Harvest Energy Trust

Harvest Energy Trust – News Release

(HTE.UN – TSX)

HARVEST ENERGY TRUST ANNOUNCES YEAR END 2003 AUDITED FINANCIAL RESULTS AND RESERVES

Calgary, April 16, 2004 (TSX: HTE.UN) — Harvest Energy Trust (the "Trust" or "Harvest") announced today its 2003 audited financial and operating results and a summary of its independent engineering evaluation, effective January 1, 2004, completed by McDaniel & Associates Consultants Ltd. ("McDaniel"). The evaluation of the oil and natural gas reserves was prepared in accordance with National Instrument 51-101 ("NI 51-101").

FINANCIAL[1] & OPERATIONAL HIGHLIGHTS

Financial ($000's, except per trust unit and per BOE[2])	**Three Months Ended Dec. 31, 2003**	**Year Ended Dec. 31, 2003**	**Period Ended Dec. 31, 2002[3]**
Oil and natural gas sales	39,825	119,351	22,709
Net Income	6,043	16,710	5,136
Per trust unit, basic[6]	0.37	1.33	3.69
Per trust unit, diluted[6]	0.36	1.29	3.46
Per BOE	4.42	4.15	6.81
Cash flow from operations[4]	13,692	46,487	9,504
Per trust unit, basic (non GAAP) [6]	0.85	3.69	6.83
Per trust unit, diluted (non GAAP) [6]	0.82	3.58	6.43
Per BOE	10.02	11.54	12.61
Cash distributions declared	10,210	30,685	1,863
Cash distributions declared per unit	0.60	2.40	0.20
Payout ratio[5]	75%	66%	20%
Debt, net of working capital	53,555	53,555	34,563
Capital expenditures:			
Exploitation, development and other	5,096	26,623	770
Acquisitions	79,500	108,677	76,153
Weighted average trust units outstanding (000's)[6]			
Basic	16,175	12,591	1,392
Diluted	16,668	13,003	1,479

[1] All financial figures should be read in conjunction with the attached audited consolidated financial statements and accompanying notes and the Management's Discussion and Analysis for the year ended December 31, 2003.
[2] Unit Equivalency: Natural gas is converted to an oil equivalent basis utilizing a 6 mcf:1 bbl conversion ratio. BOE's may be misleading, if used in isolation. A BOE conversion ratio of 6 mcf:1 bbl is based on an energy conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
[3] From the date of formation on July 10, 2002 to December 31, 2002.
[4] Represents cash provided by operating activities before change in non-cash working capital.
[5] Cash distributions declared divided by cash flow from operations.
[6] On December 5, 2002, the Trust became a public entity listed on the Toronto Stock Exchange, at which time 9,312,500 trust units were issued. Thus these trust units were outstanding for only 27 days in 2002 and thus net income per trust unit and cash flow from operations per trust unit for the period ended December 31, 2002 reflect a low weighted average of trust units outstanding.

Operating	Three Months Ended Dec. 31, 2003	Year Ended Dec. 31, 2003	Period Ended Dec. 31, 2002
Production			
Light and medium crude oil (bbl/d)	8,741	5,314	2,718
Heavy crude oil (bbl/d)	5,756	5,444	1,463
Natural gas liquids (bbl/d)	70	64	22
Natural gas (mcf/d)	1,744	1,311	624
Total (BOE/d)	14,858	11,040	4,307
Product prices:			
Light and medium oil ($/bbl)	32.66	32.83	34.21
Heavy oil ($/bbl)	24.92	27.34	22.63
Natural gas liquids ($/bbl)	29.18	29.92	37.64
Natural gas ($/mcf)	6.01	6.70	4.54
Oil equivalent ($/BOE)	29.13	29.62	30.13
Operating expenses ($/BOE)	9.50	8.94	8.49

Trading Statistics ($ per trust unit, except volume)	Three Months Ended Dec. 31, 2003	Year Ended Dec. 31, 2003	Period Ended Dec. 31, 2002 [(1)]
High	14.20	14.20	9.50
Low	11.97	9.45	8.25
Close	14.07	14.07	9.50
Volume traded	2,925,275	7,496,032	561,757

(1) On December 5, 2002, the trust units began trading on the Toronto Stock Exchange.

MESSAGE TO UNITHOLDERS

The year ended December 31, 2003 was Harvest's first complete year of operations. Harvest's business plan has remained constant since its formation in July 2002, and has proved to be successful in the past year in achieving its fundamental objectives of providing Unitholders with stable and reliable distributions while sustaining asset value per unit. This plan employs a strategy of focusing on a hands-on approach to acquiring, developing and operating high quality, mature oil and natural gas properties in the Western Canadian sedimentary basin. Harvest's current production consists of primarily oil producing properties located in the Provost region of East Central Alberta and the Carlyle region of Southeastern Saskatchewan. During the first full year of operations Harvest achieved strong financial and operating results. Harvest doubled production through acquisitions, most significantly acquiring the Carlyle properties in Southeastern Saskatchewan, and an active optimization and development program. Performance at operated properties exceeded internal targets for production and reserve replacement. These successes supported our primary goal of delivering to Unitholders monthly distributions of $0.20 per unit throughout 2003, while enabling Harvest to retain approximately 30% of cash flow for reinvestment. Our capital expenditure and acquisition program supported a successful year of asset renewal, with strong reserve replacement performance.

2003 Highlights

- Harvest maintained a stable monthly distribution payment of $0.20 per trust unit per month throughout 2003 for a total of $2.40 per trust unit in distributions for the year;
- Capital investment totaled $135.3 million in 2003, of which $108.7 million was for acquisitions of producing properties. The remainder was used to fund our capital program, including 21 wells drilled with a 100% success ratio;
- Harvest acquired high quality producing oil properties at Carlyle in Southeastern Saskatchewan in October 2003 for $80 million, adding production of 5,100 BOE per day;
- The December 2003 exit rate production was approximately 15,400 BOE per day resulting in an 80% increase from December 2002;
- Year-end independent engineering evaluation provided positive reserve appreciation, an increase in working interest reserves before the deduction of royalties of 139% on a proved plus probable basis and a replacement of production of 577% on a gross working interest basis before deduction of royalties. Finding, development and acquisition costs amounted to $6.75 per BOE on a proved plus probable basis;
- Harvest exited 2003 with net debt (demand loan plus working capital) to annualized fourth quarter cash flow of 1.0:1.

Hedging

Harvest has developed a risk management policy that uses commodity hedges to mitigate commodity price risk, particularly as it relates to oil sales. The objective of Harvest's risk management policy is to provide Unitholders with greater distribution stability and certainty. Note 12 to the attached Consolidated Financial Statements describes Harvest's commodity contracts as at December 31, 2003.

Taxability

Cash distributions are comprised of a return of capital portion (tax deferred) and a return on capital portion (taxable). For cash distributions received by a Canadian resident, outside of a registered pension or retirement plan the distribution declared in December 2002 and paid in January 2003 was deemed to be 100% tax deferred. For the distributions declared in 2003 and paid in the months of February 2003 through to January 2004, 41% of the distributions were taxable and 59% were tax deferred.

RESERVES

Reserve estimates have been calculated in compliance with the newly implemented NI 51-101. These new standards establish a higher mandated confidence level for both proven and probable reserve determination. Under NI 51-101, proven reserves are defined as reserves that can be estimated with a high degree of certainty to be recoverable with a target of a 90% probability that the actual reserves recovered over time will equal or exceed proven reserve estimates, while probable reserves are defined as having an equal (50%) probability that the actual reserves recovered will equal or exceed the proven plus probable reserve estimates. In accordance with NI 51-101, proven undeveloped reserves have been recognized in cases where plans are in place to bring the reserves on production within a short, well defined time frame. Proven undeveloped reserves often involve infill drilling into existing pools.

Reserve Highlights

- Total proved plus probable reserves increased 139% from the prior year to 33.0 million BOE, prior to accounting for production on a gross working interest basis before deduction of royalties. Accounting for 2003 production (4.029 MBOE), total proved plus probable reserves increased by 168%;
- Over 577% of 2003 production was replaced through reserve additions on a gross working interest basis before deduction of royalties;
- Proved plus probable reserve life index (RLI) increased 40%, from 4.5 years to 6.3 years;
- Proven plus probable finding, development and acquisition costs for 2003 were $6.75 per BOE;
- The cost of acquiring proven plus probable reserves was $5.32 per BOE on a gross basis before deduction of royalties.

Additional reserve disclosure tables, as required under NI 51-101, will be contained in the Annual Information Form that will be filed on SEDAR. The reserve estimates contained in the following table are working interest reserves before the deduction of royalties.

Reserves Summary January 1, 2004 – McDaniel Jan. 1/04 Pricing	**Crude Oil** (Mbbl)	**NGLs** (Mbbl)	**Natural Gas** (Mmcf)	**Total** (MBOE)
Proved Producing	25,437	115	1,910	25,870
Total Proved	26,763	122	1,988	27,216
Probable	5,670	32	711	5,821
Total Proved plus Probable	32,433	154	2,699	33,037
Established Reserves: Equivalent to 2004 Proved + Probable January 1, 2003	13,387	90	2,108	13,829
% Increase	142%	71%	28%	139%

2004 OUTLOOK

- Based on current operations Harvest provides the following guidance for 2004:

	Guidance **2004**	**Results** **2003**
Daily production (BOE/d)	15,000 - 15,500	11,040
Average Royalty Rate	15% - 17%	13.8%
Operating expense ($/BOE)	$10.00 - $10.50	$8.94

For further information, please contact either:

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ADVISORY: Certain information regarding Harvest Energy Trust and Harvest Operations Corp. including management's assessment of future plans and operations, may constitute forward-looking statements under applicable securities law and necessarily involve risks associated with oil and natural gas exploration, production, marketing and transportation such as loss of market, volatility of prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers and ability to access sufficient capital from internal and external sources. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

Harvest Energy Trust

Consolidated Balance Sheets (Audited)

		December 31, 2003		December 31, 2002
Assets				
Current assets				
Cash and short-term investments	**$**	**-**	$	4,502,947
Accounts receivable		**19,167,646**		13,577,870
Prepaid expenses and deposits		**12,130,895**		534,573
		31,298,541		18,615,390
Deferred financing charges, net of amortization		**1,988,728**		2,209,792
Future income tax *[Note 11]*		**11,585,000**		1,272,000
Property, plant and equipment *[Notes 4 and 5]*		**175,377,231**		71,631,507
	$	**220,249,500**	$	93,728,689
Liabilities and Unitholders' Equity				
Current liabilities				
Accounts payable and accrued liabilities	**$**	**17,186,335**	$	5,640,176
Cash distributions payable		**3,421,801**		1,862,500
Accrued interest payable		**231,507**		389,349
Equity bridge interest payable *[Notes 10 and 14]*		**665,069**		-
Demand loan *[Note 6]*		**63,348,972**		45,286,396
		84,853,684		53,178,421
Site restoration provision *[Note 7]*		**4,321,558**		544,178
		89,175,242		53,722,599
Unitholders' equity				
Unitholders' capital *[Note 8]*		**117,406,737**		36,727,997
Equity bridge notes *[Note 10]*		**25,000,000**		-
Accumulated income		**20,975,821**		5,136,093
Contributed surplus		**239,063**		4,500
Accumulated cash distributions		**(32,547,363)**		(1,862,500)
		131,074,258		40,006,090
	$	**220,249,500**	$	93,728,689

Subsequent events [Note 15]

Commitments and contingencies [Note 16]

See accompanying notes to consolidated financial statements.

