Harvest ENERGY

Q3 Third Quarter Report
for the three month period ending September 30, 2009

SELECTED INFORMATION

The table below provides a summary of our financial and operating results for the three and nine months ended September 30, 2009 and 2008.

	Three Months Ended September 30			Nine Months Ended September 30		
($000s except where noted)	**2009**	2008	Change	**2009**	2008	Change
Revenue, net[1]	**991,854**	1,597,195	(38%)	**2,285,946**	4,596,625	(50%)
Cash From Operating Activities	**98,979**	133,493	(26%)	**396,603**	472,147	(16%)
Per Trust Unit, basic	**$ 0.55**	$ 0.87	(37%)	**$ 2.35**	$ 3.11	(24%)
Per Trust Unit, diluted	**$ 0.55**	$ 0.84	(35%)	**$ 2.30**	$ 2.95	(22%)
Net (Loss) Income[2]	**(713,697)**	295,788	(341%)	**(922,612)**	133,379	(792%)
Per Trust Unit, basic	**$ (3.95)**	$ 1.93	(305%)	**$ (5.46)**	$ 0.88	(720%)
Per Trust Unit, diluted	**$ (3.95)**	$ 1.73	(328%)	**$ (5.46)**	$ 0.88	(720%)
Distributions declared	**27,162**	138,511	(80%)	**155,657**	410,678	(62%)
Distributions declared, per Trust Unit	**$ 0.15**	$ 0.90	(83%)	**$ 0.95**	$ 2.70	(65%)
Distributions declared as a percentage of Cash From Operating Activities	**27%**	104%	(77%)	**39%**	87%	(48%)
Bank debt				**1,050,850**	1,199,773	(12%)
$7^{7/8}$% Senior Notes				**263,499**	260,120	1%
Convertible Debentures[3]				**834,563**	824,771	1%
Total debt[3]				**2,148,912**	2,284,664	(6%)
Total assets				**4,423,802**	5,659,227	(22%)
UPSTREAM OPERATIONS						
Daily Production						
Light to medium oil (bbl/d)	**22,793**	25,210	(10%)	**23,775**	25,362	(6%)
Heavy oil (bbl/d)	**10,066**	11,485	(12%)	**10,520**	12,182	(14%)
Natural gas liquids (bbl/d)	**2,648**	2,627	1%	**2,719**	2,575	6%
Natural gas (mcf/d)	**89,163**	93,628	(5%)	**92,284**	96,394	(4%)
Total daily sales volumes (boe/d)	**50,368**	54,926	(8%)	**52,395**	56,184	(7%)
Operating Netback ($/boe)	**27.24**	60.38	(55%)	**23.45**	56.08	(58%)
Cash capital expenditures	**12,455**	69,098	(82%)	**154,556**	188,337	(18%)
Business and property dispositions, net	**(766)**	132,130	(101%)	**(61,494)**	127,581	(148%)
DOWNSTREAM OPERATIONS						
Average daily throughput (bbl/d)	**102,940**	99,127	4%	**86,677**	103,832	(17%)
Average Refining Gross Margin (US$/bbl)	**5.37**	10.47	(49%)	**9.77**	8.38	17%
Cash capital expenditures	**7,945**	17,199	(54%)	**34,778**	31,845	9%

(1) Revenues are net of royalties.

(2) Net (Loss) Income includes goodwill impairment charges of $677.6 million and $884.1 million for the three and nine months ended September 30, 2009, respectively (nil for the three and nine months ended September 30, 2008), a future income tax expense of $12.0 million and $2.0 million for the three and nine months ended September 30, 2009, respectively ($149.5 million and $32.5 million for the three and nine months ended September 30, 2008) and an unrealized net loss from risk management activities of $2.1 million and $27.3 million for the three and nine months ended September 30, 2009, respectively (net gain of $359.7 million and a net loss of $6.3 million for the three and nine months ended September 30, 2008).

(3) Includes current portion of Convertible Debentures and excludes the equity component of Convertible Debentures.

MESSAGE TO UNITHOLDERS

On October 21, 2009, Harvest Energy announced that it has entered into an agreement (the "Arrangement Agreement") with Korea National Oil Corporation ("KNOC") for the purchase of all the issued and outstanding trust units (the "Units") at a price of C$10.00 per Unit for total cash consideration of approximately C$1.8 billion plus the assumption of C$2.3 billion of debt. The Arrangement represents a 47% premium over the 30-day weighted average trading price of the Units on the Toronto Stock Exchange up to and including October 20, 2009.

The Board of Directors has unanimously approved the Arrangement and determined that it is fair from a financial perspective and that the transaction is in the best interest of Harvest and its unitholders. Thus, the Board of Directors intends to vote their respective Units, totaling 7.0 million Units, in favor of the Arrangement and recommends that unitholders do the same. Specific details, subject to receipt of all necessary approvals and other conditions, in respect of the Arrangement will be contained in an Information Circular and Proxy Statement of the Trust which is expected to be mailed on or about November 16, 2009 to Security holders of record on November 9, 2009. The special meeting of unitholders and holders of trust unit rights and unit awards is scheduled for the Lecture Theatre at the Metropolitan Centre, 333 – 4th Avenue S.W., Calgary, Alberta on December 15, 2009, at 10:00 a.m. (Calgary time) and the completion of the Arrangement is expected to occur on or about December 22, 2009, with closing expected to occur prior to year-end. The Arrangement Agreement has been filed on SEDAR and EDGAR and formal KNOC board approval of the definitive Arrangement Agreement has now been received.

Harvest included a goodwill impairment charge in our third quarter results. The writedown of goodwill in the upstream business included in this quarter's results was necessary due to the offer made by KNOC and the Board's recommendation to unitholders to support the offer, which is less than the book value of the company. This does not reflect a change in the long term value of the upstream assets as upstream performance has continued to be very strong during 2009 exceeding internal and external analyst expectations.

The Arrangement is also subject to court and regulatory approval along with the approval of $66^{2/3}$% of unitholders represented in person or by proxy at the December 15, 2009 special meeting.

Upstream

While natural gas prices continue to remain weak, we have witnessed oil prices making significant gains over the quarter. Partially mitigating this upward trend was the strength in the Canadian dollar. Despite the quarter over quarter decline in production, operational results continue to exceed our expectations as continued reservoir maintenance at Hay River, coupled with strong production additions at Chedderville continue to supplement production. As a result, cash flow in the third quarter was $116.8 million, compared to $121.1 million in the prior quarter.

We continue to be extremely pleased with our operating results. Production volumes were above our expectations for the first nine months of the year despite the sale of approximately 1,020 boe/d in the second quarter as we continued to benefit from the results of our enhanced oil recovery projects as well as new drilling activites. There was a modest $12.5 million of capital spent in the third quarter predominantly focused on well equipment, pipelines and facilities.

Harvest Energy continues to be positioned with short term growth opportunities coupled with long-term enhanced recovery prospects with over 2 billion barrels of estimated original oil in place on conventional land. Future EOR opportunities have been identified in Hayter, Hay River, Kindersley and southeast Saskatchewan, while carbon dioxide (CO2) flooding and sequestration, oilsands and coal bed methane (CBM) represent longer term recovery opportunities for Harvest.

Downstream

After a successful second quarter turnaround, Harvest improved throughput volumes to 102,940 bbl/d, from 52,808 bbl/d in the second quarter 2009. While we achieved a significant increase in throughput volumes in the third quarter, record high refined product inventories coupled with weakened refined product demand put continued pressure on refined product prices. The net impact resulted in Harvest's downstream cash flow increasing to $11.9 million, from a $38.8 million deficiency in the second quarter of 2009.

On October 13, 2009 Harvest Energy announced its North Atlantic Refining Limited subsidiary renewed and extended its existing crude oil supply and refined product offtake agreement ("SOA") with Vitol Refining S.A. ("Vitol"). Similar to the terms of the previous agreement, Vitol will provide to NARL comprehensive working capital, financing of feedstocks and finished products, including Letters of Credit, in-transit and in-storage inventories, and trade credit. Additionally, Vitol will provide feedstock procurement and shipping, finished product marketing and shipping, price risk management, administrative and back office services. The amended SOA became effective beginning in November 1, 2009 for an initial period of 2 years, after which, it will automatically renew. The Vitol SOA replaces the existing agreement in place since Harvest's acquisition of NARL in October 2006, and is based on more favorable financing charges, fees, and product sales prices. Further, the renewed SOA will provide for the inclusion of high sulfur fuel oil inventories and other amendments, which will increase the amount of working capital financing realized under this agreement.

Corporate

With the October 21, 2009 announced offer by Korea National Oil Corporation to purchase all of the issued and outstanding units at a significant premium to recent market prices, Harvest Energy will have a special meeting of unitholders and holders of trust unit rights and unit awards, which is scheduled for the Lecture Theatre at the Metropolitan Centre, 333 – 4th Avenue S.W., Calgary, Alberta on December 15, 2009, at 10:00 a.m. We encourage all unitholders to vote their respective units.

In the meantime, we continue full operations and anticipate our upstream production will be approximately 51,500 boe/d, compared to our previous guidance of 50,000 boe/d to 51,000 boe/d in 2009 despite selling $63 million of properties producing over 1,000 boe/d in the second quarter 2009. For our downstream operations, we anticipate average throughput for the fourth quarter to be 80,000 boe/d due to weak refining margins and a maintenance shut down of the crude unit, with purchased energy and operating costs to average $4.30/bbl and $2.85/bbl, respectively.

Harvest has consistently maintained a disciplined approach in health, safety and environmental issues and remains committed to operating in a socially responsible manner. We regularly conduct emergency response training, and perform safety and environmental audits of our operating facilities.

On a sad note, it is with regrets that we advise of the death of Dale Blue who has served on Harvest's Board of Directors since the merger with the Viking Energy Royalty Trust and prior to the merger, on Viking's Board since 2001. Dale's wisdom and judgment has always been valued by both our Board and Management. His contribution will be missed.

In closing, we thank all of our stakeholders for your support of and interest in Harvest Energy.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") of the financial condition and results of operations of Harvest Energy Trust should be read in conjunction with our audited consolidated financial statements and accompanying notes for the years ended December 31, 2008 and 2007, our MD&A for the year ended December 31, 2008 as well as our interim consolidated financial statements and notes for the three and nine month periods ended September 30, 2009 and 2008. The information and opinions concerning our future outlook are based on information available at November 13, 2009.

In this MD&A, reference to "Harvest", "we", "us" or "our" refers to Harvest Energy Trust and all of its controlled entities on a consolidated basis. All references are to Canadian dollars unless otherwise indicated. Tabular amounts are in thousands of dollars unless otherwise stated. Natural gas volumes are converted to barrels of oil equivalent ("boe") using the ratio of six thousand cubic feet ("mcf") of natural gas to one barrel of oil ("bbl"). Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf to 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. In accordance with Canadian practice, petroleum and natural gas revenues are reported on a gross basis before deduction of Crown and other royalties. In addition to disclosing reserves under the requirements of National Instrument 51-101, we also disclose our reserves on a company interest basis which is not a term defined under National Instrument 51-101. This information may not be comparable to similar measures by other issuers.

NON-GAAP MEASURES

Throughout this MD&A we have referred to certain measures of financial performance that are not specifically defined under Canadian GAAP. Cash G&A and Operating Netbacks are non-GAAP measures used extensively in the Canadian energy trust sector for comparative purposes. Cash G&A are G&A expenses excluding the effect of our unit based compensation plans, while Operating Netbacks are always reported on a per boe basis, and include gross revenue, royalties, operating expenses, and transportation and marketing expenses. Gross Margin is also a non-GAAP measure and is commonly used in the refining industry to reflect the net funds received from the sale of refined products after considering the cost to purchase the feedstock and is calculated by deducting purchased products for resale and processing from total revenue. Earnings From Operations and Cash From Operations are also non-GAAP measures and are commonly used for comparative purposes in the petroleum and natural gas and refining industries to reflect operating results before items not directly related to operations. This information may not be comparable to similar measures by other issuers.

FORWARD-LOOKING INFORMATION

This MD&A highlights significant business results and statistics from our consolidated financial statements for the three and nine months ended September 30, 2009 and the accompanying notes thereto. In the interest of providing our Unitholders and potential investors with information regarding Harvest, including our assessment of our future plans and operations, this MD&A contains forward-looking statements that involve risks and uncertainties. Such risks and uncertainties include, but are not limited to, risks associated with conventional petroleum and natural gas operations; risks associated with refining and marketing operations; the volatility in commodity prices and currency exchange rates; risks associated with realizing the value of acquisitions; general economic, market and business conditions; changes in environmental legislation and regulations; the availability of sufficient capital from internal and external sources and such other risks and uncertainties described from time to time in our regulatory reports and filings made with securities regulators.

Forward-looking statements in this MD&A include, but are not limited to, the forward looking statements made in the "Outlook" section as well as statements made throughout with reference to production volumes, refinery throughput volumes, royalty rates, operating costs, commodity prices, administrative costs, price risk management activity, acquisitions and dispositions, capital spending, reserve estimates, distributions, access to credit facilities, income taxes, cash from operating activities, and regulatory changes. For this purpose, any statements that are contained herein that are not statements of historical fact may be deemed to be forward-looking statements. Forward-looking statements often contain terms such as "may", "will", "should", "anticipate", "expects", and similar expressions.

Readers are cautioned not to place undue reliance on forward-looking statements as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. Although we consider such information reasonable at the time of preparation, it may prove to be incorrect and actual results may differ materially from those anticipated. We assume no obligation to update forward-looking statements should circumstances, estimates or opinions change, except as required by law. Forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement.

Consolidated Financial and Operating Highlights – Third Quarter 2009

- Subsequent to the end of the Quarter, we entered into an Arrangement Agreement with Korea National Oil Corporation for the purchase of all of the Harvest Trust Units for $10.00 per Trust Unit subject to the approval of $66^{2/3}$% of the Unitholders as well as court and regulatory approvals.

- Quarterly cash flow from operating activities of $99.0 million as compared to $133.5 million reported in the prior year reflects a $102.5 million improvement in the settlement of price risk management contracts more than offset by reductions in the contribution from our Upstream operations as well as Downstream operations of $179.6 million and $35.3 million, respectively.

- Upstream operating cash flow of $116.8 million as compared to $121.1 million in the Second Quarter of this year reflects a further strengthening of commodity prices somewhat offsetting a decline in our average daily production to 50,368 boe/d from 52,745 boe/d in the prior quarter. Capital spending totaled $12.5 million as compared to $69.1 million in the Third Quarter in prior year. In August 2009, we completed the acquisition of Pegasus Oil and Gas Inc., adding approximately 650 boe/d in production.

- Operating cash flow from our Downstream operations totaled $11.9 million as compared to cash flow of $47.2 million generated in the prior year reflecting weak refining margins as well as restricted throughput due to crude unit operating constraints. Capital spending totaled $7.9 million as compared to $17.2 million in the prior year most of which was directed towards the visbreaker enhancement project completed in 2008.

- Our bank borrowings totaled $1,050.9 million, a net reduction of $47.0 million during the quarter as the assumption of bank debt with the acquisition of Pegasus Oil and Gas Inc. partially offset the benefit of lower capital spending and our $0.05 monthly distributions.

SELECTED INFORMATION

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Revenue, net[1]	**991,854**	1,597,195	(38%)	**2,285,946**	4,596,625	(50%)
Cash From Operating Activities	**98,979**	133,493	(26%)	**396,603**	472,147	(16%)
Per Trust Unit, basic	**$ 0.55**	$ 0.87	(37%)	**$ 2.35**	$ 3.11	(24%)
Per Trust Unit, diluted	**$ 0.55**	$ 0.84	(35%)	**$ 2.30**	$ 2.95	(22%)
Net (Loss) Income[2]	**(713,697)**	295,788	(341%)	**(922,612)**	133,379	(792%)
Per Trust Unit, basic	**$ (3.95)**	$ 1.93	(305%)	**$ (5.46)**	$ 0.88	(720%)
Per Trust Unit, diluted	**$ (3.95)**	$ 1.73	(328%)	**$ (5.46)**	$ 0.88	(720%)
Distributions declared	**27,162**	138,511	(80%)	**155,657**	410,678	(62%)
Distributions declared, per Trust Unit	**$ 0.15**	$ 0.90	(83%)	**$ 0.95**	$ 2.70	(65%)
Distributions declared as a percentage of Cash From Operating Activities	**27%**	104%	(77%)	**39%**	87%	(48%)
Bank debt				**1,050,850**	1,199,773	(12%)
$7^{7/8}$% Senior Notes				**263,499**	260,120	1%
Convertible Debentures[3]				**834,563**	824,771	1%
Total debt[3]				**2,148,912**	2,284,664	(6%)
Total assets				**4,423,802**	5,659,227	(22%)
UPSTREAM OPERATIONS						
Daily Production						
Light to medium oil (bbl/d)	**22,793**	25,210	(10%)	**23,775**	25,362	(6%)
Heavy oil (bbl/d)	**10,066**	11,485	(12%)	**10,520**	12,182	(14%)
Natural gas liquids (bbl/d)	**2,648**	2,627	1%	**2,719**	2,575	6%
Natural gas (mcf/d)	**89,163**	93,628	(5%)	**92,284**	96,394	(4%)
Total daily sales volumes (boe/d)	**50,368**	54,926	(8%)	**52,395**	56,184	(7%)
Operating Netback ($/boe)	**27.24**	60.38	(55%)	**23.45**	56.08	(58%)
Cash capital expenditures	**12,455**	69,098	(82%)	**154,556**	188,337	(18%)
Business and property dispositions, net	**(766)**	132,130	(101%)	**(61,494)**	127,581	(148%)
DOWNSTREAM OPERATIONS						
Average daily throughput (bbl/d)	**102,940**	99,127	4%	**86,677**	103,832	(17%)
Average Refining Gross Margin (US$/bbl)	**5.37**	10.47	(49%)	**9.77**	8.38	17%
Cash capital expenditures	**7,945**	17,199	(54%)	**34,778**	31,845	9%

(4) Revenues are net of royalties.

(5) Net (Loss) Income includes goodwill impairment charges of $677.6 million and $884.1 million for the three and nine months ended September 30, 2009, respectively (nil for the three and nine months ended September 30, 2008), a future income tax expense of $12.0 million and $2.0 million for the three and nine months ended September 30, 2009, respectively ($149.5 million and $32.5 million for the three and nine months ended September 30, 2008) and an unrealized net loss from risk management activities of $2.1 million and $27.3 million for the three and nine months ended September 30, 2009, respectively (net gain of $359.7 million and a net loss of $6.3 million for the three and nine months ended September 30, 2008).

(6) Includes current portion of Convertible Debentures and excludes the equity component of Convertible Debentures.

REVIEW OF OVERALL PERFORMANCE

Harvest is an integrated energy trust with our petroleum and natural gas business focused on the operation and further development of assets in western Canada (our "upstream operations") and our refining and marketing business focused on the safe operation of a medium gravity sour crude oil hydrocracking refinery and a retail and wholesale petroleum marketing business both located in the Province of Newfoundland and Labrador (our "downstream operations"). Our earnings and cash flow from operating activities are largely determined by the realized prices for our crude oil and natural gas production as well as refined product crack spreads, including the effects of changes in the U.S. dollar to Canadian dollar exchange rate. Recently, the changes in crude oil and natural gas prices have been partially offset by changes in the exchange rate between U.S. dollars and Canadian dollars.

On October 21, 2009, Harvest entered into an Arrangement Agreement with Korea National Oil Corporation ("KNOC") for the purchase of all of the issued and outstanding Trust Units of Harvest at a price of $10.00 per Trust Unit for an aggregate cash consideration of approximately $1.8 billion plus the assumption of approximately $2.3 billion of debt. The Trust Unit consideration represents a 47% premium over the 30-day weighted average trading price on the Toronto Stock Exchange. The transaction is subject to the approval of $66^{2/3}$% of the Unitholders as well as court and regulatory approvals. A special meeting of the Unitholders has been scheduled for December 15, 2009 with the closing expected on December 22, 2009. The transaction has been unanimously approved by the Board of Directors of both Harvest and KNOC with the Harvest Board receiving a favourable fairness opinion from its financial advisor. In accordance with the indentures governing Harvest's $7^{7/8}$% Senior Notes and Convertible Debentures, KNOC is obligated, within 30 days of the closing date of the transaction, to make an offer to re-purchase these securities from their holders at a price of 101% of the principal amount plus accrued and unpaid interest. Should a competitive bid arise, the Arrangement Agreement provides KNOC with five days to match the competing offer and if the transaction does not proceed, Harvest is required, in certain circumstances, to pay KNOC $100 million in damages. This transaction will be completed by way of a plan of arrangement under the Business Corporations Act (Alberta).

