Third Quarter 2005 Financial and Operational Summary

The table below provides a summary of Harvest's financial and operating results for the three and nine month periods ended September 30, 2005.

($000's, except where noted)	Three months ended September 30			Nine months ended September 30		
FINANCIAL	**2005**	2004 (restated[5])	Change	**2005**	2004 (restated[5])	Change
Revenue, net of royalties	**169,654**	85,096	99%	**399,848**	168,856	137%
Net income (loss)[5]	**52,862**	1,740	2938%	**29,308**	(359)	-
Per Trust Unit, basic[5]	**$ 1.09**	$ 0.06	1724%	**$ 0.66**	$ (0.02)	-
Per Trust Unit, diluted[5]	**$ 1.08**	$ 0.06	1700%	**$ 0.64**	$ (0.02)	-
Funds flow from operations[4,5]	**103,508**	41,267	151%	**213,412**	72,372	195%
Per Trust Unit, basic[4,5]	**$ 2.14**	$ 1.42	51%	**$ 4.78**	$ 3.46	38%
Per Trust Unit, diluted[4,5]	**$ 2.09**	$ 1.12	87%	**$ 4.55**	$ 2.59	76%
Distributions per Trust Unit, declared[6]	**$ 0.95**	$ 0.60	58%	**$ 2.15**	$ 1.80	19%
Distributions declared	**46,691**	18,434	153%	**108,957**	39,740	174%
Payout ratio[2,4]	**45%**	45%	0%	**46%**	55%	(9%)
Capital asset additions (excluding acquisitions)	**33,594**	13,182	155%	**84,007**	31,695	165%
Net acquisitions	**209,666**	513,815	100%	**239,296**	590,942	(60%)
Net debt[3,4]	**418,169**	403,372	4%	**418,169**	403,372	4%
Weighted average Trust Units outstanding, basic	**48,306**	29,058	66%	**44,612**	20,938	113%
Weighted average Trust Units outstanding, diluted	**49,365**	29,700	66%	**45,719**	20,938	118%
Trust Units outstanding, end of period	**51,558**	36,875	40%	**51,558**	36,875	40%
Trust Units fully diluted[7], end of period	**55,680**	44,851	24%	**55,680**	44,851	24%
OPERATING						
Daily sales volumes						
Light oil (bbl/d)	**10,076**	9,087	11%	**9,949**	6,461	54%
Medium oil (bbl/d)	**8,792**	5,416	62%	**6,669**	4,553	46%
Heavy oil (bbl/d)	**13,735**	7,894	74%	**13,906**	6,271	122%
Natural gas liquids (bbl/d)	**850**	377	125%	**810**	190	326%
Natural gas (mcf/d)	**24,574**	11,909	106%	**26,839**	5,049	432%
Total (BOE/d)[1]	**37,549**	24,759	52%	**35,807**	18,317	95%
OPERATING NETBACK[4] ($/BOE)[1]						
Revenues	**60.39**	44.83	35%	**49.27**	40.43	22%
Realized loss on derivative contracts	**(6.85)**	(7.22)	(5%)	**(6.76)**	(7.52)	(10%)
Royalties	**(11.28)**	(7.47)	51%	**(8.37)**	(6.78)	23%
As a percent of revenue (%)	**18.7%**	16.7%	2%	**17.0%**	16.8%	0%
Operating expense[8]	**(8.96)**	(8.34)	7%	**(8.87)**	(9.22)	(4%)
Operating netback[4]	**33.30**	21.80	53%	**25.27**	16.90	50%

Note 1 *Natural gas converted to barrel of oil equivalent (BOE) on a 6:1 basis.*

Note 2 *Ratio of distributions, excluding special distribution, to Funds Flow from Operations. In the third quarter, reflects distributions declared of $0.25 (July) and $0.35 (August and September) per unit.*

Note 3 *Net debt is bank debt, senior notes, equity bridge notes, convertible debentures and any working capital deficit excluding the current portion of derivative contracts, future income tax and the accounting liability related to our Trust Unit incentive plan.*

Note 4 *These are non-GAAP measures; please refer to "Certain Financial Reporting Measures" included in our MD&A.*

Note 5 *Prior year restated to reflect adoption of new accounting standards with respect to exchangeable shares and financial instruments. See Note 2 to the Consolidated Financial Statements.*

Note 6 *As if the Trust Unit was held throughout the period.*

Note 7 *Fully diluted Units differ from diluted Units for purposes of calculating earnings per unit and funds flow per unit, and is meant to reflect the number of units which would be outstanding if all potentially dilutive elements were exercised. Fully diluted includes Trust Units outstanding as at September 30 plus the impact of the conversion or exercise of exchangeable shares, Trust Unit rights and convertible debentures if converted at September 30.*

Note 8 *Includes realized gain on electricity derivative contracts of $0.43 ($0.24 – 2004) and $0.18 ($0.29 – 2004) for the three and nine month periods ended September 30, 2005 and 2004, respectively.*

Third Quarter Message to Unitholders

During the third quarter, we enjoyed another successful period of growth and development as we increased distributions and continued to build the Trust's assets for future performance. We achieved significant per unit distribution increases, strengthened our asset base and financial structure and achieved the highest quarterly funds flow from operations in Harvest's history at $2.14 per basic trust unit (an increase of 62% over the second quarter of 2005).

Specific highlights during the quarter include increasing our monthly distribution by 75% while still retaining a low payout ratio of 45%; investing $33.6 million in property enhancement activities, which included drilling 20 wells with a 98% success rate; closing the Hay River property acquisition and concurrent financing; listing our trust units for trading on the New York Stock Exchange (NYSE); and implementing an enhanced Distribution Reinvestment, Premium Distribution™, and Optional Trust Unit Purchase Plan for our Canadian resident unitholders. Each of these initiatives contributed to the long-term sustainability of Harvest.

On August 2, we added approximately 5,200 barrels of oil equivalent per day (BOE/day) of crude oil from the Hay River, B.C. property acquisition. A full quarter's impact from Hay River will be reflected in Harvest's fourth quarter results. Hay River is an excellent fit with our existing portfolio, and enhances our already significant development inventory. Furthermore, Hay River's lower operating costs and premium price realizations relative to the benchmark for medium gravity crude oil help to strengthen our overall corporate netbacks. We anticipate significant drilling activity (approximately 30 wells) in the area during this winter drilling season.

Our commitment to sustainability is supported by our strong financial position. We believe that we can maintain our C$0.35 per trust unit monthly distribution level through a downturn in oil prices due to our low payout ratio and our hedging program. Our hedging strategy underpins our cash flow and provides stability during volatile crude oil price environments by providing downside protection while allowing for upside participation. For example, Harvest's 2006 hedging program would enable us to sustain the current monthly distribution level of $0.35 per unit, finance a significant capital program, and generate an annual payout ratio of approximately 75% even if crude oil prices should drop to U.S.$40 per barrel for all of 2006. We have not hedged any of our natural gas production, and therefore have fully benefited from rising natural gas spot prices in Alberta.

Our capital development program, which is designed to replace naturally declining production and reserves by making prudent investments in low-risk property enhancement projects, further demonstrates our commitment to sustainability. During the third quarter, Harvest invested approximately $33.6 million in our capital development program, with 64% of that amount allocated to drilling. Our third quarter drilling activities were focused in Southern Alberta and Saskatchewan, where we drilled 7 and 11 net wells, respectively. We also drilled one well in each of East Central and North Central Alberta, for a total of 20 net wells in the quarter, and achieved an overall success rate of 98%. We expect to drill approximately 90 net wells in 2005, while continuing to dedicate resources to our ongoing optimization and efficiency projects. We will continue to focus on operating efficiency measures in our capital program, and remain committed to operating cost reductions. Operating costs have increased due to very significant power price increases impacting our small unhedged power volume requirement.

During the quarter, we invested in optimization projects such as a water handling expansion at Chauvin to add pumping capacity, and the deepening of injection wells at Hayter, Big Marsh and Moose Valley to improve the efficiency of water reinjection at these properties. Infrastructure additions were also completed during the quarter, with a satellite field treating facility added in Hazelwood, and a fluid processing facility installed in West Provost. Subsequent to the end of the quarter, we expanded our 2005 capital budget to approximately $130 million to pursue additional value adding projects identified by our operational teams. This reflects the second supplement to our 2005 capital program as our technical teams were able to identify and support solid economic investment opportunities as their knowledge of our properties has matured. The full impact of this optimization capital is expected to be realized as the majority of the new production comes on-line during the first quarter of 2006. We are also finalizing our operating budget for 2006, which is expected to be complete by early December, after which time we will be providing our guidance for 2006.

Third quarter production volumes averaged 37,549 BOE/d, and include the addition of the Hay River production from August 2 through September 30. Several factors combined during the quarter to result in lower realized oil production relative to capacity. An unscheduled outage and subsequent repairs at our Suffield property impacted production for 6 days, and production was further impacted by wet ground conditions in Alberta and Saskatchewan delaying completion of scheduled workovers and other projects. However, the impact of these items was partially mitigated by new drilling activity in our Hazelwood and East Hayter areas where production was initiated sooner than expected. Our third quarter operating expenses were $8.96 per BOE and reflect the rising cost environment and short-term production outages. This is slightly less than the second quarter ($9.08/BOE), but still higher than we believe is achievable with our asset base.

We also strengthened our capital structure during the quarter by concluding a financing of 6.5 million trust units at $26.90 for $175 million, and $75 million of 6.5% convertible debentures with a conversion price of $31.00. The proceeds from this offering were primarily used to repay bank debt incurred in acquiring the Hay River property. By the end of the quarter our net debt was reduced to approximately $418 million from $437 million at the end of the second quarter, and we increased annualized funds flow from operations by $183 million. This has resulted in quarter end net debt to annualized funds flow of 1.0 times – a figure that reinforces our strong capital structure and is in line with our peers. Harvest units also realized a dramatic improvement in trading liquidity with a listing on the NYSE. Total trading volumes increased by 194% relative to the second quarter.

With our current capital structure and approximately $350 million of undrawn borrowing capacity, we are well positioned to take advantage of any acquisition opportunities that may arise. Our criteria for acquisition opportunities include return on equity and upside potential. We are not limited to a narrow range of property types, commodity types or RLI. We have the advantage of remaining opportunistic toward the acquisition marketplace due to our deep portfolio of future development opportunities that currently offers several years of drilling locations.

For 2005, we anticipate production volumes to average between 36,250 and 36,750 BOE per day, operating expenses of $8.75 to $9.00 per BOE, development capital expenditures of approximately $130 million, and cash G&A (before unit right compensation expenses) between $1.00 and $1.10 per BOE.

Harvest has positioned itself with a strong balance sheet, significant commodity price protection and a large undrawn debt facility to allow us to be opportunistic. We have a solid asset base, a prudent risk management program, a strong capital structure, and a dedicated team. With these fundamentals, Harvest will continue to focus on long-term sustainability and our goal of maintaining or increasing funds flow per unit.

Government Policy Initiatives

In a consultation paper issued on September 8, 2005, the Canadian Federal Government expressed concerns about several economic policy issues arising from the recent proliferation of income trusts in Canada. These concerns included the impact on the Canadian economy and possible reductions to overall federal tax revenues. The Government has requested comments and feedback from interested stakeholders regarding the tax treatment of income trusts by December 31, 2005. The government of Alberta has expressed similar concerns regarding the impact of energy trusts on tax revenues, although it has acknowledged the benefits to Alberta and the energy industry in general arising from energy trust investment activity.

Energy income trusts fill a vital and active role in the Canadian energy sector. The current tax treatment of energy trusts is crucial to enable the Canadian energy industry to attract the capital necessary to meet Canada's current and future energy needs. Energy trusts also provide a ready source of capital to more conventional exploration focused oil and natural gas corporations through acquisitions and further development of their mature properties. Harvest is working to ensure that its views and the views of its unitholders are represented to both the provincial and federal governments, through support given to industry associations.

We encourage existing or potential unitholders and other stakeholders who wish to voice their support for the preservation of the current income trust taxation structure to contact the Department of Finance via the following Web site: www.fin.gc.ca/admin/contact-e.html. Alberta resident unitholders can contact their Member of Legislative Assembly (MLA) via the following website http://www.assembly.ab.ca/net/index.aspx?p=mla_home to provide feedback on the Alberta government's concerns with respect to trusts. Harvest's website at www.harvestenergy.ca includes a list of contact information for all Canadian Members of Parliament (MP) and we encourage all Canadian resident unitholders to contact their MP to express their views.

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, 2004 as well as our unaudited consolidated financial statements and notes for the three and nine month periods ended September 30, 2005. Certain comparative figures have been reclassified to conform with the current period presentation.

All references are to Canadian dollars unless otherwise indicated. Natural gas volumes recorded in thousand cubic feet ("mcf") are converted to barrels of oil equivalent ("BOE") using the ratio of six (6) thousand cubic feet to one (1) barrel of oil ("bbl"). BOE's may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 mcf:1 bbl is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. All references to WTI in the following document refer to West Texas Intermediate, a high quality grade of crude oil used as a benchmark in oil pricing.

Forward-Looking Information

This third quarter report 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 reserve 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 as at November 7th, 2005.

Certain Financial Reporting Measures

The Trust utilizes certain measures of financial reporting that are commonly used as benchmarks within the oil and natural gas industry in the following MD&A discussion. These measures include: Funds Flow from Operations before changes in non-cash working capital and settlement of asset retirement obligations ("Funds Flow from Operations") calculated below, Net Operating Income, Net Debt, Payout Ratio and Operating Netback (calculated in tables within the MD&A). 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. Specifically, management uses Funds Flow from Operations (referred to as cash flow from operations in our year end 2004 MD&A), to analyze operating performance and leverage. Funds Flow from Operations should not be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. For the three and nine month periods ended September 30, 2005 and 2004, Funds Flow from Operations is reconciled to its closest GAAP measure, cash flow from operating activities, as follows:

$000s	**Three months ended September 30, 2005**	Three months ended September 30, 2004	**Nine months ended September 30, 2005**	Nine months ended September 30, 2004
Funds Flow from Operations before changes in non-cash working capital and settlement of asset retirement obligations	**103,508**	41,267	**213,412**	72,372
Changes in non-cash working capital	**29,810**	(9,093)	**(25,867)**	(12,405)
Settlement of asset retirement obligations	**(1,169)**	(154)	**(2,333)**	(307)
Cash flow from operating activities	**132,149**	32,020	**185,212**	59,660

Trust Overview and Strategy

Harvest Energy Trust is an oil and natural gas royalty trust, which focuses on the operation of high quality, mature properties. We employ a disciplined approach to the oil and natural gas production business, whereby we acquire high working interest, large resource-in-place, mature producing properties and employ "best practice" technical and field operational processes to extract maximum value. These operational processes include: diligent hands-on management to maintain and maximize production rates, the application of technology and selective capital investment to maximize reservoir recovery, the enhancement of operational efficiencies to control and reduce expenses, and unique marketing arrangements complemented by corporate hedging strategies to effectively manage Funds Flow from Operations. We have operations in four core areas: Northern (which includes the newly acquired Hay River property in Northeast British Columbia), East Central Alberta, Southern Alberta and Southeast Saskatchewan. Our objective is to maintain or increase Funds Flow from Operations on a per unit basis.

Acquisitions and Events

On August 2, 2005, we closed the acquisition of the Hay River property, as well as a $250 million bought deal equity and convertible debenture financing. The impact of the acquisition and financing on Harvest's financial statements is effective as of the closing date, and therefore this quarter only reflects two months' results from Hay River.

