserves and production are converted at the energy equivalent ratio of six thousand cubic feet of natural gas to one barrel of oil). These reserve additions do not include the Trust's recent $81 million acquisition of Capio Petroleum Corporation ("Capio"), which closed on January 6, 2004.

- Excluding the Capio assets, proved plus probable reserves increased by more than 120 percent, and 2003 production was replaced by more than 740 percent.

- Completed 3 major acquisitions and 14 minor top-up acquisitions which added approximately 3,600 boepd of production, and 10.2 mmboe of proved and 13.1 mmboe of proved plus probable reserves.

- Achieved positive technical revisions of 105 mboe and 841 mboe, and positive development revisions of 2,115 mboe and 3,244 mboe in the proved and proved plus probable reserve categories respectively. Technical and development revisions replaced 2003 production by 200 percent. This demonstrates Crescent Point's successful strategy of acquiring and developing incremental reserves in high quality, large oil and gas in place properties.

- Including the Capio assets, Crescent Point has increased its reserves by 144 percent proved and 172 percent proved plus probable to 22.2 mmboe proved and 29.4 mmboe proved plus probable reserves, as independently engineered by GLJ. Crescent Point increased its reserve life index to 7.0 years proved and 9.2 years proved plus probable, based on the Trust's forecasted 2004 production of 8,750 boepd.

- Drilled 27 gross wells and 17 net wells with a success rate of 89 percent.

- Generated an "all-in" 2003 finding, development and acquisition cost of $10.90 per proved boe, and $8.07 per proved plus probable boe of reserves, on oil and gas capital expenditures of $123.6 million.

- Increased average daily production from 1,974 boepd in 2002, to 5,659 boepd in 2003. This represents a year over year production increase of 187 percent.

- Increased cash flow from $11.9 million or $1.07 per unit in 2002 to $36.6 million or $1.99 per unit in 2003. 2003 cash flow includes non-recurring general and administrative costs of $5.2 million incurred in the corporate re-organization. Without these costs cash flow for the year would have been $41.8 million or $2.27 per unit.

- Maintained an excellent balance sheet throughout the year which continues to position the Trust for continued growth in 2004 and beyond.

- The Trust has identified more than 100 low risk infill development drilling locations with more than 5,000 boepd of risked production additions.

FOURTH QUARTER 2003 HIGHLIGHTS

- Production increased from 2,942 boepd in the fourth quarter of 2002, to 7,331 boepd in the fourth quarter of 2003. This represents a quarter over quarter production increase of 149 percent.

- Cash flow increased from $4.7 million or $0.36 per unit in the fourth quarter of 2002, to $12.0 million or $0.62 per unit in the fourth quarter of 2003.

- Maintained consistent monthly distributions of $0.17 per unit, totaling $0.51 per unit for the fourth quarter of 2003 which represents a payout ratio of 82 percent.

- Completed an equity offering of approximately $31.8 million in the month of December 2003.

- Identified, negotiated and executed an agreement to acquire all of the issued and outstanding shares of Capio for total consideration of approximately $81 million, which subsequently closed on January 6, 2004.

- Entered into a bought deal equity financing to raise gross proceeds of $65.7 million which subsequently closed on January 6, 2004.

- Completed two top-up and two new area acquisitions which added approximately 300 boepd and 1.1 mmboe of proved plus probable reserves for approximately $11.4 million.

- Drilled 8 gross wells and 5.5 net wells with a success rate of 100 percent.

FINANCIAL AND OPERATING HIGHLIGHTS

	Three months ended			Twelve months ended		
($000's except per unit amounts)	**Dec. 31, 2003**	**Dec. 31, 2002**	**% Change**	**Dec. 31, 2003**	**Dec. 31, 2002**	**% Change**
Financial						
Production revenue (net of royalties)	18,291	8,184	123	60,810	20,302	200
Hedge gain (loss)	(560)	(701)	20	(2,722)	(1,543)	(76)
Total revenue	17,731	7,483	137	58,088	18,759	210
Cash flow from operations	11,975	4,694	155	36,627	11,893	208
Per unit (2002 – combined A & B shares)	0.63	0.37	70	1.99	1.12	78
Per unit – diluted	0.62	0.36	72	1.99	1.07	86
Net income (loss)*	(663)*	1,488	(145)	9,020	3,300	173
Per unit (2002 – combined A & B shares)	(0.03)	0.12	(125)	0.49	0.31	58
Per unit – diluted	(0.03)	0.11	(127)	0.49	0.30	63
Capital expenditures, net	22,584	11,267	100	124,464	54,846	127
Total debt (net of working capital)	38,417	17,413	121	38,417	17,413	121
Trust units outstanding (MM)						
Units (2002 – combined A & B shares)	19.3	12.6	53	19.3	12.6	53
Exchangeable Shares	1.9	-	-	1.9	-	-
Weighted average common units outstanding (MM)						
Units (2002 – combined A & B shares)	19.1	12.6	52	18.4	10.6	74
Diluted	19.3	13.2	46	18.4	11.1	66