Harvest Energy Trust

Consolidated Statement of Income and Accumulated Income (Audited)

		Year ended December 31, 2003		Period from July 10 (date of formation) to December 31, 2002
Revenue				
Oil and natural gas sales	**$**	**119,351,486**	$	22,708,921
Hedging loss		**(18,924,364)**		(1,009,060)
Royalty income		**660,452**		119,982
Royalty expense		**(17,072,534)**		(2,864,411)
		84,015,040		18,955,432
Expenses				
Operating		**36,044,629**		6,396,294
General and administrative		**4,339,738**		576,780
Interest		**2,975,236**		2,010,032
Finance charges and amortization of deferred finance charges		**2,607,240**		635,511
Site restoration and reclamation		**4,354,620**		544,178
Depletion, depreciation and amortization		**29,361,741**		5,136,829
Foreign exchange gain		**(4,373,510)**		(255,056)
		75,309,694		15,044,568
Income before taxes		**8,705,346**		3,910,864
Taxes				
Large corporation tax		**157,382**		46,771
Future tax recovery *[Note 11]*		**(8,162,038)**		(1,272,000)
Net income for the period		**16,710,002**		5,136,093
Interest on equity bridge notes *[Note 10]*		**(870,274)**		-
Accumulated income, beginning of period		**5,136,093**		-
Accumulated income, end of period	**$**	**20,975,821**	$	5,136,093
Net income per trust unit *[Note 9]*				
Basic	**$**	**1.33**	$	3.69
Diluted	**$**	**1.29**	$	3.46

See accompanying notes to consolidated financial statements.

Harvest Energy Trust

Consolidated Statement of Cash Flows (Audited)

	Year ended December 31, 2003	Period from July 10 (date of formation) to December 31, 2002
Cash provided by (used in)		
Operating Activities		
Net income for the period	**$ 16,710,002**	$ 5,136,093
Items not requiring cash		
Site restoration and reclamation	**4,354,620**	544,178
Depletion, depreciation and amortization	**29,361,741**	5,136,829
Foreign exchange (gain) loss	**1,432,074**	(255,056)
Amortization of finance charges	**2,555,769**	209,788
Future tax expense	**(8,162,038)**	(1,272,000)
Unit based compensation	**234,563**	4,500
Cash flow from operations	**46,486,731**	9,504,332
Change in non-cash working capital *[Note 13]*	**(12,285,485)**	(6,974,243)
	34,201,246	2,530,089
Financing Activities		
Issue of trust units, net of costs	**61,691,083**	31,727,997
Issue of trust units under the distribution reinvestment plan, net of costs *[Note 8]*	**10,637,657**	-
Issue of equity bridge notes *[Note 10 and 14]*	**33,500,000**	-
Repayment of equity bridge notes *[Note 10 and 14]*	**(8,500,000)**	-
Issue of bridge notes *[Note 14]*	**25,000,000**	-
Repayment of bridge notes *[Note 14]*	**(25,000,000)**	-
Interest on equity bridge notes	**(205,205)**	-
Initial financing	**-**	55,041,491
Repayment of initial financing	**-**	(55,041,491)
Issuance of debentures	**-**	5,000,000
Increase in demand loan	**143,660,601**	60,202,789
Repayment of demand loan	**(128,397,535)**	(14,661,337)
Repayment of promissory note payable	**(850,000)**	-
Financing costs	**(2,334,705)**	(2,419,580)
Cash distributions	**(29,125,562)**	-
Change in non-cash working capital balances related to financing activities *[Note 13]*	**2,224,370**	781,049
	82,300,704	80,630,918
Investing Activities		
Acquisition of properties	**(90,549,403)**	(76,153,324)
Acquisition of a private company *[Note 4]*	**(3,000,000)**	-
Additions to property, plant and equipment	**(27,208,770)**	(770,162)
Site restoration and reclamation	**(577,240)**	-
Proceeds on disposition of property, plant and equipment	**-**	155,150
Change in non-cash working capital balances related to investing activities *[Note 13]*	**330,516**	(1,889,724)
	(121,004,897)	(78,658,060)
Increase (decrease) in cash and short-term investments	**(4,502,947)**	4,502,947
Cash and short-term investments, beginning of period	**4,502,947**	-
Cash and short-term investments, end of period	**$ -**	$ 4,502,947
Cash interest payments	**$ 2,865,684**	$ 1,886,921
Cash tax payments	**$ 157,382**	$ -
Cash distributions declared per unit *[Note 8]*	**$ 2.40**	$ 0.20

See accompanying notes to consolidated financial statements.

1. Structure of the trust

Harvest Energy Trust (the "Trust") is an open-ended, unincorporated investment trust formed under the laws of Alberta. Pursuant to trust indentures and an administration agreement, the Trust is managed by its wholly owned subsidiary, Harvest Operations Corp. ("Harvest Operations"). The Trust acquires and holds net profit interests in oil and natural gas properties in Alberta acquired and held by Harvest Operations and WestCastle Energy Inc. ("WestCastle"). The Trust acquires and holds net profit interests in oil and natural gas properties in Saskatchewan and held by Harvest Sask. Energy Trust. The Trust is the sole unitholder of the Harvest Sask. Energy Trust. Harvest Operations is the sole shareholder of WestCastle. All properties under the Trust, are operated by Harvest Operations.

The beneficiaries of the Trust are the holders of trust units. The Trust makes monthly distributions of its distributable cash to unitholders of record on the last business day of each calendar month.

2. Significant accounting policies

These consolidated financial statements of the Trust have been prepared by management in accordance with Canadian generally accepted accounting principles ("Canadian GAAP").

(a) Consolidation

These consolidated financial statements include the accounts of the Trust and its wholly-owned subsidiaries Harvest Operations, WestCastle and Harvest Sask. Energy Trust. All inter-entity transactions and balances have been eliminated upon consolidation.

(b) Use of estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenues and expenses during the period. Specifically, amounts recorded for depletion, depreciation, amortization and site restoration and reclamation and amounts used for the ceiling test calculation are based on estimates of oil and natural gas reserves and future costs required to develop those reserves. By their nature, these estimates are subject to measurement uncertainty.

(c) Revenue recognition

Revenues associated with the sale of the subsidiaries crude oil, natural gas and natural gas liquids are recognized when title passes from the subsidiaries to their customers.

(d) Cash and short-term investments

Short-term investments with maturities less than three months are considered to be cash equivalents and are recorded at cost, which approximate market value.

(e) Joint venture accounting

The subsidiaries of the Trust conduct substantially all of their oil and natural gas production activities through joint ventures, and the accounts reflect only their proportionate interest in such activities.

(f) Property, plant and equipment

The Trust follows the full cost method of accounting. All costs of acquiring oil and natural gas properties and related exploration and development costs, including overhead charges directly related to these activities, are capitalized and accumulated in one cost center. Maintenance and repairs are charged against income. Renewals and enhancements that extend the economic life of the capital assets are capitalized.

Gains and losses are not recognized on disposition of oil and natural gas properties unless that disposition would alter the rate of depletion by 20% or more.

Ceiling test

The Trust places a limit on the aggregate cost of capital assets, which may be carried forward for depletion against net revenues of future periods (the ceiling test). The ceiling test is a cost recovery test whereby the capitalized costs, less accumulated depletion and site restoration and the lower of cost and market value of unproved land, are limited to an amount equal to estimated undiscounted future net revenues from proved reserves, less general and administrative expenses, site restoration, management fees, future financing costs and applicable income taxes. Costs and prices at the balance sheet date are used. Any costs carried on the balance sheet in excess of the ceiling test limitation are charged to income.

Site restoration and reclamation provision

The Trust provides for the cost of future site restoration and reclamation, based on estimates by management, using the unit-of-production method. Actual site restoration costs are charged against the accumulated liability.

Depletion, depreciation and amortization

Provision for depletion and depreciation of petroleum and natural gas assets is calculated on the unit-of-production method, based on proved reserves before royalties as estimated by independent petroleum engineers. The basis used for the calculation of the provision is the capitalized costs of petroleum and natural gas assets plus the estimated future development costs of proved undeveloped reserves. Reserves are converted to equivalent units on the basis of six thousand cubic feet of natural gas to one barrel of oil.

Depreciation and amortization of office furniture and equipment is provided for at rates ranging from 20% to 50% per annum.

(g) Income taxes

The Trust and Harvest Sask. Energy Trust are taxable entities under the *Income Tax Act (Canada)* and are taxable only on income that is not distributed or distributable to the unitholders. As both the Trust and Harvest Sask. Energy Trust plan to distribute all of their taxable income to their respective unitholders and meet the requirements of the *Income Tax Act (Canada)* applicable to a Trust, neither the Trust nor Harvest Sask. Energy Trust make provisions for future income taxes.

Harvest Operations and WestCastle follow 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 its financial statements and its respective tax base, using enacted or substantively enacted 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.

(h) Unit-based compensation

The Trust uses the fair value method of accounting for the Trust Unit incentive plan *[Note 9]*. Under the terms of the plan, the exercise price of rights granted may be reduced in future periods based on the distributions made to Trust unitholders. The compensation expense is recognized into income over the vesting period of the associated unit appreciation right.

(i) Deferred financing charges

Deferred financing charges relate to costs incurred on the issuance of debt and are amortized on a straight-line basis over the term of the debt, and are included in the associated interest expense.