The addition of the Hay River property in August increased our production volume by approximately 5,200 BOE/d at that time. The Hay River barrels sell at a premium to our average medium gravity crude production, and coupled with the impact of the lower Hay River operating expenses, will improve our corporate netbacks. The accretive nature of the transaction has contributed to an increase in our per Trust Unit Funds Flow from Operations, as demonstrated by our third quarter results. Hay River has a higher royalty rate than our corporate average, which will increase our royalties as a percentage of revenue. In the future, due to the winter access nature of this property, the first quarter results from Hay River will reflect high operating and capital expenditures and lower volumes than the remainder of the year. The second quarter results should reflect the benefits of the activities undertaken in the first quarter, and as a result, the first quarter will not be indicative of the operating and financial results expected for the balance of the year.

The proceeds from the bought deal financing were used to repay bank debt incurred in the Hay River property acquisition. We issued 6.5 million Trust Units at $26.90 for $175 million, and $75 million of 6.5% convertible debentures, with a conversion price of $31.00. At the time of writing, approximately 52.2 million Trust Units are outstanding; approximately $53 million of convertible debentures are outstanding, and our net debt (excluding convertible debentures) is $10 million lower than the level reported at September 30, 2005.

We listed our Trust Units on the NYSE on July 21, 2005; this has lead to improved liquidity and visibility for Harvest, improved access to U.S. equity markets and greater financing flexibility.

Summary of Historical Quarterly Results

	2005			*(Restated - Refer to note 2 of the consolidated financial statements)* 2004				*(Restated)* 2003
Financial	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Revenue, net of royalties	**$ 169,654**	$ 120,263	$ 109,931	$ 106,964	$ 85,096	$ 44,461	$ 39,298	$ 33,575
Operating expense	**(32,441)**	(28,635)	(27,348)	(25,725)	(19,538)	(14,306)	(13,873)	(13,335)
Net operating income[1]	**$ 137,213**	$ 91,628	$ 82,583	$ 81,239	$ 65,558	$ 30,155	$ 25,425	$ 20,240
Net income (loss)	**52,862**	19,516	(43,070)	11,600	1,740	151	(2,250)	5,495
Per Trust Unit, basic[2]	**1.09**	0.45	(1.02)	0.29	0.06	0.01	(0.13)	0.30
Per Trust Unit, diluted[2]	**1.08**	0.44	(1.02)	0.27	0.06	0.01	(0.13)	0.29
Funds Flow from Operations[1,2,3]	**103,508**	57,217	52,687	52,870	41,267	15,839	13,734	13,699
Per Trust Unit, basic[1,2]	**2.14**	1.32	1.25	1.31	1.42	0.91	0.80	0.85
Per Trust Unit, diluted[1,2]	**2.09**	1.29	1.19	1.18	1.12	0.78	0.67	0.82
Sales Volumes								
Crude oil (bbl/d)	**32,603**	28,855	30,087	30,992	22,397	14,775	14,626	14,497
Natural gas liquids (bbl/d)	**850**	798	780	1,309	377	141	50	70
Natural gas (mcf/d)	**24,574**	28,857	27,114	28,338	11,909	2,249	915	1,744
Total (BOE/d)	**37,549**	34,463	35,386	37,024	24,759	15,291	14,829	14,858

Note 1 This is a non-GAAP measure as referred to under "Certain Financial Reporting Measures" in this MD&A.
Note 2 The sum of the interim periods does not equal the total per year amount as there were large fluctuations in the weighted average number of Trust Units outstanding in each individual quarter.
Note 3 Funds Flow from Operations in 2005 includes interest on convertible debentures and equity bridge notes. In prior reporting periods, these items were reflected in financing activities.

The above table highlights Harvest's performance for the third quarter of 2005, and the preceding 7 quarters.

Net revenues and net operating income have trended steadily higher over the eight quarters shown above. The significantly higher revenue and funds flow in the third quarter of 2005 relative to the second quarter of 2005 is primarily due to higher production from the Hay River acquisition, stronger crude oil prices and narrower heavy oil differentials early in the quarter. The most significant increase in revenue occurred through the third and fourth quarters of 2004, as a result of the two acquisitions completed in 2004, which closed in June and September. The increasing revenue trend since the fourth quarter of 2003 is also attributable to the strong commodity price environment through 2004 and 2005.

Net income reflects both cash and non-cash items. Changes in non-cash items, including depletion, depreciation and accretion (DD&A) expense, unrealized foreign exchange gains and losses, unrealized gains and losses on derivative contracts, Trust Unit right compensation expense and future income taxes can cause net income to vary significantly from period to period. However, these items do not impact the Funds Flow from Operations available for distribution to Unitholders, and therefore we believe net income may be a less meaningful measure of performance for Harvest. The main reason for the volatility in net income (loss) between quarters in 2005 is due to the changes in the fair value of our derivative instruments. We ceased hedge accounting for all of our derivative instruments in October 2004 switching to a "mark to market" accounting methodology and this has accounted for increased volatility in our earnings. Due primarily to the inclusion of unrealized mark-to-market gains and losses on derivative contracts, net income (loss) has not reflected the same trend as net revenues or Funds Flow from Operations.

Funds Flow from Operations is an important measure for an energy royalty trust because it represents the source for cash distributions to Unitholders. Funds Flow from Operations is also the means by which we finance repayment of debt and capital expenditures which are used to replace produced reserves, contributing to sustainability. Our low payout ratio is a key competitive advantage in creating future sustainability. Funds Flow from Operations can be impacted by factors outside of management's control such as commodity prices and currency exchange rates. We strive to mitigate the impact of these factors by hedging (generally referred to herein as 'derivatives' or 'derivative contracts') a portion of our production volumes. This takes several forms including establishing a fixed floor for future commodity prices, and mitigating the impact of fluctuating heavy oil price differentials and currency exchange rates.

Revenues

	Three months ended September 30			Nine months ended September 30		
	2005	2004	Change	**2005**	2004	Change
Oil and natural gas sales ($/BOE)	**60.39**	44.83	35%	**49.27**	40.43	22%
Royalty expense ($/BOE)	**(11.28)**	(7.47)	51%	**(8.37)**	(6.78)	23%
Net revenues ($/BOE)	**49.11**	37.36	31%	**40.90**	33.65	22%
Net revenues ($ millions)	**169.7**	85.1	99%	**399.8**	168.9	137%

Net revenue is impacted by production volumes, commodity prices, currency exchange rates and royalty rates. Due to the two significant acquisitions completed during the latter half of 2004, which substantially increased production volumes, and a crude oil price environment that has continued to strengthen for the past 4 quarters, our net revenues in the three and nine month periods ending September 30, 2005 increased 99% and 137%, respectively, over the same periods in 2004. In addition, the increase in third quarter revenues reflect two months of production and net revenue from the Hay River properties. Changes in realized prices, volumes and royalty rates are discussed separately below. The impact of our hedging activities on current and future periods' income is discussed under "Derivative Contracts".

Sales Volumes

At 37,549 BOE/d, third quarter 2005 sales volumes were 52% higher than the 24,759 BOE/d realized in the three month period ended September 30, 2004 and were in line with expectations. Volumes averaged 35,807 BOE/d for the first nine months of 2005, and were 95% higher than the 18,317 BOE/d realized in the same period in 2004. The increase in production year-over-year is due to the volumes associated with properties acquired in June and September 2004, the acquisition of the Hay River properties in August 2005, as well as successful development and optimization work within all of our core areas. Third quarter 2005 natural gas production was 24,574 mcf/day compared to 27,114 mcf/day in the first quarter. The decrease is due to natural declines. We are working on incorporating natural gas development projects into our 2006 budget to help offset these natural declines. Our second quarter natural gas production of 28,857 mcf/day reflects positive prior period adjustments relating to previously acquired natural gas wells. We anticipate that future natural gas production will be consistent with the volumes reported in the third quarter.

The average daily sales volumes by product were as follows:

	Three months ended September 30				
	2005		2004		
	Volume	**Weighting**	Volume	Weighting	% Change
Light oil (Bbl/d)	**10,076**	**27%**	9,087	36%	11%
Medium oil (Bbl/d)	**8,792**	**23%**	5,416	22%	62%
Heavy oil (Bbl/d)	**13,735**	**37%**	7,894	32%	74%
Total oil (Bbl/d)	**32,603**	**87%**	22,397	90%	46%
Natural gas liquids (Bbl/d)	**850**	**2%**	377	2%	125%
Total oil and natural gas liquids (Bbl/d)	**33,453**	**89%**	22,774	92%	47%
Natural gas (mcf/d)	**24,574**	**11%**	11,909	8%	106%
Total oil equivalent (BOE/d)	**37,549**	**100%**	24,759	100.0%	52%

	Nine months ended September 30				
	2005		2004		
	Volume	**Weighting**	Volume	Weighting	% Change
Light oil (Bbl/d)	**9,949**	**28%**	6,461	35%	54%
Medium oil (Bbl/d)	**6,669**	**19%**	4,553	25%	46%
Heavy oil (Bbl/d)	**13,906**	**39%**	6,271	34%	122%
Total oil (Bbl/d)	**30,524**	**86%**	17,285	94%	77%
Natural gas liquids (Bbl/d)	**810**	**2%**	190	1%	326%
Total oil and natural gas liquids (Bbl/d)	**31,334**	**88%**	17,475	95%	79%
Natural gas (mcf/d)	**26,839**	**12%**	5,049	5%	432%
Total oil equivalent (BOE/d)	**35,807**	**100%**	18,317	100%	95%

Third quarter 2005 production was impacted by an unscheduled outage at our Suffield property, which caused production to be shut-in for just over 2 days. This was immediately followed by a heavy rain fall which delayed the installation of additional equipment and further impacted production levels for a total of approximately 6 days. This downtime, in addition to scheduled turnarounds and wet ground conditions experienced in other areas in Alberta and Saskatchewan, resulted in lower realized oil production in the third quarter relative to capacity.

With the closing of the Hay River, B.C. property acquisition on August 2, 2005, we acquired approximately 5,200 BOE/d of medium gravity crude oil.. While current production levels are between 38,000 to 39,000 BOE/d, we continue to estimate that our full year 2005 production will average between 36,250 and 36,750 BOE/d.

Realized Commodity Prices

The following table provides a breakdown of our third quarter and year to date 2005 and 2004 average commodity prices by product type before realized losses on derivative contracts.

	Three months ended September 30			Nine months ended September 30		
	2005	2004	Change	**2005**	2004	Change
Product prices:						
Light oil ($/bbl)	**$ 70.57**	$ 53.46	32%	**$ 61.94**	$ 46.52	33%
Medium oil ($/bbl)	**60.14**	43.54	38%	**49.75**	39.89	25%
Heavy oil ($/bbl)	**52.37**	37.64	39%	**39.98**	35.67	12%
Natural gas liquids ($/bbl)	**54.23**	45.69	19%	**46.17**	37.37	24%
Natural gas ($/mcf)	**10.69**	6.22	72%	**8.31**	5.83	43%
BOE ($/BOE)	**$ 60.39**	$ 44.83	35%	**$ 49.27**	$ 40.43	22%
Realized loss on derivative contracts gain (loss) ($/BOE)[1]	**(6.85)**	(7.22)	(5%)	**(6.76)**	(7.52)	(10%)
Realized price after hedging ($/BOE)	**$ 53.45**	$ 37.61	42%	**$ 42.52**	$ 32.91	29%

[1] *Includes amounts realized on WTI, heavy price differential and foreign exchange contracts, and excludes amounts realized on electricity contracts.*

Average realized prices continued to strengthen during the third quarter and were 35% higher during the period compared to the third quarter of 2004. For the first nine months of 2005, our average realized prices were 22% higher than the same period in 2004. In the three and nine months ended September 30, 2005, the realized losses on crude oil and foreign exchange derivative contracts totaled $23.7 million and $66.0 million, respectively. This is higher than the $16.5 million and $37.8 million losses realized in the three and nine months ended September 30, 2004, respectively and is primarily attributable to higher commodity prices in 2005 relative to 2004.

Relative to the second quarter of 2005, our per BOE realized revenues were $14.72 higher, yet we did not experience a corresponding increase in the realized losses on our derivative contracts. In fact, our realized loss on derivative contracts decreased from $7.49 per BOE in the second quarter of 2005 to $6.85 per BOE in the third quarter of 2005, attributable to the expiry of contracts with fixed price ceilings at June 30, 2005 and higher production volumes. All of our WTI price swap and collar contracts, which provide a fixed ceiling on WTI prices, expire at the end of 2005. All of our 2006 and 2007 hedges provide a firm floor while still allowing Harvest to participate in upward oil price movements. As a result, we anticipate lower hedge losses in 2006 then 2005 assuming similar world oil prices. For the nine month period ended September 30, 2005, the realized loss on derivative contracts per BOE was $6.76 per BOE compared to $7.52 per BOE in the same period the previous year.

Despite a 42% increase in the price of WTI to September 30, 2005, the reported decline in hedging losses per BOE reflects the evolution of our hedging strategy, which provides firm floors with upside participation. Examples of such contracts include 'indexed puts' and 'participating swaps', and additional information on these and other commodity derivative contracts can be found in the "Derivative Contracts" section of this MD&A. We anticipate that these structures will enable us to realize oil prices that are closer to spot price levels during 2006 and 2007 than would have been the case with our 2004 hedging instruments which were primarily swaps and collars. The table below provides an example of the impact of Harvest's 2006 commodity derivative contracts in light of varying WTI oil price levels. This data is designed to provide readers with directional information only.

Average Annual Oil Price Assumed ($U.S.)	Harvest Average WTI Oil Price After Hedging ($U.S.)
$35.00 WTI	$41.19
$55.00 WTI	$50.29
$75.00 WTI	$69.88

At the time of writing, we have hedged against downward WTI price movements on approximately 70% of our total 2005 net crude oil production, approximately 79% of our estimated 2006 net crude oil production, and approximately 24% of our estimated 2007 net crude oil production (based on an assumption of flat production through 2007). The majority of our remaining 2005 and all of our 2006 and 2007 commodity derivative contracts provide a fixed crude oil floor price, while retaining the ability to participate in upward price appreciation. For example, Harvest would participate in approximately 70% of any increases in WTI prices above the floor price during 2006, and approximately 90% of any increases in WTI prices above the floor during 2007 (assuming a $60.00 WTI price and flat production). We believe that this hedging format provides a good balance between downside protection and upside participation for our unitholders.

	Three months ended September 30			Nine months ended September 30		
Benchmarks	**2005**	2004	Change	**2005**	2004	Change
West Texas Intermediate crude oil (US$ per barrel)	**$ 63.19**	$ 43.88	44%	**$ 55.40**	$ 39.11	42%
Edmonton Par light crude ($ per barrel)	**$ 76.51**	$ 56.32	36%	**$ 67.91**	$ 50.83	34%
Lloyd blend crude oil ($ per barrel)	**$ 53.30**	$ 40.87	30%	**$ 43.46**	$ 36.74	18%
Bow river blend crude oil ($ per barrel)	**$ 54.94**	$ 41.55	32%	**$ 44.80**	$ 37.70	19%
Natural Gas Liquids ($ per barrel)	**$ 58.39**	$ 44.83	30%	**$ 53.79**	$ 41.49	30%
AECO natural gas ($ per mcf)	**$ 9.29**	$ 6.21	50%	**$ 7.85**	$ 6.54	20%
U.S. / Canadian dollar exchange rate	**1.201**	1.307	(8%)	**1.224**	1.328	(8%)
Bank of Canada interest rate	**2.82%**	2.31%	0.5%	**2.77%**	2.44%	0.3%

The benchmark price of WTI crude oil has the greatest impact on our revenues as the majority of the Trust's production is crude oil. Foreign exchange also has an impact on our revenues as oil prices are denominated in U.S. dollars, so a strengthening Canadian dollar against the U.S. dollar has a negative impact on our revenues. Given our third quarter production weighting to natural gas of approximately 11%, fluctuations in natural gas prices also have an impact, albeit a smaller one, on our revenue.