Cash flow from operating activities of $99.0 million in the Third Quarter of 2009 is comprised of contributions of $116.8 million and $11.9 million from the Upstream and Downstream operations, respectively, plus $8.0 million of net cash receipts from our price risk management activities less $26.3 million of financing and other costs. Compared to the $133.5 million cash flow from operating activities reported in 2008, the $34.5 million decrease is attributed to a $179.6 million drop in contribution from the Upstream operations and a $35.3 million drop in cash flow provided by our Downstream operations offset by a $102.5 million favourable change in the cash settlements of our price risk management contracts.

Cash flow provided by our Upstream operations totaled $116.8 million during the Third Quarter of 2009, relatively unchanged from the $121.1 million reported in the prior quarter and a decrease of $179.7 million compared to the $296.5 million reported in the Third Quarter of 2008. As expected, our financial performance is heavily influenced by the West Texas Intermediate benchmark price which averaged US$68.30 during the Third Quarter of 2009 as compared to US$59.62 in the Second Quarter of 2009 and US$117.98 in the Third Quarter of the prior year. Our Third Quarter production of 50,368 boe/d was 5% lower than the 52,745 boe/d produced in the Second Quarter of 2009 and 8% lower than in the Third Quarter of the prior year due to declines in production as a result of reduced investment during 2009. Operating costs of $13.02/boe, as compared to $14.51/boe in the Third Quarter of 2008, reflect a 21% per boe reduction in power costs attributed to lower prices in Alberta and a 17% per boe reduction in well servicing and internal labour costs. Our netback for the Third Quarter of 2009 was $27.24/boe as compared to $60.38/boe in the Third Quarter of the prior year a result of reduced commodity prices. Capital spending of $12.5 million focused on the tie-in and completion of wells drilled earlier in the year as well as the drilling of 3 wells in the quarter. On August 11, 2009, we closed our acquisition of Pegasus Oil and Gas Inc ("Pegasus")., a natural gas weighted producer with approximately 650 boe/d of production, with the issuance of 670,288 Trust Units and the assumption of $13.9 million of bank indebtedness. The principal asset of Pegasus is a 7% working interest in a liquids rich natural gas property in the Crossfield area which is operated by Harvest.

During the Third Quarter, the Downstream operations averaged 102,940 bbl/d of throughput following the completion of a significant turnaround in the Second Quarter of this year. Our Downstream cash flow of $11.9 million was $35.3 million less than in the Third Quarter of the prior year and reflects an average refining margin of US$5.37/bbl of throughput which is a drop of US$5.10/bbl from the prior year and results in a $43.6 million drop in the aggregate gross refining margin. While our operating costs were relatively unchanged at $22.5 million for the quarter, our costs for purchased energy and marketing expenses were $3.6 million and $4.9 million lower than in the prior year, respectively. Throughout 2009, our refining margins have been significantly impacted by the deterioration in distillate crack spreads and a tightening of the quality discounts of our feedstock despite the improvement in heavy fuel oil margins and lower costs for purchased energy and power. Included in the Downstream gross margin and cash from operations are US$9.8 million and US$67.0 million of operational hedging gains for the three and nine months ended September 30, 2009, respectively, generated by the month-to-month hedging of the WTI price component of our crude oil feedstock purchase commitments.

During the Third Quarter, we repaid $59.6 million of bank borrowings with cash flow from operating activities and assumed $13.9 million of debt with our acquisition of Pegasus. At the end of the Third Quarter, our bank borrowings totaled $1,050.9 million reflecting our reduced capital spending and monthly distributions to Unitholders of $0.05 per Trust Unit. Our Third Quarter 2009 monthly distributions of $0.05 per Trust Unit represents 27% of our cash from operating activities as compared to a monthly distribution of $0.30 per Trust Unit and 104% of cash from operating activities in the Third Quarter of the prior year. Subsequent to the payment of $0.05 per Trust Unit to Unitholders on November 16, 2009, there will be no further distributions declared prior to the Special Meeting of the Unitholders scheduled for December 15, 2009 and effective with the October 21, 2009 announcement of the Arrangement Agreement with KNOC, our distribution re-investment programs have been suspended until further notice.

Business Segments

The following table presents selected financial information for our two business segments:

	Three Months Ended September 30					
	2009			2008		
(in $000s)	**Upstream**	**Downstream**	**Total**	Upstream	Downstream	Total
Revenue[1]	**191,126**	**800,728**	**991,854**	382,297	1,214,898	1,597,195
Earnings From Operations[2]	**(670,393)**	**(6,418)**	**(676,811)**	195,380	30,509	225,889
Cash From Operations[2]	**116,828**	**11,879**	**128,707**	296,465	47,165	343,630
Capital expenditures	**12,455**	**7,945**	**20,400**	69,098	17,199	86,297
Total assets[3]	**3,026,074**	**1,388,215**	**4,423,802**	3,982,397	1,670,107	5,659,227

	Nine Months Ended September 30					
	2009			2008		
(in $000s)	**Upstream**	**Downstream**	**Total**	Upstream	Downstream	Total
Revenue[1]	**543,433**	**1,742,513**	**2,285,946**	1,092,182	3,504,443	4,596,625
Earnings From Operations[2]	**(712,153)**	**(150,221)**	**(862,374)**	507,059	22,556	529,615
Cash From Operations[2]	**309,223**	**115,052**	**424,275**	837,047	73,016	910,063
Capital expenditures	**154,556**	**34,778**	**189,334**	188,337	31,845	220,182
Total assets[3]	**3,026,074**	**1,388,215**	**4,423,802**	3,982,397	1,670,107	5,659,227

(1) Revenues are net of royalties.
(2) This is a non-GAAP measure; please refer to “Non-GAAP Measures” in this MD&A.
(3) Total assets on a consolidated basis as September 30, 2009 include $9.5 million (2008 - $6.7 million) relating to the fair value of risk management contracts.

Our Upstream and Downstream operations are each discussed separately in the sections that follow. Additionally, we have included a section entitled “Risk Management, Financing and Other” that discusses, among other things, our cash flow risk management program.

UPSTREAM OPERATIONS

Third Quarter Highlights

- Third Quarter 2009 operating cash flow of $116.8 million, as compared to $296.5 million in the prior year, reflecting a year-over-year drop in commodity prices as well as lower production due to reduced capital spending and normal decline.
- Average production of 50,368 boe/d during the Third Quarter of 2009 as compared to production of 54,926 boe/d in the Third Quarter of 2008 and 52,745 boe/d during the Second Quarter of 2009 reflecting normal decline rates and the impact of reduced capital spending.
- Third Quarter 2009 operating netback of $27.24/boe, representing a $33.14/boe (55%) drop over the same period in the prior year, attributed to substantially lower commodity prices.

Summary of Financial and Operating Results

	Three Months Ended September 30			**Nine Months Ended September 30**		
(in $000s except where noted)	**2009**	2008	Change	**2009**	2008	Change
Revenues	**226,920**	455,565	(50%)	**631,955**	1,304,664	(52%)
Royalties	**(35,794)**	(73,268)	(51%)	**(88,522)**	(212,482)	(58%)
Net revenues	**191,126**	382,297	(50%)	**543,433**	1,092,182	(50%)
Operating expenses	**60,330**	73,314	(18%)	**196,982**	218,729	(10%)
General and administrative	**10,006**	2,148	366%	**26,274**	26,766	(2%)
Transportation and marketing	**4,569**	3,855	19%	**11,085**	10,232	8%
Depreciation, depletion, amortization and accretion	**109,002**	107,600	1%	**343,633**	329,396	4%
Goodwill impairment	**677,612**	-	100%	**677,612**	-	100%
Earnings (Loss) From Operations[(1)]	**(670,393)**	195,380	(443%)	**(712,153)**	507,059	(240%)
Cash capital expenditures (excluding acquisitions)	**12,455**	69,098	(82%)	**154,556**	188,337	(18%)
Property and business acquisitions, net of dispositions	**(766)**	132,130	(101%)	**(61,494)**	127,581	(148%)
Daily sales volumes						
Light to medium oil (bbl/d)	**22,793**	25,210	(10%)	**23,775**	25,362	(6%)
Heavy oil (bbl/d)	**10,066**	11,485	(12%)	**10,520**	12,182	(14%)
Natural gas liquids (bbl/d)	**2,648**	2,627	1%	**2,719**	2,575	6%
Natural gas (mcf/d)	**89,163**	93,628	(5%)	**92,284**	96,394	(4%)
Total (boe/d)	**50,368**	54,926	(8%)	**52,395**	56,184	(7%)

(1) This is a non-GAAP measure; please refer to “Non-GAAP Measures” in this MD&A.

Commodity Price Environment

	Three Months Ended September 30			**Nine Months Ended September 30**		
Benchmarks	**2009**	2008	Change	**2009**	2008	Change
West Texas Intermediate crude oil (US$ per barrel)	**68.30**	117.98	(42%)	**57.00**	113.29	(50%)
Edmonton light crude oil ($ per barrel)	**71.60**	121.59	(41%)	**62.36**	114.94	(46%)
Bow River blend crude oil ($ per barrel)	**64.98**	105.12	(38%)	**57.01**	95.74	(40%)
AECO natural gas daily ($ per mcf)	**2.94**	7.74	(62%)	**3.77**	8.62	(56%)
Canadian / U.S. dollar exchange rate	**0.911**	0.960	(5%)	**0.858**	0.982	(13%)

The average WTI benchmark price in the Third Quarter 2009 of US$68.30 was 15% higher than in the Second Quarter of 2009, which was greater than the increase in the average Edmonton light crude oil price (“Edmonton Par”) of 9% due to the 6% appreciation in the Canadian dollar. For the three and nine months ended September 30, 2009, the average WTI benchmark price was 42% and 50% lower, respectively, as compared to the prior year. Edmonton Par also decreased significantly, resulting in a Third Quarter 2009 price of $71.60, a decrease of 41% compared to the prior year and an average price of $62.36 for the nine months ended September 30, 2009, a decrease of 46% compared to the prior year. The decrease in the Edmonton Par benchmark price has been less than that of the WTI benchmark price due to the relative weakening of the Canadian dollar relative to the U.S. dollar.

Heavy oil differentials fluctuate based on a combination of factors including the level of heavy oil inventories, pipeline capacity to deliver heavy crude to U.S. markets and the seasonal demand for heavy oil. During the three and nine months ended September 30, 2009, the Bow River heavy oil differential relative to Edmonton Par averaged $6.62/bbl and $5.35/bbl, respectively, as compared $16.47/bbl and $19.20/bbl, respectively, in the prior year. On a per barrel basis, heavy oil differentials have tightened in 2009 as production shortfalls and increased refinery demand for heavier grades of oil put upward pressure on pricing.

	2009			2008				2007
Differential Benchmarks	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1	Q4
Bow River Blend differential to Edmonton Par ($/bbl)	**6.62**	**3.91**	**5.50**	14.07	16.47	21.50	19.63	29.51
Bow River Blend differential as a % of Edmonton Par	**9.2%**	**5.9%**	**11.1%**	22.2%	13.5%	17.1%	20.2%	34.2%

Compared to the prior year, the average AECO daily natural gas price was 62% and 56% lower during the three and nine months ended September 30, 2009, respectively, due to increased storage levels and decreased economic activity which has led to a decline in industrial consumption.

Realized Commodity Prices (1)

The following table summarizes our average realized price by product for the three and nine months ended September 30, 2009 and 2008.

	Three Months Ended September 30			**Nine Months Ended September 30**		
	2009	2008	Change	**2009**	2008	Change
Light to medium oil ($/bbl)	**64.57**	110.70	(42%)	**54.25**	102.15	(47%)
Heavy oil ($/bbl)	**58.57**	99.21	(41%)	**49.96**	87.75	(43%)
Natural gas liquids ($/bbl)	**44.71**	88.17	(49%)	**42.71**	85.16	(50%)
Natural gas ($/mcf)	**3.22**	8.44	(62%)	**4.15**	9.16	(55%)
Average realized price ($/boe)	**48.97**	90.15	(46%)	**44.18**	84.75	(48%)

(1) Realized commodity prices exclude the impact of price risk management activities.

Our realized price for light to medium oil sales decreased by $46.13/bbl (42%) in the Third Quarter of 2009 as compared to the prior year, reflecting the $49.99/bbl (41%) decrease in Edmonton Par pricing. During the nine months ended September 30, 2009, our realized price for light to medium oil sales decreased by $47.90/bbl (47%) as compared to the prior year reflecting the $52.58/bbl (46%) decrease in Edmonton Par Pricing.

Harvest's heavy oil price decreased by $40.64/bbl (41%) in the Third Quarter of 2009 as compared to the prior year, reflecting the $40.14/bbl (38%) decrease in the Bow River price. During the nine months ended September 30, 2009, our realized price for heavy oil decreased by $37.79/bbl (43%) as compared to the prior year reflecting the $38.73/bbl (40%) decrease in the Bow River price.

Our average realized price for our natural gas production decreased by $5.22/mcf (62%) in the Third Quarter of 2009 as compared to the prior year, reflecting the $4.80/mcf (62%) decrease in the AECO daily price. During the nine months ended September 30, 2009, our realized price for natural gas decreased by $5.01/mcf (55%), reflecting the $4.85/mcf (56%) decrease in the AECO daily price.

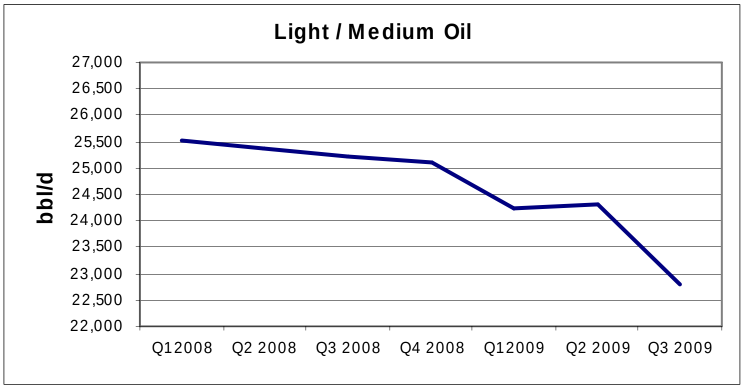
Sales Volumes

The average daily sales volumes by product were as follows:

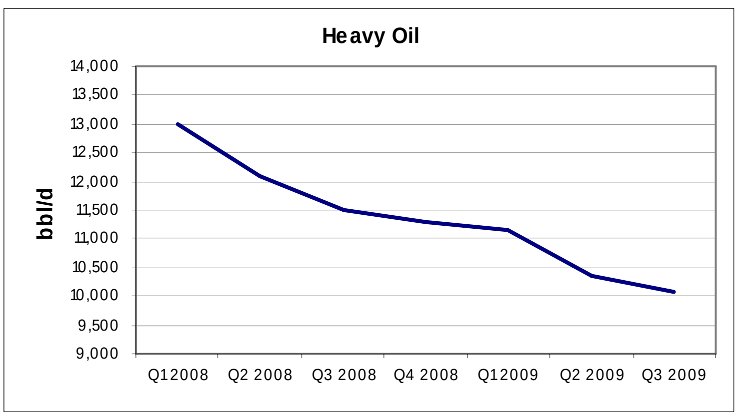
	Three Months Ended September 30				
	2009		2008		
	Volume	**Weighting**	Volume	Weighting	% Volume Change
Light to medium oil (bbl/d)(1)	**22,793**	**45%**	25,210	46%	(10%)
Heavy oil (bbl/d)	**10,066**	**20%**	11,485	21%	(12%)
Natural gas liquids (bbl/d)	**2,648**	**5%**	2,627	5%	1%
Total liquids (bbl/d)	**35,507**	**70%**	39,322	72%	(10%)
Natural gas (mcf/d)	**89,163**	**30%**	93,628	28%	(5%)
Total oil equivalent (boe/d)	**50,368**	**100%**	54,926	100%	(8%)

	Nine Months Ended September 30				
	2009		2008		
	Volume	**Weighting**	Volume	Weighting	% Volume Change
Light to medium oil (bbl/d)[1]	**23,775**	**45%**	25,362	45%	(6%)
Heavy oil (bbl/d)	**10,520**	**20%**	12,182	22%	(14%)
Natural gas liquids (bbl/d)	**2,719**	**5%**	2,575	5%	6%
Total liquids (bbl/d)	**37,014**	**70%**	40,119	72%	(8%)
Natural gas (mcf/d)	**92,284**	**30%**	96,394	28%	(4%)
Total oil equivalent (boe/d)	**52,395**	**100%**	56,184	100%	(7%)

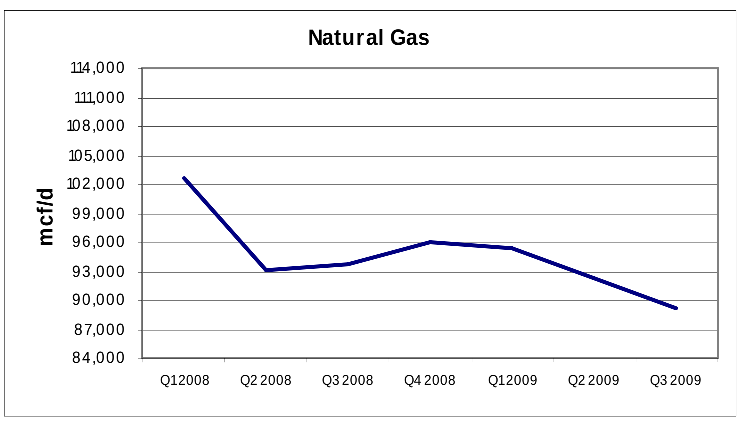
(1) Harvest classifies our oil production, except that produced from Hay River, as light to medium and heavy according to NI 51-101 guidance. The oil produced from Hay River has an average API of 24° (medium grade) and is classified as a light to medium oil, notwithstanding that, it benefits from a heavy oil royalty regime and therefore would be classified as heavy oil according to NI 51-101.



Harvest's Third Quarter 2009 light to medium oil production was 22,793 bbl/d, a 2,417 bbl/d or 10% reduction from the prior year. Relative to the Second Quarter of 2009, our Third Quarter light to medium oil production decreased by 1,523 bbl/d or 6%. Production in the Third Quarter of 2009 was impacted by downtime at Hay River, our largest production area, due to disruptions in pipeline service which were not fully mitigated with short term trucking arrangements. The reduction in light to medium oil production for the three and nine months ended September 30, 2009 of 10% and 6%, respectively, as compared to the prior year is largely the result of normal decline and reduced capital spending.



During the Third Quarter of 2009, our heavy oil production averaged 10,066 bbl/d, a 1,419 bbl/d or 12% decrease from the prior year. Relative to the Second Quarter of 2009, our Third Quarter heavy oil production decreased by 299 bbl/d or 3%, mainly due to downtime for servicing work at Lloydminster and a reduced level of capital spending. The reduction in heavy oil production for the three and nine months ended September 30, 2009 of 12% and 14%, respectively, as compared to the prior year is largely the result of normal decline, increased water cuts on our larger producing wells in the west central Saskatchewan and Lloydminster areas, and reduced spending on our heavy oil properties due to weak commodity prices.



Natural gas production averaged 89,163 mcf/d in the Third Quarter of 2009, a 4,465 mcf/d or 5% reduction from the prior year. Relative to the Second Quarter of 2009, our Third Quarter natural gas production decreased by 3,172 mcf/d or 3%, primarily due the divestment of approximately 5,000 mcf/d at Channel Lake in the Second Quarter partially offset by the acquisition of Pegasus in August 2009. The reduction in natural gas production for the three and nine months ended September 30, 2009 of 5% and 4%, respectively, as compared to the same period in the prior year is mainly due to natural declines and reduced capital spending.