(j) Financial instruments

Harvest Operations enters into financial instruments to manage its exposure to adverse fluctuations in commodity prices, foreign currency exchange rates, electricity costs and interest rates. Harvest Operation's policy is not to utilize derivative financial instruments for trading or speculative purposes. Realized gains or losses on financial instruments that are designated and assessed effective as hedges are recognized in income concurrently with the underlying hedged transaction. If the hedge of an anticipated transaction is terminated or ceases to be effective, the associated gain or loss at that date is deferred and recognized concurrently with the anticipated transaction. Subsequent changes in value of the financial instruments are reflected in income. Harvest may also enter into debt denominated in U.S. dollars as an economic hedge of the impact of foreign currency exchange rates on future revenues.

(k) Foreign currency translation

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

(l) Comparative figures

Certain prior period's comparative figures have been reclassified to conform to the current year's presentation.

3. Changes in accounting policy

Trust unit incentive plan

The Trust has elected to prospectively adopt the amendments to CICA Handbook section 3870 "Stock-based Compensation and Other Stock-based payments". Under this section, the Trust has chosen to recognize compensation expense when trust unit rights are granted under the trust unit incentive plan with no cash settlement features on a prospective basis. As such, compensation expense has been calculated on all trust unit rights issued on or subsequent to January 1, 2003. The fair value of trust unit rights issued has been determined using a binomial option pricing model. The binomial model has been utilized by the Trust as it allows the calculation of the fair value of a trust unit right with a decreasing exercise price, based on the distributions paid from the date of issue to the date of vesting.

As a result of adopting this amendment, the net income for the year ended December 31, 2003 has decreased by $234,503.

4. Acquisitions

On June 1, 2003, the Trust acquired all of the common shares and the Net Profit Interest of a private company. Total consideration paid by the Trust was $10.1 million, and consisted of the issuance of 625,000 trust units at a price of $10.00 per trust unit *[Note 8]*, $3 million in cash and an $850,000 unsecured demand promissory note that bears interest at 10% per annum effective June 27, 2003. The acquisition has been accounted for using the purchase price method.

On October 16, 2003, the Trust acquired the Carlyle Properties in Southeastern Saskatchewan for total consideration of approximately $79.5 million before costs and purchase price adjustments. The acquisition was partially financed by the issue of trust units on October 16, 2003 *[Note 8]* with the balance being funded by Harvest Operations bank facility.

The following summarizes the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition. Harvest Operations has not yet completed its final calculation of the assets acquired and liabilities assumed and therefore, the purchase price allocation maybe subject to change.

		Amount
Acquisition of Private Company		
Property, plant & equipment	$	15,400,255
Working capital, net		(2,500,745)
Bank debt		(2,799,510)
		10,100,000
Acquisition of Carlyle properties		
Property, plant & equipment		79,500,000
	$	89,600,000

5. Property, plant and equipment

	December 31, 2003					
		Cost		**Accumulated depletion, depreciation and amortization**		**Net book value**
Oil and natural gas properties	$	162,079,020	$	(25,977,561)	$	136,101,459
Production facilities and equipment		47,071,008		(8,345,533)		38,725,475
Office furniture and equipment		707,773		(157,476)		550,297
	$	209,857,801	$	(34,480,570)	$	175,377,231

December 31, 2002						
		Cost		Accumulated depletion, depreciation and amortization		Net book value
Oil and natural gas properties	$	55,188,754	$	(3,841,661)	$	51,347,093
Production facilities and equipment		21,343,287		(1,271,752)		20,071,535
Office furniture and equipment		236,295		(23,416)		212,879
	$	76,768,336	$	(5,136,829)	$	71,631,507

General and administrative costs of $1,311,233 and $174,425 have been capitalized during the year ended December 31, 2003 and period ended December 31, 2002, respectively.

All costs are subject to depletion and depreciation at December 31, 2003. In addition, future development costs of $15.2 million (2002 - $9.9 million) are included in depletion and depreciation calculations at December 31, 2003.

In accordance with Canadian GAAP, the Trust has performed a ceiling test as at December 31, 2003. Using December 31, 2003 commodity prices of WTI $US 32.78 per barrel for crude oil and AECO $5.87 per mcf for natural gas, resulted in a ceiling test excess.

6. Demand loan

On October 16, 2003, Harvest Operations Corp. entered into a credit agreement with a syndicate of Canadian chartered banks and the Alberta Treasury Branches. The revolving reducing demand loan provides a borrowing base of $89 million with availability reducing by $4.5 million on the last day of each calendar month starting January 31, 2004. The demand loan permits drawings in Canadian or U.S. dollars, and includes bankers acceptances, LIBOR, $10 million in letters of credit and a $3 million mark to market facility to be used for financial instrument hedging. The demand loan bears interest at rates ranging from 0.25% to 2% above the applicable Canadian or U.S. prime depending upon the type of borrowing and the debt to annualized cash flow ratio. The demand loan is secured by a $150 million debenture with a floating charge over all of the assets of the Corporation. The distributions payable to the Trust's unitholders, the Equity Bridge notes *[Note 10]*, and the convertible debentures *[Note 15]* are subordinate to the obligations of the demand loan. Certain restrictive covenants, including a working capital ratio of at least one to one and that Harvest maintains a minimum hedging of 50% and 25% of oil volumes for the first four forward quarters and next four calendar quarters respectively, are required to be maintained for the purpose of measuring Harvest Operations' ability to meet its obligation under the credit agreement.

7. Site restoration and reclamation

Site restoration involves the surface clean up and reclamation of well site and field production facilities. In addition, certain plant facilities will require decommissioning, which involves dismantlement of facilities as well as the decontamination and reclamation of these lands. Total estimated future costs are approximately $29.9 million of which $4.3 million has been accrued to December 31, 2003. The board of directors has established a notional fund to ensure that cash is available to carry out the future site restoration and reclamation work. This fund is an allocation restricting utilization of the borrowing base under the demand loan, and is currently being accrued at $125,000 per month, the monthly accrued amount is reviewed annually. The fund is reduced for actual site restoration and reclamation expenditures incurred. The balance of the fund as at December 31, 2003 was $1,047,760.

8. Unitholders' capital

(a) Authorized

The authorized capital consists of an unlimited number of trust units.

Each trust unitholder is entitled to a beneficiary interest in any distribution of the Trust and in any net assets in the event of termination or wind-up. Trust units are redeemable at any time at the option of the holder. The redemption price is equal to the lesser of 95% of the average market price of the trust units during a 10 day period commencing immediately after the redemption date and the closing market price on the redemption date. The total amount payable by the Trust in respect of redemptions in any calendar month shall not exceed $100,000. To the extent that a unitholder is entitled to a redemption payment, it will be satisfied by a cash payment from the Trust or by the Trust distributing a pro-rata number of Harvest Operations notes or distributing its own notes.

(b) Issued

	Number of units		Amount
Issued for cash on formation (i)	100	$	100
Initial public offering (ii)	4,312,500		34,500,000
Settlement of debenture (iii)	5,000,000		5,000,000
Cancel the initial units issued on formation (i)	(100)		(100)
Unit issue costs	–		(2,772,003)
As at, December 31, 2002	9,312,500	$	36,727,997
Exercise of warrants (iv)	150,000		150,000
Special warrant exercise (v)	1,500,000		15,000,000
Acquisitions (vi)	825,000		8,350,000
Trust unit issue (vii)	4,312,500		48,645,000
Distribution reinvestment plan issuance (iix)	1,009,006		10,637,657
Share issue costs	–		(2,103,917)
As at, December 31, 2003	17,109,006	$	117,406,737

(i) On July 10, 2002, the Trust issued 100 units for cash proceeds of $100. As per the agreement on the initial issuance, the units were cancelled upon the completion of the initial public offering on December 5, 2002.

(ii) On December 5, 2002, the Trust issued 3,750,000 trust units for $27.6 million, net of a 6% underwriters' fee and $702,003 of issue costs. The net proceeds were used to fully repay a loan from a corporation controlled by a director of Harvest Operations and partially repay the bank loans. In conjunction with this initial public offering, the Trust granted the underwriters an option, to purchase up to an additional 562,500 trust units at a price of $8.00 per unit. On December 17, 2002, the underwriters exercised the option; the net proceeds were used to partially repay the bank loans.

(iii) Upon completion of the initial public offering the Trust paid the trust debenture principal and interest thereon, by the issuance of 5,000,000 trust units and a cash payment of $34,829.

(iv) On January 24, 2003, 150,000 trust units were issued to a corporation controlled by a director of Harvest Operations on the exercise of a warrant. The $150,000 in proceeds was added to working capital.

(v) On March 7, 2003, 1,500,000 special warrants were exercised into trust units. The special warrants were issued on February 4, 2003 for $13,700,000 net of a 5% underwriters' fee and approximately $550,000 of issues costs.

(vi) On May 27, 2003, the Trust issued 200,000 trust units at a price of $10.50 per trust unit, for consideration of the purchase of a crude oil producing property.

On June 27, 2003, the Trust issued 625,000 trust units at a price of $10.00 per trust unit, for partial consideration of the purchase of a private company *[Note 4]*.

(vii) On October 16, 2003, the Trust issued 4,312,500 trust units at a price of $12.00 per trust unit, for proceeds of $51.75 million net of a 6% underwriters' fee and $346,000 of issue costs. The net proceeds were used to partially fund the acquisition of Carlyle properties in South East Saskatchewan.

(iix) The following table summarizes the issuance of trust units under the distribution reinvestment plan ("DRIP"):

Distribution Month	Record Date	Payment Date	Trust units issued under DRIP		Amount
January	January 31, 2003	February 17, 2003	79,208	$	794,650
February	February 28, 2003	March 17, 2003	73,230		780,223
March	March 31, 2003	April 15, 2003	96,019		907,805
April	April 30, 2003	May 15, 2003	98,535		925,662
May	May 31, 2003	June 16, 2003	103,059		990,697
June	June 30, 2003	July 15, 2003	104,425		989,718
July	July 31, 2003	August 15, 2003	92,818		989,612
August	August 29, 2003	September 15, 2003	88,095		1,007,068
September	September 30, 2003	October 15, 2003	89,578		1,028,349
October	October 31, 2003	November 14, 2003	88,256		1,046,629
November	November 28, 2003	December 15, 2003	95,783		1,177,244
As at, December 31, 2003			1,009,006	$	10,637,657

(c) Per unit information

The following table summarizes the trust units used in calculating income per trust unit.