The unusual hurricane activity in the third quarter combined with the tight overall crude oil balance in the world has resulted in unprecedented prices for crude oil. Relative to the significant increases in the benchmark price of WTI, the realized price for our physical crude oil streams was somewhat different. This is partly due to the strengthening Canadian dollar versus the US dollar, which negatively impacts our realized price in Canadian dollars, as well as changes in crude quality differentials. Thus, although WTI increased 44% from the third quarter of 2004, our light oil price increased 30%. The differential between heavy and light crude oil prices widened early in 2005 reflecting the attractiveness of the lighter blends to refiners as capacity to convert heavy oil barrels to light oil products became constrained. As the table below demonstrates,, the benchmark Lloyd Blend (LLB) and Bow River differentials narrowed through the third quarter compared to the first and second quarters of 2005. Approximately 80% our medium and heavy production prices are based on the Bow River Blend benchmark (adjusted for stream quality), which is reflected as a percentage discount to the Edmonton Light price. The discount will vary due to seasonality and refinery demand.

Differential Benchmarks	**Q1 2005**	**Q2 2005**	**Q3 2005**
Bow River blend differential to Edmonton Light	36.6%	39.6%	28.2%
Lloyd Blend (LLB) differential to Edmonton Light	39.4%	39.7%	30.3%

Differentials narrowed between May and August and our medium and heavy gravity crudes were positively impacted as a result. Towards the end of the third quarter of 2005, however, heavy oil price differentials did begin to widen again. Overall, average heavy oil differentials in the third quarter of 2005 were significantly lower than the second quarter despite a US$10.00 per barrel increase in the price of WTI in the third quarter. The widening differential trend observed at the end of the third quarter has continued into the fourth quarter. However, we have proactively mitigated our exposure to this volatility by hedging the differential to WTI on 10,000 bbl/day or 87% of our net heavy oil production through the end of 2006 at a ratio very close to long term historical averages (29%). Had our differential hedges been in place for the nine month period ending September 30, 2005, our total gain on those contracts would have been $9 million. In addition to the pricing support realized from our hedging program, our medium oil production from the Hay River property commands a higher premium over the benchmark Bow River blend price compared to our other medium gravity oil production.

Natural gas prices in the third quarter were also at all time highs. The natural gas supply / demand imbalance is tighter than in recent years after the shut-ins caused by the hurricanes in the major production areas offshore the US Gulf Coast. Due to the prospect of increased demand caused by cold weather, and the need to substitute high priced heating oil with natural gas, natural gas prices have remained very well supported. We have benefited from these higher prices by maintaining a portfolio that is almost exclusively tied to the daily spot price of natural gas traded at the AECO “C” hub. We have not hedged any of our natural gas production at this time, and have fully benefited from the increase in natural gas prices. Our realized natural gas prices exceed AECO due to the natural gas produced in our more significant properties having a higher than average heat content.

Royalties

In the third quarter of 2005, royalties as a percentage of revenues before hedging loss, were approximately 18.7% compared to 16.7% in the third quarter of 2004. The new Hay River properties acquired in August 2005 have a higher royalty rate, which increased our average royalty rate in the third quarter, and is estimated to increase our overall royalty rates to approximately 18% to 19% for the balance of 2005. For the nine month period ended September 30, 2005, royalties as a percent of revenue were 17.0%, compared to 16.8% in the same period in 2004. The Saskatchewan government recently changed its legislation to make its resource surcharge applicable to trusts producing oil and natural gas in the province effective April 1, 2005. The surcharge is 3.6% of gross resource revenues (2% for production from wells drilled subsequent to October 2002). We estimate the blended rate applied to Harvest’s Saskatchewan properties will be approximately 3.1% with Saskatchewan revenues which makes up approximately 20% of Harvest’s total. This surcharge, along with the impact of the higher royalty Hay River property, increased our royalty rate from 16% in the second quarter of 2005 to 18.7% in the third quarter, and caused the slight increase compared to the nine months ended September 30, 2004.

Operating Expenses

	Three months ended September 30			Nine months ended September 30		
($ per BOE)	**2005**	2004	Change	**2005**	2004	Change
Operating expense	**$ 9.39**	$ 8.58	9%	**$ 9.05**	9.51	(5%)
Realized gains on electricity derivative contracts	**(0.43)**	(0.24)	79%	**(0.18)**	(0.29)	(38%)
Net operating expense	**$ 8.96**	$ 8.34	7%	**$ 8.87**	$ 9.22	(4%)

The decrease in operating expenses (before gains on electricity derivative contracts), during the nine months ended September 30, 2005 compared to the same period of 2004 reflects lower cost assets purchased late in 2004, as well as the effect of operating cost reduction projects completed since then. These operating cost reductions have been somewhat offset by cost inflation in the Western Canadian oil and natural gas sector and the impact of incremental workover costs spread over lower volumes as a result of the downtime described under "Sales Volumes". This negatively impacted the third quarter operating cost per BOE. The Hay River properties acquired in August 2005 have lower operating costs at approximately $7.75 per BOE, which can help to partially offset rising operating costs per BOE. We expect our full year 2005 operating expenses to average between $8.75 and $9.00 per BOE.

Operating costs per BOE declined slightly from the second quarter ($9.08/BOE), but not as much as had been anticipated with the impact of the lower cost Hay properties. The is primarily attributable to weather related delays lengthening rig times for services, non-hedged power cost increases and the impact of the volume shortfalls discussed previously. For the three and nine month periods ended September 30, 2005, approximately 28% of our operating costs are related to the consumption of electricity. The third quarter demonstrated continued volatility for Alberta electricity prices despite the recently added generation of the Genesee #3 power plant. July settled at the lowest average monthly pool price of the year at $37.75 only to be followed by the two highest average monthly prices in the year in August and September at $88.33 and $74.30/MWh, respectively. July's unit availability was excellent, however August was plagued with coal fired plant outages. September saw slightly fewer coal fired outages but an increased number of gas units on maintenance outages. Management has utilized fixed price electricity contracts to mitigate electricity price risk within Alberta, which has benefited us due to the rising price of natural gas and increased volatility in power costs in the latter part of 2005. Approximately 82% of our estimated Alberta electricity usage is hedged at an average price of $48.31 per MWh through December 2006, and we successfully entered into two new hedges for 2007 and 2008 that secure a power price of $55.00 per MWh. Assuming we maintained flat electricity consumption in through 2008, we would have protected approximately 60% of our expected power consumption from price spikes and volatility. Our electricity hedges will help moderate the impact of future cost swings, as will realizing the benefits of capital projects undertaken in 2004 and to date in 2005 that have been dedicated to power efficiency projects.

	Three months ended September 30			Nine months ended September 30		
Benchmark Price	**2005**	2004	Change	**2005**	2004	Change
Alberta Power Pool electricity price ($ per MWh)	**$ 66.79**	$ 54.33	23%	**54.72**	54.43	1%

General and Administration Expenses ("G&A")

	Three months ended September 30			Nine months ended September 30		
($millions except per BOE)	**2005**	2004	Change	**2005**	2004	Change
G&A - cash	**$ 3.8**	1.8	111%	**9.9**	4.5	120%
Per BOE ($/BOE)	**1.09**	0.79	38%	**1.02**	0.90	13%
G&A - non-cash unit compsentation expense	**9.2**	0.4	2200%	**15.1**	0.8	1788%
Per BOE ($/BOE)	**2.66**	0.18	1378%	**1.54**	0.16	863%
Total G&A	**$ 13.0**	$ 2.2	491%	**$ 25.0**	$ 5.3	372%
Per BOE ($/BOE)	**$ 3.75**	$ 0.97	287%	**$ 2.56**	1.06	142%

The increase in cash G&A, excluding non-cash unit right compensation expense, is the result of higher staff and system expenses associated with the additional properties in our portfolio. In addition, a portion of our cash G&A is related to our unit right compensation plan to the extent rights were exercised for cash. For the three and nine month periods ended September 30, 2005, cash unit right compensation expense was $800,000 and $980,000, respectively. For the same periods in 2004, there were no cash costs incurred relating to the unit right compensation plan. For 2005, we anticipate that Harvest's cash G&A per BOE will be between $1.00 and $1.10 per BOE, before unit right compensation expenses. As expected, there was not a significant increase in cash G&A expenses associated with the Hay acquisition.

General and administration expenses charged against income in the third quarter of 2005 totaled $13.0 million ($3.75/BOE) compared to $2.2 million ($0.97/BOE) in the same quarter in 2004. For the nine month period ended September 30, 2005, G&A charged against income totaled $25.0 million ($2.56/BOE) compared to $5.3 million ($1.06/BOE) in the same period in 2004.

The significant increase in total G&A in 2005 compared to 2004 is a result of a prospective change in accounting for Unit appreciation rights (UARs). In the third quarter of 2004, the Plan was modified so UAR holders could settle in cash and therefore we now value vested UARs at the difference between exercise price and market price at each reporting period end to determine the related liability at that date. Changes in the assumptions used in determining this liability, such as our Trust Unit price, the exercise price and the number of UARs vested at each accounting period will cause this liability to fluctuate and the difference is reflected as an expense on the consolidated statement of income.

Interest Expense

	Three months ended September 30			Nine months ended September 30		
	2005	2004	Change	**2005**	2004	Change
($millions)		*(restated)*			*(restated)*	
Interest on short term debt	**$ 1.1**	$ 3.5	(69%)	**$ 4.0**	$ 4.6	(13%)
Amortization of deferred charges - short term debt	**-**	0.5	(100%)	**2.5**	1.8	39%
Total interest on short term debt	**1.1**	4.0	(73%)	**$ 6.5**	$ 6.4	2%
Interest on long term debt	**7.0**	2.7	159%	**20.0**	5.0	300%
Amortization of deferred charges - long term debt	**0.7**	0.2	250%	**1.5**	0.4	250%
Total interest on long term debt	**7.7**	2.9	166%	**21.5**	5.4	298%
Total interest expense	**$ 8.8**	$ 6.9	28%	**$ 28.0**	$ 11.8	136%

In the three and nine month periods ended September 30, 2005, cash interest on short term debt totaled $1.1 million and $4.0 million, compared to $3.5 million and $4.6 million for the same periods in 2004. Interest on short term debt relates to the interest paid on our outstanding bank debt, and for 2004, interest on our equity bridge loan. Cash interest on long term debt totaled $7.0 million and $20.0 million in the third quarter and nine months ended September 30, 2005, and $2.7 million and $5.0 million in the same periods in 2004. Of the interest on long term debt, $5.9 million in the three month period and $17.9 million in the nine month period ended September 30, 2005 pertains to our U.S.$250 million senior notes, issued in October 2004. These notes provide Harvest with a long-term (Oct 15, 2011 maturity), fixed interest rate (7.875%) debt instrument, a natural hedge to currency exchange rates, and a fourth year redemption feature. For the three and nine month periods ending September 30, 2005, the remaining $1.1 million and $2.1 million of long term interest expense relates to our convertible debentures. Previously, we had recorded the interest incurred on our convertible debentures as a charge to accumulated deficit rather than net income. As a result of changes in accounting standards that came into effect for the first quarter of 2005, we now reflect this as interest expense on the statement of income. This change is discussed further under "New Accounting Policies" and the 2004 amounts have been retroactively restated to reflect this new presentation. Interest on short-term debt is lower in the third quarter of 2005 than 2004 as bank debt levels are substantially lower. Bank debt was partially repaid with the proceeds from the senior note issuance in 2004.

Our third quarter total interest expense and amortization of deferred charges of $8.8 million is higher than the $6.9 million reflected in the third quarter of 2004. For the nine month period ended September 30, 2005 total interest expense and amortization of deferred charges was $27.9 million compared to $11.8 million for the same period in 2004. The increase in total interest expense in 2005 is due to the senior notes.

Depletion, Depreciation and Accretion (DD&A)

	Three months ended September 30, 2005					Nine months ended September 30				
($millions except per BOE)		**2005**		2004	Change		**2005**		2004	Change
Depletion and depreciation	**$**	**40.4**	$	24.4	66%	**$**	**109.3**	$	44.1	148%
Depletion of capitalized asset retirement costs		**6.2**		2.5	148%		**11.6**		6.0	93%
Accretion on asset retirement obligation		**2.4**		1.2	100%		**7.0**		2.9	141%
Total depletion, depreciation and accretion	**$**	**49.0**	$	28.1	74%	**$**	**127.9**	$	53.0	141%
Per BOE ($/BOE)	**$**	**14.18**	$	12.34	15%	**$**	**13.09**	$	10.56	24%

Relative to the third quarter of 2004 and the nine month period ended September 30, 2004, our higher DD&A is primarily attributable to the significant acquisitions completed in June and September 2004 and August 2005, and the resulting higher DD&A rates are justified due to the higher netback production acquired in each of these acquisitions. We anticipate full year 2005 DD&A rates to range between $13 and $15 per BOE.

Foreign Exchange Losses and Gains

Foreign exchange gains and losses are attributable to the effect of changes in the value of the Canadian dollar relative to the U.S. dollar on our U.S. dollar denominated senior notes, as well as any U.S. dollar deposits and credit facility balances. Our senior notes, which were issued in October 2004, reduce our net exposure to fluctuations in foreign exchange rates by offsetting the impact of fluctuations on net oil prices realized. We have entered into a currency exchange put option for calendar 2005, on U.S. $8.33 million per month at $1.20 per $1 U.S. to provide a further hedge against foreign exchange volatility.

The largest portion of our foreign exchange gains and losses are directly related to our U.S. dollar denominated senior notes. In the third quarter of 2005, the Canadian dollar strengthened against the U.S. dollar, and we incurred unrealized gains on our senior notes of $15.6 million. This amount was partially offset by realized settlements of amounts held on deposit denominated in U.S. dollars. The net result for the third quarter 2005 was a foreign exchange gain of $14.0 million. In the third quarter of 2004, we did not have any U.S. dollar denominated debt and consequently, did not record significant foreign exchange gains or losses in that period.

For the nine month period ended September 30, 2005, we realized a foreign exchange gain of $8.6 million, compared to a foreign exchange gain of $565,000 for the same period in 2004. Again, the gain in 2005 reflects the impact of a stronger Canadian dollar on our senior notes.

Derivative Contracts

All of our hedging activities are carried out pursuant to policies approved by the Board of Directors of Harvest Operations Corp. Management intends to facilitate stable, long-term monthly distributions by reducing the impact of volatility in commodity prices. As part of our risk management policy, management utilizes a variety of derivative instruments (primarily options) to manage commodity price, heavy oil price differentials, foreign currency and interest rate exposures. These instruments are commonly referred to as ‘hedges’ but may not receive hedge treatment for accounting purposes. Management also enters into electricity price and heat rate based derivatives to assist in maintaining stable operating costs. We reduce our exposure to credit risk associated with these financial instruments by only entering into transactions with financially sound, credit-worthy counterparties.

As of October 1, 2004, we ceased to apply hedge accounting to our derivative contracts. As a result, from October 1, 2004 all of our derivatives are marked-to-market as at the balance sheet date with the resulting gain or loss reflected in earnings for the reporting period. The mark-to-market valuation represents the amount that would be required to settle each contract on the period end date. Collectively, our derivative contracts had a mark-to-market unrealized non-cash loss position on the balance sheet of $80.7 million as at September 30, 2005. The difference between this value and the mark-to-market amount at December 31, 2004 ($15.4 million) is reflected as an unrealized loss in the nine month period ended September 30, 2005. Please refer to Note 11 to the consolidated financial statements for further information.

The following table provides a reconciliation of the changes in Harvest's mark-to-market position on its derivative contracts from January 1, 2005 to September 30, 2005.