	Three months ended			Twelve months ended		
	Dec. 31, 2003	**Dec. 31, 2002**	**% Change**	**Dec. 31, 2003**	**Dec. 31, 2002**	**% Change**
Operations						
Average daily production						
Crude oil and NGL's (bopd)	5,773	2,213	161	4,536	1,517	199
Natural gas (mcf/d)	9,349	4,375	114	6,738	2,741	146
Barrels of oil equivalent (boepd)	7,331	2,942	149	5,659	1,974	187
Average product prices						
Crude oil and NGL's (C$/bbl)	34.07	38.47	(11)	36.07	37.01	(3)
Hedge gain (loss)	(1.00)	(3.44)	71	(1.49)	(2.97)	50
	33.07	35.03	(6)	34.58	34.04	2
Natural gas (C$/mcf)	5.32	5.11	4	6.15	4.16	48
Hedge gain (loss)	(0.03)	-	-	(0.11)	0.10	(210)
	5.29	5.11	4	6.04	4.26	42
Wells drilled						
Gross	8	16	(50)	27	27	-
Net	5.5	12	(54)	17	17	-
Success rate (percent)	100	94	6	89	88	1

* Excluding the non-recurring future taxes of $2,183, net income for the fourth quarter would have been $1,519. See fourth quarter 2003 net income discussion.

2003 OPERATIONS REVIEW

Crescent Point drilled a total of 27 wells in 2003, achieving an overall success rate of 89 percent. Of these wells 2 were exploratory and 25 were classified as development.

The following table summarizes the Trust's 2003 exploration and development drilling results:

AREA	GAS	OIL	D&A	TOTAL	NET	% SUCCESS
Southeast Saskatchewan	0	14	0	14	12.3	100%
South/Central Alberta	4	5	2	11	3.5	82%
Northeast B.C. West Peace River Arch, Alberta	1	0	1	2	1	50%
TOTAL	5	19	3	27	17	89%

Southeast Saskatchewan

As part of management's corporate growth strategy, Crescent Point continued to focus on acquisition and exploitation opportunities in the southern plains of Saskatchewan. Through the strategic acquisition of Tappit, the Trust consolidated interests in the Manor/Queensdale area of southeast Saskatchewan and added a new core area at Tatagwa. As a result, Crescent Point gained operatorship and high working interests in 4 long life, light oil pools at Manor, Queensdale, Wildwood and Tatagwa. These 4 pools have total combined original oil-in-place of more than 270 million barrels.

In 2003, Crescent Point drilled 14 (12 net) successful horizontal development wells in Manor, Wildwood and Queensdale that met or exceeded expectations. The Trust has identified an additional 45 locations remaining in inventory with up to 10 development wells planned for 2004.

At Tatagwa, the Trust completed battery modifications and pumpjack upgrades to increase fluid handling capability. With the implementation of the water flood in the Midale Marly formation in early 2003, production has steadily increased due to the initial water flood response.

South/Central Alberta

During 2003, Crescent Point continued to exploit its existing properties at Little Bow, Sounding Lake and John Lake. At John Lake 2 gas wells were drilled and encountered Colony, Viking, Labiche and Second White Specks gas zones. Currently, 1 well is on production, while the second awaits completion and tie-in. Additional land and seismic was acquired at John Lake to follow-up on the drilling success. Ongoing compression optimization and workovers have continued to add production and value to the John Lake property. Optimization work has continued throughout 2003 at Little Bow with 2 injection wells being drilled in order to enhance the water injection scheme.

Northeast B.C. - Cypress/Chowade

As part of the Plan, the Cypress/Chowade area was divested to StarPoint.

2004 Drilling Program Update

To date in 2004, Crescent Point has successfully drilled 3 Manor horizontal development oil wells and 1 horizontal new pool discovery at Auburnton in southeast Saskatchewan. Currently, 2 light oil wells have been completed and are on production, and the 2 other wells are undergoing completion operations. An additional well at Glen Ewen has been drilled and is currently being evaluated.

In the first quarter, a 7 well development drilling program has commenced in the Doe area of northeast B.C. To date, 1 well has been placed on stream, 4 are currently being drilled, and 2 are standing pending evaluation.

Gas is gathered to the Trust's operated compressor facility and produced directly into the adjacent Duke/Westcoast sales line resulting in low operating costs, reduced royalty rates and high netbacks.