Revenues

	Three Months Ended September 30			Nine Months Ended September 30		
(000s)	**2009**	2008	Change	**2009**	2008	Change
Light to medium oil sales	**$ 135,394**	$ 256,744	(47%)	**$ 352,119**	$ 709,825	(50%)
Heavy oil sales	**54,240**	104,826	(48%)	**143,487**	292,883	(51%)
Natural gas sales	**26,395**	72,690	(64%)	**104,644**	241,873	(57%)
Natural gas liquids sales and other	**10,891**	21,305	(49%)	**31,705**	60,083	(47%)
Total sales revenue	**226,920**	455,565	(50%)	**631,955**	1,304,664	(52%)
Royalties	**(35,794)**	(73,268)	(51%)	**(88,522)**	(212,482)	(58%)
Net revenues	**$ 191,126**	$ 382,297	(50%)	**$ 543,433**	$ 1,092,182	(50%)

Our revenue is impacted by changes to production volumes, commodity prices and currency exchange rates. Our total sales revenue for the three months ended September 30, 2009 of $226.9 million is $228.6 million lower than the same period of the prior year, of which $187.8 million is attributed to lower realized prices and $40.8 million is attributed to lower production volumes. The price decrease reflects the 41% decrease in Edmonton Par pricing and the 62% decrease in AECO daily natural gas pricing in the Third Quarter of 2009 as compared to 2008, while our decreased production volumes are attributed to natural decline rates and reduced capital spending. Our revenues were also impacted by the relative weakening in the Canadian dollar, which resulted in a favourable variance of approximately $11.6 million. For the nine months ended September 30, 2009, our total sales revenue of $632.0 million is $672.7 million lower than the same period of the prior year, of which $577.0 million is attributed to lower realized prices, as the Edmonton Par price decreased by 46% and the AECO daily natural gas price decreased by 56%, and $95.7 million is attributed to lower production.

As discussed earlier, light to medium oil sales revenue for the Third Quarter of 2009 was $121.3 million lower than the comparative period due to a $96.7 million unfavourable price variance and a $24.6 million unfavourable volume variance. For the nine months ended September 30, 2009, light to medium oil sales revenue was $357.7 million lower than the comparative period due to a $310.9 million unfavourable price variance and a $46.8 million unfavourable volume variance. Heavy oil sales revenue in the Third Quarter of 2009 was $50.6 million lower than in the prior year due to a $37.6 million unfavourable price variance and a $13.0 million unfavourable volume variance. For the nine months ended September 30, 2009, heavy oil revenue was $149.4 million lower than the comparative period due to a $108.5 million unfavourable price variance and a $40.9 million unfavourable volume variance. Natural gas sales revenue in the Third Quarter of 2009 was $46.3 million lower than in the prior year due to a $42.8 million unfavourable price variance and a $3.5 million unfavourable volume variance. For the nine months ended September 30, 2009, natural gas sales revenue was $137.2 million lower than the comparative period due to a $126.1 million unfavourable price variance and an $11.1 million unfavourable volume variance.

During the Third Quarter of 2009, natural gas liquids and other sales revenue decreased by $10.4 million compared to the prior year resulting from a $10.6 million unfavourable price variance offset by a $0.2 million favourable volume variance. For the nine months ended September 30, 2009, natural gas liquids and other sales revenue decreased by $28.4 million as compared to the prior year resulting from a $31.5 million unfavourable price variance offset by a $3.1 million favourable volume variance. Generally, the natural gas liquids volume variance will be aligned with our production of natural gas while the price variances will be aligned with the prices realized for our oil production. The positive volume variances for the three and nine months ended September 30, 2009, is attributed to a few natural gas wells drilled in 2008 and during the First Quarter of 2009 which yielded significant natural gas liquids.

Royalties

We pay Crown, freehold and overriding royalties to the owners of mineral rights from which production is generated. These royalties vary for each property and product and our Crown royalties are based on a sliding scale dependent on production volumes and commodity prices.

For the Third Quarter of 2009, net royalties as a percentage of gross revenue were 15.8% (2008 – 16.1%) and aggregated to $35.8 million (2008 - $73.3 million). For the nine months ended September 30, 2009, net royalties as a percentage of gross revenue were 14.0% (2008 – 16.3%) and aggregated to $88.5 million (2008 – $212.5 million). The decrease in our royalty rate for the three and nine months ended September 30, 2009 is due to reduced royalty rates in a lower commodity price environment as mandated by the Government of Alberta's New Royalty Framework.

Operating Expenses

	Three Months Ended September 30				
	2009		2008		Per BOE
(000s except per boe amounts)	**Total**	**Per BOE**	Total	Per BOE	Change
Operating expense					
Power and fuel	**$ 13,589**	**$ 2.93**	$ 18,622	$ 3.69	(21%)
Well servicing	**10,736**	**2.32**	14,126	2.80	(17%)
Repairs and maintenance	**9,892**	**2.13**	13,035	2.58	(17%)
Lease rentals and property taxes	**7,234**	**1.56**	6,548	1.30	20%
Processing and other fees	**4,030**	**0.87**	2,566	0.51	71%
Labour – internal	**5,101**	**1.10**	6,314	1.25	(12%)
Labour – contract	**3,412**	**0.74**	4,455	0.88	(16%)
Chemicals	**2,793**	**0.60**	3,040	0.60	-%
Trucking	**2,182**	**0.47**	2,664	0.53	(11%)
Other	**1,361**	**0.30**	1,944	0.37	(19%)
Total operating expense	**$ 60,330**	**$ 13.02**	$ 73,314	$ 14.51	(10%)
Transportation and marketing expense	**$ 4,569**	**$ 0.99**	$ 3,855	$ 0.76	30%

	Nine Months Ended September 30				
	2009		2008		Per BOE
(000s except per boe amounts)	**Total**	**Per BOE**	Total	Per BOE	Change
Operating expense					
Power and fuel	**$ 42,993**	**$ 3.01**	$ 59,755	$ 3.88	(22%)
Well servicing	**36,188**	**2.53**	37,285	2.42	5%
Repairs and maintenance	**32,184**	**2.25**	35,867	2.33	(3%)
Lease rentals and property taxes	**21,582**	**1.51**	21,160	1.37	10%
Processing and other fees	**12,503**	**0.87**	7,795	0.51	71%
Labour – internal	**16,695**	**1.17**	18,405	1.20	(3%)
Labour – contract	**11,650**	**0.81**	12,487	0.81	-%
Chemicals	**10,615**	**0.74**	12,273	0.80	(8%)
Trucking	**8,172**	**0.57**	8,371	0.54	6%
Other	**4,400**	**0.31**	5,331	0.35	(11%)
Total operating expense	**$ 196,982**	**$ 13.77**	$ 218,729	$ 14.21	(3%)
Transportation and marketing expense	**$ 11,085**	**$ 0.77**	$ 10,232	$ 0.66	17%

Third Quarter 2009 operating costs totaled $60.3 million, a decrease of $13.0 million as compared to the same period in the prior year primarily due to lower power and fuel, repairs and maintenance, and well servicing costs. On a per barrel basis, operating costs have decreased to $13.02/boe in the Third Quarter 2009 as compared to $14.51/boe during the same period in the prior year, a 10% decrease substantially attributed to reduced costs partially offset by lower production volumes. On a year-to-date basis, operating costs totaled $197.0 million, a decrease of $21.7 million as compared to the same period in the prior year. On a per barrel basis, year-to-date operating costs have decreased by 3% to $13.77/boe as lower power and fuel costs have been substantially offset by higher processing fees coupled with lower production volumes.

Power and fuel costs, comprised primarily of electric power costs, represented approximately 23% of our total operating costs during the Third Quarter of 2009. The average Alberta electric power price of $49.75/MWh in the Third Quarter of 2009 was 38% lower than the average price of $80.36/MWh in the Third Quarter of 2008. Similarly, the average Alberta electric power price for the first nine months of 2009 of $48.35/MWh was 45% lower than the same period in the prior year. However, the decrease is not fully reflected in our power and fuel costs during the three and nine months ending September 30, 2009 due to increased power consumption at Hay River as we began purchasing power from BC Hydro late in the First Quarter of 2008. Beginning in April 2009, we have electric power price risk management contracts on 10 MWh at an average price of $61.90 per MWh through December 2009, which has resulted in losses of $0.3 million and $0.9 million, respectively, for the three and nine months ended September 30, 2009 as compared to gains of $1.8 million and $7.0 million, respectively, in the prior year. The following table details the electric power costs per boe before and after the impact of our price risk management program.

	Three Months Ended September 30			Nine Months Ended September 30		
(per boe)	**2009**	2008	Change	**2009**	2008	Change
Electric power and fuel costs	**$ 2.93**	$ 3.69	(21%)	**$ 3.01**	$ 3.88	(22%)
Realized losses (gains) on electricity risk management contracts	**0.06**	(0.36)	(117%)	**0.06**	(0.45)	(113%)
Net electric power and fuel costs	**$ 2.99**	$ 3.33	(10%)	**$ 3.07**	$ 3.43	(10%)
Alberta Power Pool electricity price (per MWh)	**$ 49.75**	$ 80.36	(38%)	**$ 48.35**	$ 88.21	(45%)

For the three and nine months ended September 30, 2009, transportation and marketing expense increased to $4.6 million and $11.1 million, respectively, as compared to the prior year when transportation and marketing expense totaled $3.9 million and $10.2 million, respectively. The increase in transportation and marketing expense in the Third Quarter of 2009 relative to the same period in the prior year is primarily due to additional trucking costs at our Hay River property while the facilities were in turnaround and pipeline service was disrupted. Transportation and marketing costs relate primarily to delivery of natural gas to Alberta's natural gas sales hub, the AECO Storage Hub, and to a lesser extent, our costs of trucking clean crude oil to pipeline receipt points. As a result, the total dollar amount of costs fluctuates in relation with our natural gas production volumes while the cost per boe typically remains relatively constant.

Operating Netback

	Three Months Ended September 30		Nine Months Ended September 30	
(per boe)	**2009**	2008	**2009**	2008
Revenues	**$ 48.97**	$ 90.15	**$ 44.18**	$ 84.75
Royalties	**(7.72)**	(14.50)	**(6.19)**	(13.80)
Operating expense	**(13.02)**	(14.51)	**(13.77)**	(14.21)
Transportation and marketing expense	**(0.99)**	(0.76)	**(0.77)**	(0.66)
Operating netback[1]	**$ 27.24**	$ 60.38	**$ 23.45**	$ 56.08

[1] This is a non-GAAP measure; please refer to "Non-GAAP Measures" in this MD&A.

Harvest's operating netback represents the net amount realized on a per boe basis after deducting directly related costs. For the three and nine months ended September 30, 2009, our operating netback decreased by $33.14/boe and $32.63/boe, respectively, as compared to the prior year. The decreases are primarily attributed to lower realized commodity prices, reflecting the decrease in Edmonton Par, Bow River and AECO pricing, partially offset by a decrease in royalties.

General and Administrative ("G&A") Expense

	Three Months Ended September 30			Nine Months Ended September 30		
(000s except per boe)	**2009**	2008	Change	**2009**	2008	Change
Cash G&A	**$ 9,370**	$ 8,557	10%	**$ 25,969**	$ 25,344	2%
Unit based compensation expense (recovery)	**636**	(6,410)	(110%)	**305**	1,422	(79%)
Total G&A	**$ 10,006**	$ 2,148	366%	**$ 26,274**	$ 26,766	(2%)
Cash G&A per boe	**$ 2.02**	$ 1.69	20%	**$ 1.82**	$ 1.65	10%

For the three and nine months ended September 30, 2009, cash G&A costs increased by $0.8 million and $0.6 million, respectively, as compared to the same period in the prior year, primarily due to a $1.3 million reduction in capitalized G&A in the Third Quarter, due to the reduced capital activity, partially offset by cost reduction efforts made throughout 2009. Generally, approximately 75% of our cash G&A expenses are related to salaries and other employee related costs.

Our unit based compensation plans provide employees with the option of settling outstanding awards with cash. As a result, unit based compensation expense is determined using the intrinsic method, being the difference between the Trust Unit trading price and the strike price of the unit awards adjusted for the proportion that is vested. For the three months ended September 30, 2009, total unit based compensation expense increased by $7.0 million as compared to the same period in the prior year as the closing market price of our Trust Units increased by $0.64 in the Third Quarter of 2009 as compared to a decrease of $6.83 in the same period in the prior year. For the nine months ended September 30, 2009, total unit based compensation expense decreased $1.1 million as compared to the same period in the prior year as the market price of our Trust Units dropped by $3.53 in 2009, which was more than the drop of $2.71 realized in the same period in the prior year.

Depletion, Depreciation, Amortization and Accretion Expense

	Three Months Ended September 30			Nine Months Ended September 30		
(000s except per boe)	**2009**	2008	Change	**2009**	2008	Change
Depletion, depreciation and amortization	**$ 98,604**	$ 99,607	(1%)	**$ 311,654**	$ 305,231	2%
Depletion of capitalized asset retirement costs	**4,375**	3,295	33%	**13,864**	10,273	35%
Accretion on asset retirement obligation	**6,023**	4,698	28%	**18,115**	13,892	30%
Total depletion, depreciation, amortization and accretion	**$ 109,002**	$ 107,600	1%	**$ 343,633**	$ 329,396	4%
Per boe	**$ 23.52**	$ 21.29	10%	**$ 24.02**	$ 21.40	12%

Our overall depletion, depreciation, amortization and accretion ("DDA&A") expense for the three and nine months ended September 30, 2009 was $1.4 million and $14.2 million higher, respectively, compared to the prior year. The increase is attributed to higher accretion expense due to an increase in the asset retirement obligation balance quarter over quarter and slightly higher finding, development and acquisition costs that have increased our depletion rate, which was offset by lower production volumes.

Capital Expenditures

	Three Months Ended September 30		Nine Months Ended September 30	
(000s)	**2009**	2008	**2009**	2008
Land and undeveloped lease rentals	$ 1,675	$ 1,183	$ 2,863	$ 3,331
Geological and geophysical	-	1,523	1,252	5,470
Drilling and completion	2,113	45,349	73,964	118,635
Well equipment, pipelines and facilities	7,326	18,317	69,752	52,984
Capitalized G&A expenses	1,326	2,672	6,620	7,805
Furniture, leaseholds and office equipment	15	54	105	112
Development capital expenditures excluding acquisitions and non-cash items	12,455	69,098	154,556	188,337
Non-cash capital additions (recoveries)	130	(1,294)	22	61
Total development capital expenditures excluding acquisitions	$ 12,585	$ 67,804	$ 154,578	$ 188,398

Capital activity in the Third Quarter was modest. We drilled 1 gross (0.5 net) Bakken horizontal well in our southeast Saskatchewan area and completed a number of tie-ins relating to both our Second Quarter and Third Quarter drilling activity.

The following summarizes Harvest's participation in gross and net wells drilled during the three months ended September 30, 2009:

	Total Wells		Successful Wells		Abandoned Wells	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Hay River	-	-	-	-	-	-
Southeast Saskatchewan	1.0	0.5	1.0	0.5	-	-
Southeast Alberta	-	-	-	-	-	-
Red Earth	-	-	-	-	-	-
Suffield	-	-	-	-	-	-
Lloydminster/Hayter	-	-	-	-	-	-
Rimbey	1.0	0.1	1.0	0.1	-	-
Markerville	-	-	-	-	-	-
Northwest Alberta	-	-	-	-	-	-
Other Areas	1.0	0.1	1.0	0.1	-	-
Total	3.0	0.7	3.0	0.7	-	-

The following summarizes Harvest's participation in gross and net wells drilled during the nine months ended September 30, 2009:

	Total Wells		Successful Wells		Abandoned Wells	
Area	Gross(1)	Net	Gross	Net	Gross	Net
Hay River	43.0	43.0	43.0	43.0	-	-
Southeast Saskatchewan	5.0	4.0	5.0	4.0	-	-
Southeast Alberta	25.0	11.5	25.0	11.5	-	-
Red Earth	1.0	1.0	1.0	1.0	-	-
Suffield	1.0	1.0	1.0	1.0	-	-
Lloydminster/Hayter	-	-	-	-	-	-
Rimbey	11.0	3.7	11.0	3.7	-	-
Markerville	-	-	-	-	-	-
Northwest Alberta	-	-	-	-	-	-
Other Areas	2.0	1.0	2.0	1.0	-	-
Total	88.0	65.2	88.0	65.2	-	-

(1) Excludes 1 additional well that we have an overriding royalty interest in.

Asset Retirement Obligation ("ARO")

In connection with property acquisitions and development expenditures, we record the fair value of the ARO as a liability in the same year the expenditures occur. The associated asset retirement costs are capitalized as part of the carrying amount of the assets and are depleted and depreciated over our estimated net proved reserves. Once the initial ARO is measured, it is adjusted at the end of each period to reflect the passage of time as well as changes in the estimated future cash flows of the underlying obligation. Our asset retirement obligation increased by $8.8 million during the first nine months of 2009 as a result of accretion expense of $18.1 million and new liabilities recorded of $1.9 million, offset by $8.7 million of asset retirement expenditures and net dispositions of $2.5 million.

Acquisitions and Divestitures

During the Second Quarter, we closed the sale of two non-operated properties with net proceeds of approximately $63 million. The sale of our natural gas interests in Channel Lake for $43 million resulted in a disposition metric of approximately $53,000 per boe based on its current production of 4,860 mcf/d and approximately $2.30 per mcf based on proved plus probable reserves of approximately 19 bcf. Our sale of certain non-operated interests in the Pembina area for $20 million resulted in a disposition metric of approximately $94,800 per boe based on its current production of 211 boe/d (weighted 70% light oil and natural gas liquids and 30% natural gas) and approximately $13.00 per boe based on proved plus probable reserves of 1,520 mboe. The net proceeds were applied to reduce our bank borrowings.

On August 11, 2009, we acquired approximately 93.5% of the issued and outstanding class A shares and 90.6% of the issued and outstanding class B shares of Pegasus Oil and Gas Inc. ("Pegasus"), a natural gas weighted producer with approximately 650 boe/d of production, in exchange for Trust Units. Subsequent to August 11, 2009 and pursuant to the compulsory acquisition provisions of the Business Corporations Act (Alberta), we purchased the remaining Pegasus shares and de-listed the Pegasus Shares from the TSX Venture Exchange. Including the obligation to assume approximately $13.9 million of bank debt, the acquisition metrics were approximately $30,000 per boe/d of production and approximately $4.25 per boe of reserves on a proved plus probable basis. The principal asset in this acquisition is a 7% working interest in liquids rich natural gas production from a property in the Crossfield area which is operated by Harvest. This potential acquisition includes access to over 150,000 acres of land and over $50 million of income tax pools. The President and Chief Executive Officer of Harvest as well as two Directors of Harvest each held a nominal number of shares in Pegasus.

Goodwill

We assess goodwill for impairment annually, or more frequently if events or changes in circumstances warrant. At September 30, 2009, it was determined that an impairment test was required for the Upstream reporting unit due to the reasonable expectation that a significant portion, or all, of the reporting unit would be sold. The Arrangement Agreement with KNOC has been considered to be an indication of the fair value of the issued and outstanding Trust Units of Harvest from which a fair value of the Upstream reporting unit could be reasonably determined. Based on this, it was determined that the fair value of the Upstream reporting unit was below its carrying value as at September 30, 2009, indicating a potential impairment. Subsequently, the fair value of the Upstream goodwill was determined by valuing the reporting unit's net assets in the same manner as allocating a purchase price in a business combination. It was determined that the goodwill associated with the Upstream reporting unit was fully impaired and a charge of $677.6 million was recorded at September 30, 2009.

DOWNSTREAM OPERATIONS

Third Quarter Highlights

- During the Third Quarter of 2009, Downstream refining gross margin averaged US$5.37/bbl reflecting a US$5.10/bbl decrease over the prior year mainly due reduced margins on distillate products and lower discounts on our feedstock purchases, partially offset by improved margins on high sulphur fuel oil (“HSFO”) and gasoline products, all relative to the WTI benchmark price.