($millions)	**As at September 30, 2005**	As at December 31, 2004
Opening mark-to-market position	**(15.4)**	-
Unrealized loss on outstanding derivative contracts[1]	**(75.3)**	(27.9)
Unrealized gain on outstanding derivative contracts[1]	**10.0**	12.5
Closing mark-to-market position	**(80.7)**	(15.4)

Note 1 *Excludes amortization of deferred charges (gain) recorded upon adoption of mark-to-market accounting and reflected in unrealized gains and losses on derivative contracts on the statement of income.*

We determine the value of our derivative contracts using prices from actively quoted markets. Where we are unable to obtain quoted prices, we use widely accepted valuation models.

In the three months ended September 30, 2005, we recorded a net realized loss on all derivative contracts of $22.2 million ($6.85/BOE), and a net unrealized loss, including amortization of deferred charges and gains, of $3.9 million ($1.14/BOE) for a total loss of $26.1 ($7.56/BOE) million. For the nine month period ended September 30, 2005, we recorded a realized loss on all derivative contracts of $64.3 million ($6.76/BOE), and an unrealized loss including amortization of deferred charges and gains, of $73.5 ($7.52/BOE) million for a total loss of $137.8 million ($14.09/BOE). The realized loss portion reflects the effective cost of our hedges related to production during the period.

Realized losses on derivative contracts for the three months ended June 30, 2005 were $23.3 million ($7.49/BOE). The decrease from $23.3 million in the second quarter to $22.2 million in the third quarter of 2005 is due to the expiration of contracts with fixed price ceilings, higher volumes in the third quarter, and higher gains realized on our electricity hedges. However, that portion of our realized losses relating specifically to our crude oil hedges increased from $23.3 million in the second quarter of 2005 to $24.0 million in the third quarter of 2005 due to a US$10.02 increase in the benchmark WTI crude oil price from US$53.17 in the second quarter to US$63.19 in the third quarter of 2005. Our losses relative to the increase in WTI were lower in the third quarter compared to the second quarter of 2005, due to the expiration of hedge contracts noted above. Assuming a similar pricing environment in 2006, we would expect lower losses than those realized in 2005 because we have no production hedged with fixed price derivative instruments, such as swaps and collars in 2006 or 2007.

The table below provides a summary of gains and losses on derivative contracts:

	Three months ended September 30, 2005				Three months ended September 30, 2004
($thousands)	Oil	Currency	Electricity	Total	Total
Unrealized (losses) / gains on derivative contracts	(7,285)	704	3,396	(3,185)	(19,664)
Realized (losses) / gains on derivative contracts	(23,984)	332	1,470	(22,182)	(15,912)
Amortization of deferred charges relating to derivative contracts	(1,207)	-	-	(1,207)	-
Amortization of deferred gains relating to derivative contracts	-	-	444	444	-
Total (losses) / gains on derivative contracts	(32,476)	1,036	5,310	(26,130)	(35,576)

($thousands)	Nine months ended September 30, 2005 Oil	Currency	Electricity	Total	Nine months ended September 30, 2004 Total
Unrealized (losses) / gains on derivative contracts	(71,801)	(3,488)	9,982	(65,307)	(23,906)
Realized (losses) / gains on derivative contracts	(67,042)	1,004	1,783	(64,255)	(36,311)
Amortization of deferred charges relating to derivative contracts	(9,551)	-	-	(9,551)	(5,490)
Amortization of deferred gains relating to derivative contracts	-	-	1,334	1,334	-
Total (losses) / gains on derivative contracts	(148,394)	(2,484)	13,099	(137,779)	(65,707)

Prepaid Expenses and Deposits

Our prepaid expenses and deposits balance of $1.8 million includes $463,000 of amounts which are held on margin with counterparties to our derivative contracts. The balance held on margin of $463,000 is substantially lower than the second quarter 2005 balance of $44.5 million due to the successful transfer of several of our derivative contracts to an alternate counterparty that requires lower margin deposits. Cash released from these deposits was used to repay bank debt.

Deferred Charges and Deferred Gains

The deferred charges asset balance on the balance sheet is comprised of two main components: deferred financing charges and deferred assets related to the discontinuation of hedge accounting. The deferred financing charges relate primarily to the issuance of the senior notes, convertible debentures and bank debt and are amortized over the life of the corresponding debt.

Deferred charges

($thousands)	As at September 30, 2005				As at December 31, 2004			
	On Dis-continuation of Hedge Accounting	**Financing Costs**	**Discount on Senior Notes**	**Total**	On Dis-continuation of Hedge Accounting	Financing Costs (restated)	Discount on Senior Notes	Total
Opening Balance	10,759	12,781	2,000	25,540	-	1,989	-	1,989
Additions	-	5,063	-	5,063	25,705	20,971	2,075	48,751
Transferred to unit issue costs	-	(1,402)	-	- - (1,402)	-	(5,721)	-	- - (5,721)
Amortization	(9,551)	(3,992)	(222)	(13,765)	(14,946)	(4,458)	(75)	(19,479)
Closing Balance	1,208	12,450	1,778	15,436	10,759	12,781	2,000	25,540

We discontinued the use of hedge accounting for all of our derivative financial instruments effective October 1, 2004. For contracts where hedge accounting had previously been applied, a deferred charge and a deferred gain was recorded equal to the fair value of the contracts at the time hedge accounting was discontinued, and a corresponding amount was recorded as a derivative contracts asset or liability. The deferred amount is recognized in income in the period in which the underlying transaction is recognized.

For the nine month period ended September 30, 2005, $9.6 million of the deferred charge and $1.3 million of the deferred gain was amortized and recorded in gains and losses on derivative contracts. At September 30, 2005, a $1.2 million deferred charge and an $843,000 deferred gain is remaining relating to the balances initially set up upon discontinuation of hedge accounting.

Goodwill

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the fair value for accounting purposes of the net identifiable assets and liabilities of that acquired business. In June 2004, Harvest completed a Plan of Arrangement with Storm Energy Ltd., and acquired certain oil and natural gas producing properties in North Central Alberta for total consideration of $192.2 million. This transaction has been accounted for using the purchase price method, and resulted in Harvest recording goodwill of $43.8 million in 2004. This goodwill balance will be assessed annually for impairment or more frequently if events or changes in circumstances would reasonably be expected to reduce the fair value of the acquired business to a level below its carrying amount. No goodwill was recorded in association with the Hay River acquisition in August 2005, as the fair value of assets acquired approximated the total consideration paid.

Future Income Taxes

Future income taxes reflect the net tax effects of temporary differences between the financial statement amounts of assets and liabilities held in Harvest's corporate operating subsidiaries and the related income tax balances. Future income taxes arise, for example, as depletion and depreciation expense recorded against capital assets differs from claims against related tax pools. Future income taxes also arise when tax pools associated with assets acquired are different from the purchase price recorded for accounting purposes. We recorded future income tax expense (recovery) for the three and nine month period ended September 30, 2005 of $1.2 million and $(28.6) million, respectively, compared to $(9.8) million and $(14.0) million for the same periods in 2004. The significant increase in the future income tax recovery in the nine month period, despite positive earnings before taxes in the period, is due to the accounting earnings being attributable to non-corporate subsidiaries of the Trust. The corporate subsidiaries of the Trust earned an accounting loss in this period.

Asset Retirement Obligation (ARO)

In connection with a property acquisition or development expenditure, we record the discounted fair value of the ARO as a liability in the year in which an obligation to reclaim and restore the related asset is incurred, which is generally when the related well or facility is created or acquired. Our ARO costs are capitalized as part of the carrying amount of the related assets, and are depleted and depreciated over estimated net proved reserves. ARO estimates are adjusted at the end of each period to reflect the impact of the passage of time on the discounted present value as well as changes in the estimated future costs that make up the obligation, and for changes to any assumptions used in the estimation of the ARO.

Our asset retirement obligation has increased by approximately $10.4 million in the nine months ended September 30, 2005 mainly due to the additional obligation recorded in connection with the Hay River properties as well as the accretion of the asset retirement obligation.

Non-Controlling Interest

At September 30, 2005, we have recorded a non-controlling interest amount on our consolidated balance sheet of $3.0 million. The non-controlling interest arises as a result of adopting the guidance from the Emerging Issues Committee ("EIC") of the Canadian Institute of Chartered Accountants regarding exchangeable shares (EIC 151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts") (see "New Accounting Policies – Exchangeable Shares"). This EIC requires that when shares are issued by a subsidiary of a trust, and they are exchangeable into Units of the trust, they should be classified as either non-controlling interest or equity. EIC 151 requires, among other things, that exchangeable shares not be transferable to third parties in order to be classified as equity. As the exchangeable shares issued by Harvest Operations Corp. do not meet the criteria to be considered equity of the Trust, they have been classified as non-controlling interest. Previously, they had been recorded as part of the equity of the Trust.

The exchangeable shares were originally issued by Harvest Operations Corp. as partial consideration for the purchase of a corporate entity in 2004. The exchangeable shares rank equally with the Trust Units and participate in distributions through an increase in the exchange ratio applied to the exchangeable shares when they are ultimately converted to Trust Units. The total number of exchangeable shares converted in the nine months ended September 30, 2005 was 263,865, leaving a balance of exchangeable shares of 191,682 at September 30, 2005 compared to a balance of 455,547 at January 1, 2005. The exchange ratio at September 30, 2005 was 1:1.14463, which would result in an additional 219,405 trust units if all of the exchangeable shares were converted at the end of the third quarter.

Over time, the exchangeable shares will continue to be converted into Trust Units and the non-controlling interest on the balance sheet will be eliminated. The non-controlling interest on the balance sheet represents the book value of the remaining exchangeable shares plus the accumulated earnings or loss of the Trust attributed to those exchangeable shares.

The non-controlling interest on the income statement represents the current period income or loss attributed to the non-controlling interest holders during the period. This allocation is calculated on a monthly basis and as such, we may report net income on a quarterly basis and continue to allocate a loss to the exchangeable shareholders due to conversions during the period and net losses reported in any given month within the period. The total net income (loss) attributed to non-controlling interest holders for the three and nine months ended September 30, 2005 was $219,000 and $(156,000) ($40,000 – three and nine months ended September 30, 2005), respectively.

Liquidity and Capital Resources

Our drilling and operational enhancement programs, as well as current financial commitments, are expected to be financed from Funds Flow from Operations (see "Certain Financial Reporting Measures" in this MD&A). Our cash distributions to Unitholders are financed solely from Funds Flow from Operations. In the third quarter of 2005, our distribution payout ratio of 45% (2004 – 45%) (calculated by dividing distributions to Unitholders by Funds Flow from Operations) resulted in excess Funds Flow from Operations available for our capital expenditure programs. Our payout ratio for the nine month period ended September 30, 2005 was 46% (excluding the special distribution of 2004 income paid in Trust Units in April) compared to 55% for the same period in 2004. In the previous quarter, we announced a 25% increase to our monthly distribution level, effective with the July distribution, payable in August. In the third quarter, we announced a further 40% increase to our monthly distribution level to $0.35 per Trust Unit per month. Management anticipates that this level could be maintained through 2006, while maintaining a significant capital program, in almost any WTI price scenario because of our hedging program. This increase in distributions is a reflection of the success of our strategy to date.

As at September 30, 2005, Harvest's net debt decreased to $418.2 million from $429.6 million at December 31, 2004.

We anticipate that sufficient Funds Flow from Operations for the balance of 2005 will be available to finance our planned capital development program, expected distributions of $0.35 per Unit per month and still leave us with sufficient funds to continue repayment of our outstanding bank debt. It is also important to note that following the August implementation of our new Distribution Reinvestment, Premium Distribution and Optional Trust Unit Purchase Plan ("DRIP Plan"), the participation level in the DRIP Plan has risen to approximately 40%. This participation directly reduces the cash component of our monthly distribution payments and affords us additional financial flexibility.

The table below provides an analysis of our debt structure, including some key debt ratios. We believe that the current capital structure is appropriate given our low payout ratio, the significant oil price protection in place, and the long term to maturity of the majority of our debt. As noted above, we intend to use Funds Flow from Operations after distributions and capital expenditures to continue repaying bank debt through the balance of 2005 and through 2006. Currently, we have $350 million of undrawn borrowing capacity under our credit facility.

($ millions)		**As at September 30, 2005**		As at December 31, 2004	Change
Bank debt	**$**	**34.6**	$	75.5	(54%)
Working capital deficit excluding bank debt[1]		**28.4**		27.8	(2%)
Senior notes, due 2011		**290.7**		300.5	(3%)
Convertible debentures, due 2009-2010		**64.5**		25.8	150%
Net debt obligations	**$**	**418.2**	$	429.6	(3%)
Annualized quarterly funds flow[2]	**$**	**414.0**	$	211.5	96%
Net debt to funds flow (times)		**1.0**		2.0	(50%)

Note 1 Excludes current portion of derivative contracts assets and liabilities, future income tax and Trust Unit incentive plan liability.

Note 2 Reflects realized hedging losses which were significant in the third quarter given the nature of our oil price hedges.

Since inception, we have communicated our intention to pursue a strategy that will allow us to sustain or increase our Funds Flow from Operations and distributions per unit. During the three month periods ended September 30, 2005 and 2004, we declared $46.7 million and $18.4 million, respectively, in distributions payable to unitholders ($0.25 per Trust Unit declared in July, and $0.35 per Unit declared in each of August and September 2005). Prior to the July distribution declaration, Harvest had paid a consistent $0.20 per Trust Unit per month since our inception in December 2002. For the purposes of the cash flow statements, distributions are reported on a cash paid basis, however, we accrue distributions declared as at each period end.

Year to date in 2005, distributions declared total $109.0 million, including the payment of a special one-time distribution relating to undistributed 2004 taxable income of $10.7 million, compared to $39.7 million declared during the same period in 2004. The higher level of distributions paid in 2005 reflects the rising distributions paid per unit, as well as an increased number of Trust Units outstanding compared to the same period in 2004. The increase in Trust Units outstanding is primarily due to the issuance of 6.5 million Trust Units on August 2, 2005 and the continued conversion of convertible debentures.

Our DRIP Plan gives Canadian Unitholders the option to reinvest their cash distributions back into Harvest Units or in the Premium Distribution™ component, to receive a cash payment equal to 102% of the regular distribution amount. Enrollment in either the distribution reinvestment or Premium Distribution™ component enables Unitholders to make additional purchases of Trust Units directly from treasury through the Optional Trust Unit Purchase Plan. Both components of the DRIP Plan reduce the net cash outlay Harvest is required to make on a monthly basis. Management anticipates that for the balance of 2005, participation in the DRIP Plan will be approximately 40%, the same level as that experienced in September.

Distribution payments to U.S. Unitholders are subject to 15% Canadian withholding tax. After consulting with our U.S. tax advisors, we are of the view that our distributions are "qualified dividends" under the Jobs and Growth Tax Relief Reconciliation Act of 2003. These dividends are eligible for the reduced tax rate applicable to long-term capital gains. However, the distributions may not be qualified dividends in certain circumstances, depending on the holder’s personal situation (i.e. if an individual holder does not meet a holding period test). Where the distributions do not qualify, they should be reported as ordinary dividends. U.S. and other non-resident Unitholders are urged to obtain independent legal advice on how their distributions should be treated for tax purposes.

Harvest’s Trust Units were listed for trading on the NYSE on July 21, 2005. This listing has provided Harvest’s unitholders with additional liquidity, and Harvest with greater access to the U.S. capital markets. From time to time the Trust may require external financing, in the form of either debt or equity, to further its business plan of maintaining production, reserves and distributions through acquisitions and capital expenditures. Our ability to obtain the necessary financing is 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.

Of the convertible debentures outstanding at September 30, 2005, approximately $13.1 million have converted into Units through November 7th, 2005 and we anticipate continued conversions of in-the-money debentures through 2005.