	Year ended December 31, 2003	Period from July 10 (date of formation) to December 31, 2002
Weighted average trust units outstanding, basic	12,590,937	1,391,608
Effect of trust unit rights	411,868	87,500
Weighted average trust units outstanding, diluted	13,002,805	1,479,108

9. Trust unit incentive plan

A trust unit incentive plan has been established whereby the Trust is authorized to grant non-transferable rights to purchase trust units to directors, officers, consultants, employees and other service providers to an aggregate of 1,121,000 trust units. The initial exercise price of rights granted under the plan is equal to the closing market price on the date immediately prior to the date the rights are granted and the maximum term of each right is not to exceed five years. The exercise price of the rights is adjusted downwards from time to time based upon the cash distributions made on the trust units if the minimum distribution rate is met. The following summarizes the trust units reserved for issuance under the trust unit incentive plan:

	Trust unit rights	**Weighted average exercise price**
Granted on November 25, 2002	787,500	$ 8.00
Average reduction in exercise price due to distributions	-	(0.20)
As at, December 31, 2002	787,500	7.80
Granted, January 24, 2003	32,500	10.21
Granted, February 14, 2003	34,500	10.75
Granted, July 15, 2003	12,500	10.18
Granted, July 17, 2003	7,500	10.20
Granted, July 18, 2003	11,000	10.30
Granted, October 17, 2003	73,400	12.19
Granted, December 15, 2003	106,250	13.15
Average reduction in exercise price due to distributions	-	(2.02)
As at, December 31, 2003	1,065,150	$ 6.86

All of the trust unit rights outstanding vest equally over the next four years on their anniversary date.

For purposes of estimating fair value disclosures below, the fair value of each trust unit right has been estimated on the grant date using the following weighted-average assumptions:

	Year ended December 31, 2003	Period from July 10 (date of formation) to December 31, 2002
Expected volatility	23.30%	25.60%
Risk free interest rate	4.08%	3.00%
Expected life of the trust unit rights	4 years	4 years
Estimated annual distributions per unit	$2.40	$2.40

For the purposes of pro forma disclosures, the estimated fair value of all of the trust unit rights is amortized to expense over the vesting periods. The Trust's pro forma net income and per trust amounts would have been accounted for as follows:

		Year ended December 31, 2003	Period from July 10 (date of formation) to December 31, 2002
Net income	As reported	$16,710,002	$5,136,093
	Pro forma	$15,422,502	$4,969,520
Income per unit - basic	As reported	$1.33	$3.69
	Pro forma	$1.20	$3.57
Income per unit - diluted	As reported	$1.29	$3.46
	Pro forma	$1.16	$3.35

During the year ended December 31, 2003 and the period from July 10 to December 31, 2002, the Trust has recognized $234,563 and $4,500 respectively, in compensation expense and included it in general and administrative expense in the consolidated statement of income and accumulated income.

10. Equity bridge note

On July 28, 2003, the Trust entered into two equity bridge note agreements, which provide for advances in aggregate of up to $40 million. The terms and conditions are identical for both agreements, which is comprised of a $30 million agreement with a corporation controlled by a director of Harvest Operations, and a $10 million agreement with a director of Harvest Operations.

Under the terms of the agreements, interest is paid quarterly in arrears and is calculated daily at a fixed rate of 10% per annum. The Trust has the option to settle the quarterly interest payments with cash or the issue of trust units. If the Trust elects to issue trust units, the number of trust units to be issued to settle a quarterly payment shall be the equivalent to the quarterly payment amount divided by 90% of the most recent ten-day weighted average trading price.

The Trust also has the option to repay the principal amounts outstanding at any time. If the Trust chooses to partially repay the outstanding principal amount, such payment is to be made in cash. If the Trust elects to repay the full principal amount plus the accrued quarterly payment at maturity, the Trust then has the option to settle its obligation with cash or with the issue of trust units. The terms to settle with units is the same as with the interest option described above. The outstanding principal portion and all accrued and unpaid interest on the equity bridge note agreements is due and payable in full on January 1, 2005. Security has been provided in the form of a fixed and floating debenture on the Trust's NPI. The equity bridge lenders may demand payment of the full amount if specified events of default under the equity bridge note agreements occur. On September 29, 2003, the equity bridge note agreements were amended to extend the uses permitted under the previous agreements, to include repayment of bank debt. As at December 31, 2003, there was $25 million drawn on the equity bridge notes, and accrued interest of $665,069 which was paid subsequent to the year end *[Note 15]*. Total interest incurred and paid during the year on the equity bridge was $870,274 and $205,205 respectively. Interest in respect of the equity bridge notes is a charge to unitholders' equity and not included in income.

11. Income taxes

Future income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities of Harvest Operations and WestCastle Energy Inc. for financial reporting purposes and the amounts used for income tax purposes. During 2003, legislation regarding the reduction of certain Federal and Provincial corporate income tax rates have received Royal Assent. These rate changes are expected to be applied in varying degrees over the next five years, and have resulted in an effective tax rate of approximately 34% for the Trust, to be applied on the temporary difference in the future tax calculation.

The provisions for future income taxes varies from the amount that would be computed by applying the combined Canadian federal and provincial income tax rates to the reported income before taxes as follows:

		Year ended December 31, 2003		Period from July 10 (date of formation) to December 31, 2002
Income before taxes	$	8,705,346	$	3,910,864
Computed income tax expense at the statutory rates of 40.6% and 42.1%, respectively		3,536,112		1,646,473
Amount included in Trust income		(13,293,485)		(2,912,280)
		(9,757,373)		(1,265,807)
Increase (decrease) resulting from the following:				
Non-deductible crown royalties and other payments		(61,482)		9,400
Federal resource allowance		2,061,812		(17,000)
Unit appreciation rights expense		98,935		-
Foreign exchange gain		(1,281,561)		-
Rate change		794,419		
Other		(16,788)		1,407
Future income taxes	$	(8,162,038)	$	(1,272,000)

The components of the future tax assets are as follows:

		Year ended December 31, 2003		Period from July 10 (date of formation) to December 31, 2002
Future tax assets:				
Tax pools of oil and natural gas in excess of net book value	$	8,782,000	$	552,700
Resource allowance		1,203,000		172,000
Tax loss carryforwards		1,600,000		547,300
Net future tax asset	$	11,585,000	$	1,272,000

At December 31, 2003, the Trust has tax pools aggregating $118 million, including $0.8 million in non-capital losses which will expire in 2009. The tax pools exceed the corresponding book values by approximately $7.7 million.

At December 31, 2003, Harvest Sask Energy Trust has tax pools aggregating $47.5 million. The corresponding book values exceed the tax pools by approximately $4 million.

At December 31, 2003, Harvest Operations has tax pools aggregating $44.8 million, including $4.1 million in non-capital losses of which $1.1 million and $3 million expire in 2009 and 2010, respectively. The tax pools exceed the corresponding book values by approximately $24.7 million.

At December 31, 2003, Westcastle Energy Inc. has tax pools aggregating $7.1 million. The tax pools exceed the corresponding book values by approximately $7 million.

12. Financial instruments

The Trust is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations.

(a) Fair values

Financial instruments of the Trust consist mainly of cash, accounts receivable, prepaid expenses, accounts payable and accrued liabilities, distributions payable, large corporation taxes payable and current debt. As at December 31, 2003, there were no significant differences between the carrying amounts of these financial instruments reported on the balance sheet and their estimated fair value.

(b) Interest rate risk

The Trust is exposed to interest rate risk on its long-term debt.

(c) Credit risk

Substantially all of the accounts receivable are due from customers in the oil and natural gas industry and are subject to normal industry credit risks. Concentration of credit risk is mitigated by having a broad customer base, which includes a significant number of companies engaged in joint operations with the Trust. The Trust periodically assesses the financial strength of its partners and customers, including parties involved in the marketing or other commodity arrangements. The carrying value of accounts receivable reflects management’s assessment of the associated credit risks.

(d) Foreign exchange rate risk

The Trust is exposed to the risk of changes in the Canadian / U.S. dollar exchange rate on sales of commodities that are denominated in U.S. dollars or directly influenced by U.S. dollar benchmark prices. During 2003, the Trust borrowed funds denominated in U.S. dollars as an economic hedge of the impact of exchange rates on sales during the year. As at December 31, 2003 all of the U.S. dollar debt had been repaid.

(e) Commodity risk management

The Trust uses oil sales contracts and derivative financial instruments to comply with this requirement. Under the terms of some of the derivative instruments, Harvest Operations is required to provide security from time to time based on the underlying market commodity price of those contracts. The Trust is also exposed to counterparty risk for theses derivative contracts. This risk is managed by diversifying the Trust’s derivative portfolio among a number of counterparties.

The following is a summary of the oil sales contracts with price swap or collar features as at December 31, 2003, that have fixed future sales prices:

Commodity collar contracts based on West Texas Intermediate

Daily Quantity	Term	Price per Barrel (Note 1)	Mark to Market Gain (Loss) Cdn $
2,500 Bbls/d	January through December 2004	U.S. $22.00 – 28.10	($2,456,677)
1,000 Bbls/d	January through December 2004	U.S. $23.00 – 27.95 ($18.00)	($1,095,885)
1,000 Bbls/d	January through December 2004	U.S. $25.00 – 28.25 ($18.00)	($954,367)
500 Bbls/d	January through December 2004	U.S. $27.50 – 31.00 ($20.25)	$154,929
500 Bbls/d	January through December 2004	U.S. $27.65 – 33.00 ($21.00)	($47,173)

Note 1 Harvest has sold a put option at the price denoted in parenthesis, for the same volumes as the associated commodity contract. The counterparty may exercise this option if the respective index falls below the specified price on a monthly settlement basis.