Acquisition Update

In January 2004, Crescent Point acquired all of the issued and outstanding shares of Capio for consideration of approximately $81 million. The acquisition closed on January 6, 2004. Crescent Point management believes this strategic, high quality, natural gas and light oil acquisition complements and balances the Trust's existing large oil and gas in place assets. The acquisition also provides additional drilling inventory for natural gas with significant production and reserves growth.

2004 MARKET GUIDANCE

Crescent Point has a high quality, predictable production, reserve and cash flow base focused in 6 principal properties. Each of these properties is characterized by high working interests, operated and with significant development upside.

During 2003, Crescent Point continued to expand the Trust's development drilling inventory. Crescent Point now has an inventory of more than 100 low risk development locations in its core areas, which will provide for sustainable production volumes and distributions through 2004 and beyond.

The Trust has already seen positive results from the water flood project at Tatagwa in southeast Saskatchewan. With minimum capital expenditures since acquiring the property, the Trust has been able to steadily increase production due to the initial water flood response to date.

Crescent Point continues to lock in commodity price swaps for 2004 and 2005 at attractive crude oil pricing parameters to reduce risk on distribution levels (see "Risk Management" below).

Crescent Point has an excellent balance sheet with debt of less than 1.0 times current annualized cash flow and approximately $50 million of unutilized credit lines.

Crescent Point has had an excellent start to 2004 by successfully closing its acquisition of Capio, raising $65.7 million of new equity and revising upward its 2004 average daily production estimate to 8,750 boepd.

In 2004 Crescent Point is projecting to maintain its 8,750 boepd of production with capital expenditures of approximately $16 million for drilling, land and seismic. Estimates for 2004 are as follows:

Production	
Oil and NGL's (bopd)	5,750
Natural gas (mcf/d)	18,000
boepd (6:1)	8,750
Cash flow ($000's)	$60,000
Cash flow per outstanding unit ($)	$2.40
Capital expenditures ($000's)	$16,000
Wells drilled, net	18-20
Pricing	
Crude oil ($US/bbl) - WTI	$29.50
($Cdn/bbl) – Corporate	$38.00
Natural gas ($US/mcf) Corporate	$4.75
($Cdn/mcf) Corporate	$5.75
Exchange rate ($Cdn/$US)	0.75

2003 YEAR END

The following discussion and analysis should be read in conjunction with the consolidated financial statements and related notes for a full understanding of the financial position and results of operations of the Trust. All amounts are expressed in Canadian dollars. A barrel of oil equivalent ("boe") is based on a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. Certain information regarding the Trust contained herein may constitute forward-looking statements under applicable securities laws. Such statements are subject to known or unknown risks and uncertainties that may cause actual results to differ materially from those anticipated or implied in the forward-looking statements.

Plan of Arrangement

Crescent Point completed a strategic merger whereby it acquired Tappit and converted into an oil and gas royalty trust through the Plan. In addition, the shareholders of Crescent Point Energy and Tappit received shares in 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.

Production and Pricing

In 2003 the Trust's production averaged 5,659 boepd, comprised of 4,536 bopd of oil and 6,738 mcf/d of natural gas. In 2002 the Trust's production averaged 1,974 boepd, comprised of 1,517 bopd of oil and 2,741 mcf/d of natural gas. This represents an increase of 187 percent in year over year production volumes.

The average price received by the Trust for crude oil and NGL's in 2003 was $36.07 per bbl before hedging, and $34.58 per bbl after hedging. For natural gas the average price received by the Trust in 2003 was $6.15 per mcf before hedging, and $6.04 per mcf after hedging. In 2002 the average price received by the Trust for crude oil and NGL's was $37.01 per bbl before hedging, and $34.04 per bbl after hedging. For natural gas the average price received by the Trust in 2002 was $4.16 per mcf before hedging, and $4.26 per mcf after hedging. This represents a year over year increase of 2 percent for oil and NGL's prices, and a 42 percent increase in natural gas prices.

Cash Flow

Royalties in 2003 were $14,043,616 resulting in net oil and gas revenue before expenses of $58,087,917. In 2002 royalties were $4,352,968 and net oil and gas revenue before expenses were $18,759,128.

The average royalty rate before hedging incurred by Crescent Point in 2003, net of the Alberta Royalty Tax Credit ("ARTC"), was 19 percent. In 2002 the average royalty rate net of ARTC, was 18 percent.

Operating expenses in 2003 totaled $11,696,435 or $5.66 per boe. In 2002 total operating expenses were $4,211,906 or $5.85 per boe. This represents a decrease in operating expense per boe of approximately 3 percent. The Trust experienced a decrease in year over year operating expenses per boe due to its successful development drilling program at Manor, Saskatchewan, and the field optimization activities at Manor, Little Bow and Sounding Lake.