A breakdown of our outstanding Trust Units and potentially dilutive elements is as follows:

	As at September 30, 2005	As at December 31, 2004	As at September 30, 2004
Market price of Trust Units at end of period ($/unit)	**38.00**	22.95	20.79
Trust Units outstanding	**51,558,576**	41,788,500	36,874,829
Exchangeable shares outstanding[1]	**191,682**	455,547	552,972
Trust Units represented by Exchangeable shares	**219,405**	485,003	583,961
Total market value of Trust Units at end of period[2] ($millions)	**$ 1,968**	$ 970	$ 779
9% Convertible debentures[3], face value ($000)	**$ 1,898**	$ 10,700	$ 24,915
8% Convertible debentures[4], face value ($000)	**$ 5,758**	$ 15,159	$ 71,219
6.5% Convertible debentures[5], face value ($000)	**$ 56,827**	$ -	$ -
Trust Unit rights outstanding[6]	**1,573,099**	1,128,387	1,230,225
Total Trust Units, diluted[7]	**55,679,556**	45,099,038	44,851,365

Note 1 *Exchangeable shares are exchangeable into Trust Units at the election of the holder at any time. The exchange ratio in effect on September 30, 2005 was 1.14463:1, and on December 31, 2004 was 1.06466:1. The September 30, 2005 exchange ratio was used to determine Trust Units represented by Exchangeable shares.*

Note 2 *Including Trust Units outstanding and assuming exchange of all exchangeable shares.*

Note 3 *Each debenture in this series has a face value of $1,000 and is convertible, at the option of the holder at any time, into Trust Units at a price of $13.85 per Trust Unit. (Prior to April 1, 2005, the conversion price was $14.00) If Debenture holders converted all outstanding debentures in this series at Sept. 30, 2005 and December 31, 2004, an additional 137,040 and 764,286 Trust Units would be issuable, respectively. For accounting purposes the convertible debentures are recorded at a discount to reflect the implied interest rate on issuance.*

Note 4 *Each debenture in this series has a face value of $1,000 and is convertible, at the option of the holder at any time, into Trust Units at a price of $16.07 per Trust Unit. (Prior to April 1, 2005, the conversion price was $16.25) If Debenture holders converted all outstanding debentures in this series at Sept. 30, 2005 and December 31, 2004, an additional 358,307 and 932,862 Trust Units would be issuable, respectively. For accounting purposes the convertible debentures are recorded at a discount to reflect the implied interest rate on issuance.*

Note 5 *Each debenture in this series has a face value of $1,000 and is convertible, at the option of the holder at any time, into Trust Units at a price of $31.00 per Trust Unit. If Debenture holders converted all outstanding debentures in this series at Sept. 30, 2005 and December 31, 2004, an additional 1,833,129 and nil Trust Units would be issuable, respectively. For accounting purposes the convertible debentures are recorded at a discount to reflect the implied interest rate on issuance.*

Note 6 *Exercisable at an average price of $16.70 per Trust Unit as at September 30, 2005, and $10.09 per Trust Unit as at December 31, 2004. Also includes Unit Award Incentive Plan Rights of 35,024 as at September 30, 2005 and 10,662 at December 31, 2004. Each Unit Award Incentive Plan Right can be converted into one Trust Unit once vested with no additional consideration.*

Note 7 *Fully diluted Units differ from diluted Units for accounting purposes. Fully diluted includes Trust Units outstanding as at September 30, 2005 or December 31, 2004 plus the impact of the conversion or exercise of exchangeable shares, Trust Unit Rights, Unit Award Rights and convertible debentures if completed at September 30, 2005 or December 31, 2004.*

($millions)	**As at September 30, 2005**	As at December 31, 2004	% Change
Total market capitalization[1]	**$ 1,967.6**	$ 970.2	103%
Net debt	**418.2**	429.6	(3%)
Enterprise value (total capitalization)[2]	**$ 2,385.8**	$ 1,399.8	70%
Net debt as a percentage of enterprise value[3] (%)	**18%**	31%	24%

Note 1 *Reflects conversion of exchangeable shares into Trust Units.*

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

Note 3 *This ratio changed following the $175 million Trust Unit and $75 million convertible debenture financing which closed on August 2, 2005. As of that date, the ratio was approximately 25%.*

Contractual Obligations

Our contractual obligations have not changed significantly from those disclosed in the MD&A and financial statements for the year ended December 31, 2004.

Off Balance Sheet Arrangements

We have a number of immaterial operating leases in place on moveable field equipment, vehicles and office space. The leases require periodic lease payments and are recorded as either operating costs or G&A. We also finance our annual insurance premiums, whereby a portion of the annual premium is deferred and paid monthly over the balance of the term.

Related Party Transactions

A corporation controlled by one of our directors sublets office space from us and we provide administrative services to that corporation on a cost recovery basis. See Note 13 to the Consolidated Financial Statements.

Capital Asset Expenditures

	Three months ended September 30, 2005			Nine months ended September 30		
	2005	2004	Change	**2005**	2004	Change
Development capital expenditures						
excluding acquisitions & non-cash items	**$ 31.7**	$ 13.2	140%	**$ 81.0**	$ 31.7	156%
Non-cash capital additions	**1.9**	-	0%	**3.0**	-	0%
Total development capital expenditures	**33.6**	13.2	155%	**84.0**	31.7	165%
Net property acquisitions	**209.7**	513.8	(59%)	**239.3**	590.9	(60%)
Total net capital asset expenditures	**$ 243.3**	$ 527.0	(54%)	**$ 323.3**	$ 622.6	(48%)

Development capital expenditures in the three and nine month periods ending September 30, 2005, include non-cash capital additions of approximately $1.9 million and $3.0 million, respectively relating to non-cash UAR costs that have been capitalized. The increase in development capital expenditures in the three and nine months ended September 30, 2005 compared to 2004 is due to several factors, including an increased number of producing properties, higher drilling activity, additional well workovers and optimization activities, and generally reflects the expanded base of internal growth opportunities resulting from our acquisitions. Subsequent to the end of the quarter, we increased our 2005 full year capital budget to approximately $130 million, which reflects increased development opportunities identified by our operations teams, as well as some minor working interest acquisitions in our core areas. We anticipate that the production impact of this additional capital will be predominantly realized in the second quarter of 2006.

For the three month period ended September 30, 2005, net property acquisitions totaled $209.7 million and were primarily for the Hay River acquisition, excluding $26 million paid in the second quarter. For the nine month period ended September 30, 2005, net property acquisitions totaled $239.3 million. The Hay River acquisition was financed initially with bank debt, which was subsequently paid off with the issuance of $75 million of convertible debentures and $175 million of equity. Property acquisition expenditures for the same periods in 2004 were $513.8 million and $590.9 million, respectively. The acquisition of Storm Energy took place in the second quarter of 2004 and the acquisition of the EnCana properties in the third quarter of 2004, represent the majority of the acquisition expenditures for the nine month ended September 30, 2004. The Storm Energy acquisition was financed with $75 million of debt and the remainder with Trust Units and Exchangeable Shares. The EnCana acquisition was financed with the credit facility, the equity bridge notes and an offering of equity and convertible debentures.

We closed the acquisition of the Hay River property on August 2, 2005, and added 5,000 BOE/d of medium oil production, 19.8 mmBOE of proved plus probable reserves, 54,000 net acres of undeveloped land, and numerous future drilling locations. We will continue to be active in analyzing potential acquisition opportunities. However, in the event the acquisition market becomes too expensive and we do not see the potential to create value by purchasing assets, we have a sufficient drilling location inventory to keep us active for the next 2 to 3 years.

Sensitivities

The table below indicates the impact of changes in key variables on several financial measures of Harvest. The figures in this table are based on the Units outstanding as at September 30, 2005 and our existing hedging program, and are provided for directional information only.

	Variable					
	WTI Price/bbl	Heavy Oil Price as % of WTI	AECO Price/mcf	Crude Oil Production	Canadian Bank Prime Rate	Foreign Exchange Rate Cdn. / U.S.
Assumption	U.S.$55.00	35%	C$9.00	39,000 boe/d	4.75%	1.17
Change	U.S.$1.00	1%	C$1.00	1,000 boe/d	1%	0.01
Annualized impact on:						
Funds flow from operations ($000's)	$6,066	$1,220	$7,286	$17,456	$393	$3,821
Per Trust Unit, basic	$0.11	$0.02	$0.14	$0.33	$0.01	$0.07
Per Trust Unit, diluted	$0.11	$0.02	$0.13	$0.31	$0.01	$0.07
Payout ratio	1.1%	0.2%	1.4%	3.4%	0.1%	0.7%

As noted above, our commodity price risk management program provides significant downside price protection, while allowing Harvest to participate in upward price movements. Thus, cash flow sensitivities are less extreme with WTI price declines than with price increases.

Oil price derivative contracts in place as at September 30, 2005 are summarized in the table below. The prices shown for collars, indexed puts and participating swaps are floor prices.

	2005		2006		2007	
	Volume (bbls/d)	Pricing ($/bbl)	Volume (bbls/d)	Pricing ($/bbl)	Volume (bbls/d)	Pricing ($/bbl)
WTI Crude Oil Swaps	500	$ 24.00	-	-		
WTI Crude Oil Collars	3,500	$ 28.07	-	-		
WTI Indexed Put Contracts	18,500	$ 35.95	8,719	$ 46.04	5,000	50.00
WTI Participating Swaps[1]	-	-	11,271	$ 39.73		
WTI Participating Swaps[2]	-	-	5,000	$ 49.03	2,479	49.03

[1]50% upside participation
[2]75% upside participation.

Heavy and medium gravity crude oil trade at a price discount to WTI. Our differential hedge contracts effectively fix the percentage discount from light oil prices we receive on the sale of a portion of our medium and heavy gravity crude oil. By defining the price differential between the heavy oil benchmark and the light oil WTI benchmark, we have mitigated the uncertainty caused by fluctuating heavy oil price differentials.

The percent of WTI shown in the table below represents the average of all outstanding contracts used to hedge the heavy oil price differential to WTI.

	2005		2006	
	Volume (bbls/d)	Percent of WTI	Volume (bbls/d)	Percent of WTI
Oil Price Differential Swap Contracts				
Oct 2005 - Dec 2006 contracts	10,000	28.7%	10,000	28.7%

Critical Accounting Policies and Critical Accounting Estimates

Our critical accounting policies and estimates are substantially the same as those presented in our 2004 annual MD&A.

Impact on Net Income of Change in Accounting Policies

The implementation of new accounting policies in 2005 as discussed below resulted in changes to the accounting treatment for exchangeable shares, convertible debentures and the equity bridge notes. As a result, we have restated previously reported annual and quarterly net income. The restatements were required per the transitional provisions of the respective accounting standards.

The following table illustrates the impact of the new accounting policies on quarterly net income (loss) and net income (loss) per Unit for periods which have been presented for comparative purposes:

	2004			
($ thousands)	Q4	Q3	Q2	Q1
Net Income (loss) before change in accounting policies[1]	12,536	5,166	1,594	(1,064)
Increase (decrease) in net income:				
Interest expense[2]	(751)	(3,386)	(1,443)	(1,186)
Non-controlling interest[3]	(185)	(40)	-	-
Net income (loss) after change in accounting policies	11,600	1,740	151	(2,250)
Net income (loss) per Trust Unit, as reported				
Basic	0.29	0.07	0.02	(0.13)
Diluted	0.28	0.07	0.02	(0.13)
Net income (loss) per Trust Unit, as restated				
Basic	0.29	0.06	0.01	(0.13)
Diluted	0.27	0.06	0.01	(0.13)

Note 1 This represents net income as reported before retroactive restatement for changes in accounting policies.

Note 2 Adoption of the amendment to CICA Handbook Section 3860 "Financial Instruments – Disclosure and Presentation" resulted in the convertible debentures and equity bridge notes being classified as debt whereas previously they were classified as equity. In addition, the interest expense relating to these instruments was required to be charged against net income rather than directly to accumulated income. Also, the deferred financing charges associated with the convertible debentures are now reflected separately in deferred charges on the balance sheet and amortized to income over the term of the debt; previously they were applied as a reduction to the outstanding balance.

Note 3 Adoption of EIC 151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts", resulted in the exchangeable shares being classified as minority interest and the income attributed to minority interest holders being applied against net income.

New Accounting Policies

Financial Instruments

On January 1, 2005, the Trust retroactively adopted the amendment to the Canadian Institute of Chartered Accountants ("CICA") handbook section 3860 "Financial Instruments". These changes require that fixed-amount contractual obligations that can be settled by issuing a variable number of equity instruments be classified as liabilities. The convertible debentures and the equity bridge notes previously issued by the Trust have characteristics that meet the noted criteria and we have retroactively accounted for these instruments as debt and reflected related interest costs as interest expense in the statement of income.

Exchangeable Shares

On January 19, 2005, the CICA issued EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts" that states that equity interests held by third parties in subsidiaries of an income trust should be reflected as either non-controlling interest or debt in the consolidated balance sheet unless they meet certain criteria. EIC-151 requires that the shares be non-transferable in order to be classified as equity. The exchangeable shares issued by Harvest Operations Corp. are transferable and, in accordance with EIC-151, have been reclassified to non-controlling interest on the consolidated balance sheet. In addition, a portion of consolidated income or loss before non-controlling interest is reflected as a reduction to such income or loss in the Trust's consolidated statement of income. Prior periods have been retroactively restated.

Variable Interest Entities ("VIEs")

In June 2003, the CICA issued Accounting Guideline 15 "Consolidation of Variable Interest Entities" ("AcG-15"). AcG-15 defines VIEs as entities in which either: the equity at risk is not sufficient to permit that entity to finance its activities without additional financial support from other parties; or equity investors lack voting control, an obligation to absorb expected losses or the right to receive expected residual returns. AcG-15 harmonizes Canadian and U.S. GAAP and provides guidance for companies consolidating VIEs in which it is the primary beneficiary. The guideline is effective for all annual and interim periods beginning on or after November 1, 2004. We have performed a review of entities in which Harvest has an interest and have determined that we do not have any variable interest entities at this time.

Recent Canadian Accounting and Related Pronouncements

In an effort to harmonize Canadian GAAP with U.S. GAAP, the Canadian Accounting Standards Board has recently issued new Handbook sections:

- 1530, Comprehensive Income;
- 3855, Financial Instruments – Recognition and Measurement; and
- 3865, Hedges.

Under these new standards, all financial assets should be measured at fair value with the exception of loans, receivables and investments that are intended to be held to maturity and certain equity investments, which should be measured at cost. Similarly, all financial liabilities should be measured at fair value when they are held for trading or they are derivatives. Gains and losses on financial instruments measured at fair value will be recognized in the income statement in the periods they arise with the exception of gains and losses arising from:

- financial assets held for sale, for which unrealized gains and losses are deferred in other comprehensive income until sold or impaired; and
- certain financial instruments that qualify for hedge accounting.

Sections 3855 and 3865 make use of the term "other comprehensive income". Other comprehensive income comprises revenues, expenses, gains and losses that are excluded from net income. Unrealized gains and losses on qualifying hedging instruments, unrealized foreign exchange gains and losses, and unrealized gains and losses on financial instruments held for sale will be included in other comprehensive income and reclassified to net income when realized. Comprehensive income and its components will be a required disclosure under the new standard. These standards are effective for interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006. As we do not apply hedge accounting to any of our derivative instruments, we do not expect these pronouncements to have a significant impact on our consolidated financial results. However, we do have unrealized foreign exchange gains and losses.

Non-Monetary Transactions

The AcSB has issued Section 3831, *Non-Monetary Transactions*, which replaces Section 3830, and requires all non-monetary transactions to be measured at fair value unless:

- the transaction lacks commercial substance;
- the transaction is an exchange of production or property held for sale in the ordinary course of business for production or property to be sold in the same line of business to facilitate sales to customers other than the parties to the exchange;
- neither the fair value of the assets or services received nor the fair value of the assets or services given up is reliably measurable; or
- the transaction is a non-monetary, non-reciprocal transfer to owners that represents a spin-off or other form of restructuring or liquidation.