- During the Third Quarter of 2009, the operational hedging of the WTI component of our feedstock costs through the Supply and Offtake Agreement resulted in a US$9.8 million reduction in our feedstock costs (US$1.03/bbl of throughput). Further, the weakening of the Canadian dollar relative to the U.S. dollar in the Third Quarter of 2009 as compared to the Third Quarter of 2008, added $5.6 million to our gross margin in 2009 as our U.S. dollar denominated margins are translated to Canadian dollars.

- During the Third Quarter of 2009, refining operating costs averaged $1.85/bbl of throughput as compared to $2.02/bbl in the prior year, while the cost of purchased energy averaged $3.21/bbl of throughput in the Third Quarter of 2009 as compared to $3.72/bbl in the prior year, reflecting a lower commodity price environment.

- Capital expenditures totaled $7.9 million during the quarter including $4.6 million related to debottlenecking projects.

Summary of Financial and Operational Results

	Three Months Ended September 30			Nine Months Ended September 30		
(in $000's except where noted below)	**2009**	2008	Change	**2009**	2008	Change
Revenues	**800,728**	1,214,898	(34%)	**1,742,513**	3,504,443	(50%)
Purchased feedstock for processing and products purchased for resale	**731,872**	1,099,963	(33%)	**1,436,564**	3,220,513	(55%)
Gross margin[1]	**68,856**	114,935	(40%)	**305,949**	283,930	8%
Costs and expenses						
Operating expense	**22,483**	23,357	(4%)	**73,423**	74,868	(2%)
Purchased energy expense	**30,385**	33,958	(11%)	**58,153**	106,985	(46%)
Turnaround and catalyst expense	**-**	1,011	(100%)	**47,487**	1,011	4,597%
Marketing expense	**3,617**	8,560	(58%)	**9,718**	26,558	(63%)
General and administrative expense	**490**	345	42%	**1,365**	1,514	(10%)
Depreciation and amortization expense	**18,299**	17,195	6%	**59,559**	50,438	18%
Goodwill impairment	**-**	-	-	**206,465**	-	100%
Earnings (Loss) From Operations[1]	**(6,418)**	30,509	(121%)	**(150,221)**	22,556	(766%)
Cash capital expenditures	**7,945**	17,199	(54%)	**34,778**	31,845	9%
Feedstock volume (bbl/day)[2]	**102,940**	99,127	4%	**86,677**	103,832	(17%)
Yield (000's barrels)						
Gasoline and related products	**3,318**	2,757	20%	**8,011**	8,801	(9%)
Ultra low sulphur diesel and jet fuel	**3,942**	3,985	(1%)	**9,266**	12,001	(23%)
High sulphur fuel oil	**2,387**	2,348	2%	**5,940**	7,448	(20%)
Total	**9,647**	9,090	6%	**23,217**	28,250	(18%)
Average refining gross margin (US$/bbl)[3]	**5.37**	10.47	(49%)	**9.77**	8.38	17%

(1) These are non-GAAP measures; please refer to "Non-GAAP Measures" in this MD&A.
(2) Barrels per day are calculated using total barrels of crude oil feedstock and vacuum gas oil.
(3) Average refining gross margin is calculated based on per barrel of feedstock throughput.

Refining Benchmark Prices

The following average benchmark prices and currency exchange rates are the reference points from which we discuss our refinery's financial performance:

	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	Change	**2009**	2008	Change
WTI crude oil (US$/bbl)	**68.30**	117.98	(42%)	**57.00**	113.29	(50%)
Brent crude oil (US$/bbl)	**69.01**	116.87	(41%)	**58.15**	111.07	(48%)
Basrah Official Sales Price Discount (US$/bbl)	**(2.90)**	(6.70)	(57%)	**(2.84)**	(7.52)	(62%)
RBOB gasoline (US$/bbl/gallon)	**78.05/1.86**	123.91/2.95	(37%)	**67.35/1.60**	120.57/2.87	(44%)
Heating Oil (US$/bbl/gallon)	**74.30/1.77**	138.66/3.30	(46%)	**65.37/1.56**	134.13/3.19	(51%)
High Sulphur Fuel Oil (US$/bbl)	**62.74**	96.03	(35%)	**50.22**	83.75	(40%)
Canadian / U.S. dollar exchange rate	**0.911**	0.960	(5%)	**0.858**	0.982	(13%)

During the Third Quarter of 2009, the Heating Oil crack spread averaged US$6.00/bbl, an increase of US$0.29/bbl over the Second Quarter of 2009 and a decrease of US$14.68/bbl over the US$20.68/bbl averaged in the Third Quarter of the prior year. The RBOB Gasoline crack spread averaged US$9.75/bbl in the Third Quarter of 2009, a decrease of US$2.50/bbl from the Second Quarter of 2009 and US$3.82/bbl higher than the US$5.93/bbl averaged in the Third Quarter of the prior year, as North American refinery output was curtailed to balance weak demand. The HSFO price averaged US$5.56/bbl less than WTI in the Third Quarter of 2009, an improvement of US$3.13/bbl over the Second Quarter of 2009 and an improvement of US$16.39/bbl over the same period in the prior year, all relative to the WTI benchmark price. Similarly, for the nine months ended September 30, 2009, as compared to the same period in the prior year, the Heating Oil crack spread decreased by US$12.47/bbl to US$8.37/bbl, the RBOB Gasoline crack spread increased by US$3.07/bbl to US$10.35/bbl, and the HSFO price relative to WTI improved by US$22.76/bbl to US$6.78/bbl less WTI.

During the three and nine months ended September 30, 2009, the Canadian/U.S. dollar exchange rate averaged 0.911 and 0.858, respectively, as compared to 0.960 and 0.982, respectively, in the prior year. The weakening of the Canadian dollar in 2009 has improved the contribution from our Downstream operations as substantially all of its gross margin, cost of purchased energy and marketing expense are denominated in U.S. dollars. The net impact of a weakening Canadian dollar increased our refining gross margin by $5.6 million in the Third Quarter as compared to the prior year.

Summary of Gross Margin

The following table summarizes our Downstream gross margin for the three and nine months ended September 30, 2009 and 2008 segregated between refining activities and petroleum marketing and other related businesses.

	Three Months Ended September 30					
	2009			2008		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	Refining	Marketing	Total
Sales revenue(1)	**774,781**	**137,118**	**800,728**	1,187,890	220,402	1,214,898
Cost of feedstock for processing and products for resale(1)	**718,937**	**124,106**	**731,872**	1,088,455	204,902	1,099,963
Gross margin(2)	**55,844**	**13,012**	**68,856**	99,435	15,500	114,935
Average refining gross margin (US$/bbl)	**5.37**			10.47		

	Nine Months Ended September 30					
	2009			2008		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	Refining	Marketing	Total
Sales revenue(1)	**1,675,840**	**340,627**	**1,742,513**	3,425,471	544,698	3,504,443
Cost of feedstock for processing and products for resale(1)	**1,406,375**	**304,143**	**1,436,564**	3,182,804	503,435	3,220,513
Gross margin(2)	**269,465**	**36,484**	**305,949**	242,667	41,263	283,930
Average refining gross margin (US$/bbl)	**9.77**			8.38		

(1) Downstream sales revenue and cost of products for processing and resale are net of intra-segment sales of $111.2 million and $274.0 million for the three and nine months ended September 30, 2009 ($193.4 million and $465.7 million – three and nine months ended September 30, 2008) reflecting the refined products produced by the refinery and sold by the Marketing Division.

(2) This is a non-GAAP measure; please refer to "Non-GAAP Measures" in this MD&A.

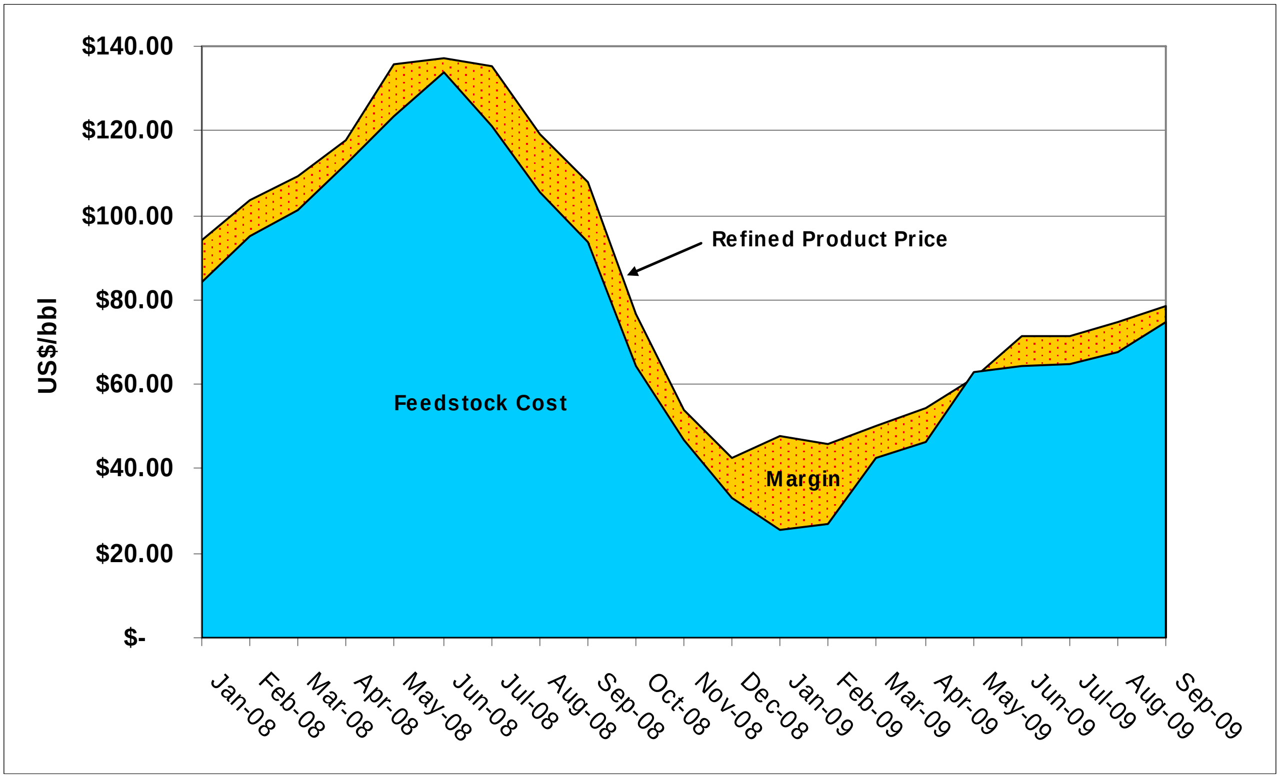
For the three months ended September 30, 2009, our refining gross margin was $55.8 million, an increase of $19.5 million as compared to the Second Quarter of 2009 and a decrease of $43.6 million as compared to the Third Quarter of the prior year. Compared to the same quarter in 2008, our 2009 Third Quarter refining margin decreased by 44%, primarily due to a reduction in the Heating Oil benchmark crack spread of US$14.68 or 71%, coupled with a US$9.87/bbl (87%) reduction in our feedstock discount, partially offset by a US$16.39/bbl (75%) improvement in the HSFO benchmark crack spread and a US$9.8 million operational hedging gain on our feedstock purchases.

For the nine months ended September 30, 2009, our refining gross margin was $269.5 million as compared to $242.7 million in the prior year, an increase of $26.8 million. The increase in refining gross margin is primarily due to a US$22.76/bbl improvement in the HSFO benchmark crack spread, a US$3.07/bbl improvement in the RBOB gasoline benchmark crack spread, a US$67.0 million operational hedging gain on our feedstock purchases, and the translation of our U.S. dollar denominated gross margin to Canadian dollars in light of the weaker Canadian dollar. These factors were partially offset by a US$12.47/bbl decrease in the Heating Oil benchmark crack spread and a reduction in throughput primarily due to a significant planned turnaround in the Second Quarter of 2009. The reduction in throughput resulted in an unfavourable volume variance of $40.9 million while the net impact of the changes in refined product and feedstock prices resulted in a favourable price variance of $67.5 million, of which $29.2 million relates to the change in the Canadian/U.S. dollar exchange rate.

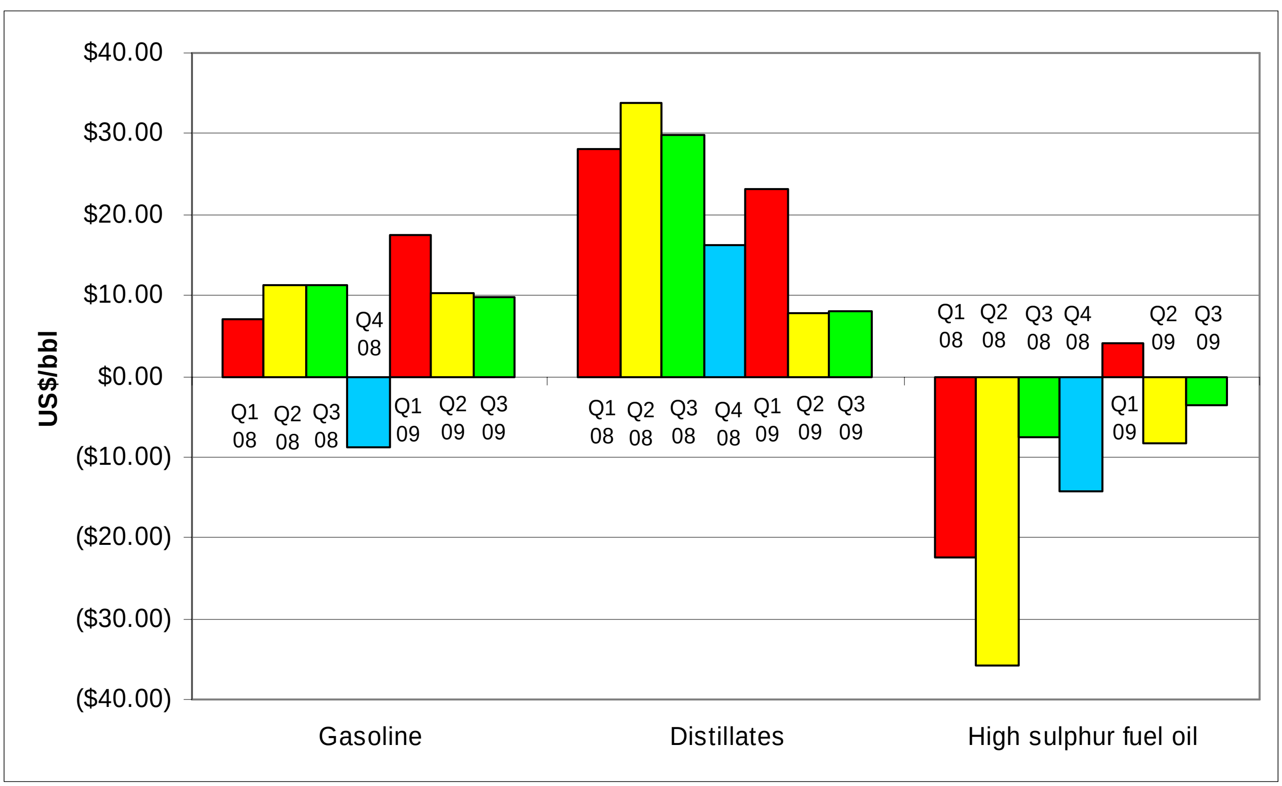
For the three and nine months ended September 30, 2009, our marketing division earned a gross margin of $13.0 million and $36.5 million, respectively, as compared to $15.5 million and $41.3 million, respectively, in the prior year. The decrease for the three and nine months ended September 30, 2009 of 16% and 12% respectively, compared to the prior year is primarily due to reduced margins on sulphur sales.

Refining Gross Margin

The following graph summarizes our average refining gross margin relative to the cost of feedstock for the period of January 2008 to September 2009:



The following chart summarizes our refining gross margin by refined product over the same time period by quarter:



Refinery Sales Revenue

Our refinery sales revenue is dependent on the selling price as well as the yield of refined products produced from the crude oil and other feedstocks processed. Although our yield can be altered slightly by adjusting refinery operations to react to market conditions and seasonal demand, product yields are primarily impacted by the type of crude oil feedstock processed and refinery performance. A comparison of our refinery yield, product pricing and revenue for the three and nine months ended September 30, 2009 and 2008 is presented below:

	Three Months Ended September 30					
		2009			2008	
	Refinery Revenues	**Volume**	**Sales Price[1]**	Refinery Revenues	Volume	Sales Price[1]
	(000's of Cdn $)	(000s of bbls)	(US$ per bbl/ US$ per US gal)	(000's of Cdn $)	(000s of bbls)	(US$ per bbl/ US$ per US gal)
Gasoline products	**292,873**	**3,485**	**76.56/1.82**	408,292	3,329	117.74/2.80
Distillates	**320,659**	**3,905**	**74.81/1.78**	545,610	3,841	136.37/3.25
High sulphur fuel oil	**161,249**	**2,329**	**63.07**	233,988	2,267	99.09
	774,781	**9,719**	**72.62**	1,187,890	9,437	120.84
Inventory adjustment		**(72)**			(347)	
Total production		**9,647**			9,090	
Yield (as a % of Feedstock) [2]		**102%**			100%	

	Nine Months Ended September 30					
		2009			2008	
	Refinery Revenues	**Volume**	**Sales Price[1]**	Refinery Revenues	Volume	Sales Price[1]
	(000's of Cdn $)	(000s of bbls)	(US$ per bbl/ US$ per US gal)	(000's of Cdn $)	(000s of bbls)	(US$ per bbl/ US$ per US gal)
Gasoline products	**628,233**	**8,426**	**63.97/1.52**	1,130,160	9,567	116.00/2.76
Distillates	**709,612**	**9,220**	**66.04/1.57**	1,664,774	11,901	137.37/3.27
High sulphur fuel oil	**337,995**	**5,860**	**49.49**	630,537	7,235	85.58
	1,675,840	**23,506**	**61.17**	3,425,471	28,703	117.19
Inventory adjustment		**(289)**			(453)	
Total production		**23,217**			28,250	
Yield (as a % of Feedstock) [2]		**98%**			99%	

(1) Average product sales prices are based on the deliveries at our refinery loading facilities.
(2) After adjusting for changes in inventory held for resale.

For the three months ended September 30, 2009, our refinery yield was comprised of 34% gasoline products, 41% distillates and 25% HSFO compared to the Third Quarter of the prior year when refinery yield averaged 30%, 44% and 26% for the same products respectively. The shift in product yield from distillate product in 2008 to a higher proportion of gasoline products in 2009 reflects a planned shift to optimize the favourable margins for distillate products in 2008 and more favourable economics for gasoline in 2009. For the nine months ended September 30, 2009, our refinery yield comprised 35% gasoline products, 40% distillates and 25% HSFO as compared to 31%, 43%, and 26%, respectively, in the prior year. The shift in product yield in 2009 from distillates to gasoline is attributed to end of run activity of the hydrocracker catalyst as well as other end of run conditions in the First Quarter of 2009 prior to the scheduled turnaround completed in the Second Quarter of 2009 as well as operational changes to capitalize on the higher gasoline margins in 2009.

In the Third Quarter of 2009, our average refined product sales price was US$72.62/bbl (a premium of US$4.32/bbl over WTI) as compared to an average selling price of US$120.84/bbl in the prior year (a premium of US$2.86/bbl over WTI). This increase in premium relative to WTI represents a $15.5 million favourable price variance. For the nine months ended September 30, 2009, our average refined product sales price was US$61.17/bbl (a premium of US$4.17/bbl over WTI) as compared to an average selling price of US$117.19/bbl in the prior year (a premium of US$3.90/bbl over WTI). This increase in premium relative to WTI represents a $7.4 million favourable price variance.

During the Third Quarter of 2009, the average sales price of our gasoline products of US$76.56/bbl was an US$8.26/bbl premium to the average WTI price as compared to a US$0.24/bbl discount to WTI realized in Third Quarter of the prior year, representing a $32.5 million increase in gross margin. This US$8.50/bbl year-over-year increase in our gasoline refining gross margin relative to WTI is reflective of the US$3.82/bbl increase in the NYMEX benchmark RBOB gasoline crack spread. For the nine months ended September 30, 2009, the average sales price of our gasoline products of $63.97/bbl was a US$6.97/bbl premium to the average WTI price as compared to a US$2.71/bbl premium over WTI realized in the prior year, representing a $41.8 million increase in gross margin. This US$4.26/bbl increase in our gasoline refining gross margin relative to WTI is attributed to the US$3.07/bbl increase in the NYMEX benchmark RBOB gasoline crack spread.