General and administrative expenses incurred by the Trust during 2003 (excluding unit-based compensation) totaled $3,611,570 as compared to $2,210,063 in 2002. Of the total 2003 administrative expense, $1,471,585 was capitalized as part of the Trust's exploration and development program. This compares to the amount capitalized in 2002 of $732,835. Of the amount capitalized for 2003, $523,573 represents a portion of the one time cost for the pay out of cancelled stock options. After capitalization of these costs, the Trust had net administrative expenses of $2,139,985 or $1.04 per boe. This compares to the 2002 net administrative expenses of $1,477,228 or $2.05 per boe. This represents a significant decrease in administrative expenses from 2002 on a per boe basis.

In 2003 the Trust generated cash flow from operations of $36,626,967 or $1.99 per unit. This compares to the period ended December 31, 2002, which generated cash flow from operations of $11,893,063 or $1.07 per unit. Cash flow for 2003 includes reorganization costs of $5,214,994. Without these costs cash flow would have been $41,841,961 or $2.27 per unit.

Net Income

Depletion, depreciation and amortization for the year ended December 31, 2003 was $18,765,388 or $9.08 per boe as compared to $5,742,362 or $7.97 per boe for the year ended December 31, 2002.

The unit-based compensation of $338,832 or $0.16 per boe for the year ended December 31, 2003 represents the amortized non-cash compensation cost associated with the Restricted Unit Bonus Plan. The Restricted Unit Bonus Plan was established on September 5, 2003, as part of the corporate reorganization. The Trust granted 187,950 restricted units under the plan on October 1, 2003. The compensation cost is determined based on the estimated fair value of trust units on the date the restricted units are granted under the plan. The compensation cost is recognized over the vesting period of the restricted units.

In 2003 Crescent Point had earnings of $9,020,377 or $0.49 per unit, compared to $3,299,589 or $0.30 per unit for the year ended December 31, 2002. This represents a year over year increase of 63 percent on a per unit basis. Net income for 2003 includes re-organization costs of $5,214,994 and the related future tax expense of $2,182,997. Excluding the re-organization costs, net income for 2003 would have been $16,418,368 or $0.89 per unit.

Capital Expenditures

Total capital expenditures were $124.5 million (net of dispositions) in 2003, compared to $54.8 million in 2002. Total capital expenditures excluding financing and administrative asset expenditures were $123.6 million.

Liquidity and Capital Resources

During 2003 Crescent Point completed 2 separate private placement equity financings.

On January 7, 2003 Crescent Point Energy sold 2,360,000 special warrants convertible into Class A shares for proceeds of $10,030,000 ($4.25 per special warrant) on a private placement basis. The proceeds from this equity offering were used to finance the $21.5 million Little Bow acquisition on January 31, 2003.

On December 10, 2003 the Trust sold 2,650,000 units for proceeds of $31,800,000 ($12.00 per unit) on a bought deal basis.

As at December 31, 2003, Crescent Point had total debt of $38.4 million (net of working capital), and a revolving term loan credit facility of $81 million with a major Canadian chartered bank. The debt includes a deposit of $1.0 million for the January 6, 2004 purchase of Capio.

As at January 6, 2004, with the closing of the Capio acquisition, the Trust had total debt of approximately $55 million and Crescent Point's revolving term loan credit facility was increased to $105 million.

On January 6, 2004, Crescent Point completed an equity financing in which they sold 5,150,000 units for proceeds of $65,662,500 ($12.75 per unit) on a bought deal basis.

Risk Management

In accordance with the Trust's ongoing risk management strategy, Crescent Point has currently locked in the following crude oil hedge/swaps for 2004 and 2005:

Period	Swap Volumes (bopd)	($C/bbl)
Jan 1/04 – Dec 31/04	3,000	$36.58
Jan 1/05 – Dec 31/05	2,075	$38.46

In addition, the Trust has locked in the following natural gas hedges for 2004:

Period	Swap Volumes (GJ/d)	($C/GJ)
Jan 1/04 – Mar 31/04	1,000	$6.50 - $9.25 (costless collars)
Apr 1/04 – Oct 31/04	4,500	$5.82

Reserves; Finding, Development and Acquisition Costs

All reserves quoted are defined under the new NI 51-101 guidelines. Under NI 51-101's revised reserve definitions and evaluation standards, proved plus probable reserves represent a "best estimate" and are compared to prior years "established" reserves which were defined as proved plus 50 percent probable.

Crescent Point entered 2003 with total reserves of 9.13 mmboe proved, and 10.80 mmboe proved plus probable (established), as independently evaluated by GLJ.