Commodity swap contracts based on West Texas Intermediate

Daily Quantity	Term	Price per Barrel (Note 1)	Mark to Market Gain (Loss) Cdn $
1,510 Bbls/d	January through March 2004	U.S. $23.23	($1,553,580)
1,300 Bbls/d	January through March 2004	U.S. $24.33	($1,171,187)
500 Bbls/d	January through December 2004	U.S. $24.12 ($15.50)	($1,441,863)
500 Bbls/d	January through December 2004	U.S. $24.25	($1,399,408)
500 Bbls/d	January through December 2004	U.S. $29.32	($203,583)
1,430 Bbls/d	April through June 2004	U.S. $22.93	($1,297,309)
1,200 Bbls/d	April through June 2004	U.S. $25.50	($2,911,765)
1,380 Bbls/d	July through September 2004	U.S. $22.70	($1,098,458)
500 Bbls/d	July through September 2004	U.S. $24.56	($287,414)
1,325 Bbls/d	October through December 2004	U.S. $22.54	($957,680)
500 Bbls/d	October through December 2004	U.S. $24.03	($272,808)
500 Bbls/d	January through December 2004	U.S. $30.50	$74,736
500 Bbls/d	January through December 2005	U.S. $24.00	($811,076)
1,100 Bbls/d	January through March 2005	U.S. $22.38	($714,041)
1,030 Bbls/d	April through June 2005	U.S. $22.18	($652,039)

Commodity swap contracts based on the Lloydminster Blend Crude differential

2,000 Bbls/d	January through December 2004	U.S. ($7.75)	$1,368,005
1,000 Bbls/d	January through December 2004	U.S. ($8.20)	$471,726
500 Bbls/d	January through December 2004	U.S. ($7.90)	$306,622

The following is a summary of electricity price hedging swap contracts entered into by Harvest Operations to fix the cost of future electricity usage as at December 31, 2003:

Commodity swap contracts based on electricity prices

Quantity	Term	Price per Megawatt	Mark to Market Gain (Loss)
5MW	January through December 2004	Cdn $46.00	$384,300
5MW	January through December 2004	Cdn. $46.00	$384,300
5MW	January through December 2004	Cdn. $45.50	$406,260
5MW	January through December 2005	Cdn $43.00	$153,300
9.75MW	January 2004 through March 2006	Cdn $44.50	$1,372,920

Commodity swap contracts based on electricity heat rate

Swaps	Term	Price per Megawatt	Mark to Market Gain (Loss)
5MW	January through December 2005	8.40 GJ/MWh	$46,253

Foreign Currency Contracts

Monthly Contract Amount	Term	Contract Rate	Mark to Market Gain (Loss) Cdn $
U.S. $3 million	January through December 2004	1.3333 Cdn / U.S.	$1,735,435

At December 31, 2003 the net mark-to-market unrealized loss for all the financial derivative contracts entered into by Harvest Operations was approximately $12,467,527. Harvest Operations has provided a deposit to the counterparties with some of its financial derivative contracts, based on the mark-to-market value of those contracts at the end of the trading day. As at December 31, 2003, this amount totaled $11,899,127 and is recorded in the prepaid expense and deposits balance.

13. Change in non-cash working capital

	Year ended December 31, 2003	Period from July 10 (date of formation) to December 31, 2002
Changes in non-cash working capital items:		
Accounts receivable	**$ (5,589,776)**	$ (13,577,870)
Prepaid expenses and deposits	**(11,596,322)**	(534,573)
Accounts payable and accrued liabilities	**11,546,159**	5,640,176
Cash distributions payable	**1,559,301**	-
Accrued interest payable	**(57,842)**	389,349
Equity bridge interest payable	**665,069**	-
	$ (3,473,411)	$ (8,082,918)
Changes relating to operating activities	**$ (12,285,485)**	$ (6,974,243)
Changes relating to financing activities	**2,224,370**	781,049
Changes relating to investing activities	**330,516**	(1,889,724)
Add: Non cash changes	**6,257,188**	-
	$ (3,473,411)	$ (8,082,918)

14. Related party transactions

A director and a corporation controlled by a director of Harvest Operations, have advanced $33.5 million and were repaid $8.5 million under the equity bridge note during the year ended December 31, 2003. The Trust paid $205,205 of the total $870,274 interest accrued during the year. *[Note 10]*

A corporation controlled by a director of Harvest Operations, had advanced $25 million and was repaid $25 million under a bridge note during the year ended December 31, 2003. The Trust paid $71,233 in interest on this bridge note during the year.

A corporation controlled by a director of Harvest Operations exercised warrants to purchase 150,000 trust units for proceeds of $150,000 on January 24, 2003. *[Note 8]*

A corporation controlled by a director of Harvest Operations sublets office space and is provided administrative services at fair market value.

15. Subsequent events

On January 1, 2004, WestCastle amalgamated with Harvest Operations.

On January 2, 2004, the Trust paid $665,069 of the accrued interest payable related to the equity bridge note. *[Notes 10 and 14]*

On January 29, 2004, the Trust closed an issue of 60,000 9% convertible unsecured subordinated debentures due May 31, 2009. This financing provided proceeds of $60 million. Interest on the debentures is payable semi-annually in arrears in equal installments on May 31 and November 30 in each year, commencing May 31, 2004. The debentures are convertible into fully paid and non-assessable trust units at the option of the holder at any time prior to the close of business on the earlier of May 31, 2009 and the business day immediately preceding the date specified by the Trust for redemption of the Debentures, at a conversion price of $14.00 per trust unit plus a cash payment for accrued interest and in lieu of the fractional trust units resulting on the conversion. The debentures may be redeemed by the Trust at its option in whole or in part subsequent to May 31, 2007, at a price equal to $1,050 per debenture between June 1, 2007 and May 31, 2008 and at $1,025 per debenture between June 1, 2008 and May 31, 2009. Any redemption will include accrued and unpaid interest at such time when completed. The Trust may also elect to redeem the debentures upon maturity with the issue of trust units at a price equal to 95% of the weighted average trading price for the preceding 20 consecutive trading days, 5 days prior to settlement date A settlement in trust units is subject to specified notice and regulatory approval. Upon the issue of the debentures, the Trust repaid the $25 million equity bridge note outstanding as at December 31, 2003 *[Note 10]*, and accrued interest of $185,232.

On February 16, 2004, 13,700 trust unit rights were issued to employees under the Trust unit incentive plan with an exercise price of $13.35 per unit. The trust unit rights vest equally over the next four years on their anniversary date.

On February 24, 2004, 12,000 trust unit rights were issued to employees under the Trust unit incentive plan with an exercise price of $13.75 per unit. The trust unit rights vest equally over the next four years on their anniversary date.

Between January 22, 2004 and March 31, 2004 11,250 trust unit rights were exercised or settled, of which 5,000 were settled in cash for approximately $30,000 by the Trust, and 6,250 trust units were issued at an exercise price of $5.20 per unit. Also during this period, 15,875 trust unit appreciation rights were cancelled.

On March 15, 2004, $1 million of the convertible debentures issued on January 29, 2004 were converted into 71,428 trust units. In conjunction with this conversion, the Trust also paid a total of $11,350 in cash for accrued interest and in lieu of fractional units.

On March 19, 2004, Harvest Operations entered into a fixed price swap to purchase 1,008 GJ of natural gas at $6.05 per GJ, from January 1 to December 31, 2005. This contract was purchased with the intent to be combined with the previously purchased swap on the electricity heat rate for $8.40 GJ/MWh for 5MW during the same period. These two instruments in combination, have effectively resulted in the purchase of 5 MW of electricity at $50.82 per MWh.

The following is a summary of the Trust distributions announced and paid subsequent to the year end:

Distribution Month	Record Date	Payment Date	Trust units issued under DRIP	Total Amount of Distribution
December, 2003	December 31, 2003	January 15, 2004	54,761	$ 3,421,801
January	January 31, 2004	February 16, 2004	14,870	3,432,753
February	February 27, 2004	March 15, 2004	24,980	3,435,774
March	March 31, 2004	April 15, 2004	21,825	3,456,300

On April 14, 2004 the Trust declared a distribution of $0.20 per trust unit payable to unitholders of record on April 30, 2004. The distribution payment is estimated to total $3,460,671 and will be paid on May 14, 2004.

The following is a summary of the oil sales contracts with price swap or collar features that were entered into by Harvest Operations subsequent to December 31, 2003, that have fixed future sales prices:

Commodity collar contracts based on West Texas Intermediate

Trade date	Daily Quantity	Term	Price per Barrel (Note 1)
January 21, 2004	500 Bbls/d	January through June 2005	U.S. $28.00 – 31.20 ($21.00)
February 20, 2004	500 Bbls/d	January through June 2005	U.S. $28.00 – 30.70 ($22.00)
February 20, 2004	500 Bbls/d	July through December 2005	U.S. $27.50 – 29.80 ($22.00)
February 27, 2004	500 Bbls/d	January through June 2005	U.S. $28.00 – 32.25 ($22.00)
March 10, 2004	500 Bbls/d	January through June 2005	U.S. $29.00 – 32.50 ($22.00)
March 10, 2004	500 Bbls/d	July through December 2005	U.S. $28.00 – 31.50 ($22.00)
March 18, 2004	500 Bbls/d	January through June 2005	U.S. $29.00 – 34.60 ($22.00)

Note 1 Harvest has sold a put option at the price denoted in brackets, for the same volumes as the associated commodity contract. The counterparty may exercise this option if the respective index falls below the specified price on a monthly settlement basis.

16. Commitments and contingencies

From time to time, the Trust is involved in litigation or has claims sought against it in the normal course of business operations. Management of the Trust is not currently aware of any claims or actions that would materially affect the Trust's reported financial position or results from operations.

The Trust has letters of credit outstanding in the amount of approximately $3.3 million, related to electricity infrastructure usage. These letters are provided by the Trust's lenders under the availability of the demand loan. The letters expire throughout 2004, and are expected to be renewed as required.

Management’s Discussion and Analysis

Management’s discussion and analysis (“MD&A”) of Harvest Energy Trust’s (“Harvest” or the “Trust”) financial condition and results of operations should be read in conjunction with Harvest’s audited consolidated financial statements and accompanying notes for the year ended December 31, 2003.

Forward-Looking Information

The following disclosure contains forward-looking information and estimates with respect to Harvest. This information addresses future events and conditions, and as such involves risks and uncertainties that could cause actual results to differ materially from those contemplated by the information provided. These risks and uncertainties include but are not limited to factors intrinsic in domestic and international politics and economics, general industry conditions including the impact of environmental laws and regulations, imprecision of reserves estimates, fluctuations in commodity prices, interest rates or foreign exchange rates and stock market volatility. The information and opinions concerning the Trust’s future outlook are based on information available at April 2004.

Certain Financial Reporting Measures

The Trust has used certain measures of financial reporting that are commonly used as benchmarks within the oil and natural gas production industry in the following MD&A discussion. The measures discussed are widely accepted measures of performance and value within the industry, and are used by analysts and investors to compare and evaluate oil and natural gas producing entities. These measures are not defined under Canadian generally accepted accounting principles (“GAAP”) and should not be considered in isolation or as an alternative to conventional GAAP measures. Certain of these measures are not necessarily comparable to a similarly titled measure of another company or trust. When these measures are used, they are defined as “non-GAAP” and should be given careful consideration by the reader.

Natural gas is converted to an oil equivalent basis (“BOE”) utilizing a 6 mcf:1 bbl conversion ratio. BOE’s may be misleading, if used in isolation. A BOE conversion ratio of 6 mcf:1 bbl is based on an energy conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Trust Overview

Harvest Energy Trust is an oil and natural gas royalty trust, which focuses on the operation of high quality, mature producing crude oil and natural gas properties. The Trust employs a conservative approach to the oil and natural gas production business, whereby it acquires high working interest, mature producing properties and employs unique management techniques. These techniques include diligent, hands-on management to maintain and maximize production rates, application of leading edge technologies and operating practices, and selective capital investment to maximize reservoir recovery, enhancing operational efficiencies to control and reduce expenses and unique marketing arrangements and corporate hedging techniques to effectively manage cash flow. The Trust has operations in the Provost region of Eastern Alberta and in the Carlyle region of Southeastern Saskatchewan.