During the Third Quarter of 2009, the average sales price for our distillate products of US$74.81/bbl was a US$6.51/bbl premium over the average WTI price as compared to an US$18.39/bbl premium over WTI realized in the prior year representing a $50.9 million drop in gross margin. The US$11.88/bbl decrease in our distillate refining gross margin relative to WTI reflects the US$14.68/bbl decrease in the NYMEX benchmark Heating Oil crack spread. For the nine months ended September 30, 2009, the average sales price for our distillate products of US$66.04/bbl was a US$9.04/bbl premium over the average WTI price as compared to a US$24.08/bbl premium over WTI realized in the prior year representing a $161.6 million reduction in gross margin.

During the Third Quarter of 2009, the average sales price of our HSFO of US$63.07/bbl was a US$5.23/bbl discount to the average WTI price as compared to an US$18.89/bbl discount in the prior year, representing a $34.9 million increase in gross margin. The US$13.66/bbl improvement in our HSFO refining gross margin relative to WTI reflects the US$16.39/bbl increase in the benchmark HSFO crack spread. For the nine months ended September 30, 2009, the average sales price of our HSFO of US$49.49/bbl was a US$7.51/bbl discount to the average WTI price as compared to a US$27.71/bbl discount in the prior year, representing a $138.0 million increase in gross margin. The US$20.20/bbl improvement in our HSFO refining gross margin relative to WTI reflects the US$22.76/bbl increase in the HSFO benchmark crack spread.

Refinery Feedstock

The volatility of WTI prices from month to month makes it difficult to compare the financial impact of specific crude types when our consumption of crude types varies from month to month and costs are aggregated over the quarter. Further, our refinery competes for international waterborne crude oil and vacuum gas oil ("VGO") and the WTI benchmark price reflects a land-locked North American price with limited access to the international markets.

The cost of our feedstock reflects numerous factors beyond WTI prices, including the quality of the crude oil processed, the mix of crude oil types, the costs of transporting the crude oil to our refinery, the operational hedging of the WTI component of our feedstock costs through the Supply and Offtake Agreement, the ten day delay in pricing pursuant to the Supply and Offtake Agreement and for Iraqi crude oil purchased, the Official Selling Price ("OSP") as set by the Oil Marketing Company of the Republic of Iraq. On a monthly basis, the OSP discount relative to the WTI benchmark price is announced for North American deliveries and is influenced by the quality of the crude oil as well as by the demand from other purchasers.

A comparison of crude oil and VGO feedstock processed for the three and nine months ended September 30, 2009 and 2008 is presented below:

	Three Months Ended September 30					
	2009			2008		
	Cost of Feedstock	**Volume**	**Cost per Barrel [1]**	Cost of Feedstock	Volume	Cost per Barrel [1]
	(000's of Cdn $)	(000s of bbls)	(US$/bbl)	(000's of Cdn $)	(000s of bbls)	(US$/bbl)
Iraqi	**340,960**	**4,617**	**67.28**	390,848	3,573	105.01
Russian	**246,749**	**3,369**	**66.72**	277,250	2,489	106.93
Venezuelan	**74,321**	**1,072**	**63.16**	223,918	2,093	102.70
Crude Oil Feedstock	**662,030**	**9,058**	**66.58**	892,016	8,155	105.01
Vacuum Gas Oil	**32,161**	**413**	**70.94**	120,505	965	119.88
	694,191	**9,471**	**66.77**	1,012,521	9,120	106.58
Net inventory adjustment [2]	**(13,380)**			(19,288)		
Additives and blendstocks	**38,274**			85,818		
Inventory write-down (recovery) [3]	**(148)**			9,404		
	718,937			1,088,455		

	Nine Months Ended September 30					
	2009			2008		
	Cost of Feedstock	**Volume**	**Cost per Barrel [1]**	Cost of Feedstock	Volume	Cost per Barrel [1]
	(000's of Cdn $)	(000s of bbls)	(US$/bbl)	(000's of Cdn $)	(000s of bbls)	(US$/bbl)
Iraqi	**842,243**	**14,541**	**49.70**	1,614,974	15,101	105.02
Russian	**328,262**	**4,478**	**62.90**	557,234	5,194	105.35
Venezuelan	**188,223**	**3,723**	**43.38**	580,289	5,352	106.47
Crude Oil Feedstock	**1,358,728**	**22,742**	**51.26**	2,752,497	25,647	105.39
Vacuum Gas Oil	**52,568**	**921**	**48.97**	346,470	2,802	121.43
	1,411,296	**23,663**	**51.17**	3,098,967	28,449	106.97
Net inventory adjustment [2]	**(31,214)**			(51,414)		
Additives and blendstocks	**32,924**			125,847		
Inventory write-down (recovery) [3]	**(6,631)**			9,404		
	1,406,375			3,182,804		

(1) Cost of feedstock includes all costs of transporting the crude oil to the refinery in Newfoundland.
(2) Inventories are determined using the weighted average cost method.
(3) Inventory write-downs are calculated on a product by product basis using the lower of cost or net realizable value.

During the Third Quarter of 2009, throughput volume averaged 102,940 bbl/d as compared to 99,127 bbl/d in the prior year. The increase is mainly due to improved run time in the Third Quarter of 2009, as throughput was limited in the prior year due to a decision to improve overall gross margin by reducing crude oil feedstock volumes to the level sufficient to eliminate the production of vacuum tower bottoms ("VTB's") in excess of our visbreaker unit capacity. For the nine months ended September 30, 2009, throughput volume averaged 86,677 bbl/d as compared to 103,832 bbl/d in the prior year as throughput was limited in 2009 due to a planned 42-day turnaround completed in the Second Quarter.

As is normal business practice, the WTI component of our feedstock cost is operationally hedged under the Supply and Offtake Agreement with Vitol Refining S.A. ("Vitol"). When we commit to crude oil purchases, Vitol sells a forward WTI price contract for the next contract month, which results in price fluctuations subsequent to our purchase commitment being offset by the price volatility of the forward price curve. If the timing between processing the crude oil and the expiration of the forward contract are not aligned, the volume of the forward contract relating to unprocessed crude oil is rolled to the next contract month. This practice results in better matching of our refined product sales prices with our cost of feedstock. The persistent contango shape of the NYMEX WTI futures price curve since October 2008 has resulted in operational hedging gains from the rolling forward of these price contracts, which reduce our feedstock costs in the month the feedstock is processed. During the three and nine months ended September 30, 2009, this operational hedging resulted in reductions to the cost of our feedstock of US$9.8 million and US$67.0 million, respectively, as compared to the prior year when this operational hedging resulted in a decrease of US$3.6 million and an increase of US$9.1 million, respectively, to the cost of our feedstock. The Supply and Offtake Agreement is more fully described in our Annual Information Form for the year ended December 31, 2008 filed on SEDAR at www.sedar.com.

The cost of our crude oil feedstock averaged US$66.58/bbl during the Third Quarter of 2009 representing a US$1.72/bbl discount to WTI as compared to a cost of US$105.01/bbl and a discount of US$12.97/bbl in the Third Quarter of the prior year. The US$1.72/bbl discount is comprised of a US$1.38/bbl quality discount (2008 – US$6.30/bbl), plus a US$0.97/bbl operational hedging gain (2008 – US$0.39/bbl), offset by a US$0.63/bbl charge relating to timing under the Supply and Offtake Agreement with Vitol (2008 – discount of US$6.28/bbl). For the nine months ended September 30, 2009, the cost of our crude oil feedstock averaged US$51.26/bbl representing a US$5.74/bbl discount to WTI as compared to a discount of US$7.90/bbl in the prior year. The US$5.74/bbl discount is comprised of a US$3.74/bbl quality discount (2008 – US$6.73/bbl), plus a US$2.72/bbl operational hedging gain (2008 – charge of US$0.33/bbl), offset by a US$0.72/bbl charge relating to timing under the Supply and Offtake Agreement with Vitol (2008 – discount of US$1.50/bbl).

The average cost of purchased VGO during the Third Quarter of 2009 was US$70.94/bbl representing a premium of US$2.64/bbl relative to the WTI price as compared to US$119.88/bbl and an US$1.90/bbl premium in the prior year. The premium paid in the Third Quarter of 2009 is comprised of a US$3.61/bbl pricing premium relative to WTI (2008 – US$5.05/bbl), a US$1.45/bbl charge relating to timing under the Supply and Offtake Agreement with Vitol (2008 – discount of US$2.67/bbl), offset by a US$2.42/bbl operational hedging gain (2008 – US$0.48/bbl). For the nine months ended September 30, 2009, the average cost of purchased VGO was US$48.97/bbl representing a discount of US$8.03/bbl relative to WTI as compared to an US$8.14/bbl premium in the prior year. The US$8.03 discount is comprised of a US$1.71/bbl pricing discount relative to WTI (2008 – premium of US$4.68/bbl), a US$5.67/bbl operational hedging gain (2008 – charge of US$0.20/bbl) and a US$0.65 reduction related to timing under the Supply and Offtake Agreement with Vitol (2008 – charge of US$3.26/bbl). The pricing discount for the nine months ended September 30, 2009 is attributed to supply and demand disruptions in the very tightly balanced VGO market coupled with the benefit of our operational hedging.

Operating Expenses

The following summarizes the operating costs from the refinery and marketing division for the three and nine months ended September 30, 2009 and 2008:

	Three Months Ended September 30					
	2009			2008		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	Refining	Marketing	Total
Operating expense	**17,475**	**5,008**	**22,483**	18,458	4,899	23,357
Turnaround and catalyst	**-**	**-**	**-**	1,011	-	1,011
Purchased energy	**30,385**	**-**	**30,385**	33,958	-	33,958
	47,860	**5,008**	**52,868**	53,427	4,899	58,326

	Nine Months Ended September 30					
	2009			2008		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	Refining	Marketing	Total
Operating expense	**58,989**	**14,434**	**73,423**	60,022	14,846	74,868
Turnaround and catalyst	**47,487**	**-**	**47,487**	1,011	-	1,011
Purchased energy	**58,153**	**-**	**58,153**	106,985	-	106,985
	164,629	**14,434**	**179,063**	168,018	14,846	182,864

The largest component of refining operating expense is wages, salaries and benefits which totaled $11.6 million during the Third Quarter of 2009 (2008 - $12.5 million) while the other significant components were maintenance and repair costs of $3.1 million (2008 - $2.0 million), insurance of $1.4 million (2008 - $1.5 million) and professional services of $0.7 million (2008 - $1.6 million). During the three months ended September 30, 2009, refining operating expenses were $1.85/bbl which is consistent with $2.02/bbl in the prior year reflecting a similar level of operating expenses and a similar level of throughput. During the Third Quarter of 2009, the marketing division's operating expenses of $5.0 million remained relatively unchanged from the $4.7 million incurred in the Second Quarter of 2009 and the $4.9 million incurred in the prior year.

Turnaround and catalyst expenditures for the nine months ended September 30, 2009 of $47.5 million relate to costs incurred in preparation for and completion of the scheduled turnaround in the Second Quarter of 2009 of the hydrocracking and hydrogen units, replacement of distillate hydrotreating and hydrocracker catalyst, and the regeneration of the naphtha reforming unit catalyst. Of the total costs incurred related to the turnaround, $21.5 million relates to catalyst replacement, while the balance relates to other turnaround activities. Harvest's accounting policy is to expense all turnaround and catalyst replacement and regeneration expenditures, while capitalizing projects that provide future economic benefit.

Purchased energy, consisting of low sulphur fuel oil and electricity, is required to provide heat and power to refinery operations. Our purchased energy for the three and nine months ended September 30, 2009 was $3.21/bbl and $2.46/bbl of throughput, respectively, as compared to $3.72/bbl and $3.76/bbl, respectively, in the same periods of the prior year. In the Third Quarter of 2009, we purchased approximately 426,000 barrels of fuel oil at an average price of US$59.65/bbl as compared to approximately 355,000 barrels purchased in the Third Quarter of 2008 at an average price of US$85.03/bbl. The $3.6 million decrease in the cost of purchased fuel oil is due to a $9.9 million decrease in price offset by a $6.3 million increase in purchased volumes. Our electricity costs in the Third Quarter of 2009 were $2.5 million, unchanged from the same period in the prior year.

Marketing Expense and Other

During the three and nine months ended September 30, 2009, marketing expense was comprised of $0.9 million and $2.3 million respectively (three and nine months ended September 30, 2008 - $0.9 million and $2.5 million) of marketing fees (based on US$0.08/bbl) to acquire feedstock and $2.7 million and $7.4 million, respectively (three and nine months ended September 30, 2008 - $7.7 million and $24.1 million) of "Time Value of Money" charges both pursuant to the terms of the Supply and Offtake Agreement. The decreased "Time Value of Money" charge is mainly the result of a lower LIBOR rate in 2009 coupled with a lower crude oil inventory investment due to the lower commodity prices. As at September 30, 2009, Harvest had commitments totaling approximately $523.9 million in respect of future crude oil feedstock purchases and related transportation from Vitol.

Capital Expenditures

Capital spending for the three and nine months ended September 30, 2009 totaled $7.9 million and $34.8 million, respectively, (three and nine months ended September 30, 2008 - $17.2 million and $31.8 million) relating to various capital improvement projects including $4.6 million related to debottlenecking projects in the Third Quarter.

Depreciation and Amortization Expense

The following summarizes the depreciation and amortization expense for the three and nine months ended September 30, 2009 and 2008:

	Three Months Ended September 30					
	2009			2008		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	Refining	Marketing	Total
Tangible assets	**16,003**	**756**	**16,759**	15,045	652	15,697
Intangible assets	**1,221**	**319**	**1,540**	1,159	339	1,498
	17,224	**1,075**	**18,299**	16,204	991	17,195

	Nine Months Ended September 30					
	2009			2008		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	Refining	Marketing	Total
Tangible assets	**52,172**	**2,464**	**54,636**	44,225	1,817	46,042
Intangible assets	**3,903**	**1,020**	**4,923**	3,400	996	4,396
	56,075	**3,484**	**59,559**	47,625	2,813	50,438

The process units are amortized over an average useful life of 20 to 30 years. The intangible assets, consisting of engineering drawings, customer lists and fuel supply contracts, are amortized over a period of 20 years, 10 years and the term of the expected cash flows respectively.

Goodwill

We assess goodwill for impairment annually, or more frequently if events or changes in circumstances warrant. At June 30, 2009, it was determined that an impairment test was required due to expectations of lower refining gross margins and the probable deferral of certain future capital expenditures. The fair value of the Downstream reporting unit was determined using a discounted cash flow approach which incorporated management's expectations of future throughput and expenses and the forward curve for refined product crack spreads. At June 30, 2009, the fair value of the Downstream reporting unit was below its carrying value, indicating a potential impairment. Subsequently, the fair value of the Downstream goodwill was determined by valuing the reporting unit's net assets in the same manner as allocating a purchase price in a business combination. It was determined that the goodwill associated with the Downstream reporting unit was fully impaired and a charge of $206.5 million was recorded in the financial results at June 30, 2009.

RISK MANAGEMENT, FINANCING AND OTHER

Cash Flow Risk Management

With respect to our cash flow risk management program, see "Cash Flow Risk Management" in our MD&A for the year ended December 31, 2008 filed on SEDAR at www.sedar.com. The details of our commodity price contracts outstanding at September 30, 2009 are included in the notes to our consolidated financial statements which are also filed on SEDAR at www.sedar.com.

During the three and nine months ended September 30, 2009, the lower commodity price environment resulted in Harvest realizing gains of $8.0 million and $53.0 million, respectively, on our risk management contracts, while the higher commodity prices experienced in the 2008 comparative periods resulted in realized losses of $94.5 million and $225.2 million, respectively. The table below provides a summary of these gains and losses realized on our price risk management contracts:

	Three Months Ended September 30			Nine Months Ended September 30		
(000s)	**2009**	2008	Change	**2009**	2008	Change
Crude oil	**$ -**	$ (17,568)	(100%)	**$ -**	$ (41,255)	(100%)
Refined product	**-**	(78,648)	(100%)	**45,705**	(195,738)	(123%)
Natural gas	**(6)**	(67)	(91%)	**(94)**	(325)	(71%)
Currency exchange rates	**8,326**	(33)	(25,330%)	**8,326**	5,125	62%
Electric power	**(274)**	1,818	(115%)	**(919)**	6,977	(113%)
Total	**$ 8,046**	$ (94,498)	(109%)	**$ 53,018**	$ (225,216)	(124%)

The settlement of our refined product contracts during the first half of 2009 consisting of 12,000 bbl/d of NYMEX heating oil and 8,000 bbl/d of Platts heavy fuel oil realized gains of $45.7 million, due to the lower commodity price environment as compared to losses of $78.6 million and $195.7 million, respectively, during the three and nine months ended September 30, 2008 when commodity prices were higher.

For the three and nine months ended September 30, 2009, our currency exchange rate contracts realized gains of $8.3 million compared to net losses of $33,000 and net gains of $5.1 million, respectively, in the three and nine months ended September 30, 2008 reflecting the weakening of the U.S. dollar.

For the three and nine months ended September 30, 2009, our electricity price contracts realized losses of $0.3 million and $0.9 million, respectively, compared to gains of $1.8 million and $7.0 million in the same periods of the prior year. In the Third Quarter we entered into electricity price swap contracts for 15 MWh at $56.33/MWh from January to December 2010.

During 2009, Harvest did not have any crude oil contracts in place, while in the three and nine months ended September 30, 2008, losses on our crude oil contracts totaled $17.6 million and $41.3 million, respectively.

As at September 30, 2009, the mark-to-market value on our currency contracts, natural gas contracts and electric power contracts aggregated to $8.6 million.

Interest Expense

	Three Months Ended September 30			Nine Months Ended September 30		
(000s)	**2009**	2008	Change	**2009**	2008	Change
Interest on short term debt						
Bank loan	**$ 3,357**	$ -	100%	**$ 5,780**	$ -	100%
Convertible Debentures	**37**	32	16%	**149**	233	(36%)
	3,394	32	10,506%	**5,929**	233	2,445%
Interest on long-term debt						
Bank loan	**-**	12,514	(100%)	**7,557**	40,959	(82%)
Convertible Debentures	**19,581**	19,290	2%	**58,120**	49,899	16%
$7^{7/8}$% Senior Notes	**5,925**	5,584	6%	**18,730**	16,231	15%
Amortization of deferred finance charges – long term debt	**-**	675	(100%)	**675**	2,024	(67%)
	25,506	38,063	(33%)	**85,082**	109,113	(22%)
Total interest expense	**$ 28,900**	$ 38,095	(24%)	**$ 91,011**	$ 109,346	(17%)

Interest expense for the three and nine months ended September 30, 2009, including the amortization of related financing costs, decreased $9.2 million (24%) and $18.3 million (17%), respectively, compared to the prior year as interest on our bank borrowings decreased by $9.2 million and $27.6 million, respectively, due to lower interest rates and lower borrowings.

The interest on our Revolving Credit Facility is at a floating rate of 75 basis points over bankers' acceptances for Canadian dollar borrowings. During the three and nine months ended September 30, 2009, interest charges on bank loans reflected an average interest rate of 1.20% and 1.52%, respectively, compared to 3.92% and 4.29%, respectively, in the prior year.

The interest on our Convertible Debentures totaled $19.6 million and $58.3 million during the three and nine months ended September 30, 2009 respectively, representing a $0.3 million and $8.1 million increase, respectively, compared to the prior year. The year-to-date increase is due to the issuance of $250 million face value of 7.5% Convertible Debentures due 2015 in April 2008. Details on the Convertible Debentures outstanding are fully described in Note 12 to the audited consolidated financial statements for the year ended December 31, 2008 filed on SEDAR at www.sedar.com. Interest on the Convertible Debentures is based on the effective yield of the debt component of the Convertible Debentures, and as a result, the interest expense recorded is greater than the cash interest paid.