As a result of the Trust's activities in 2003, Crescent Point added 9.28 mmboe proved, and 13.26 mmboe of proved plus probable reserves, net of 2.07 mmboe of production. The Trust exited 2003 with 18.41 mmboe proved, and 24.05 mmboe of proved plus probable reserves, as independently engineered by GLJ.

The 2003 results do not include any reserves relating to the Trust's January 6, 2004 Capio acquisition.

SUMMARY OF RESERVES AND ECONOMICS
Company Interest
(as at December 31, 2003)

	RESERVES								BEFORE TAX PRESENT VALUE - $M			
	Oil (Mstb)		Gas (Mmcf)		NGL (Mstb)		Total (Mboe)		Discount Rate			
Description	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Undiscounted	10%	12%	15%
Proved producing	12,959	11,297	14,666	11,642	102	87	15,504	13,323	191,046	132,398	125,573	116,872
Proved non-producing	2,626	2,274	1,401	1,173	45	40	2,905	2,511	35,434	18,826	16,954	14,634
Total proved	**15,585**	**13,571**	**16,067**	**12,815**	**147**	**127**	**18,409**	**15,834**	**226,480**	**151,224**	**142,527**	**131,506**
Probable	4,824	4,193	4,719	3,847	33	29	5,644	4,863	80,357	35,848	32,070	27,625
Total proved plus probable	**20,409**	**17,764**	**20,786**	**16,662**	**180**	**156**	**24,053**	**20,697**	**306,837**	**187,072**	**174,597**	**159,131**

Note:
1. Based on GLJ's January 1, 2004 escalated price forecast. "Gross reserves" are the total Trust's working interest share before deduction of any royalties. "Net reserves" are the total Company's working interest share after deducting royalties.

RESERVE RECONCILIATION

	CRUDE OIL AND LIQUIDS (Mstb)			NATURAL GAS (Mmcf)			BOE (Mboe)		
	Proved	Probable	Total	Proved	Probable	Total	Proved	Probable	Total
Opening Balance January 1, 2003	7,414	1,319	8,733	10,315	2,060	12,375	9,134	1,662	10,796
Acquired	9,228	2,758	11,986	5,743	828	6,571	10,185	2,896	13,081
Disposed	-	-	-	(6,381)	(4,678)	(11,059)	(1,064)	(780)	(1,843)
Production	(1,649)	-	(1,649)	(2,501)	-	(2,501)	(2,066)	-	(2,066)
Development	645	279	924	8,821	5,098	13,919	2,115	1,129	3,244
Technical Revisions	94	501	595	70	1,411	1,481	105	737	841
Closing Balance December 31, 2003	**15,732**	**4,857**	**20,589**	**16,067**	**4,719**	**20,786**	**18,409**	**5,644**	**24,053**

Note:

1. The opening balance probable reserves which were evaluated under national policy 2B were risked 50 percent so as to compare to the 2003 year end reserves which were prepared under NI 51-101.
2. Acquired reserves do not include Capio Petroleum Corporation acquisition which closed January 6, 2004.
3. Disposed reserves relate to the Cypress/Chowade, B.C. property divested to StarPoint Energy Ltd.
4. Developed reserves include reserves developed and then divested to StarPoint Energy Ltd

FINDING, DEVELOPMENT AND ACQUISITION COSTS

	CAPITAL EXPENDITURES		RESERVES				FINDING, DEVELOPMENT AND ACQUISITION	
			Total Proved		Proved Plus Probable*		Proved	Proved Plus Probable*
	$M	%	Mboe	%	Mboe	%	$/Boe	$/Boe
Exploration Development and Revisions	23,959	19	2,221	20	4,086	27	10.79	5.86
Acquisitions Net of Dispositions	99,675	81	9,122	80	11,238	73	10.93	8.87
Total	**123,634**	**100**	**11,343**	**100**	**15,324**	**100**	**10.90**	**8.07**

Note:

1. Exploration Development and 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 $1.998 million and $3.308 million respectively to the proved and proved plus probable reserves categories. Including these changes, the proved and proved plus probable finding and development costs are $11.69 and $6.67 per barrel respectively.
2. Approximately $5.0 million of capital was expended on the assets divested to StarPoint prior to its spin out as a result of Crescent Point's reorganization into a Trust.

During 2003 total oil and gas capital expenditures net of dispositions for the Trust was $123.6 million. Based on reserve additions of 11.34 mmboe proved, and 15.32 mmboe proved plus probable, the Trust had an "all-in" 2003 finding and development cost of $10.90 per proved boe, and $8.07 per proved plus probable boe.

Including the Capio acquisition, the Trust has 22.2 mmboe proved and 29.4 mmboe proved plus probable reserves with a reserve life index of 7.0 years proved and 9.2 years proved plus probable, based on the Trust's forecasted 2004 production of 8,750 boepd.