Industry Overview

Prices	(average for the year) 2003	2002	Change
West Texas intermediate crude oil (US$ per barrel)	$ 30.99	$ 26.15	18.51%
Edmonton light crude ($ per barrel)	43.77	40.41	8.31%
Lloyd blend crude oil ($ per barrel)	31.48	30.73	2.44%
Bow river blend crude oil ($ per barrel)	32.39	31.77	1.95%
AECO natural gas ($ per mcf)	6.67	4.09	63.08%
Alberta Power Pool electricity price ($ per MWh)	62.99	43.93	43.39%
U.S. / Canadian dollar exchange rate (US$)	0.713	0.637	12.01%
Bank of Canada bank rate	3.19%	2.70%	18.15%

The average price for world crude oil increased year over year, with the North American benchmark West Texas Intermediate crude oil price averaging U.S. $30.99 in 2003, in comparison with U.S. $26.15 for 2002. The price varied throughout the year with a low of U.S. $25.24 and a high of U.S. $37.83, primarily due to tensions in the Middle East and uncertainty regarding international supply. With low inventories persisting, uncertainty in Iraq and renewed turmoil a possibility in Venezuela, these fluctuating prices are expected to persist through at least the first part of 2004.

The differential between heavy and light crude oil is locally recognized in the pricing of Lloyd and Bow River blend crude prices. Although heavy differentials widened, heavy prices followed light prices increasing slightly during the year by 2.4% and 2%, respectively.

The exchange rate between the U.S. and Canadian dollars changed substantially during the year relative to 2002, with the Canadian dollar increasing in value by approximately 12% on an average annual basis. The increase in closing price year over year was even more substantial, with the Canadian dollar closing at $0.774US in comparison to $0.635US as at December 31, 2003 and 2002 respectively. With no indicative signs of the U.S. Federal Reserve supporting the U.S. dollar against worldwide currencies, the Canadian dollar is anticipated by many to remain strong throughout the upcoming year.

The overall average price increase in WTI of approximately 18.5% during the year, is somewhat mitigated by the 12% increase in the Canadian dollar versus the U.S. dollar. The bench mark for Canadian crude oil prices is the posted price for light crude oil delivered to Edmonton ("Edmonton Light"). The average Edmonton Light crude price increased 8.3% in 2003. This increase is a combination of higher WTI prices offset by a stronger Canadian dollar.

The average Alberta Power Pool electricity price increased approximately 43% over 2002, mostly due to the 63% increase in the 2003 average AECO natural gas prices. Marginal electricity prices are driven by natural gas fired power generation in Alberta. There was also as a slight increase of 5.5% in overall Alberta consumer demand which contributed to this price increase.

Acquisitions

During April and May 2003 Harvest closed the acquisition of various interests in two properties in the Killarney area of Alberta. On the acquisition date the properties were producing approximately 925 BOE/D. The properties, including an interest in two oil batteries, were acquired from two major oil and natural gas producers for $13.2 million and the issuance of 200,000 trust units. The cash consideration was financed through the Trust's credit facilities.

On June 27, 2003, Harvest completed the acquisition of all of the common shares and Net Profit Interest ("NPI") of a private company in exchange for total consideration of approximately $10.1 million (consisting of the issuance of 625,000 Trust Units, $3 million in cash and a $850,000 unsecured promissory note) plus the assumption of $2.8 million in bank debt and $2.3 million in working capital deficit. The oil and natural gas producing properties acquired provided production of approximately 1,350 BOE/d at the acquisition date and include working interests ranging from 20% to 100% in the fields of Amisk, Czar and Killarney, all of which are operated by the Trust.

On October 16, 2003, the Trust closed the acquisition of oil and natural gas properties producing about 5,100 BOE/d in the Carlyle region of Southeastern Saskatchewan. The total consideration for the properties was approximately $79.5 million, prior to adjustments and transaction costs.

Summary of Results

Financial		Year ended December 31, 2003		Period ended December 31, 2002		Q4		Q3		Q2		Q1
						Quarterly Information for 2003						
Revenue, net of royalties and hedging	$	84,015	$	18,955	$	30,474	$	21,181	$	17,622	$	14,738
Operating expense		36,045		6,396	$	12,984		9,661		6,596		6,804
Net operating income	$	47,970	$	12,559	$	17,490	$	11,520	$	11,026	$	7,934
Net income		16,710		5,136		6,043		5,751		1,180		3,736
Per trust unit, basic		1.33		3.69		0.37		0.46		0.10		0.36
Per trust unit, diluted		1.29		3.46		0.36		0.45		0.10		0.34
Per BOE		4.15		6.81		4.42		5.50		1.37		5.05
Cash flow from operations		46,487		9,504		13,692		16,759		9,547		6,489
Per trust unit, basic (non GAAP)		3.69		6.83		0.85		1.35		0.84		0.62
Per trust unit, diluted (non GAAP)		3.58		6.43		0.82		1.31		0.82		0.60
Per BOE		11.54		12.61		10.02		16.02		11.12		8.77
Sales Volumes												
Crude oil (bbl/d)		10,758		4,181		14,497		11,054		9,371		8,034
Natural gas liquids (bbl/d)		64		22		70		77		67		43
Natural gas (mcf/d)		1,311		624		1,744		1,453		1,161		875
Total (BOE/d)		11,040		4,307		14,858		11,373		9,632		8,223

Sales Volumes

Harvest's production consists of light, medium and heavy crude oil, natural gas liquids, and natural gas from properties located in East Central Alberta and Southeastern Saskatchewan. Sales volumes, on a barrel of oil equivalent, averaged 11,040 BOE/d, in comparison to 4,307 BOE/d for the year ended December 31, 2003, and the period ended December 31, 2002, respectively. In the fourth quarter of 2003, average crude oil and natural gas sales were 14,858 BOE/d with the increase primarily due to acquisition of the properties in Saskatchewan in mid October. The average daily sales volumes by product were as follows:

	Three month period ended December 31, 2003		**Year ended December 31, 2003**		Period ended December 31, 2002	
Light and medium crude oil (Bbls/d)	**8,741**	**59%**	**5,314**	**48%**	2,718	63%
Heavy crude oil (Bbls/d)	**5,756**	**39%**	**5,444**	**49%**	1,463	34%
Total oil (Bbls/d)	**14,497**	**98%**	**10,758**	**97%**	4,181	97%
Natural gas liquids (Bbls/d)	**70**	**0%**	**64**	**1%**	22	1%
Total oil and natural gas liquids (Bbls/d)	**14,567**	**98%**	**10,822**	**98%**	4,203	98%
Natural gas (mcf/d)	**1,744**	**2%**	**1,311**	**2%**	624	2%
Total oil equivalent (6:1 BOE/d)	**14,858**	**100%**	**11,040**	**100%**	4,307	100%

Harvest exited December 31, 2003 with a daily production rate of approximately 15,400 BOE/d, a 79% increase year over year, which reflects the impact of the ongoing development and optimization activities, and acquisitions throughout the year. In comparison, the exit rate for the period ended December 31, 2002 was approximately 8,600 BOE/d.

Revenues

Revenues net of hedging loss and before royalties totaled $100.4 million and $21.7 million, which was the result of average realized prices of $24.95 and $28.79 per barrel of oil equivalent for the year ended December 31, 2003 and period ended December 31, 2002 respectively. For the three month period ended December 31, 2003, the revenue before royalties was $36.8 million, with an average realized price of $26.95 per barrel of oil equivalent. The increase in realized prices of approximately 13% in the fourth quarter versus the third quarter of 2003, was primarily due to the increase in the overall corporate quality (API gravity) of crude produced, and the addition of unhedged production as a result of the properties acquired in Saskatchewan.

	Three month period ended December 31, 2003	**Year ended December 31, 2003**	Period ended December 31, 2002
Product prices:			
Light Oil ($/bbl)	**35.56**	**35.56**	-
Medium Oil ($/bbl)	**32.18**	**30.13**	34.21
Heavy Oil ($/bbl)	**27.34**	**24.92**	22.63
Natural Gas Liquids ($/bbl)	**29.92**	**29.18**	37.64
Natural Gas ($/mcf)	**6.70**	**6.01**	4.54
BOE ($/BOE)	**29.13**	**29.62**	30.13

Operating Netbacks

The following is a summary of Harvest's operating netbacks:

	(Amounts are expressed on a $ per barrel of oil equivalent)		
	Three month period ended December 31, 2003	**Year ended December 31, 2003**	Period ended December 31, 2002
Market price	**$29.13**	**$29.62**	$30.13
Hedging loss	**2.18**	**4.67**	1.34
Realized price	**26.95**	**24.95**	28.79
Royalties, net	**4.66**	**4.07**	3.64
Operating costs	**9.50**	**8.94**	8.49
Netback	**$12.79**	**$11.94**	$16.66

Harvest paid net royalties of $16.4 million and $2.8 million during the year ended December 31, 2003 and the period ended December 31, 2002, or approximately $4.07 per BOE and $3.64 per BOE, respectively. The net royalty amount for the year ended December 31, 2003 is comprised of $11.1 million in freehold royalties and freehold mineral tax, $5.2 million in crown royalties and $0.8 million in gross overriding royalties net of $0.7 million in royalty income received. In comparison, the net royalty amount for the period ended December 31, 2002 was comprised of $1.5 million in freehold royalties and freehold mineral tax, $1.2 million in crown royalties and $0.2 million in gross overriding royalties net of $0.1 million in royalty income received. For the three month period ended December 31, 2003, the net royalties paid were $6.4 million which is approximately a 3% increase with respect to revenue over the previous quarter, due to the change in the Harvest royalty structure as the result of the addition of the Saskatchewan properties.

Harvest's operating expenses were $36.0 million and $6.4 million or approximately $8.94 and $8.49 per BOE for the year and period ended December 31, 2003 and 2002, respectively. For the three month period ended December 31, 2003 the operating costs were $13 million or $9.50 per BOE. Substantially all of the entity's properties are operated by Harvest. Approximately 60% of Harvest's operating costs are in respect of electricity. Management has utilized fixed price delivery contracts to mitigate electricity price risk within Alberta. For fiscal year 2004 Harvest anticipates realizing further benefits from its electricity hedges with approximately 25 MWh of its estimated Alberta electricity hedged at an average price of $45.34 per MWh. This accounts for approximately 89% of the electricity used by Harvest in Alberta.