The new requirements apply to non-monetary transactions, initiated in periods beginning on or after January 1, 2006. Earlier adoption is permitted as of the beginning of a period beginning on or after July 1, 2005. We do not expect the adoption of this section will have a material impact on our results of operations or financial position.

Operational and Other Business Risks
Our operational and other business risks are substantially the same as those presented in our 2004 annual MD&A.

In addition to the risks outlined in our 2004 annual MD&A, we have identified a possible risk relating to the future tax treatment of income trusts in Canada. In a consultation paper issued on September 8, 2005, the Canadian Federal Government expressed concerns about several policy issues arising from the recent proliferation of income trusts in Canada. This paper communicates the government's concerns over how the tax treatment of trusts impacts the Canadian economy, with specific reference to federal tax revenues. The government has requested comments and feedback from interested stakeholders regarding the tax treatment of income trusts through December 31, 2005. The government of Alberta has expressed similar concerns regarding the impact of energy trusts on tax revenues, although it has acknowledged the benefits from the contributions made by trusts to Alberta and the energy industry in general. It is possible that changes imposed by the Canadian or Alberta governments could have an impact on the Trust's cost of capital, or our ability to raise capital in Canada or in the United States.

Key Performance Indicators and Outlook
We have indicated guidance on full year 2005 performance measures elsewhere in this MD&A.

Harvest plans to continue with its business plan of acquiring and operating high quality, mature crude oil and natural gas properties that can be enhanced through operational and exploitation techniques. Harvest also plans to continue to identify new geographic areas that can support sustainable distributions and growth in net asset value per Unit.

It is important to note that any future guidance provided is based upon management's current expectations. The ultimate results may vary, perhaps materially.

Additional information on Harvest Energy Trust, including our most recently filed Annual Information Form and annual report, can be accessed from SEDAR at www.sedar.com or from our website at www.harvestenergy.ca.

Harvest Energy Trust
Consolidated Balance Sheets (Unaudited)
(thousands of Canadian dollars)

	September 30, 2005	(Restated, Note 2) December 31, 2004
Assets		
Current assets		
Accounts receivable	**$ 84,621**	$ 44,028
Current portion of derivative contracts *[Note 11]*	**19,405**	8,861
Prepaid expenses and deposits	**1,758**	3,014
Future income tax	**30,795**	3,101
	136,579	59,004
Deferred charges *[Note 11]*	**15,436**	25,540
Long term portion of derivative contracts *[Note 11]*	**2,409**	3,710
Capital assets *[Note 3]*	**1,129,016**	918,397
Goodwill	**43,832**	43,832
	$ 1,327,272	$ 1,050,483
Liabilities and Unitholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities *[Note 4]*	**$ 118,285**	$ 76,251
Cash distribution payable	**17,966**	8,358
Current portion of derivative contracts *[Note 11]*	**92,500**	27,927
Bank debt	**-**	75,519
	228,751	188,055
Bank debt	**34,649**	-
Deferred gains *[Note 11]*	**843**	2,177
Long term portion of derivative contracts *[Note 11]*	**9,977**	-
Convertible debentures *[Notes 1, 2 and 10]*	**60,800**	25,750
Senior notes	**290,675**	300,500
Asset retirement obligation *[Note 5]*	**100,511**	90,085
Future income tax	**36,833**	37,772
	763,039	644,339
Non-controlling interest *[Notes 1,2 and 9*]	**3,012**	6,895
Unitholders' equity		
Unitholders' capital *[Note 7]*	**703,641**	465,524
Equity component of convertible debentures *[Notes 1 and 10]*	**3,620**	116
Accumulated deficit	**(146,040)**	(66,391)
	561,221	399,249
	$ 1, 327,272	$ 1,050,483

Commitments, contingencies and guarantees [Note 14]

See accompanying notes to these consolidated financial statements.

Harvest Energy Trust
Consolidated Statements of Income and Accumulated Income (Unaudited)
(thousands of Canadian dollars, except per Trust Unit amounts)

	Three Months Ended September 30, 2005	*(Restated, Note 2)* Three Months Ended September 30, 2004	**Nine Months Ended September 30, 2005**	*(Restated, Note 2)* Nine Months Ended September 30, 2004
Revenue				
Oil and natural gas sales	**$ 208,628**	$ 102,112	**$ 481,672**	$ 202,902
Royalty expense	**(38,974)**	(17,016)	**(81,824)**	(34,046)
	169,654	85,096	**399,848**	168,856
Expenses				
Operating	**32,441**	19,538	**88,424**	47,717
General and administrative	**12,971**	2,175	**25,046**	5,255
Interest on short-term debt	**1,083**	4,010	**6,452**	6,422
Interest on long-term debt	**7,682**	2,920	**21,460**	5,357
Depletion, depreciation and accretion	**48,969**	28,062	**127,944**	53,002
Foreign exchange loss (gain)	**(13,974)**	725	**(8,607)**	(565)
Derivative contracts *[Note 11]*	**26,130**	35,576	**137,779**	65,707
	115,302	93,006	**398,498**	182,895
Income(loss) before taxes and non-controlling interest	**54,352**	(7,910)	**1,350**	(14,039)
Taxes				
Large corporations tax	**76**	120	**831**	256
Future income tax expense (recovery)	**1,195**	(9,810)	**(28,633)**	(13,976)
	1,271	(9,690)	**(27,802)**	(13,720)
Net income (loss) before non-controlling interest	**53,081**	1,780	**29,152**	(319)
Non-controlling interest *[Notes 1, 2 and 9]*	**219**	40	**(156)**	40
Net income (loss)	**52,862**	1,740	**29,308**	(359)
Accumulated deficit, beginning of period, as previously reported	**(152,211)**	(36,269)	**(65,694)**	(13,069)
Retroactive changes in accounting policies	**-**	(205)	**(697)**	-
Accumulated deficit, beginning of period, as restated	**(152,211)**	(36,474)	**(66,391)**	(13,069)
Distributions	**(46,691)**	(18,434)	**(108,957)**	(39,740)
Accumulated income, end of period	**$ (146,040)**	$ (53,168)	**$ (146,040)**	$ (53,168)
Net income (loss) per trust unit, basic *[Note 7]*	**$ 1.09**	$ 0.06	**$ 0.66**	$ (0.02)
Net income (loss) per trust unit, diluted *[Note 7]*	**$ 1.08**	$ 0.06	**$ 0.64**	$ (0.02)

See accompanying notes to these consolidated financial statements.

Harvest Energy Trust
Consolidated Statements of Cash Flows (Unaudited)
(thousands of Canadian dollars, except per Trust Unit amounts)

	Three Months Ended September 30, 2005	*(Restated, Note 2)* Three Months Ended September 30, 2004	**Nine Months Ended September 30, 2005**	*(Restated, Note 2)* Nine Months Ended September 30, 2004
Cash provided by (used in)				
Operating Activities				
Net income(loss) for the period	**$ 52,862**	$ 1,740	**$ 29,308**	$ (359)
Items not requiring cash				
Depletion, depreciation and accretion	**48,969**	28,062	**127,944**	53,002
Unrealized foreign exchange loss (gain)	**(13,829)**	492	**(8,038)**	1,256
Amortization of deferred finance charges	**707**	686	**3,992**	2,228
Unrealized loss on derivative contracts	**3,948**	19,664	**73,524**	29,396
Non-cash interest expense	**187**	15	**342**	16
Future income tax expense (recovery)	**1,195**	(9,810)	**(28,633)**	(13,976)
Non-controlling interest	**219**	40	**(156)**	40
Non-cash unit right compensation expense	**9,250**	378	**15,129**	769
	103,508	41,267	**213,412**	72,372
Settlement of asset retirement obligation	**(1,169)**	(154)	**(2,333)**	(307)
Change in non-cash working capital *[Note 12]*	**29,810**	(9,093)	**(25,867)**	(12,405)
	132,149	32,020	**185,212**	59,660
Financing Activities				
Trust unit issuance, net of issue costs	**167,595**	166,063	**167,507**	165,932
Issue of equity bridge notes	**-**	5,000	**-**	30,000
Repayment of equity bridge notes *[Notes 6 and 13]*	**-**	(20,000)	**-**	(45,000)
Issuance of convertible debentures *[Note 10]*	**75,000**	100,000	**75,000**	160,000
Issue costs for convertible debentures	**(3,223)**	(4,500)	**(3,223)**	(7,166)
Financing costs	**(1,518)**	(3,951)	**(2,052)**	(3,973)
Net increase (reduction) in bank debt	**(103,442)**	257,037	**(40,871)**	279,771
Cash distributions	**(29,286)**	(11,226)	**(74,314)**	(28,728)
Change in non-cash working capital *[Note 12]*	**5,960**	2,126	**5,647**	1,892
	111,086	490,549	**127,694**	552,728
Investing Activities				
Additions to capital assets	**(31,655)**	(13,182)	**(81,032)**	(31,695)
Property acquisitions	**(210,631)**	(513,815)	**(241,473)**	(515,942)
Property dispositions	**965**	-	**2,177**	-
Corporate acquisition	**-**	-	**-**	(75,000)
Change in non-cash working capital *[Note 12]*	**(1,914)**	4,428	**7,422**	10,249
	(243,235)	(522,569)	**(312,906)**	(612,388)
Increase in cash and short-term investments	**-**	-	**-**	-
Cash, beginning of period	**-**	-	**-**	-
Cash, end of period	**$ -**	$ -	**$ -**	$ -
Cash interest payments	**$ 13,041**	$ 1,654	**$ 17,257**	$ 4,375
Cash tax payments	**$ 1,733**	$ 461	**$ 2,079**	$ 527
Cash distributions declared per trust unit	**$ 0.95**	$ 0.60	**$ 2.15**	$ 1.80

See accompanying notes to these consolidated financial statements.

1. Significant accounting policies

These interim consolidated financial statements of Harvest Energy Trust (the "Trust") have been prepared by management in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). 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. In the opinion of management, these financial statements have been prepared within reasonable limits of materiality. Except as noted below, these interim consolidated financial statements follow the same significant accounting policies as described and used in the consolidated financial statements of the Trust for the year ended December 31, 2004 and should be read in conjunction with that report. Certain comparative figures have been reclassified to conform to the current period's presentation.

These consolidated financial statements include the accounts of Harvest Energy Trust, its wholly owned subsidiaries and its proportionate interest in a partnership with a third party.

a) Convertible debentures

The Trust presents its convertible debentures in their debt and equity component parts, where applicable, as follows:

(i) The debt component represents the total discounted present value of the semi-annual interest obligations to be satisfied by cash and the principal payment due at maturity, using the rate of interest that would have been applicable to a non-convertible debt instrument of comparable term and risk at the date of issue. Typically, this results in a lower accounting value assigned to the debt component of the convertible debentures compared to the principal amount due at maturity. The debt component amount presented on the balance sheet increases over the term of the relevant debenture to the full face value of the outstanding debentures. The difference is reflected as increased interest expense with the result that adjusted interest expense reflects the effective yield of the debt component of the convertible debenture.

(ii) The equity component of the convertible debentures is presented under "Unitholders' Equity" in the consolidated balance sheet. The equity component represents the value ascribed to the conversion right granted to the holder. This amount remains unchanged in "Unitholders' Equity" until conversion of the debentures into Trust Units by the holders, at which time a proportionate amount is transferred to Unitholders' capital.

b) Non-controlling interest

Non-controlling interest represents the exchangeable shares issued by a subsidiary of the Trust to third parties which are ultimately only exchangeable for Trust Units. These exchangeable shares were issued as partial consideration for the acquisition of Storm Energy Ltd. in 2004. Non-controlling interest on the consolidated balance sheet reflects the fair value of the exchangeable shares at issuance together with a portion of the Trust's subsequent accumulated earnings or loss attributable to the non-controlling interest. Net income or loss is reduced by the portion of earnings attributable to the non-controlling interest. As the exchangeable shares are converted to Trust Units, the non-controlling interest on the consolidated balance sheet is reduced on a pro-rata basis together with a corresponding increase in Unitholders' capital.

2. Changes in accounting policy

a) Financial Instruments

On January 1, 2005, the Trust retroactively adopted the amendment to the Canadian Institute of Chartered Accountants ("CICA") handbook section 3860 "*Financial Instruments – Disclosure and Presentation*" ("Section 3860"). These changes require that fixed-amount contractual obligations that can be settled by issuing a variable number of equity instruments be classified as liabilities. The convertible debentures and the equity bridge notes previously issued by the Trust have characteristics that meet the noted criteria.

Convertible debentures

The convertible debentures may be redeemed at the option of the Trust on or after a predetermined date, and may, at the option of the Trust, be redeemed through the issuance of units. The number of units issued varies depending on the weighted average market price of the units for the preceding 20 consecutive trading days, five days prior to the settlement date.

The convertible debentures also have an option that allows the holder to convert the debentures into a fixed number of units. In accordance with CICA handbook section 3860, the convertible debentures have been reclassified from equity to long term debt with a portion, representing the value of the equity conversion feature, remaining in equity.

Equity bridge notes

Under the terms of the equity bridge notes, the interest and principal may have been repaid, at the option of the Trust, with Trust Units. The number of Trust Units issued would have been dependent on the market value of the units at the time of issue. As at September 30, 2004, $10 million of equity bridge notes were outstanding and at December 31, 2004 there were no equity bridge notes payable. For the three and nine month periods ended September 30, 2004 and the year ended December 31, 2004, interest payments were made related to these notes. In accordance with the amended CICA handbook section 3860, these notes would have been classified as debt rather than equity. The interest associated with these notes has been reflected in these consolidated financial statements as a direct charge to income rather than to equity as it was previously classified.

b) Exchangeable shares

On January 19, 2005, the CICA issued EIC-151 "*Exchangeable Securities Issued by Subsidiaries of Income Trusts*" ("EIC-151") that states that equity interests held by third parties in subsidiaries of an income trust should be reflected as either non-controlling interest or debt in the consolidated balance sheet unless they meet certain criteria. EIC-151 requires that the shares be non-transferable in order to be classified as equity. The exchangeable shares issued by Harvest Operations Corp. (the "Corporation") are transferable and, in accordance with EIC-151, have been reclassified to non-controlling interest on the consolidated balance sheets. In addition, a provision for non-controlling interest is reflected in the consolidated statements of income. Prior periods have been retroactively restated to reflect this presentation.