The interest on our $7^{7/8}$% Senior Notes totaled $5.9 million and $18.7 million for the three and nine months ended September 30, 2009, respectively, which is an increase of $0.3 million and $2.5 million, respectively, over the prior year. The year-to-date increase is due to the weakening of the Canadian dollar compared to the prior year, as the interest on these notes is denominated in U.S. dollars. Similar to our Convertible Debentures, interest expense on our Senior Notes is based on the effective yield, and as a result, the interest expense recorded is greater than the cash interest paid.

Included in the long term interest expense is the amortization of the discount on the $7^{7/8}$% Senior Notes and the accretion on the debt component balance of the Convertible Debentures to face value at maturity. The amortization of commitment fees and legal costs incurred for our credit facility, all totaling $0.7 million for the nine months ended September 30, 2009, were fully amortized as of March 31, 2009.

Currency Exchange

Currency exchange rate gains and losses are attributed to the changes in the value of the Canadian dollar relative to the U.S. dollar on our U.S. dollar denominated $7^{7/8}$% Senior Notes as well as any other U.S. dollar cash balances. Realized foreign exchange losses of $1.6 million and $3.4 million for the three and nine months ended September 30, 2009, respectively, have resulted from the settlement of U.S. dollar denominated transactions. Unrealized foreign exchange losses in the Third Quarter were $0.8 million with $23.9 million in losses relating to the Downstream and

$22.7 million in gains attributed to the Senior Notes resulting from the weakening of the U.S dollar over this period. Since December 31, 2008, the Canadian dollar has strengthened compared to the U.S. dollar resulting in year-to-date unrealized gains of $9.9 million, of which $36.2 million is related to the Senior Notes offset by $27.0 million in losses attributed to the Downstream.

Our Downstream operations are considered a self-sustaining operation with a U.S. dollar functional currency. The foreign exchange gains and losses incurred by our Downstream operations relate to Canadian dollar transactions converted to U.S. dollars as their functional currency is U.S. dollars. The cumulative translation adjustment recognized in other comprehensive income represents the translation of our Downstream operation's U.S. dollar functional currency financial statements to Canadian dollars using the current rate method. During the Third Quarter of 2009, the strengthening of the Canadian dollar relative to the U.S. dollar resulted in an $86.9 million net cumulative translation loss (2008 – gain of $56.6 million) as the weaker U.S. dollar results in a decrease in the relative value of the net assets in our Downstream operations.

Future Income Tax

At the end of 2008, we had a net future income tax provision on our balance sheet totaling $204.0 million comprised of a $372.6 million provision for our mutual fund trust and other "flow through" entities and a net asset of $168.6 million for our corporate entities. For the three and nine months ended September 30, 2009, we have recorded a future income tax expense of $12.0 million and $2.0 million, respectively, to reflect the changes in both the temporary differences held in our corporate entities and for changes in our forecasted temporary differences for our "flow through" entities as well as legislative tax rate changes both as of January 1, 2011. At September 30, 2009 we have a net future tax liability on our balance sheet totaling $189.9 million comprised of a $191.4 million net asset for our corporate entities offset by a $381.3 million provision for our mutual fund trust and other "flow through" entities. The future income tax asset recorded by our corporate entities will fluctuate during each accounting period to reflect changes in the respective temporary differences between the book value and tax basis of their assets as well as further legislative tax rate changes.

Currently, the principal source of our corporate entities' temporary differences is the difference between our net book value of our property, plant and equipment versus our unclaimed tax pools and the recognition for accounting purposes of a mark-to-market position on our risk management contracts.

Income Tax Reassessment

In January 2009, the Canada Revenue Agency ("CRA") issued a Notice of Reassessment to Harvest Energy Trust in respect of its 2002 through 2004 taxation years claiming past taxes, interest and penalties totaling $6.2 million. The CRA has adjusted taxable income to include the net profits interest revenue to an accrual basis whereas our income tax filings have been prepared on a cash basis. Management and our legal advisors believe the reassessment by the CRA has not properly applied a provision of the Income Tax Act (Canada) and accordingly, the amount of this contingent liability has not been accrued at September 30, 2009. In addition to presenting the merit of our position to the CRA, we have filed a Notice of Objection with the CRA and filed a Notice of Appeal with the Tax Court. The CRA has advised that they will file their Reply/Statement of Defense shortly and we have now scheduled examinations for discovery for December 2009.

Contractual Obligations and Commitments

We have contractual obligations and commitments entered into in the normal course of operations including the purchase of assets and services, operating agreements, transportation commitments, sales commitments, royalty obligations, and land lease obligations. These obligations are of a recurring and consistent nature and impact cash flow in an ongoing manner. As at September 30, 2009, we also have contractual obligations and commitments that are of a less routine nature as disclosed in the following table:

		Maturity			
Annual Contractual Obligations *(000s)*	**Total**	Less than 1 year	1-3 years	4-5 years	After 5 years
Long-term debt[1]	**$ 1,318,525**	$ 1,050,850	$ 267,675	$ -	$ -
Interest on long-term debt[3]	**50,184**	8,460	41,724	-	-
Interest on Convertible Debentures[2]	**276,968**	16,419	127,864	105,386	27,299
Operating and premise leases	**19,197**	2,138	13,521	2,957	581
Purchase commitments[4]	**13,623**	13,623	-	-	-
Asset retirement obligations[5]	**1,180,638**	5,542	30,592	26,942	1,117,562
Transportation [6]	**5,266**	869	3,800	597	-
Pension contributions[7]	**38,326**	1,700	14,217	14,791	7,618
Feedstock commitments	**523,906**	523,906	-	-	-
Total	**$ 3,426,633**	$ 1,623,507	$ 499,393	$ 150,673	$ 1,153,060

(1) Assumes that the outstanding Convertible Debentures either convert at the holders' option or are redeemed for Trust Units at our option.
(2) Assumes no conversions and redemption by Harvest for Trust Units at the end of the second redemption period.
(3) Assumes a constant foreign exchange rate.
(4) Relates to drilling commitments, AFE commitments and downstream purchase commitments.
(5) Represents the undiscounted obligation by period.
(6) Relates to firm transportation commitment on the Nova pipeline.
(7) Relates to the expected contributions for employee benefit plans.

We have a number of operating leases for moveable field equipment, vehicles and office space and our commitments under those leases are noted in our annual contractual obligations table above. 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.

Change in Accounting Policies

Effective January 1, 2009, Harvest adopted the new Canadian Institute of Chartered Accountants ("CICA") accounting standard "Goodwill and Intangible Assets", section 3064 which replaced section 3062 "Goodwill and Other Intangible Assets" and section 3450, "Research and Development Costs". Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of intangible assets and goodwill subsequent to its initial recognition. The new standard contains additional guidance with respect to the recognition of intangible assets.

DISTRIBUTIONS TO UNITHOLDERS

The following table summarizes our cash from operating activities, net (loss) income, distributions declared and proceeds from our distribution reinvestment programs as well as distributions as a percentage of cash from operating activities for the three and nine months ended September 30, 2009 and 2008:

	Three Months Ended September 30			Nine Months Ended September 30		
(000s except per trust unit amounts)	**2009**	2008	Change	**2009**	2008	Change
Cash from Operating Activities	**$ 98,979**	$ 133,493	(26%)	**$ 396,603**	$ 472,147	(16%)
Net (Loss) Income	**$ (713,697)**	$ 295,788	(341%)	**$ (922,612)**	$ 133,379	(792%)
Distributions declared	**$ 27,162**	$ 138,511	(80%)	**$ 155,657**	$ 410,678	(62%)
Per trust unit	**$ 0.15**	$ 0.90	(83%)	**$ 0.95**	$ 2.70	(65%)
Distribution reinvestment proceeds	**$ 6,497**	$ 35,153	(82%)	**$ 41,597**	$ 106,515	(61%)
Distributions as a percentage of cash from operating activities	**27%**	104%	(77%)	**39%**	87%	(48%)

LIQUIDITY AND CAPITAL RESOURCES

During the first nine months of 2009, cash flow from operating activities was $396.6 million as compared to $472.1 million in the prior year while cash flow from operating activities for the Third Quarter of 2009 totaled $99.0 million as compared to $133.5 million in the prior year. Cash flow from operating activities before changes in non-cash working capital totaled $386.2 million during the first nine months of 2009 as compared to $571.0 million during the same period of the prior year. During the first nine months of 2009, we declared distributions of $155.7 million ($114.1 million net of our distribution re-investment programs) and required $189.3 million for capital expenditures resulting in $82.8 million available for working capital requirements, including a $31.6 million build in our Downstream inventories.

Generally, the global economic and financial crisis continues with reduced levels of economic activity resulting in reduced demand for commodities and lower prices. The current prospect is for the demand for energy to increase in late 2009 and early 2010 with the underlying assumptions heavily dependent on the timing and sustainability of a global economic recovery. There also continues to be liquidity concerns in financial markets with a tightening of capital availability and higher costs for new credit commitments. In light of the higher costs of credit, we have been reluctant to enter into new credit commitments as alternative sources of funding and changes in corporate structure were being evaluated.

On October 21, 2009, we entered into an Arrangement Agreement with Korea National Oil Corporation ("KNOC") for the purchase of all the Trust Units of Harvest at a price of $10.00 per Trust Unit subject to the approval of $66^{2/3}$% of the Unitholders at a Special Meeting scheduled for December 15, 2009 as well as court and regulatory approvals. Should this transaction be consummated, the capital structure of Harvest will be impacted by the covenants and conditions of our Revolving Credit Facility, $7^{7/8}$% Senior Notes and Convertible Debenture agreements, each of which is explained in more detail below. In addition, pursuant to the covenants of the Arrangement Agreement, there will be no further re-financings of our balance sheet prior to the consummation or termination of the Arrangement Agreement and during the term of the Arrangement Agreement, Harvest is required to maintain $100 million of available liquidity to fund purchaser damages, if required.

Since the beginning of 2009, we have reduced our bank borrowings by $175.4 million primarily with the $120.2 million of net proceeds from the issuance of Trust Units and $63 million raised with the sale of two non-core properties. At the end of September 2009, our bank borrowing totaled $1,050.9 million relative to our stated target of reducing bank borrowings to less than $1.0 billion by April 2010. During the Third Quarter, we also settled the maturing of $1.6 million of 8% Convertible Debentures with the issuance of 259,184 Trust Units. The following table summarizes our capital structure as at September 30, 2009 and December 31, 2008.

(in millions)	**September 30, 2009**	December 31, 2008
SUMMARY OF CAPITALIZATION		
Revolving Credit Facility	**$1,050.9**	$1,226.2
$7^{7/8}$% Senior Notes Due 2011 (US$250 million)[1]	**267.7**	304.5
Convertible Debentures, at principal amount	**914.2**	916.7
Total Debt	**2,232.8**	2,447.4
Unitholder's Equity, at book value less equity component of Convertible Debentures		
181,930,672 issued at September 30, 2009	**1,492.6**	
157,200,701 issued at December 31, 2008		2,559.2
TOTAL CAPITALIZATION	**$3,725.4**	$5,006.6
FINANCIAL RATIOS		
Secured Debt to Annualized EBITDA[2]	1.8	1.5
Senior Debt to Annualized EBITDA[2]	2.2	1.8
Secured Debt to Total Capitalization	28%	25%
Senior Debt to Total Capitalization	35%	31%

(1) Face value converted at the period end exchange rate.
(2) Annualized Earnings Before Interest, Taxes, Depreciation and Amortization based on twelve month rolling average.

Our Revolving Credit Facility matures in April 2010 and is classified as a current liability. The consummation of the Arrangement Agreement will trigger a default for our Revolving Credit Facility and unless all the lenders in our syndicated facility consent, KNOC will be required to repay all bank borrowings concurrent with its acquisition of the Harvest Trust Units. Should the acquisition not be approved, we expect to re-engage the two co-leads of our current banking syndicate to arrange a new credit facility which will likely be a two year revolving credit facility supported by the borrowing base of our Upstream reserves plus an amount based on the Earnings Before Interest, Taxes, Depreciation and Amortization for our Downstream business with some measure of scheduled principal reduction and a minimum level of liquidity to maintain distributions to Unitholders and/or pursue acquisitions and growth initiatives.

Similar to the Revolving Credit Facility, our $7^{7/8}$% Senior Notes contain a Change of Control covenant which will be triggered by KNOC's purchase of Harvest's Trust Units. This covenant requires an Offer to Re-Purchase be made to the holders of the $7^{7/8}$% Senior Notes at a price of 101% of the principal amount plus any accrued and unpaid interest to the date of repurchase. In addition, Harvest may call the $7^{7/8}$% Senior Notes for redemption at a price of 101.969% of the principal amount plus any accrued and unpaid interest to the redemption date and effective October 15, 2010 and thereafter, at a price of 100% of the principal amount plus any accrued and unpaid interest to the redemption date. Should the KNOC acquisition proceed, the holders of the $7^{7/8}$% Senior Notes should expect to receive an Offer to Re-Purchase the $7^{7/8}$% Senior Notes and/or a redemption notice. Should the acquisition not be approved, the $7^{7/8}$% Senior Notes will remain intact with a maturity date of October 15, 2011. With the announcement of Arrangement Agreement with KNOC, each of Moody's Investor Services ("Moody's) and Standard & Poor's Ratings Services (S&P) have placed Harvest's corporate rating of "B-" and "B3", respectively, and "CCC" and "Caa1", respectively, for the $7^{7/8}$% Senior Notes under review for possible upgrade pending the completion of KNOC's acquisition of the Trust Units. KNOC is 100% owned by the Republic of Korea and has been rated as "A/Stable" by both Moody's and S&P.

At September 30, 2009, we have $914.2 million of principal amount of Convertible Debentures issued in five series all of which will also be impacted by KNOC's purchase of the Trust Units of Harvest. The Change in Control covenant for the Convertible Debentures requires that within 30 days of the acquisition of $66^{2/3}$% or more of Harvest Trust Units, an Offer to Re-Purchase be made to all holders of the Convertible Debentures at a price of 101% of the principal amount plus any accrued and unpaid interest. If 90% or more of the principal amount of each series of Convertible Debentures outstanding at the time the Offer to Re-Purchase is made have been tendered, Harvest has the right and obligation to redeem all of the remaining Convertible Debentures of the respective series at a price of 101% of the principal amount plus any accrued and unpaid interest. Should the acquisition not proceed or all of the Convertible Debentures not be tendered, the Convertible Debentures may remain intact to their respective maturity dates or could be redeemed subsequent to the following dates at prices set forth below pursuant to the terms of the respective series of Convertible Debentures and, in each case, plus any accrued and unpaid interest:

	Redemption Price		
	$1,050	**$1,025**	**$1,000**
6.5% Debentures due 2010 - $37.1 million	January 1, 2009	January 1, 2010	-
6.4% Debentures due 2012 - $174.6 million	November 1, 2008	November 1, 2009	November 1, 2010
7.25% Debentures due 2013 - $379.3 million	October 1, 2009	October 1, 2010	October 1, 2011
7.25% Debentures due 2014 - $73.2 million	March 1, 2010	March 1, 2011	March 1, 2012
7.50% Debentures due 2015 - $250.0 million	June 1, 2011	June 1, 2012	June 1, 2013

With the KNOC acquisition, the holders of Convertible Debentures should expect that these obligations will be settled with a cash payment whether pursuant to an Offer to Re-Purchase, a call for redemption, or at maturity.

Should the acquisition not be approved, the Convertible Debentures will likely remain intact with their most restrictive term limiting the issuance of additional Convertible Debentures when the principal amount of all issued and outstanding Convertible Debentures immediately after the issuance exceeds 25% of the total market capitalization, being an aggregate of the principal amount of all issued and outstanding Convertible Debentures plus an amount equal to the current market price of all of the issued and outstanding Trust Units. Using the $10.00 per Trust Unit price offer by KNOC, our total market capitalization would be approximately $2.7 billion which would prohibit the issuance of further Convertible Debentures.

We are authorized to issue an unlimited number of Trust Units and at the end of the Third Quarter of 2009, approximately 66% of the 181,930,672 Trust Units issued were held by non-residents of Canada. Since the announcement of the Arrangement Agreement with KNOC on October 21, 2009, the combined trading of our Trust Units on the Toronto Stock Exchange and New York Stock Exchange has exceeded the total of our issued and outstanding Trust Units such that the current holders of our Trust Units are likely substantially different than prior to the announcement. The following summarizes the trading value of our Trust Units year-to-date for 2009:

	Trading Price		
Month	**High**	**Low**	**Volume**
TSX Trading			
January 2009	$ 11.91	$ 10.36	10,266,136
February 2009	$ 10.57	$ 5.87	13,739,710
March 2009	$ 6.20	$ 3.87	16,343,646
April 2009	$ 6.18	$ 4.44	8,769,868
May 2009	$ 8.72	$ 5.71	21,261,237
June 2009	$ 7.24	$ 5.91	14,518,231
July 2009	$ 6.22	$ 5.12	8,381,376
August 2009	$ 6.73	$ 6.09	9,968,858
September 2009	$ 7.27	$ 5.74	10,472,670
October 2009	$ 9.91	$ 6.29	101,171,754
November 1 to 12, 2009	$ 9.91	$ 9.85	39,077,199

NYSE Trading (in US$)	High	Low	Volume
January 2009	$ 10.10	$ 8.25	25,461,464
February 2009	$ 8.55	$ 4.69	36,881,966
March 2009	$ 4.83	$ 3.00	36,763,788
April 2009	$ 5.08	$ 3.50	21,501,439
May 2009	$ 7.47	$ 4.80	36,288,909
June 2009	$ 6.67	$ 5.12	24,119,534
July 2009	$ 5.59	$ 4.41	25,765,389
August 2009	$ 6.20	$ 5.50	20,621,244
September 2009	$ 6.85	$ 5.17	21,318,003
October 2009	$ 9.36	$ 5.76	74,802,710
November 1 to 12, 2009	$ 9.46	$ 9.11	16,535,827

During the first nine months of 2009, we did not purchase any securities pursuant to our Normal Course Issuer Bid which enabled the purchase for cancellation at prevailing market prices up to 14,826,261 Trust Units as well as up to $91.4 million principal amount of Convertible Debentures. On October 20, 2009, the Normal Course Issuer Bid expired and it will not be re-instated during the term of the Arrangement Agreement with KNOC. Similarly, our distribution re-investment programs have also been suspended concurrent with the announcement of the Arrangement Agreement with KNOC.

Concurrent with our purchase of our Downstream assets in 2006, we entered into a Supply and Offtake Agreement that required the ownership of all crude oil feedstock and substantially all of the refined product inventory at the refinery be retained by Vitol Refining S.A. (an international oil trader) and granted Vitol the right and obligation to provide and deliver crude oil feedstock to the refinery as well as the right and obligation to purchase all refined products produced by the refinery. This arrangement provides Harvest with financial support for its crude oil purchase commitments as well as working capital financing for its inventories of crude oil and refined products held for sale. For a more complete description of this Supply and Offtake Agreement, see the description of the Supply and Offtake Agreement in our Annual Information Form for the year ended December 31, 2008 filed on SEDAR at www.sedar.com. On October 13, 2009, we renewed and extended the Supply and Offtake Agreement with Vitol for an initial period of two years with an effective date of November 1, 2009 at terms and conditions which provide a lower marketing fee, improved “Time-Value-For-Money” charges and enhanced economics for refined product pricing. The agreement also requires that all of our production of HSFO be marketed by Vitol in due course.

Pursuant to the Supply and Offtake Agreement, we estimate that Vitol held inventories of VGO, crude oil feedstock (both delivered and in-transit) valued at approximately $523.9 million at September 30, 2009 ($319.7 million at December 31, 2008) which may otherwise have been assets of Harvest.