NATIONAL INSTRUMENT 51-101

Crescent Point's year end reserves report is compliant with National Instrument 51-101 ("NI 51 – 101").

Background

On July 18, 2003 the Alberta Securities Commission (ASC) issued a Notice with respect to the previous National Policy Statement No. 2-B *Guide for Engineers and Geologists Submitting Oil and Gas Reports to Canadian Provincial Securities Administrators* ("NP 2-B") used to evaluate and annually report a company's reserves. The ASC stated that the Canadian Securities Administrators (CSA) "no longer consider the reserves definitions and the specific disclosure requirements set out in NP 2-B to be sufficiently clear or comprehensive to meet the needs of market participants." As such, NI 51-101 was developed to "enhance investor confidence in Canadian capital markets and facilitate the raising of new capital by oil and gas reporting issuers…. The Instrument establishes disclosure standards and procedures somewhat akin to those long applied to financial disclosure." Implementation of NI 51 -101 becomes standard for reporting issuers engaged in upstream oil and gas activities effective December 31, 2003. NI 51-101 establishes a program of continuous disclosure and includes specific reporting requirements. The Standing Committee on Reserves Evaluation of the Calgary Chapter of the Society of Petroleum Evaluation Engineers ("SPEE") and the Standing Committee on Reserves Definitions of the Canadian Institute of Mining, Metallurgy and Petroleum ("CIM") (Petroleum Society) developed the Canadian Oil and Gas Evaluation Handbook ("COGEH") to serve as the guideline for conducting and reporting reserve evaluations. Canadian Securities regulators require reporting issuers to comply with COGEH. Volume 1 of the handbook entitled "Reserve Definitions and Evaluation Practices and Procedures" was published in June 2002. Continuing clarification of the guidelines is expected as companies make the transition to the new reporting requirements.

New COGEH Reserve Definitions

Proved Reserves
Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. There is at least a 90 percent probability that recovered reserves will equal or exceed the assigned proved reserves.

Probable Reserves
Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. There is at least a 50 percent probability that the quantities recovered will equal or exceed the sum of the assigned proved plus probable reserves. As such, under the definitions of NI 51-101, the proved plus probable reserves represent the "best estimate" of recoverable reserves.

Possible Reserves
Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

Effect on Crescent Point Reserves Assignment

In consultation with Crescent Point's independent engineers, proved reserves assigned under NI 51-101 are generally expected to be equal to or slightly less than those that would have been assigned under NP-2B while proved plus probable reserves assigned under NI 51-101 would be roughly comparable to the proved plus 50 percent risked probable or "established" reserves under NP-2B. For comparison to previous reports prepared under NP-2B, proved reserves are compared on an equivalent basis while the new proved plus probable reserves are compared to the previous "established" reserves.

Other Effects

- Finding, development and acquisition costs are reported on a proved and proved plus probable reserves basis only.
- Reserves expected to be produced beyond fifty years from the effective date are excluded from reporting.
- Drills previously classified as probable may not be included under the new definition of probable depending on their previously assigned risk level.
- The majority of drills forecast must be forecast over the next two years.

FOURTH QUARTER 2003

Production and Pricing

Production in the fourth quarter of 2003 averaged 7,331 boepd comprised of 5,773 bopd of crude oil and NGL's, and 9,349 mcf/d of natural gas production. Production in the fourth quarter of 2002 averaged 2,942 boepd, comprised of 2,213 bopd of crude oil and NGL's, and 4,375 mcf/d of natural gas production. This represents a quarter over quarter increase in production of 149 percent.

The average price received by the Trust for crude oil and NGL's in the fourth quarter of 2003 was $34.07 per bbl before hedging and $33.07 per bbl after hedging. For natural gas the average price received by the Trust in the fourth quarter of 2003 was $5.32 per mcf before hedging and $5.29 per mcf after hedging. In the fourth quarter of 2002 the average price received by the Trust for crude oil and NGL's was $38.47 per bbl before hedging, and $35.03 per bbl after hedging. For natural gas the average price realized by the Trust in the fourth quarter of 2002, was $5.11 per mcf.

Cash Flow

Cash flow for the fourth quarter of 2003 was $11,974,788 or $0.62 per unit. Cash flow in the fourth quarter of 2002 was $4,694,289 or $0.36 per unit. This represents a quarter over quarter increase of 72 percent on a per unit basis.

Royalties for the fourth quarter of 2003 were $4,384,171 or 19 percent of production revenue before hedging. Royalties in the fourth quarter of 2002 were $1,703,455 or 17 percent of production revenue before hedging.