(Tabular amounts in thousands of Canadian dollars, except where noted)

c) Impact of changes in accounting policy

Balance sheet	**As reported December 31, 2004**	**Change upon adoption of CICA Section 3860**	**Change upon adoption of EIC -151**	**As restated December 31, 2004**
Deferred charges	$ 24,507	$ 1,033	$ -	$ 25,540
Convertible debentures - debt	-	25,750	-	25,750
Non-controlling interest	-	-	6,895	6,895
Unitholders' capital	465,131	335	58	465,524
Exchangeable shares	6,728	-	(6,728)	-
Convertible debentures-equity	24,696	(24,580)	-	116
Accumulated deficit	(65,694)	(472)	(225)	(66,391)

Income statement	**Three months ended September 30, 2004**	**Nine months ended September 30, 2004**
Interest on long-term debt - as reported	$ -	$ -
Add: interest on convertible debentures	2,741	4,974
Add: amortization of deferred financing costs	179	383
Interest on long-term debt - as restated	$ 2,920	$ 5,357

Income statement	**Three months ended September 30, 2004**	**Nine months ended September 30, 2004**
Interest on short-term debt - as reported	$ 3,037	$ 3,919
Add: interest on equity bridge notes	466	658
Add: amortization of deferred financing costs[1]	507	1,845
Interest on short-term debt - as restated	$ 4,010	$ 6,422

(1) Previously classified as finance charges

Income statement	**Three months ended September 30, 2004**	**Nine months ended September 30, 2004**
Non-controlling interest – as reported	$ -	$ -
Add: non-controlling interest	40	40
Non-controlling interest – as restated	40	40

Net income (loss)	**Three months ended September 30, 2004**	**Nine months ended September 30, 2004**
Net income - as reported	$ 5,166	$ 5,696
Less: amortization of deferred financing costs	(179)	(383)
Less: interest on equity bridge notes	(466)	(658)
Less: interest on convertible debentures	(2,741)	(4,974)
Less: non-controlling interest	(40)	(40)
Net income (loss) - as restated	$ 1,740	$ (359)

Income (loss) per unit	**Three months ended September 30, 2004**	**Nine months ended September 30, 2004**
Basic as reported	$ 0.07	$ -
Basic as restated	0.06	(0.02)
Diluted as reported	0.07	-
Diluted as restated	0.06	(0.02)

(Tabular amounts in thousands of Canadian dollars, except where noted)

3. Acquisitions

On August 2, 2005, the Trust completed the acquisition of the Hay River Properties. The Trust acquired certain oil and natural gas producing properties for total consideration of approximately $238 million, which was settled with cash.

This transaction has been accounted for using the purchase price method. The following summarizes the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition.

Allocation of purchase price:		**Amount**
Working capital deficit	$	(2,644)
Capital assets		244,995
Asset retirement obligation		(4,568)
	$	237,783
Consideration for the acquisition:		
Cash	$	237,783

The above amounts are estimates made by management based on currently available information. Amendments may be made to the purchase equation as the cost estimates and balances are finalized.

4. Accounts payable and accrued liabilities

		September 30, 2005		**December 31, 2004**
Trade accounts payable	**$**	26,889	$	13,697
Accrued interest		11,537		5,993
Trust unit incentive plans		21,503		9,774
Premium on derivative contracts		2,209		4,500
Accrued closing adjustments on asset acquisition		-		13,546
Other accrued liabilities		55,017		27,139
Large corporations tax payable		1,130		1,602
	$	118,285	$	76,251

5. Asset retirement obligation

The Trust's asset retirement obligation results from its net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Trust estimates the total undiscounted amount of its asset retirement obligation is approximately $369.9 million, the majority of which will be settled between 2015 and 2026. A credit-adjusted risk-free rate of 10 percent was used to calculate the fair value of the asset retirement obligation on the consolidated balance sheet.

A reconciliation of the asset retirement obligation is provided below:

		Three months ended September 30, 2005		**Three months ended September 30, 2004**
Balance, beginning of period	$	94,042	$	50,007
Revision of estimates		-		-
Liabilities incurred		5,253		45,134
Liabilities settled		(1,169)		(154)
Accretion expense		2,385		1,213
Balance, end of period	$	100,511	$	96,200

	Nine months ended September 30, 2005	Nine months ended September 30, 2004	Year ended December 31, 2004
Balance, beginning of period	$ 90,085	$ 42,009	$ 42,009
Revision of estimates	45	-	(8,704)
Liabilities incurred	5,688	51,611	53,488
Liabilities settled	(2,333)	(307)	(929)
Accretion expense	7,026	2,887	4,221
Balance, end of period	$ 100,511	$ 96,200	$ 90,085

6. Equity bridge notes

No equity bridge notes were outstanding at September 30, 2005.

On June 29, 2004 and July 9, 2004, the Trust drew $25 million and $5 million respectively, under an equity bridge note agreement with a corporation controlled by a director of the Corporation. On August 11, 2004, the Trust repaid $20 million of this balance with proceeds from subscription receipts issued [Note 7] and on December 30, 2004, repaid the remaining balance. Interest in respect of the equity bridge notes accrues at 10% per annum and is a charge to income.

On January 26 and 29, 2004, the Trust repaid two equity bridge notes outstanding in the amounts of $7.4 million and $17.6 million, respectively. During the nine months ended September 30, 2004, the Trust also paid accrued and outstanding interest in the amount of $1.5 million.

7. Unitholders' capital

(a) Authorized

The authorized capital consists of an unlimited number of Trust Units.

(b) Issued

	Number of Trust Units (000s)	Amount (restated Note 2)
As at December 31, 2003	**17,109**	**$ 117,407**
Issued pursuant to corporate acquisition	2,721	40,183
Conversion of subscription receipts	12,167	175,200
Convertible debenture conversions-9% series	3,521	49,287
Convertible debenture conversions-8% series	5,221	84,226
Equity component of convertible debenture conversions-9% series	-	14
Equity component of convertible debenture conversions-8% series	-	632
Exchangeable share retraction	152	2,200
Distribution reinvestment plan issuance	752	12,553
Unit appreciation rights exercise	145	721
Issue costs	-	(16,899)
As at December 31, 2004	**41,788**	**$ 465,524**

	Number of Trust Units (000s)	Amount (restated Note 2)
Issued	6,508	175,053
Unit appreciation rights exercise	187	6,845
Convertible debenture conversions-9% series	635	8,800
Convertible debenture conversions-8% series	581	9,339
Convertible debenture conversions-6.5% series	586	16,999
Equity component of convertible debenture conversions-9% series	-	3
Equity component of convertible debenture conversions-8% series	-	70
Equity component of convertible debenture conversions-6.5% series		1,195
Exchangeable share retraction	289	3,727
Distribution reinvestment plan issuance (including premium drip)	519	14,357
Special distribution	465	10,678
Issue costs	-	(8,949)
As at September 30, 2005	**51,558**	**$ 703,641**

On February 28, 2005, the Trust declared a special distribution of 2004 income to be made to unitholders' effective as at December 31, 2004. The special distribution was paid in units, with each unitholder of record on March 31, 2005 receiving 0.01098 of a Trust Unit per Trust unit held on that date.

On August 17, 2005, the Trust implemented a premium distribution program. The premium distribution program enables investors to receive a cash payment equal to 102% of the regular distribution amount. The impact to the Trust is the same as the regular DRIP whereby it settles distributions with units, rather than cash.

(c) Per Trust Unit information

The following table summarizes the Trust Units and net income (loss) used in calculating income (loss) per Trust Unit:

Net income adjustments:

	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	**Nine Months Ended September 30, 2005**	Nine Months Ended September 30, 2004
Net income (loss), basic	52,862	1,740	29,308	(359)
Non-controlling interest	219	-	(156)	-
Net income (loss), diluted[(1)]	**53,081**	1,740	29,152	(359)

Weighted average Trust Unit adjustments:

Number of units (000s)	**Three Months Ended September 30, 2005**	Three Months Ended September 30, 2004	**Nine Months Ended September 30, 2005**	Nine Months Ended September 30, 2004
Weighted average Trust Units outstanding, basic	48,306	29,058	44,612	20,938
Effect of exchangeable shares	268	-	301	-
Effect of unit appreciation rights	791	642	806	-
Weighted average Trust Units outstanding, diluted[1]	49,365	29,700	45,719	20,938

Note 1 *Weighted average Trust Units, diluted, does not include the impact of the conversion of the convertible debentures as the impact would be anti-dilutive. Total units excluded amount to* 509 *and* 1,409 *for the three and nine month period ended September 30, 2005, respectively (9,001 and 9,921 - for the three months and nine months ended September 30, 2004). Weighted average Trust Units, diluted, for the nine months ended September 30, 2004 do not include the impact of the Trust Unit appreciation rights as the impact would be anti-dilutive. Total Units excluded were 571 for the nine months ended September 30, 2004. Weighted average Trust Units, diluted, for the three month period ended September 30, 2004 and the nine months ended September 30, 2004 excludes the impact of exchangeable shares as the impact would be anti-dilutive. Total units excluded were 611 and 265 respectively.*

8. Trust Unit incentive plans

As at September 30, 2005, a total of 1,538,075 unit appreciation rights were outstanding under the regular Trust Unit incentive plan at an average exercise price of $16.70. This represents 3% of the total Trust Units outstanding.

For the three and nine month periods ended September 30, 2005, the Trust incurred non-cash compensation costs related to this incentive plan of $10.8 million and $17.5 million, respectively ($378,000 and $769,000 – three and nine month periods ended September 30, 2004, respectively). For the three months ended September 30, 2005, $8.9 million ($378,000 - September 30, 2004) of this amount was expensed and reflected as general and administrative costs in the statement of income, and $1.9 million (nil – September 30, 2004) of costs associated with personnel whose compensation is reflected in capital asset costs was capitalized. For the nine months ended September 30, 2005 $14.6 million ($769,000 – September 30, 2004) was expensed and $2.9 million (nil – September 30, 2004) was capitalized.

(Tabular amounts in thousands of Canadian dollars, except where noted)

The following summarizes the Trust Units reserved for issuance under the Trust Unit incentive plan:

	Nine months ended September 30, 2005		Year ended December 31, 2004	
	Number of Unit Appreciation Rights	**Weighted Average Exercise Price**	Number of Unit Appreciation Rights	Weighted Average Exercise Price
Outstanding, beginning of period	1,117,725	$ 11.92	1,065,150	$ 9.04
Granted	744,725	26.18	445,600	16.47
Exercised	(253,975)	9.14	(253,750)	8.30
Cancelled	(70,400)	18.84	(139,275)	10.91
Outstanding before exercise price reductions	1,538,075	18.86	1,117,725	11.92
Exercise price reductions	-	(2.16)	-	(1.83)
Outstanding, end of period	1,538,075	$ 16.70	1,117,725	$ 10.09
Exercisable before exercise price reductions	208,300	$ 10.32	206,688	$ 8.89
Exercise price reductions	-	(3.72)	-	(2.64)
Exercisable, end of period	208,300	$ 6.60	206,688	$ 6.25

The following table summarizes information about unit appreciation rights outstanding at September 30, 2005.

Exercise Price before price reductions	**Exercise Price net of price reductions**	**Number Outstanding at September 30, 2005**	**Exercise Price net of price reductions[a]**	**Remaining Contractual Life (Years)[a]**	**Number Exercisable at September 30, 2005**	**Exercise Price net of price reductions[a]**
$8.00 - 10.21	$3.75 - $5.96	330,625	$ 3.88	2.2	124,375	$ 3.88
$10.30 - $13.15	$6.55 - $10.15	169,250	8.79	3.0	50,625	8.15
$13.35 - $17.95	$10.54 -$15.78	216,125	12.98	3.7	21,550	12.60
$18.55 - $25.68	$16.72 - $24.45	617,575	22.56	4.4	11,750	17.62
$27.49 - $36.92	$26.93 - $36.92	204,500	30.20	4.8	-	n/a
$8.00 - $36.92	$3.75 - $36.92	1,538,075	$ 16.70	3.7	208,300	$ 6.60

[a] *Based on weighted average unit appreciation rights outstanding*

When the Trust adopted the fair value method of accounting for its Trust Unit incentive plan on January 1, 2003, it was required to calculate the pro forma impact of having adopted that method from the date all rights were initially granted.

For purposes of those calculations the fair value of each Trust Unit right has been estimated on the grant date using the following:

	September 30, 2004
Expected volatility	23.3%
Risk free interest rate	4.0%
Expected life of the trust unit rights	4 years
Estimated annual distributions per unit[a]	$2.40

[a] *Based on the annual distribution rate at the time the assumptions were made.*

(Tabular amounts in thousands of Canadian dollars, except where noted)

As at September 30, 2004 for the purposes of pro forma disclosures, the expense related to all of the Trust Unit rights issued prior to December 31, 2002 is reflected in pro forma net income as shown below:

		(Restated Note 2) Three Months Ended September 30, 2004	*(Restated Note 2)* Nine Months Ended September 30, 2004
Net income (loss)	As reported	$ 1,740	$ (359)
	Pro forma	1,357	(1,507)
Income (loss) per unit – basic	As reported	$ 0.06	$ (0.02)
	Pro forma	$ 0.05	$ (0.07)
Income (loss) per unit – diluted	As reported	$ 0.06	$ (0.02)
	Pro forma	$ 0.05	$ (0.07)

Unit Award Incentive Plan

At September 30, 2005, 35,024 units were outstanding under the Unit Award Incentive Plan. The Trust recorded compensation expense of $248,000 and $487,000 for the three and nine month periods ended September 30, 2005, respectively (nil – three and nine month periods ended September 30, 2004) related to this plan. For the three and nine month periods ended September 30, 2005, $77,100 (nil – three and nine month periods September 30, 2004) was capitalized relating to the unit award incentive plan.

Number	**Nine Months Ended September 30, 2005**	Year ended December 31, 2004
Outstanding, beginning of period	10,662	-
Granted	23,466	15,000
Adjusted for distributions	896	662
Cancelled	-	(5,000)
Outstanding, end of period	35,024	10,662

9. Exchangeable shares

(a) Authorized

Harvest Operations Corp., a wholly-owned subsidiary of the Trust, is authorized to issue an unlimited number of exchangeable shares without nominal or par value.

(Tabular amounts in thousands of Canadian dollars, except where noted)

(b) Issued

Exchangeable shares, series 1 (Number)	**Nine Months Ended September 30, 2005**	Year Ended December 31, 2004
Outstanding, beginning of period	455,547	-
Issued pursuant to corporate acquisition	-	600,587
Shareholder retractions	(263,865)	(145,040)
Outstanding, end of period	191,682	455,547
Exchange ratio at end of period	1:1.14463	1:1.06466

(c) Non-controlling interest

The Trust retroactively applied EIC-151 "Exchangeable Securities Issued by a Subsidiary of an Income Trust" at January 1, 2005. The non-controlling interest on the consolidated balance sheet consists of the fair value of the exchangeable shares upon issuance plus the accumulated earnings attributable to such non-controlling interest less conversions to date. The non-controlling interest on the statement of income represents the share of net income or loss attributable to the non-controlling interest based on the Trust Units issuable for exchangeable shares in proportion to total Trust Units issued and issuable at each period end.

The following is a summary of the non-controlling interest:

	September 30, 2005	(restated, Note 2) December 31, 2004
Non-controlling interest, beginning of period	**$ 6,895**	$ -
Issue of exchangeable shares	**-**	8,870
Exchanged for Trust Units	**(3,727)**	(2,200)
Current period (loss) income attributable to non-controlling interest	**(156)**	225
Non-controlling interest, end of period	**3,012**	6,895
Accumulated (loss) income attributable to non-controlling interest	**69**	225

10. Convertible debentures

The following is a summary of certain terms of the Trust's outstanding series of convertible debentures:

Issue date	**Interest rate**	**Original face value**	**Conversion price**	**Maturity**	**Earliest redemption date**
January 29, 2004	9%	$60 million	$13.85 per trust unit[(a)]	May 31, 2009	May 31, 2007
August 10, 2004	8%	$100 million	$16.07 per trust unit[(a)]	September 30, 2009	September 30, 2007
August 2, 2005	6.5%	$75 million	$31.00 per trust unit	December 31, 2010	December 31, 2008

(a) The conversion price for the 9% debentures and the 8% debentures changed from $14.00 and $16.25 per unit respectively, as a result of the special distribution described in Note 7.

On August 2, 2005 the Trust issued $75 million of 6.5% convertible unsecured subordinated debentures due December 31, 2010. Interest on the debentures is payable semi-annually in arrears in equal installments on June 30 and December 31 in each year, commencing December 31, 2005. 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 December 31, 2010 and the business day immediately preceding the date specified by the Trust for redemption of the debentures, at a conversion price of $31.00 per Trust Unit plus a cash payment for accrued interest and in lieu of any 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 December 31, 2008, at a price equal to $1,050 per debenture between January 1, 2009 and December 31, 2009 and at $1,025 per debenture between January 1, 2010 and December 31, 2010. Any redemption will include accrued and unpaid interest at such time. Under both redemption options, the Trust may elect to pay both the principal and accrued interest in the form 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.