SUMMARY OF QUARTERLY RESULTS

The following table and discussion highlights our Third Quarter of 2009 relative to the preceding seven quarters:

	2009			2008				2007
(000s except where noted)	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Revenue, net of royalties	**$ 991,854**	$ 562,997	$ 731,095	$ 892,739	$ 1,597,195	$ 1,622,079	$ 1,377,352	$ 879,124
Net (Loss) Income	**$ (713,697)**	$ (265,779)	$ 56,864	$ 78,640	$ 295,788	$ (162,063)	$ (346)	$ (113,585)
Per Trust Unit, basic[(1)]	**$ (3.95)**	$ (1.59)	$ 0.36	$ 0.50	$ 1.93	$ (1.07)	$ -	$ (0.77)
Per Trust Unit, diluted[(1)]	**$ (3.95)**	$ (1.59)	$ 0.36	$ 0.50	$ 1.73	$ (1.07)	$ -	$ (0.77)
Cash from Operating Activities	**$ 98,979**	$ 75,879	$ 221,745	$ 183,740	$ 133,493	$ 210,534	$ 128,119	$ 87,998
Per Trust Unit, basic	**$ 0.55**	$ 0.45	$ 1.40	$ 1.18	$ 0.87	$ 1.39	$ 0.85	$ 0.60
Per Trust Unit, diluted	**$ 0.55**	$ 0.45	$ 1.28	$ 1.10	$ 0.84	$ 1.26	$ 0.83	$ 0.60
Distributions per Unit, declared	**$ 0.15**	$ 0.15	$ 0.65	$ 0.90	$ 0.90	$ 0.90	$ 0.90	$ 0.98
Total debt	**$ 2,148,912**	$ 2,216,452	$ 2,373,925	$ 2,352,196	$ 2,284,664	$ 2,105,998	$ 2,209,451	$ 2,172,417
Total assets	**$ 4,423,802**	$ 5,296,596	$ 5,785,269	$ 5,745,407	$ 5,659,227	$ 5,637,879	$ 5,574,528	$ 5,451,683

(1) 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.

Net revenues are comprised of revenues net of royalties from our Upstream operations as well as sales of refined products from our Downstream operations. Throughout the first three quarters of 2008, net revenues were the highest in Harvest’s history due to strong commodity prices;

however the significant decrease in commodity prices in the Fourth Quarter of 2008 through to the Third Quarter 2009 coupled with the refinery turnaround in the Second Quarter of 2009, resulted in a significant decrease in net revenues.

Cash from operating activities is closely aligned with the trend in commodity prices for our Upstream operations and reflects the cyclical nature of the Downstream segment. It is also significantly impacted by changes in working capital. In the Third Quarter of 2009, cash from operating activities was lower than normal due to lower commodity prices and refining margins.

Net (loss) income reflects both cash and non-cash items. Changes in non-cash items, including future income tax, DDA&A expense, unrealized foreign exchange gains and losses, unrealized gains on risk management contracts, goodwill impairment and Trust Unit right compensation expense cause net income to vary significantly from period to period. In the Third Quarter of 2009, a goodwill impairment charge of $677.6 million relating to the Upstream reporting unit was recognized, while in the Second Quarter of 2009, a goodwill impairment charge of $206.5 million relating to the Downstream reporting unit was recognized. Changes in the fair value of our risk management contracts have also contributed to the volatility in net (loss) income over the preceding eight quarters. For these reasons, our net (loss) income does not reflect the same trends as net revenues or cash from operating activities, nor is it expected to.

Total assets over the last eight quarters have remained relatively stable until the Second Quarter of 2009. The stability reflects moderate acquisition activity offset by a reduction in net book value associated with depletion and depreciation charges. In the Second Quarter of 2009, total assets decreased due to recording an impairment charge associated with the Downstream reporting unit's goodwill, and then in the Third Quarter of 2009, a further decrease in total assets occurred resulting from a further impairment charge associated with the Upstream reporting unit's goodwill. Total debt has also remained relatively stable over the last eight quarters, reflecting moderate acquisition activity, offset by the issuance of Trust Units in the Second Quarter of 2009, and a net surplus of cash from operating activities over distributions to Unitholders.

OUTLOOK

Over the past three months, the West Texas Intermediate crude oil price has appreciated from the mid US$65.00 range to approximately US$80.00 at the end of October 2009 despite weak demand for North American refined products, particularly distillate products. For the balance of 2009, the forward curve anticipates the West Texas Intermediate price to fluctuate around US$80.00 with the NYMEX distillate margins expected to average approximately US$7.00 and the NYMEX RBOB gasoline margins expected to average approximately US$5.00. The strength of the Canadian dollar versus the U.S. dollar (US$0.82 per Canadian dollar at the end of 2008 as compared to US$0.93 at the end of October 2009) will negatively impact our cash flow as our revenue is primarily based on U.S. dollars. We are expecting that our financial results for the Fourth Quarter of 2009 will be similar to our Third Quarter as improved pricing in our Upstream operations will be offset by the impact of reduced throughput in our Downstream operations. Fourth Quarter capital spending is expected to be approximately $19 million in our Upstream operations and $13 million in our Downstream operations. We are targeting bank borrowings to be approximately $1 billion by the end of December 2009 based on the current forward curve for commodity price and exchange rate expectations and a final distribution payment of $0.05 per Trust Unit on November 16, 2009.

In our Upstream operations, we expect production to average approximately 51,500 boe/d in 2009 comprised of 36,400 bbl/d of oil and natural gas liquids and approximately 91,000 mcf/d of natural gas. We expect our operating costs will continue to benefit from lower electricity pricing and continued cost pressure on service providers and anticipate our operating costs will be approximately $13.80 per boe during the Fourth Quarter. Our general and administrative costs will reflect a lower level of capitalization due to reduced capital spending as well as the increased costs associated with recent corporate development initiatives.

During the Fourth Quarter 2009, we expect that our refinery throughput will be constrained due to weak margins and a maintenance shut down of the crude unit with throughput expected to average approximately 80,000 bbl/d of feedstock. We expect our operating costs will be unchanged at approximately $21 million with unit operating costs of approximately $2.85 per barrel of throughput and our cost of purchased energy to average approximately $4.30 per barrel of throughput aggregating to $7.15 per barrel of throughput. Our "Time-Value-Of-Money" and marketing fees paid to Vitol should be reduced reflecting the improved economics of the new Supply and Offtake Agreement which became effective November 1, 2009. Based on the current forward curve pricing for refined products, the cash flow contributions from our Downstream operations during the Fourth Quarter will likely be nominal.

During the First Quarter of 2009, we entered into exchange rate contracts that fixed the exchange rate on US$15 million per month for the period from July through December 2009 at approximately US$0.78/Cdn$1.00 representing 20% of our estimated exchange rate exposure, prior to considering the offsetting exposure of our U.S. dollar denominated $7^{7/8}$% Senior Notes. In addition, we entered into contracts to fix the price of 10 MWh of Alberta power prices for the period from April through December 2009 at a price of $61.90 which represents approximately 25% of our Upstream operating costs, and for 2010, we have entered into contracts to fix the price of 25 MWh of Alberta power prices at a price of $59.22. Currently, we have no crude oil, refined product or natural gas price contracts in place.

We manage our exposure to fluctuations in interest rates by maintaining a mix of short and longer term financing with the short term financing typically carrying floating interest rates and longer term financing (our $7^{7/8}$% Senior Notes and Convertible Debentures) carrying fixed rates of interest. Our short term financing consists of bank borrowings under our credit facilities which totaled $1,050.9 million at September 30, 2009, representing approximately 47% of our total debt. As a result, approximately 47% of our interest rate exposure is floating and 53% is fixed. Currently, our most significant exposure to increasing interest rates is through the re-pricing of bank borrowings should we have to renew our credit facilities. As described in the Liquidity and Capital Resources discussion of this MD&A, the acquisition of the Harvest Trust Units by KNOC will result in an obligation to Offer to Re-Purchase all of the $7^{7/8}$% Senior Notes and Convertible Debentures. In the absence of an Offer to Re-Purchase, our US$250 million of $7^{7/8}$% Senior Notes mature in October 2011 and the re-financing of this maturity also presents an exposure to increased borrowing costs while the maturing of the $914.2 million of principal amount of Convertible Debentures (2010 - $37.1 million; 2012 – $174.6 million; 2013 - $379.3 million; 2014 - $73.2 million and 2015 - $250.0 million) will not necessarily result in an exposure to increased borrowing costs as we anticipate that as these Convertible Debentures mature, or are converted into Trust Units before their maturity date, the principal amount will be settled with the issuance of Trust Units.

Pursuant to the covenants in the Arrangement Agreement, there will be no further distributions declared beyond the $0.05 per Trust Unit payable on November 16, 2009 and a special meeting of Unitholders will be held on December 15, 2009 to seek approval to proceed with KNOC's acquisition of the Harvest Trust Units. Should the transaction not close by January 31, 2010 and without the mutual consent to extend beyond that date, we will be required to continue with a constrained level of capital spending in 2010 of less than $200 million and re-engage our lead banks to amend and extend our credit arrangements which would likely include significant capital and distribution constraints as well as cash sweeps of proceeds from asset sales in favour of a commitment to a scheduled debt reduction program.

CRITICAL ACCOUNTING ESTIMATES

There are a number of critical estimates underlying the accounting policies applied when preparing the consolidated financial statements due to timing differences between when certain activities are settled and when these activities are recognized for accounting purposes. Changes in these estimates could have a material impact on our reported results. These estimates are described in detail in our MD&A for the year ended December 31, 2008 as filed on SEDAR at www.sedar.com. There have been no significant changes to any of our critical accounting estimates in our consolidated financial statements for the three and nine months ended September 30, 2009 from those described in our annual MD&A.

RECENT CANADIAN ACCOUNTING AND RELATED PRONOUNCEMENTS

In June 2009, the CICA amended Section 3862, "Financial Instruments – Disclosures," to include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three level hierarchy that reflects the significance of the inputs used in making the fair value measurements. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. These amendments are effective for Harvest on December 31, 2009.

International Financial Reporting Standards

In February 2008, the CICA Accounting Standards Board ("ASB") announced that Canadian public reporting issuers will be required to report under International Financial Reporting Standards ("IFRS") commencing January 1, 2011 which will require comparative IFRS information for the 2010 year end. In mid-2008, the ASB issued an exposure draft to incorporate IFRS as of the end of 2007 into the Canadian accounting standards. For changes to IFRS subsequent to 2007, the ASB expects to issue further exposure drafts and to incorporate these into the CICA Handbook.

In July 2009, the International Accounting Standards Board ("IASB") issued an amendment with additional exemptions for first time adopters of IFRS to enable an entity to measure exploration and evaluation assets at the amount determined under the entity's previous accounting principles and it also provides for the measurement of oil and gas assets in the development or production phase, among other things, by allocating the amount determined by the entity's previous accounting principles to the underlying assets on a pro rata basis using reserve volumes or reserve values at the date of transition. These amendments will substantially ease the adoption of IFRS for Harvest.

We have established an IFRS Conversion Plan and have staffed a project team with regular reporting to our senior management team and to the Audit Committee of the Board of Directors. We have completed an initial assessment of the differences between Canadian accounting standards and IFRS and are currently completing a comprehensive assessment of the impact of adopting IFRS on our accounting policies, information technology and data systems, internal control over financial reporting, disclosure controls and procedures, financial reporting expertise as well as business activities that may be influenced such as debt covenants, capital requirements and compensation arrangements. At this stage in the project we are unable to determine the full impact of adopting IFRS on Harvest's financial position and future results.

OPERATIONAL AND OTHER BUSINESS RISKS

Both Harvest's Upstream operations and its Downstream operations are conducted in the same business environment as most other operators in the respective businesses and the business risks are very similar. However, our structure as a publicly traded mutual fund trust is significantly different than that of a traditional corporation with share capital and there are some unique business risks of our structure. In addition, Harvest's monthly cash distributions limits its accumulation of capital resources from internal sources.

We have segregated the identification of business risks into those generally applicable to Upstream operations as well as Downstream operations and those applicable to our royalty trust structure and these should be read in conjunction with the full description of these risks in our Annual Information Form for the year ended December 31, 2008 filed on SEDAR at www.sedar.com. The following summarizes the more significant risks:

Upstream Operations

- Prices received for petroleum and natural gas have fluctuated widely in recent years and are also impacted by the volatility in the Canadian/U.S. currency exchange rate.
- The differential between light oil and heavy oil compounds the fluctuations in the benchmark oil prices.
- The operation of petroleum and natural gas properties involves a number of operating and natural hazards which may result in blowouts, environmental damage and other unexpected and/or dangerous conditions.
- The production of petroleum and natural gas may involve a significant use of electrical power and since de-regulation of the electric system in Alberta, electrical power prices in Alberta have been volatile.
- The markets for petroleum and natural gas produced in western Canada depend upon available capacity to refine crude oil and process natural gas as well as pipeline capacity to transport the products to consumers.
- The reservoir and recovery information in reserve reports are estimates and actual production and recovery rates may vary from the estimates and the variations may be significant.
- Absent capital reinvestment, production levels from petroleum and natural gas properties will decline over time and absent commodity price increases, cash generated from operating these assets will also decline.
- Prices paid for acquisitions are based in part on reserve report estimates and the assumptions made preparing the reserve reports are subject to change as well as geological and engineering uncertainty.
- The operation of petroleum and natural gas properties is subject to environmental regulation pursuant to local, provincial and federal legislation and a breach of such legislation may result in the imposition of fines as well as higher operating standards that may increase costs.

Downstream Operations

- The market prices for crude oil and refined products have fluctuated significantly, the direction of the fluctuations may be inversely related and the relative magnitude may be different resulting in volatile refining gross margins.
- The prices for crude oil and refined products are generally based in U.S. dollars while our operating costs are denominated in Canadian dollars which introduces currency exchange rate exposure.
- Crude oil feedstock is delivered to our refinery via waterborne vessels which could experience delays in transporting supplies due to weather, accidents, government regulations or third party actions.
- Over 60% of our feedstock in 2008 was supplied from sources in Iraq and if Iraq curtails supply, we may not be able to find another source with an adequate amount of a similar type of crude oil.
- We are relying on the marketing ability and creditworthiness of Vitol for our purchase of feedstock and should their creditworthiness deteriorate, crude oil suppliers may restrict the sale of crude oil to Vitol and we would be required to find another counterparty to our Supply and Offtake Agreement.
- Our refinery is a single train integrated interdependent facility which could experience a major accident, be damaged by severe weather or otherwise be forced to shutdown which may reduce or eliminate our cash flow.
- Our refining operations which include the transportation and storage of a significant amount of crude oil and refined products are adjacent to environmentally sensitive coastal waters, and are subject to hazards and similar risks such as fires, explosions, spills and mechanical failures, any of which may result in personal injury, damage to our property and/or the property of others along with other significant liabilities in connection with a discharge of materials.
- The production of aviation fuels subjects us to liability should contaminants in the fuel result in aircraft engines being damaged and/or aircraft crashes.
- Collective agreements with our employees and the United Steel Workers of America may not prevent a strike or work stoppage and future agreements may result in an increase in operating costs.
- Refinery operations are subject to environmental regulation pursuant to local, provincial and federal legislation and a breach of such legislation may result in the imposition of fines as well as higher operating standards that may increase costs.

General Business Risks

- The loss of a member to our senior management team and/or key technical operations employee could result in a disruption to either our Upstream or Downstream operations.
- Our credit facility and other financing agreements contain financial covenants and maturity dates that may limit our ability to sell assets, enter into certain financing arrangements and/or pay distributions to Unitholders.
- Variations in interest rates on our current and/or future financing arrangements may result in significant increases in our borrowing costs and result in less cash available for distributions to Unitholders.
- Our crude oil sales and refining gross margins are denominated in U.S. dollars while we pay distributions to our Unitholders in Canadian dollars which results in currency exchange rate exposure.

Royalty Trust Structural Risks

- Trust Units are hybrid securities in that they share certain attributes common to both equity securities and debt instruments and represent a fractional interest in the Trust.
- Recent changes to income tax legislation related to the royalty trust structure will result in a tax, at the trust level of our structure, on distributions from Harvest at rates of tax comparable to the combined federal and provincial corporate income tax rates in Canada and to treat such distributions as dividends to the Unitholders for income tax purposes.

CHANGES IN REGULATORY ENVIRONMENT

For a detailed discussion of the most recent changes to our regulatory environment, please refer to our MD&A for the year ended December 31, 2008 as filed on SEDAR at www.sedar.com.

INTERNAL CONTROL OVER FINANCIAL REPORTING

For a detailed discussion of our internal control over financial reporting, please refer to our MD&A for the year ended December 31, 2008 as filed on SEDAR at www.sedar.com. During the three and nine months ended September 30, 2009, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting except for the upgrading of the Downstream accounting software in the Second Quarter of 2009 to versions that are supported by their vendors. This change, while strengthening our controls, required that a significant amount of historical data be converted to be compatible with the upgraded software.

ADDITIONAL INFORMATION

Further information, including our Annual Information Form, can be accessed under our public filings found on SEDAR at www.sedar.com or at www.harvestenergy.ca. Information can also be found by contacting our Investor Relations department at (403) 265-1178 or at 1-866-666-1178.

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(thousands of Canadian dollars)		**September 30, 2009**		December 31, 2008
Assets				
Current assets				
Accounts receivable and other	**$**	**166,505**	$	173,341
Fair value of risk management contracts *[Note 14]*		**9,513**		36,087
Prepaid expenses and deposits		**11,651**		11,843
Inventories *[Note 4]*		**86,830**		55,788
		274,499		277,059
Property, plant and equipment *[Note 5]*		**4,061,354**		4,468,505
Intangible assets *[Note 6]*		**87,949**		106,002
Goodwill *[Note 7]*		**-**		893,841
	$	**4,423,802**	$	5,745,407
Liabilities and Unitholders' Equity				
Current liabilities				
Bank loan *[Note 9]*	**$**	**1,050,850**	$	-
Accounts payable and accrued liabilities		**202,080**		210,097
Cash distribution payable		**9,084**		47,160
Current portion of convertible debentures		**-**		2,513
Fair value deficiency of risk management contracts *[Note 14]*		**926**		235
		1,262,940		260,005
Bank loan *[Note 9]*		**-**		1,226,228
$7^{7/8}$% Senior notes		**263,499**		298,210
Convertible debentures *[Note 10]*		**834,563**		825,246
Asset retirement obligation *[Note 8]*		**286,077**		277,318
Employee future benefits *[Note 13]*		**9,756**		10,551
Deferred credit		**335**		522
Future income tax		**189,903**		203,998
Unitholders' equity				
Unitholders' capital *[Note 11]*		**4,067,307**		3,897,653
Equity component of convertible debentures		**84,089**		84,100
Contributed surplus		**6,444**		6,433
Accumulated income		**(463,728)**		458,884
Accumulated distributions		**(2,047,331)**		(1,891,674)
Accumulated other comprehensive income		**(70,052)**		87,933
		1,576,729		2,643,329
	$	**4,423,802**	$	5,745,407

Commitments, contingencies and guarantees *[Note 16]*
Subsequent events *[Note 17]*
See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS) (UNAUDITED)

(thousands of Canadian dollars, except per Trust Unit amounts)

	Three Months Ended September 30		Nine Months Ended September 30	
	2009	2008	**2009**	2008
Revenue				
Petroleum, natural gas, and refined product sales	**$ 1,027,648**	$ 1,670,463	**$ 2,374,468**	$ 4,809,107
Royalty expense	**(35,794)**	(73,268)	**(88,522)**	(212,482)
	991,854	1,597,195	**2,285,946**	4,596,625
Expenses				
Purchased products for processing and resale	**731,872**	1,099,963	**1,436,564**	3,220,513
Operating	**113,198**	131,640	**376,045**	401,593
Transportation and marketing	**8,186**	12,415	**20,803**	36,790
General and administrative *[Note 12]*	**10,496**	2,493	**27,639**	28,280
Realized net (gains) losses on risk management contracts *[Note 14]*	**(8,046)**	94,498	**(53,018)**	225,216
Unrealized net losses (gains) on risk management contracts *[Note 14]*	**2,075**	(359,654)	**27,265**	6,331
Interest and other financing charges on short term debt, net	**3,394**	32	**5,929**	233
Interest and other financing charges on long term debt	**25,506**	38,063	**85,082**	109,113
Depletion, depreciation, amortization and accretion	**127,301**	124,795	**403,192**	379,834
Goodwill impairment *[Note 7]*	**677,612**	-	**884,077**	-
Currency exchange (gain) loss	**2,450**	7,662	**(6,442)**	22,372
Large corporations tax (recovery) and other tax	**(530)**	(25)	**(546)**	471
Future income tax expense	**12,037**	149,525	**1,968**	32,500
	1,705,551	1,301,407	**3,208,558**	4,463,246
Net (loss) income for the period	**(713,697)**	295,788	**(922,612)**	133,379
Other comprehensive income				
Cumulative translation adjustment	**(86,881)**	56,628	**(157,985)**	102,607
Comprehensive (loss) income for the period	**$ (800,578)**	**$** 352,416	**$ (1,080,597)**	**$** 235,986
Net (loss) income per Trust Unit, basic *[Note 11]*	**$ (3.95)**	$ 1.93	**$ (5.46)**	$ 0.88
Net (loss) income per Trust Unit, diluted *[Note 11]*	**$ (3.95)**	$ 1.73	**$ (5.46)**	$ 0.88