Operating expenses in the fourth quarter of 2003 were $4,033,099 or $5.98 per boe. In the fourth quarter of 2002 operating expenses were $1,836,474 or $6.79 per boe. This represents a quarter over quarter decrease of 12 percent on a per boe basis.

General and administrative expenses were $646,922 or $0.96 per boe in the fourth quarter of 2003, compared to $497,600 or $1.84 per boe in the fourth quarter of 2002. With current production after the Capio acquisition in excess of fourth quarter averages, general and administrative expense are expected to decrease on a per boe basis in the first quarter of 2004.

Net Income

Depletion, depreciation and amortization for the fourth quarter of 2003 were $7,440,663 or $11.03 per boe, compared to $1,744,499 or $6.45 per boe in the fourth quarter of 2002. The Trust showed an increase in depletion, depreciation and amortization in 2003 due to an increase in property acquisition costs.

The unit-based compensation of $338,832 or $0.50 per boe for the fourth quarter of 2003 represents the amortized non-cash compensation cost associated with the Restricted Unit Bonus Plan.

Crescent Point had a net loss of $(633,162) or $(0.03) per unit in the fourth quarter of 2003, compared to net income of $1,488,183 or $0.11 per unit in the fourth quarter of 2002. The loss can be largely attributed to a non-recurring adjustment of $2,182,997 to future income taxes resulting from general and administrative expenses incurred as part of the corporate re-organization. Excluding the future tax adjustment relating to the re-organization costs, the net income for the fourth quarter of 2003 would have been $1,519,835 or $0.08 per unit.

Capital Expenditures

Capital expenditures were $22.6 million (net of dispositions) in the fourth quarter of 2003, compared to $11.3 million in the fourth quarter of 2002. Capital expenditures in the fourth quarter of 2003 include $3.0 million of costs relating to the Tappit acquisition.

CONSOLIDATED FINANCIAL STATEMENTS

The complete consolidated financial statements and accompanying notes to the consolidated financial statements for the year ended December 31, 2003 will be posted on the SEDAR web site: www.sedar.com.

CONSOLIDATED BALANCE SHEET

	Dec. 31, 2003	Dec. 31, 2002
ASSETS	$	$
Current Assets:		
Cash	81,644	85,158
Accounts receivable	17,505,440	11,382,840
Investments in marketable securities	187,645	427,500
Prepaids and deposits	318,064	98,566
	18,092,793	11,994,064
Deposits on property, plant and equipment	1,000,000	3,225,000
Property, plant and equipment	165,149,032	59,450,376
Goodwill	21,170,610	-
	205,412,435	74,669,440
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	13,945,095	15,407,040
Cash distributions payable	2,345,067	-
Bank indebtedness	40,220,000	14,000,000
	56,510,162	29,407,040
Provision for site restoration	1,972,097	363,377
Future income taxes	29,631,990	4,805,634
	88,114,249	34,576,051
Unitholders' equity:		
Unitholders' capital	113,879,599	36,976,483
Exchangeable shares	10,781,627	-
Contributed surplus	338,832	-
Accumulated earnings	3,994,809	3,116,906
Accumulated cash distributions	(11,696,681)	-
	117,298,186	40,093,389
	205,412,435	74,669,440

CONSOLIDATED STATEMENT OF OPERATIONS AND ACCUMULATED EARNINGS

	Three months ended		Twelve months ended	
	Dec. 31, 2003	Dec. 31, 2002	Dec. 31, 2003	Dec. 31, 2002
	$	$	$	$
Revenue:				
Oil and gas sales	22,675,273	9,886,997	74,853,991	24,654,695
Royalties, net of ARTC	(4,384,171)	(1,703,455)	(14,043,616)	(4,352,968)
Hedging losses	(560,143)	(701,103)	(2,722,458)	(1,542,599)
	17,730,959	7,482,439	58,087,917	18,759,128
Expenses:				
Operating	4,033,099	1,836,474	11,696,435	4,211,906
General and administrative	646,922	497,600	2,139,985	1,477,228
Unit-based compensation	338,832	-	338,832	-
Interest on bank indebtedness	624,060	116,759	1,639,308	451,814
Depletion, depreciation and amortization	7,440,663	1,744,499	18,765,388	5,742,362
Provision for site restoration	209,418	110,701	779,309	340,812
Capital and other taxes	191,044	337,318	770,228	725,117
Reorganization costs	261,046	-	5,214,994	-
Gain on sale of investment	-	-	(313,216)	-
Writedown of investment	-	250,000	-	250,000
	13,745,084	4,893,351	41,031,263	13,199,239
Income before future income tax expense	3,985,875	2,589,088	17,056,654	5,559,889
Future income tax expense	4,649,037	1,100,905	8,036,277	2,260,300
Net income (loss) for the period	(663,162)	1,488,183	9,020,377	3,299,589
Accumulated earnings (deficit), beginning of the period	3,945,055	1,628,723	3,116,906	(182,683)
Transfer of assets pursuant to the Plan of Arrangement	712,916	-	(8,142,474)	-
Accumulated earnings, end of the period	3,994,809	3,116,906	3,994,809	3,116,906
Net income (loss) per unit				
Basic (2002 – A & B shares combined)	(0.03)	0.12	0.49	0.31
Diluted	(0.03)	0.11	0.49	0.30
Units Outstanding				
A shares [1]	-	11,989,046	-	11,989,046
B shares [1]	-	606,623	-	606,623
Units	19,282,049	-	19,282,049	-
Exchangeable shares	1,902,901	-	1,902,901	-