General and Administration Expenses

The portion of general and administrative expenditures charged against income totaled $4.3 million or $1.08 per BOE for the year ended December 31, 2003, in comparison to $0.6 million or $0.77 per BOE for the period ended December 31, 2002. During the year and period ended December 31, 2003 and December 31, 2002, $1.3 million and $0.2 million, respectively, of general and administrative costs were capitalized with regards to field enhancement and acquisition activities. For the three months ended December 31, 2003, general and administrative expenses were $2.2 million which has increased from the third quarter, primarily due to the application of the new CICA Handbook standard on stock based compensation of approximately $0.2 million and an increase in general and administrative costs as a result of the Saskatchewan property acquisition.

Interest Expense and Amortization of Deferred Financing Charges

Interest expense and deferred financing charges amounted to $5.6 million and $2.6 million for the year and period ended December 31, 2003 and 2002, respectively. The amortization of deferred financing charges associated with fees to secure bank lending facilities amounted to $2.6 million and $0.2 million for the year and period ended, December 31, 2003 and, respectively.

Depletion, Depreciation and Amortization and Future Site Reclamation Expenses

Harvest's depletion, depreciation, and amortization and site restoration provision totaled $33.7 million and $5.7 million for the year and period ended December 31, 2003 and 2002, respectively. This balance is comprised of crude oil and natural gas properties depletion and depreciation of $29.2 million and $5.1 million, approximately $0.2 million and $23,000 for depreciation of office furniture and equipment, and $4.4 million and $0.5 million for future abandonment and site restoration costs period ended December 31, 2003 and 2002, respectively. The depletion rate for oil and natural gas properties was approximately $7.29 and $6.77 per BOE for the year and period ended December 31, 2003 and 2002 respectively, and is based on the costs of the oil and natural gas properties purchased, capital expenditures incurred and capitalization of general and administrative expenses. The $1.08 and $0.72 per BOE rate for the year and period ended December 31, 2003 and 2002, respectively, used to provide for future site reclamation costs is founded on an estimate of ultimate net future expenditures of approximately $29.9 million. The depreciation of office furniture and equipment and leasehold improvement costs has been calculated on a straight-line basis ranging from 20% to 50%.

Income taxes

Income taxes for the year and period ended December 31, 2003 and 2002 ended are comprised of approximately $0.2 million and $0.1 million in large corporation tax and $8.2 million and $1.3 million recoveries of future income tax expense, respectively. Other than large corporations tax, neither the Trust nor its operating subsidiaries are expected to pay cash taxes in 2004.

Liquidity and Capital Resources

The Trust's capital investment and operational enhancement programs, as well as current and future financial commitments are expected to be supported by expected cash flow from operations and existing credit facilities while taking into account distributions to its unitholders.

The Trust's cash flow from operations and net income for the year ended December 31, 2003 was $46.5 million and $16.7 million, in comparison to $9.5 million and $5.1 million respectively, for the period ended December 31, 2002. While the strengthening Canadian dollar reduced the cash flows from the sales of oil and natural gas, the impact was partially offset through the gains realized when the US denominated debt was repaid in the third quarter of 2003.

As at December 31, 2003 the Trust had working capital, excluding demand loan of $9.8 million, in comparison to working capital of $10.7 million at the same date in 2002.

The Trust's net debt (working capital plus demand loan) at December 31, 2003 was $53.6 million, which is an increase of $18.9 million in comparison to net debt of $34.7 million as at December 31, 2002. This increase is the result of property and corporate acquisitions throughout the year, which were partially financed with bank debt. On September 30, 2003, the Trust changed is debt structure by extinguishing a demand loan denominated in U.S. dollars, and replacing it with equity bridge financing and a credit agreement with a syndicate of Canadian financial institutions. This series of transactions has lowered the overall effective interest rate on the Trust's demand loan, and has consolidated the financing requirements of counterparty collateral including a portion of the hedging activity.

During 2003 the Trust paid $29.1 million in unitholder distributions, of which $10.6 million were reinvested through the issue of 1,009,006 trust units under the Trust Unitholders' Distribution Reinvestment Plan ("DRIP"), this reflects 37% participation under the plan. The distributions paid amounted to $0.20 per month per trust unit for unitholders on record at the last business day of each month. The Trust anticipates maintaining this distribution rate in 2004.

Excluding trust units issued under the DRIP, the Trust issued 6.8 million trust units during 2003 in relation to an equity financing, acquisition of a private corporation, an exercise of warrants and the purchase of oil and natural gas properties.

Capital Expenditures

Capital expenditures totaled $135.3 million for the year ended December 31, 2003, in comparison to $76.9 million for the period ended December 31, 2002. Of these expenditures, acquisitions of oil and natural gas producing properties in Eastern Alberta accounted for approximately $29.2 million, which complement Harvest's current operations and production in this area. Additionally, Harvest purchased oil and natural gas properties in the Carlyle area located in Southeastern Saskatchewan for approximately $79.5 million.

The following table itemizes the balance of non-acquisition capital expenditures during the year:

	($000's)	
	Year ended December 31, 2003	Period ended December 31, 2002
Land and undeveloped lease rentals	**78**	-
Geological and geophysical	**182**	156
Drilling and completion	**10,095**	37
Well equipment, pipelines & facilities	**14,521**	167
Capitalized general and administrative	**1,311**	174
Furniture, leaseholds & office equipment	**436**	236
Acquisitions	**108,677**	76,153
Total capital expenditures	**135,300**	76,923

Capital Fund

The Trust maintains a notional Capital Fund to ensure that funds derived from cash flow are available for future acquisitions and capital spending. As the Capital Fund is a notional item the fund is not specifically segregated in the financial statements. The Capital Fund balance is calculated as follows: prior period ending balance plus cash flow from operations and amounts financed with net proceeds from equity issues net of distributions declared payable to unitholders and other equity charges (such as interest on Equity Bridge Notes and convertible debentures) less capital and acquisition expenditures. The Trust does not segregate the Capital Fund nor is a liability recorded in the consolidated financial statements. The Trust's policy is to retain and contribute up to 50% of cash flow net of contributions to the notional Capital Fund.

At December 31, 2003 the Capital Fund balance is a deficit of $14.2 million which represents the portion of capital and acquisition expenditures financed with bank debt and working capital.

Future Liquidity Requirements

Harvest plans to continue with its plan to optimize current production with the use of the Capital Fund. From time to time the Trust may continue to require external financing, through both debt and equity, to maintain its business plan growing through acquisitions and execution of efficient capital programs. These requirements are subject to external factors including, but not limited to fluctuations in equity and commodity markets, economic downturns and interest and foreign exchange rates. Adverse changes in these factors could require Harvest's management to alter the current business plan of the Trust. For fiscal year 2004 the Trust anticipates a capital program of approximately $34 million which will be funded with the Capital Fund, working capital management, prudent use of bank debt, DRIP activity and if necessary equity funding. Acquisitions will typically be funded with equity financings and additional bank debt resulting from an increase in the Trust borrowing base as a result of the acquisition.

The Trust has been able to utilize equity to carry out its business plan. The financial capability of the Trust has been enhanced by an issue of $60 million convertible debentures bearing interest at 9% and issued in January 2004. Access to lower cost of capital funding improves the Trust's ability to compete and cost effectively carry out its business plan. Upon filing of its Annual Information Form in late 2003, the Trust became a qualified "POP" issuer, which allows the Trust to use a "short form" prospectus for equity financing. This means that the Trust can quickly and more easily access equity markets.

Off-Balance Sheet Arrangements

The Trust has a number of immaterial operating leases in place on moveable field equipment and vehicles. The leases require periodic lease payments and are recorded as operating costs. The Trust also finances its annual insurance requirements, whereby a portion of the annual premium is deferred and paid monthly over the balance of the term.

Contractual Obligations

The Trust has entered into the following contractual obligations:

	Maturity			
Annual Contractual Obligation ($ thousands)	Less than 1 year	Years 1 - 3	Years 4 - 5	After 5 Years
Product transportation agreements	35	39	25	-
Operating and premise leases	293	646	646	-

The Trust also had $63.3 million of bank debt outstanding related to short term borrowing through its revolving credit facility. The Trust intends to extend this facility on an ongoing basis as terms permit.

As at December 31, 2003 Harvest Operations Corp. has entered into physical and financial contracts for production with a current delivery of approximately 9,800 BOE/d in 2004 and 2,500 BOE/d in 2005. Harvest has also entered into financial contracts to minimize its exposure to fluctuating electricity prices and the US / Canadian dollar exchange rate. Please see Note 10 in the Consolidated Financial Statements for further details.

The Trust has entered into a number of insignificant contractual obligations under operating leases and normal course oil and natural gas business relationships. All of these agreements are cancelable on a month to month basis, and do not require additional payment upon defeasance.

Critical Accounting Policies

The management of the Trust is required to make estimates and assumptions that affect the reported amounts of assets and liabilities when applying Canadian generally accepted accounting principles. The following is a discussion of the accounting policies that are deemed critical by management in the preparation of the financial results of the Trust.

Oil and Gas Accounting

The Trust follows the Canadian Institute of Chartered Accountants guideline for the full cost method of accounting for the oil and natural gas industry. All costs of acquiring oil and natural gas properties and related exploration and development costs, including overhead charges directly related to these activities, are capitalized and accumulated in one cost center. The maintenance and repairs are charged against income, and renewals and enhancements that extend the economic life of the capital assets are capitalized. Any gains or losses are not recognized on disposition of oil and natural gas properties unless that disposition would alter the rate of depletion by 20% or more. The provision for depletion and depreciation of petroleum and natural gas assets is calculated on the unit-of-production method, based on proved reserves before royalties as estimated by independent petroleum engineers. The basis used for the calculation of the provision is the capitalized costs of petroleum and natural gas assets plus the estimated future development costs of proved undeveloped reserves. Reserves are converted to equivalent units on the basis of six thousand cubic feet of natural gas to one barrel of oil. The reserve estimates used in these calculations can have a significant impact on the net income, and any downward revision in this estimate could result in a higher depletion and depreciation expense. In addition, a downward revision of this reserve estimate could require an additional charge to income as a result of the computation of the prescribed ceiling test calculation under this guideline.

Site restoration and reclamation provision

The Trust provides for the cost of future site restoration and reclamation based on estimates by management using the unit-of-production method and associated reserve estimates. Management estimates the expected future costs to abandon and environmentally restore a well or battery site under specific environmental legislation. These estimates are characteristically difficult to assess due to their expected timing and associated costs at that future date. Due to this estimation, any upward revision of these expected costs or revisions in timing could adversely affect the provision being charged to income.