(Tabular amounts in thousands of Canadian dollars, except where noted)

As at January 1, 2005, the Trust adopted the amended CICA Handbook Section 3860 relating to the classification of liabilities that may be settled with a variable number of equity instruments such as Trust Units. The adoption has resulted in the convertible debentures being classified as debt rather than equity, with a portion remaining in equity representing the value of the conversion feature. As the debentures are converted, a portion of the debt and equity amounts are transferred to Unitholders' capital. The debt balance associated with the convertible debentures accretes over time to the amount owing on maturity and such increases in the debt balance are reflected as non-cash interest expense in the statement of income.

The following table summarizes the issuance and subsequent conversions of the convertible debentures:

	9% Series		**8% Series**		**6.5% Series**		**Total**
	Number	**Amount**	**Number**	**Amount**	**Number**	**Amount**	**Amount**
January 29, 2004 issuance	60,000	$ 60,000	-	$ -	-	$ -	$ 60,000
August 10, 2004 issuance	-	-	100,000	100,000	-	-	100,000
Portion allocated to equity	-	(17)	-	(745)	-	-	(762)
Accretion of non-cash interest expense	-	2	-	23	-	-	25
Converted into Trust Units	(49,300)	(49,287)	(84,841)	(84,226)	-	-	(133,513)
As at December 31, 2004	10,700	$ 10,698	15,159	$ 15,052	-	$ -	$ 25,750
August 2, 2005 issuance					75,000	75,000	75,000
Portion allocated to equity	-	-	-	-	-	(4,932)	(4,932)
Accretion of non-cash interest expense	-	-	-	9	-	111	120
Converted into Trust Units	(8,802)	(8,800)	(9,401)	(9,339)	(18,173)	(16,999)	(35,138)
As at September 30, 2005	1,898	$ 1,898	5,758	$ 5,722	56,827	$ 53,180	$ 60,800

(Tabular amounts in thousands of Canadian dollars, except where noted)

The following table summarizes the reclassification of the equity component of convertible debentures to Unitholders' capital:

	9% Series Equity Value	8% Series Equity Value	6.5% Series Equity Value	Total
January 29, 2004 issuance, net	$ 17	$ -	$ -	$ 17
August 10, 2004 issuance, net	-	745	-	745
Converted into Trust Units	(14)	(632)	-	(646)
As at December 31, 2004	$ 3	$ 113	$ -	$ 116
August 2, 2005 issuance, net	-	-	4,720	4,720
Converted into Trust Units, net	(3)	(70)	(1,143)	(1,216)
As at September 30, 2005	$ -	$ 43	$ 3,577	$ 3,620

11. 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) Interest Rate Risk

The Trust is exposed to interest rate risk on its bank debt; the Trust's other debt has fixed interest rates.

(b) Credit Risk

Substantially all 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, including a 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 marketing or other commodity arrangements. The carrying value of accounts receivable reflects management's assessment of the associated credit risks.

(c) Foreign Exchange Rate Risk

The Trust is exposed to the risk of changes in the Canadian/US dollar exchange rate on sales of commodities that are denominated in US dollars or directly influenced by US dollar benchmark prices. In addition, the Trust's senior notes are denominated in US dollars (US$250 million). These notes act as an economic hedge to help offset the impact of exchange rate movements on commodity sales during the year. As at September 30, 2005 the full balance of the notes is still outstanding and is not repayable until October 15, 2011. Interest is payable semi-annually on the notes in US dollars.

(d) Commodity Risk

The Trust is exposed to fluctuations in prices for oil and natural gas and the differentials between prices received for light oil versus those received for medium and heavy gravity oil. The Trust uses derivative financial instruments to manage its commodity price exposure. Under the terms of certain of the derivative instruments, the Trust is required to provide security if the contracts favour the counterparty. The Trust is also exposed to counterparty risk on balances due if the contracts favour the Trust. This risk is managed by diversifying the Trust's derivative portfolio among a number of counterparties and by dealing with large investment grade institutions.

(Tabular amounts in thousands of Canadian dollars, except where noted)

The following is a summary of the oil sales price derivative contracts as at September 30, 2005.

Daily Quantity	Term	Price per Barrel (U.S.$)	Mark to Market Gain (Loss)	
Oil price swap contracts based on West Texas Intermediate				
500 bbl/d	October – December 2005	$24.00	$	(2,243)
Participating swap contracts based on West Texas Intermediate				
8,750 bbl/d	January – December 2006	$38.16 [(b)]	$	(50,466)
5,000 bbl/d	July – December 2006	$45.17[(b)]		(9,992)
5,000 bbl/d	January 2006 – June 2007	$49.03[(c)]		(7,757)
Oil price collar contracts based on West Texas Intermediate				
1,500 bbl/d	October – December 2005	$28.17 – 32.10 ($22.33)[(a)]	$	(5,431)
2,000 bbl/d	October – December 2005	$28.00 – 42.00		(5,122)

(a) The Trust has sold put options at the average price denoted in parenthesis, for the same volumes as the associated commodity contracts. The counterparty may exercise these options if the respective index falls below the specified price on a monthly settlement basis.
(b) This price is a floor. The Trust realizes this price plus 50% of the difference between spot price and this price.
(c) This price is a floor. The Trust realizes this price plus 75% of the difference between spot price and this price.

Oil price indexed put contracts based on West Texas Intermediate

Daily Quantity	Term	Type	Price per Bbl (U.S.$)	Mark to Market Gain (Loss)	
4,000 bbl/d	October – December 2005	Long Put	$30.00	$	44
1,972 bbl/d	October – December 2005	Short Call	$30.00		(7,621)
1,972 bbl/d	October – December 2005	Long Call	$40.00		5,528
7,000 bbl/d	October – December 2005	Long Put	$35.00[(2)]	$	(244)
2,380 bbl/d	October – December 2005	Short Call	$35.00		(7,935)
2,380 bbl/d	October – December 2005	Long Call	$45.00		5,415
7,500 bbl/d	October – December 2005	Long Put	$40.00	$	3
3,675 bbl/d	October – December 2005	Short Call	$40.00		(10,302)
3,675 bbl/d	October – December 2005	Long Call	$50.00		6,449
7,500 bbl/d	January – June 2006	Long Put	$34.00	$	678
3,750 bbl/d	January – June 2006	Short Call	$34.00		(25,526)
3,750 bbl/d	January – June 2006	Long Call	$44.00		18,208
5,000 bbl/d	January – December 2006	Long Put	$55.00	$	6,532
2,500 bbl/d	January – December 2006	Short Call	$55.00		(15,353)
2,500 bbl/d	January – December 2006	Long Call	$65.00		8,618
2,500 bbl/d	January – December 2006	Short Call	$70.00		(6,271)
2,500 bbl/d	January – December 2006	Long Call	$83.00		2,802
5,000 bbl/d	January – December 2007	Long Put	$50.00	$	7,676
2,500 bbl/d	January – December 2007	Short Call	$50.00		(18,350)
2,500 bbl/d	January – December 2007	Long Call	$60.00		11,912
2,500 bbl/d	January – December 2007	Short Call	$70.00		(7,381)
2,500 bbl/d	January – December 2007	Long Call	$83.00		3,923

(1) Each group of a long put, short call and a long call reflect an "indexed put option". These series of puts and calls serve to fix a floor price while retaining upward price exposure on a portion of price movements above the floor price.

(2) Harvest pays a premium of U.S.$1.00 per Bbl on 7,000 Bbl/d for each month in which WTI exceeds U.S.$50.00/Bbl.

(Tabular amounts in thousands of Canadian dollars, except where noted)

Oil price differential swap contract based on Bow River Crude Blend

Daily Quantity	Term	Percent of WTI (%)	Mark to Market Gain
4,000 bbl/d	October 2005 – June 2006	29.9	$ 2,129
5,000 bbl/d	October 2005 – December 31, 2006	27.5	$ 4,325
4,000 bbl/d	July – December 2006	29.58	$ 549

Oil price differential swap contract based on Wainwright Crude Blend

Daily Quantity	Term	Percent of WTI (%)	Mark to Market Gain
1,000 bbl/d	October 2005 – June 2006	29.9	$ 1,709
1,000 bbl/d	July – December 2006	29.58	$ 841

The following is a summary of electricity price physical and financial swap contracts entered into by Harvest to fix the cost of future electricity usage as at September 30, 2005.

Swap contracts based on electricity prices

Weighted Average Quantity	Term	Average Price per Megawatt	Mark to Market Gain
25 MWH	October – December 2005	Cdn $48.00	$ 1,998
35 MWH	January – December 2006	Cdn $48.58	6,394
25 MWH	January – December 2007	Cdn $55.00	1,752
25 MWH	January – December 2008	Cdn $55.00	657

Swap contracts based on electricity heat rate

Quantity	Term	Heat Rate	Mark to Market Loss
5 MW	October – December 2005	8.40 GJ/MWh	$ (271)

Natural Gas Contracts

Quantity	Term	Price per GJ	Mark to Market Gain
1,008 GJ/day	October – December 2005	6.05/GJ	448

The following is a put option related to the US/Canadian dollar exchange rate intended to mitigate the impact of a strengthening Canadian dollar on realized commodity prices.

Foreign currency contract

Monthly Contract Amount	Term	Type	Contract Rate	Mark to Market Gain
U.S. $8.33 million	July – December 2005	Long Put	1.20 Cdn / US	$ 1,012

At September 30, 2005, the net unrealized loss position reflected on the balance sheet for all the derivative contracts outstanding at that date was approximately $80.7 million.

For the three and nine month periods ended September 30, 2005, the total unrealized loss recognized in the statement of income, including amortization of deferred charges and gains, was $3.9 million ($19.7 million – three months ended September 30, 2004) and $73.5 million ($29.4 million – three months ended September 30, 2004), respectively. The realized gains and losses on all derivative contracts are included in the period in which they are incurred. These amounts are reflected in gains and losses on derivative contracts on the statement of income.

(Tabular amounts in thousands of Canadian dollars, except where noted)

At October 1, 2004, the Trust discontinued hedge accounting for all of its derivative financial instruments. For those contracts where hedge accounting had previously been applied, a deferred charge or gain was recorded equal to the fair value of the contracts at the time hedge accounting was discontinued with a corresponding amount recorded in the derivative contracts balance. The deferred charge or gain is subsequently recognized in income in the period in which the underlying transaction is recognized.

For the three and nine month periods ended September 30, 2005, $1.2 million and $9.6 million, respectively (nil – three months ended September 30, 2004 and $5.5 million-nine months ended September 30, 2004) of the deferred charge and $444,000 and $1.3 million, respectively (nil – three months ended September 30, 2004 and nil – nine months ended September 30, 2004) of the deferred gain has been amortized and recorded in gains and losses on derivative contracts in the statement of income. At September 30, 2005, $1.2 million ($10.8 million – December 31, 2004) and $843,000 ($2.2 million – December 31, 2004) has been recorded as a deferred charge and a deferred gain, respectively on the balance sheet relating to derivatives.

Deferred charges – asset	**Nine Months Ended September 30, 2005**	Year Ended December 31, 2004
Balance, beginning of period	**$ 25,540**	$ 1,989
Deferred charge related to derivative contracts recorded upon adoption of Accounting Guideline 13	**-**	5,490
Deferred charge related to derivative contracts recorded upon discontinuing hedge accounting	**-**	20,215
Discount on senior notes	**-**	2,075
Financing costs incurred	5,063	20,971
Financing costs transferred to unit issue costs on conversion of debentures	(1,402)	(5,721)
Amortization of deferred charges related to derivative contracts(1)	(9,551)	(14,946)
Accretion of senior notes discount(2)	(222)	(75)
Amortization of deferred financing costs(2)	(3,992)	(4,458)
Balance, end of period	**$** 15,436	$ 25,540

Comprised of:	**As at September 30, 2005**	As at December 31, 2004
Derivative asset	**$ 1,208**	$ 10,759
Financing costs	**12,450**	12,781
Discount on senior notes	**1,778**	2,000
	$ 15,436	$ 25,540

(Tabular amounts in thousands of Canadian dollars, except where noted)

Deferred gains - liability	**Nine Months Ended September 30, 2005**	Year Ended December 31, 2004
Balance, beginning of period	**$ 2,177**	$ -
Deferred gains related to derivative contracts recorded upon discontinuing hedge accounting	**-**	2,527
Amortization of deferred gains related to derivative contracts(1)	(1,334)	(350)
Balance, end of period	**$ 843**	$ 2,177

(1) Recorded within gains and losses on derivative contracts.
(2) Recorded within interest expense on long-term debt and short-term debt.

12. Change in non-cash working capital

	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	**Nine Months Ended September 30, 2005**	Nine Months Ended September 30, 2004
Changes in non-cash working capital items:				
Accounts receivable	$ (18,292)	$ (23,167)	$ (40,593)	$ (36,856)
Current portion of derivative contracts assets	(9,596)	-	(10,544)	-
Prepaid expenses and deposits	44,171	(620)	1,256	(3,141)
Future income tax	(20,832)	-	(27,694)	-
Accounts payable and accrued liabilities	16,613	21,740	42,034	47,658
Cash distribution payable	9,212	3,325	9,608	3,949
Current portion of derivative contracts liabilities	54,209	13,601	64,573	23,333
	$ 75,485	$ 14,879	$ 38,640	$ 34,943
Changes relating to operating activities	$ 29,810	$ (9,093)	$ (25,867)	$ (12,405)
Changes relating to financing activities	5,960	2,126	5,647	1,892
Changes relating to investing activities	(1,914)	4,428	7,422	10,249
Add: Non-cash changes	41,629	17,418	51,438	35,207
	$ 75,485	$ 14,879	$ 38,640	$ 34,943

13. Related party transactions

During the nine month period ended September 30, 2004, a director and a corporation controlled by a director of Harvest Operations Corp. issued an additional $30 million of equity bridge notes. The Trust repaid $45 million of equity bridge notes and paid $1.5 million of accrued interest during the nine month period ended September 30, 2004. See Note 6.

A corporation controlled by a director of Harvest Operations Corp. sublets office space from and is provided administrative services by the Trust on a cost recovery basis.

14. Commitments, contingencies and guarantees

From time to time, the Trust is involved in litigation or has claims brought 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.

In the normal course of operations, management may also enter into certain types of contracts that require the Trust to indemnify parties against possible third party claims, particularly when these contracts relate to purchase and sale agreements. The terms of such contracts vary and generally a maximum is not explicitly stated; as such the overall maximum amount of the obligations cannot be reasonably estimated. Management does not believe payments, if any, related to such contracts would have a material affect on the Trust's reported financial position or results from operations.

(Tabular amounts in thousands of Canadian dollars, except where noted)

The Trust has letters of credit outstanding in the amount of approximately $5.1 million related to electricity infrastructure usage. These letters are provided pursuant to the secured senior credit facility. These letters expire throughout 2005, and are expected to be renewed as required.

The following is a summary of the Trust's contractual obligations and commitments as at September 30, 2005:

	Remaining Payments Due by Period				
	2005	**2006 – 2007**	**2008 – 2009**	**Thereafter**	**Total**
Debt repayments [(1)]	$ -	$ 34,649	$ -	$ 290,675	$ 325,324
Operating leases	372	2,869	2,869	956	7,066
Total contractual obligations	$ 372	$ 37,518	$ 2,869	$ 291,631	$ 332,390

(1) Includes long-term and short-term debt. Assumes that the outstanding convertible debentures are either exchanged at the holders' option for units or are redeemed for units at the Trust's option. The initial maturity of the Trust's bank debt has been extended to July 31, 2006 with a one year term-out option available to the Trust.