[1] December 31, 2002 comparatives are restated taking into effect the share consolidation in the Plan of Arrangement.

CONSOLIDATED STATEMENT OF CASH FLOWS

	Three months ended		Twelve months ended	
	Dec. 31, 2003	**Dec. 31, 2002**	**Dec. 31, 2003**	**Dec. 31, 2002**
	$	$	$	$
Cash provided by (used in)				
Operating activities				
Net income (loss) for the period	(663,162)	1,488,183	9,020,377	3,299,589
Items not affecting cash				
Future income taxes	4,649,037	1,100,905	8,036,277	2,260,300
Gain on sale of investment	-	-	(313,216)	-
Unit-based compensation	338,832	-	338,832	-
Depletion, depreciation and amortization	7,440,663	1,744,499	18,765,388	5,742,362
Provision for site restoration	209,418	110,702	779,309	340,812
Writedown of investment	-	250,000	-	250,000
Cash flow from operations	11,974,788	4,694,289	36,626,967	11,893,063
Change in non-cash working capital				
Accounts receivable	2,433,925	(5,929,970)	1,582,807	(10,850,862)
Prepaid expenses and deposits	(139,456)	51,527	(219,498)	(52,145)
Accounts payable	(373,400)	4,537,619	(5,061,209)	9,540,457
Net change in non-cash working capital	1,921,069	(1,340,824)	(3,697,900)	(1,362,550)
	13,895,857	3,353,465	32,929,067	10,530,513
Investing activities				
Expenditures on petroleum and natural gas properties	(20,349,069)	(11,266,782)	(61,296,900)	(54,522,966)
Acquisition of Tappit Resources Ltd.	278,044	-	(7,713,626)	-
Proceeds on sale of investments	-	-	740,716	-
Petroleum and natural gas deposits	(1,000,000)	(3,225,000)	2,225,000	(2,505,000)
Change in non-cash working capital				
Accounts receivable	(2,646,226)	-	(770,301)	324,176
Accounts payable	(806,484)	2,538,754	(1,971,614)	3,923,824
	(24,523,735)	(11,953,028)	(68,786,725)	(52,779,966)
Financing activities				
Issue of trust units, net of issue costs	30,151,908	(54,111)	41,418,378	26,974,784
Increase (decrease) in bank indebtedness	(11,416,815)	8,600,000	2,520,962	14,000,000
Cash distributions paid	(8,085,196)	-	(8,085,196)	-
	10,649,897	8,545,889	35,854,144	40,974,784
Increase (decrease) in cash	22,019	(53,674)	(3,514)	(1,274,669)
Cash at beginning of period	59,625	138,832	85,158	1,359,827
Cash at end of period	81,644	85,158	81,644	85,158

Crescent Point Energy Trust is a conventional oil and gas income trust with assets strategically focused in 6 core properties comprised of high quality, long life, operated, light oil and natural gas reserves in western Canada. Trust units of Crescent Point are traded on the Toronto Stock Exchange under the symbol "CPG.UN".

FORWARD LOOKING STATEMENTS
This press release may contain forward-looking statements including expectations of future production, cash flow and earnings. These statements are based on current expectations that involve a number of risks and uncertainties, which could cause actual results to differ materially from those anticipated. These risks include, but are not limited to: the risks associated with the oil and gas industry (e.g., operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses, and health, safety and environmental risks), commodity price, price and exchange rate fluctuation and uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures. Additional information on these and other factors that could affect Crescent Point Energy's operations or financial results are included in Crescent Point Energy's reports on file with Canadian securities regulatory authorities.

The TSX has not reviewed and does not accept responsibility for the adequacy or accuracy of this release.

For further information, please contact:

Crescent Point Energy Trust
c/o Crescent Point Resources Ltd.
Scott Saxberg, President and Chief Operating Officer
Dan Toews, Treasurer and Controller

Telephone: **(403) 693-0020**
Fax: **(403) 693-0070**
Internet Address: **www.crescentpointenergy.com**