Trust unit incentive plan

The Trust has established a trust unit incentive plan whereby the Trust is authorized to grant non-transferable rights to purchase trust units to directors, officers, employees, consultants and other service personnel. The initial exercise price of rights granted under the plan is equal to the closing market price on the date immediately prior to the date the rights are granted and the maximum term of each right is not to exceed five years. The exercise price of the rights is adjusted downwards from time to time based upon the cash distributions made on the trust units subject to a specific return as outlined in the Trust Units Rights Incentive Plan. Under GAAP the Trust records a compensation expense based on the binomial model of valuation. The binomial model has been utilized by the Trust as it allows for the calculation of the fair value of a trust unit right with a decreasing exercise price, based on the distributions paid from the date of issue to date of exercise. Management is required to make certain assumptions and estimates when applying the binomial model. Further details regarding the Trust's trust unit incentive plan and assumptions and estimates used are included in the Note 9 of the Consolidated Financial Statements.

Changes in Accounting Policies

Trust unit incentive plan

The Trust has elected to prospectively adopt the amendments to CICA Handbook section 3870 "Stock-based Compensation and Other Stock-based payments". Under this section, the Trust has chosen to recognize compensation expense when trust unit rights are granted under the trust unit incentive plan on a prospective basis. As such, compensation expense has been calculated on all trust unit rights issued on or subsequent to January 1, 2003. The fair value of trust unit rights issued has been determined using a binomial option pricing model.

Changes in Accounting Standards

The following is a list of changes to accounting standards that will affect the financial reporting of the Trust in the upcoming year as at April 2004:

Asset retirement obligation

The CICA has issued a new Handbook section 3110 "Accounting for Asset Retirement Obligation" which requires that entities recognize the liability associated with the fair value of future site reclamation and abandonment costs in the financial statements at the time when the liability is incurred. The new standard is effective for fiscal years beginning on or after January 1, 2004, with earlier adoption encouraged. The Trust has elected to adopt this standard in the upcoming fiscal year.

Full cost accounting guideline

In September 2003 the CICA issued Accounting Guideline 16 "Oil and Gas Accounting – Full Cost". The guideline replaces Accounting Guideline 5 "Full Cost Accounting in the Oil and Gas Industry" and is effective for fiscal years beginning on or after January 1, 2004, with earlier adoption encouraged. Under the new guideline the definition for proved and probable reserves has been changed to synthesize with the new reserve definitions under the recently issued National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" issued by the Canadian Securities Administrators. These changes include modifications to the ceiling test calculation, additional disclosure within the notes to the financial statements and changes in accounting for disposals of properties other than by sale. The Trust has elected to adopt this standard in the upcoming fiscal year.

Hedging

In December 2001 the CICA issued Accounting Guideline 13 "Hedging Relationships" that provides guidance on the identification, designation, documentation and measurement of the effectiveness of hedging relationships for the purposes of applying hedge accounting. This guideline is effective for fiscal years beginning on or after July 1, 2003. The Trust has implemented the requirements of this guideline in 2003.

Transactions with Related Parties

A director and a corporation controlled by a director of Harvest Operations Corp., have advanced $60.5 million and were repaid $35.5 million during the year ended December 31, 2003. In addition interest totaling nearly $0.3 million was paid in respect of these advances. Also during the year, a corporation controlled by a director of Harvest Operations Corp. exercised a warrant to purchase 150,000 trust units for proceeds of $150,000. The funds generated in these transactions were used for ongoing operations and acquisition activities of the Trust. The terms under these agreements and amounts transacted were based upon arms length fair market values at the time.

A corporation controlled by a director of Harvest Operations Corp. sublets office space and is provided administrative services at fair market value.

Risk Management Activities

All of Harvest's risk management activities are carried out under policies approved by the Board of Directors. Harvest intends to execute its business plan to create value for unitholders by paying stable monthly distributions and increasing the net asset value per trust unit. Harvest's management has identified the following risks associated with the Trust's business:

- Operational risk associated with the production of oil and natural gas;
- Reserve risk with respect to the quantity of recoverable reserves;
- Commodity price risk, as oil and natural gas prices fluctuate due to market forces;
- Financial risks, such as the Canadian/US dollar exchange rate, interest rates, credit risk and debt service obligations;
- Environmental, health and safety risks associated with well and production facilities; and,
- Changing government policy risks, including revisions to royalty legislation, income tax laws, and incentive programs related to the oil and natural gas industry.

Under Harvest's risk management policies approved by the Board of Directors the Trust intends to mitigate risks listed above as follows:

Operational risk:

- Applying a proactive management approach to Harvest's properties;
- Selectively adding educated and experienced employees and providing encouragement and opportunities to maintain and improve technical competence; and;
- Remunerating employees with a combination of average industry salary and benefits combined with a merit based bonus plan to reward success in execution of the Trust's business plan.

Reserve risk:

- Acquiring oil and natural gas properties that have high quality reservoirs combined with mature, predictable and reliable production and thus reduce technical uncertainty;
- Subjecting all property acquisitions to rigorous operational, geological, financial, and environmental review; and
- Pursuing a capital expenditure program to reduce production decline rates improve operating efficiency and increase ultimate recovery of the resource in place.

Commodity price risk:

- Maintaining risk management policy and committee to continuously review effectiveness of existing actions, identify new or developing issues and devise and recommend to the Board of Directors action to be taken;
- Maintaining a program to hedge (via utilizing swaps, collars and option contracts) commodity prices and electricity costs with a portfolio of credit worthy counterparties; and
- Maintaining a low cost structure to maximize product netbacks.

Financial risk:

- Monitoring financial markets to ensure the cost of debt and equity capital is kept as low as reasonably possible;
- Retaining up to 50% of the funds available for distribution to finance capital expenditures and future property acquisitions;
- Monitoring the Trust's financial position and foreign exchange markets with the intent of taking the steps necessary to minimize the impact of fluctuations in foreign currency;
- Comparing actual financial performance against pre-determined expectations and making changes where necessary; and
- Carrying adequate insurance to cover losses and business interruption.

Environmental, health and safety risks:

- Adhering to the Trust's safety program and keeping abreast of current industry practices; and
- Accumulating sufficient cash resources to pay for future abandonment and site restoration costs.

Regulatory risks:

- Retaining an experienced, diverse and actively involved Board of Directors to ensure good corporate governance; and
- Engaging technical specialists when necessary to advise and assist with the implementation of policies and procedures as a result of the changing regulatory environment.

As at December 31 2003, Harvest Operations Corp. has entered into market price, physical contracts with a current average delivery of approximately 5,825 BOE/d for 2004 and 1,000 BOE/d for 2005. Harvest has also entered into financial swap and collared contracts for WTI crude oil, LLB differential, US / Canadian dollar exchange rate, electricity and natural gas heat rate which had a mark to market unrealized loss of $12.5 million as at December 31, 2003. Please refer to Note 10 in the Consolidated Financial Statements for further information.

The following table summarizes the risk management activities undertaken by the Trust, the volumes hedged and the associated unrecognized mark to market gains and losses as at December 31, 2003:

	Maturity		
	2004	2005	2006
Volumes Hedged			
West Texas intermediate crude oil price based swaps (bbls/d)	4,286	1,033	-
West Texas intermediate crude oil price based collars (bbls/d)	5,500	-	-
Lloyd blend crude oil price based swaps (bbls/d)	3,500	-	-
Alberta electricity price based swaps (MW)	25	15	3
Electricity heat rate (GJ/MWh)	-	5	-
Canadian / U.S. dollar based swap (Cdn $ million)	3	-	-

Mark to Market Gains (Losses) ($ thousands)			
West Texas intermediate crude oil price based swaps	(12,520)	(2,177)	-
West Texas intermediate crude oil price based collars	(4,399)	-	-
Lloyd blend crude oil price based swaps	2,146	-	-
Alberta electricity price based swaps	1,785	763	153
Electricity heat rate	-	46	-
Canadian / U.S. dollar put option	1,735	-	-
	(11,253)	(1,368)	153

Under Harvest's risk management policy Management enters into crude oil based financial and physical contracts to mitigate the risk of price volatility for its expected production. Management also enters into electricity price based swaps to assist in maintaining stable operating costs. Finally, as a further means to manage revenue risks, Management has entered into foreign exchange contracts to minimize the effect of adverse foreign exchange fluctuations of the Canadian dollar against the U.S. dollar. Readers are advised to refer to the Consolidated Financial Statement notes of Harvest for the year ended December 31, 2003 for additional information on these contracts.

Taxability of Cash Distributions paid to Unitholders

Cash distributions are comprised of a return of capital portion (tax deferred) and a return on capital portion (taxable). For cash distributions received by a Canadian resident, outside of a registered pension or retirement plan the distribution declared in December 2002 and paid in January 2003 was deemed to be 100% tax deferred. For the distributions declared in 2003 and paid in the months of February 2003 through to January 2004, 41% of the distributions are taxable and 59% are a tax deferred.

Key Performance Indicators and 2004 Outlook

Based upon current operations, the following table provides guidance in respect to 2004 and relative performance for the past year:

	Performance Goals 2004	Results 2003
Daily production (BOE/d)	15,000 - 15,500	11,040
Average Royalty Rate	15% - 17%	13.8%
Operating expense ($/BOE)	$10.00 - $10.50	$8.94

Harvest plans to continue with its business plan of acquiring and operating high quality, mature crude oil and natural gas properties that are enhanced through operational and exploitation techniques. Harvest also plans to continue to identify new areas in the Western Canadian sedimentary basin that can provide the required growth and stability for sustainable distributions and asset value per unit.

It is important to note that the above figures are estimates based upon Management's current expectations. The ultimate results may vary, perhaps materially.

The table below indicates the impact of changes of key variables on Harvest's cash flow and distributions including the impacts of the hedging program.

Sensitivities

	Variable				
	WTI price/bbl	Heavy Oil LLB differential/bbl	Crude Oil production	Canadian bank prime rate	Foreign exchange Cdn. / U.S.
Assumption	$32.00 US	$9.00 US	15,200 boe/d	4.25%	1.32
Change (plus or minus)	$1.00 US	$1.00 US	1,000 boe/d	1.00%	0.01
Cash flow from operations ($000's)	$1,700	$1,900	$6,300	$421	$800
Per trust unit, basic	$0.10	$0.11	$0.36	$0.03	$0.05
Per trust unit, diluted	$0.10	$0.11	$0.36	$0.03	$0.05
Payout ratio	2.0%	2.3%	7.5%	0.5%	1.0%