See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY (UNAUDITED)

(thousands of Canadian dollars)	Unitholders' Capital	Equity Component of Convertible Debentures	Contributed Surplus	Accumulated Income (Loss)	Accumulated Distributions	Accumulated Other Comprehensive Income (Loss)
At December 31, 2007	**$3,736,080**	**$ 39,537**	**$ -**	**$ 246,865**	**$ (1,340,349)**	**$ (196,759)**
Equity component of convertible debenture issuances						
7.5% Debentures Due 2015	-	51,000	-	-	-	-
Convertible debenture conversions						
9% Debentures Due 2009	32	-	-	-	-	-
8% Debentures Due 2009	141	(1)	-	-	-	-
10.5% Debentures Due 2008	13	(3)	-	-	-	-
Redemption of convertible debentures						
10.5% Debentures Due 2008	24,249	(6,433)	6,433	-	-	-
Exercise of unit appreciation rights and other	1,350	-	-	-	-	-
Issue costs	(2,330)	-	-	-	-	-
Currency translation adjustment	-	-	-	-	-	102,607
Net income	-	-	-	133,379	-	-
Distributions and distribution reinvestment plan	106,515	-	-	-	(410,678)	-
At September 30, 2008	**$3,866,050**	**$ 84,100**	**$ 6,433**	**$ 380,244**	**$ (1,751,027)**	**$ (94,152)**
At December 31, 2008	**$3,897,653**	**$ 84,100**	**$ 6,433**	**$ 458,884**	**$ (1,891,674)**	**$ 87,933**
Issued for cash						
June 4, 2009	126,509					
Issued for corporate acquisition	4,618					
Redemption of convertible debentures						
9% Debentures Due 2009	944	-	-	-	-	-
8% Debentures Due 2009	1,588	(11)	11	-	-	-
Exercise of unit appreciation rights and other	338	-	-	-	-	-
Issue costs, net of tax	(5,940)	-	-	-	-	-
Currency translation adjustment	-	-	-	-	-	(157,985)
Net loss	-	-	-	(922,612)	-	-
Distributions and distribution reinvestment plan	41,597	-	-	-	(155,657)	-
At September 30, 2009	**$4,067,307**	**$ 84,089**	**$ 6,444**	**$ (463,728)**	**$ (2,047,331)**	**$ (70,052)**

See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(thousands of Canadian dollars)

	Three Months Ended September 30		Nine Months Ended September 30	
	2009	2008	**2009**	2008
Cash provided by (used in)				
Operating Activities				
Net (loss) income for the period	**$ (713,697)**	$ 295,788	**$ (922,612)**	$ 133,379
Items not requiring cash				
Depletion, depreciation, amortization and accretion	**127,301**	124,795	**403,192**	379,834
Impairment of goodwill *[Note 7]*	**677,612**	-	**884,077**	-
Unrealized currency exchange (gain) loss	**820**	1,528	**(9,876)**	15,072
Non-cash interest expense and amortization of finance charges	**3,704**	4,000	**11,488**	10,040
Unrealized net losses (gains) on risk management contracts *[Note 14]*	**2,075**	(359,654)	**27,265**	6,331
Future income tax expense	**12,037**	149,525	**1,968**	32,500
Unit based compensation expense (recovery)	**653**	(6,653)	**194**	714
Employee benefit obligation	**(53)**	(404)	**(795)**	(67)
Other non-cash items	**2**	3	**(20)**	(33)
Settlement of asset retirement obligations *[Note 8]*	**(3,658)**	(3,006)	**(8,672)**	(6,761)
Change in non-cash working capital	**(7,817)**	(72,429)	**10,394**	(98,862)
	98,979	133,493	**396,603**	472,147
Financing Activities				
Issue of Trust Units, net of issue costs	**(25)**	(150)	**119,412**	(2,329)
Issue of convertible debentures, net of issue costs	**-**	-	**-**	241,600
Bank (repayments) borrowings, net	**(59,589)**	165,348	**(188,116)**	(78,868)
Cash distributions	**(20,665)**	(102,825)	**(114,060)**	(302,299)
Change in non-cash working capital	**14,326**	5,930	**(33,642)**	9,601
	(65,953)	68,303	**(216,406)**	(132,295)
Investing Activities				
Additions to property, plant and equipment	**(20,400)**	(86,297)	**(189,334)**	(220,182)
Business acquisitions	**(998)**	(36,756)	**(998)**	(36,756)
Property dispositions (acquisitions), net	**1,764**	(95,374)	**62,492**	(90,825)
Change in non-cash working capital	**(12,675)**	17,280	**(51,003)**	9,295
	(32,309)	(201,147)	**(178,843)**	(338,468)
Change in cash and cash equivalents	**$ 717**	$ 649	**$ 1,354**	$ 1,384
Effect of exchange rate changes on cash	**(717)**	(649)	**(1,354)**	(1,384)
Cash and cash equivalents, beginning of period	**-**	-	**-**	-
Cash and cash equivalents, end of period	**$ -**	$ -	**$ -**	$-
Interest paid	**$ 19,823**	$ 32,784	**$ 57,343**	$ 76,282
Large corporation tax and other tax (received) paid, net	**$ (530)**	$ (10)	**$ (546)**	$561

See accompanying notes to these consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Period ended September 30, 2009
(tabular amounts in thousands of Canadian dollars, except Trust Unit, and per Trust Unit amounts)

1. Significant Accounting Policies

These interim consolidated financial statements of Harvest Energy Trust (the "Trust" or "Harvest") 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. These interim consolidated financial statements follow the same significant accounting policies as described and used in the consolidated financial statements of Harvest for the year ended December 31, 2008 which should be read in conjunction with that report.

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

2. Change in Accounting Policy

Effective January 1, 2009, Harvest adopted the new Canadian Institute of Chartered Accountants ("CICA") accounting standard "Goodwill and Intangible Assets", section 3064 which replaced section 3062 "Goodwill and Other Intangible Assets" and section 3450, "Research and Development Costs". Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of intangible assets and goodwill subsequent to its initial recognition. The adoption of this standard had no impact on the consolidated financial statements.

3. Acquisitions

On August 11, 2009, Harvest acquired approximately 93.5% of the issued and outstanding class A shares of Pegasus Oil & Gas Inc. in exchange for 0.015 units of Harvest for each Pegasus Class A Share and approximately 90.6% of the issued and outstanding class B shares of Pegasus in exchange for 0.15 units of Harvest for each Pegasus Class B Share for total consideration of approximately $4.6 million plus the assumption of $13.9 million of debt. This amount consisted of the issuance of 670,288 Trust Units at an ascribed price of $6.89 per Trust Unit, based on the weighted average trading price of the Harvest Trust Units before and after the announcement date of June 15, 2009. The results of operations of this acquisition have been included in the consolidated financial statements since its acquisition date.

4. Inventories

		September 30, 2009		December 31, 2008
Petroleum products				
Upstream – pipeline fill	**$**	**79**	$	603
Downstream		**82,092**		50,311
		82,171		50,914
Parts and supplies		**4,659**		4,874
Total inventories	**$**	**86,830**	$	55,788

5. Property, Plant and Equipment

	September 30, 2009			December 31, 2008		
	Upstream	**Downstream**	**Total**	Upstream	Downstream	Total
Cost	**$ 4,808,178**	**$ 1,344,180**	**$ 6,152,358**	$ 4,710,725	$ 1,493,039	$ 6,203,764
Accumulated depletion and depreciation	**(1,897,967)**	**(193,037)**	**(2,091,004)**	(1,572,449)	(162,810)	(1,735,259)
Net book value	**$ 2,910,211**	**$ 1,151,143**	**$ 4,061,354**	$ 3,138,276	$ 1,330,229	$ 4,468,505

General and administrative costs of $2.9 million (2008 – $1.4 million) have been capitalized during the three months ended September 30, 2009, of which $0.1 million (2008 – recovery of $1.3 million) related to the Trust Unit Rights Incentive Plan and the Unit Award Incentive Plan. For the nine months ended September 30, 2009, $8.1 million (2008 - $7.9 million) of general and administrative costs have been capitalized, of which approximately $40,000 (2008 – $0.3 million) related to the Trust Unit Rights Incentive Plan and the Unit Award Incentive Plan.

6. Intangible Assets

	September 30, 2009			December 31, 2008		
	Cost	**Accumulated Amortization**	**Net book value**	Cost	Accumulated Amortization	Net book value
Engineering drawings	**$ 95,292**	**$ (14,095)**	**$ 81,197**	$ 108,402	$ (11,969)	$ 96,433
Marketing contracts	**6,627**	**(2,813)**	**3,814**	7,539	(2,480)	5,059
Customer lists	**4,013**	**(1,187)**	**2,826**	4,564	(1,008)	3,556
Fair value of office lease	**931**	**(819)**	**112**	931	(652)	279
Financing costs	**7,300**	**(7,300)**	**-**	7,300	(6,625)	675
Total	**$ 114,163**	**$ (26,214)**	**$ 87,949**	$ 128,736	$ (22,734)	$ 106,002

7. Goodwill Impairment

Harvest assesses goodwill for impairment annually, or more frequently if events or changes in circumstances warrant. At June 30, 2009, it was determined that an impairment test was required due to expectations of lower refining margins and the probable deferral of certain future capital expenditures. Harvest completed a two-step process to determine whether the goodwill of the Downstream reporting unit was impaired. The first step of the impairment test involves comparing the fair value of the reporting unit to its carrying value, including goodwill. The fair value was determined using a discounted cash flow approach which incorporated management's expectations of future throughput and expenses and the forward curve for refined product crack spreads. At June 30, 2009, the fair value of the Downstream reporting unit was below its carrying value, indicating a potential impairment. The second step requires the fair value of goodwill be determined by valuing a reporting unit's net assets in the same manner as allocating a purchase price in a business combination. It was determined that the goodwill associated with the Downstream reporting unit was fully impaired and a charge of $206.5 million was recorded in the financial results at June 30, 2009.

At September 30, 2009, it was determined that an impairment test was required for the Upstream reporting unit due to the reasonable expectation that a significant portion, or all, of the reporting unit would be sold. The Arrangement Agreement with the Korea National Oil Corporation, announced on October 21, 2009, has been considered to be a fair value for all of the issued and outstanding Trust Units of Harvest from which a fair value of the Upstream reporting unit could be reasonably determined. Based on this, it was determined that the fair value of the Upstream reporting unit was below its carrying value as at September 30, 2009, indicating a potential impairment. Subsequently, the fair value of the Upstream goodwill was determined by valuing the reporting unit's net assets in the same manner as allocating a purchase price in a business combination. It was determined that the goodwill associated with the Upstream reporting unit was fully impaired and a charge of $677.6 million was recorded at September 30, 2009.

8. Asset Retirement Obligation

Harvest's asset retirement obligations result from its net ownership interest in petroleum and natural gas assets including well sites, gathering systems and processing facilities and the estimated costs and timing to reclaim and abandon them. Harvest estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations to be approximately $1,181 million which will be incurred between 2009 and 2058. The majority of the costs will be incurred between 2015 and 2040. A credit-adjusted risk-free discount rate of 8% - 10% and inflation rate of approximately 2% were used to calculate the fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below:

	September 30, 2009	December 31, 2008
Balance, beginning of period	**$ 277,318**	$ 213,529
Incurred on acquisition of a private corporation	**-**	1,900
Incurred on acquisition of Pegasus Oil & Gas Inc.	**1,411**	-
Liabilities incurred	**443**	4,371
Revision of estimates	**-**	49,395
Net liabilities acquired (settled) through acquisition (disposition)	**(2,538)**	910
Liabilities settled	**(8,672)**	(11,418)
Accretion expense	**18,115**	18,631
Balance, end of period	**$ 286,077**	$ 277,318

9. Bank Loan

At September 30, 2009, Harvest had $1,050.9 million drawn of the $1.6 billion available under the Credit Facility ($1,226.2 million drawn at December 31, 2008) which matures on April 30, 2010.

The Credit Facility is secured by a $2.5 billion first floating charge over all of the assets of Harvest's operating subsidiaries plus a first mortgage security interest on the refinery assets of North Atlantic. The most restrictive covenants of Harvest's credit facility include an aggregate limitation of $25 million on financial assistance and/or capital contributions to parties other than those included in the first floating charge, a limitation to carrying on business in countries that are not members of the Organization of Economic Co-operation and Development and a limitation on the payment of distributions to Unitholders in certain circumstances including an event of default. The Credit Facility requires standby fees on undrawn amounts and interest on amounts borrowed at varying rates depending on Harvest's ratio of secured debt (excluding the $7^{7/8}$% Senior Notes and Convertible Debentures) to its earnings before interest, taxes, depletion, amortization and other non-cash amounts ("EBITDA"). In addition to the availability under this facility being limited by the Borrowing Base Covenant of the $7^{7/8}$% Senior Notes described (as described in Note 11 in the consolidated financial statements for the year ended December 31, 2008), availability is subject to the following quarterly financial covenants:

	Covenant	As at September 30, 2009
Secured debt to EBITDA	3.0 to 1.0 or less	1.8
Total senior debt to EBITDA	3.5 to 1.0 or less	2.2
Secured debt to Capitalization	50% or less	28%
Total senior debt to Capitalization	55% or less	35%

For the three and nine months ended September 30, 2009, Harvest's average interest rate on advances under the Credit Facility was 1.20% (2008 – 3.92%) and 1.52% (2008 – 4.29%) respectively.

10. Convertible Debentures

At September 30, 2009, Harvest had five series of Convertible Unsecured Subordinated Debentures outstanding, the details of which have been outlined in Harvest's consolidated financial statements for the year ended December 31, 2008.

The following table summarizes the face value, carrying amount and fair value of the Convertible Debentures:

	September 30, 2009			December 31, 2008		
	Face Value	**Carrying Amount[1]**	**Fair Value**	Face Value	Carrying Amount[1]	Fair Value
9% Debentures Due 2009	**$ -**	**$ -**	**$ -**	$ 944	$ 940	$ 984
8% Debentures Due 2009	**-**	**-**	**-**	1,588	1,573	1,540
6.5% Debentures Due 2010	**37,062**	**35,978**	**36,691**	37,062	35,387	29,650
6.4% Debentures Due 2012	**174,626**	**170,353**	**150,178**	174,626	169,455	75,089
7.25% Debentures Due 2013	**379,256**	**361,258**	**306,439**	379,256	358,533	166,835
7.25% Debentures Due 2014	**73,222**	**68,221**	**59,310**	73,222	67,549	36,611
7.5% Debentures Due 2015	**250,000**	**198,753**	**197,500**	250,000	194,322	107,500
	$ 914,166	**$ 834,563**	**$ 750,118**	$ 916,698	$ 827,759	$ 418,209

[1] Excluding the equity component.

11. Unitholders' Capital

(a) Authorized

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

(b) Number of Units Issued

	Nine months ended September 30	
	2009	2008
Outstanding, beginning of period	**157,200,701**	148,291,170
Issued for cash		
June 4, 2009 at $7.30 per Trust Unit	**17,330,000**	-
Issued for corporate acquisition	**670,288**	-
Convertible debenture conversions		
9% Debentures Due 2009	**-**	2,310
8% Debentures Due 2009	**-**	8,710
10.5% Debentures Due 2008	**-**	344
Redemption of convertible debentures		
10.5% Debentures Due 2008	**-**	1,166,593
9% Debentures Due 2009	**136,906**	-
8% Debentures Due 2009	**259,184**	-
Distribution reinvestment plan issuance	**6,260,780**	4,976,758
Exercise of unit appreciation rights and other	**72,813**	61,791
Outstanding, end of period	**181,930,672**	154,507,676

(c) Per Trust Unit Information

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

Net income adjustments	Three months ended September 30		Nine months ended September 30	
	2009	2008	**2009**	2008
Net (loss) income, basic	**$ (713,697)**	$ 295,788	**$ (922,612)**	$ 133,379
Interest on Convertible Debentures	**-**	19,322	**-**	-
Net (loss) income, diluted(1)	**$ (713,697)**	$ 315,110	**$ (922,612)**	$ 133,379

Weighted average Trust Units adjustments	Three months ended September 30		Nine months ended September 30	
	2009	2008	**2009**	2008
Number of Units				
Weighted average Trust Units outstanding, basic	**180,786,576**	153,605,340	**168,967,859**	151,826,541
Effect of Convertible Debentures	**-**	28,748,036	**-**	-
Effect of Employee Unit Incentive Plans	**-**	-	**-**	267,719
Weighted average Trust Units outstanding, diluted(2)	**180,786,576**	182,353,376	**168,967,859**	152,094,260

(1) Net (loss) income, diluted excludes the impact of the conversions of certain of the Convertible Debentures for the three and nine months ended September 30, 2009 of $19.6 million and $58.3 million respectively (2008 - nil and $50.1 million) as the impact would be anti-dilutive.

(2) Weighted average Trust Units outstanding, diluted for the three and nine months ended September 30, 2009 does not include the unit impact of 28,840,220 and 28,915,945 respectively for certain of the Convertible Debentures (2008 – nil and 25,056,361) and nil for the three and nine months ended September 30, 2009 (2008 – 302,269 and nil respectively) for the Employee Unit Incentive Plans as the impact would be anti-dilutive.

12. Employee Unit Incentive Plans

Trust Unit Rights Incentive Plan

The following summarizes the Trust Units reserved for issuance under the Trust Unit Rights Incentive Plan:

	Nine months ended September 30, 2009		Year ended December 31, 2008	
	Unit Appreciation Rights	**Weighted Average Exercise Price**	Unit Appreciation Rights	Weighted Average Exercise Price
Outstanding, beginning of period	**8,037,466**	**$ 21.19**	3,823,683	$ 30.74
Granted	**122,250**	**8.02**	5,244,102	15.68
Exercised	**(2,500)**	**18.90**	(68,675)	25.67
Forfeited	**(572,243)**	**22.17**	(961,644)	28.80
Outstanding before exercise price reductions	**7,584,973**	**20.94**	8,037,466	21.19
Exercise price reductions	**-**	**(5.28)**	-	(4.45)
Outstanding, end of period	**7,584,973**	**$ 15.66**	8,037,466	$ 16.74
Exercisable before exercise price reductions	**17,150**	**$ 15.35**	85,200	$ 22.60
Exercise price reductions	**-**	**(15.07)**	-	(15.49)
Exercisable, end of period	**17,150**	**$ 0.28**	85,200	$ 7.11

The following table summarizes information about Unit Appreciation Rights outstanding at September 30, 2009.

		Outstanding			Exercisable	
Exercise Price before price reductions	**Exercise Price net of price reductions**	**At Sep 30, 2009**	**Weighted Average Exercise Price net of price reductions[1]**	**Remaining Contractual Life [1]**	**At Sep 30, 2009 [2]**	**Weighted Average Exercise Price net of price reductions[1]**
$4.84 - $5.87	$4.54 - $5.72	32,250	$ 5.34	4.6	-	$ -
$6.74 - $9.31	$6.67 - $8.66	46,200	8.02	4.5	-	-
$10.39 - $12.51	$8.54 - $11.26	2,998,900	9.44	4.2	-	-
$14.99 - $20.96	$0.01 - $18.74	174,500	15.72	3.4	16,250	0.01
$21.08 - $30.76	$3.92 - $24.47	2,998,140	18.38	2.8	900	5.15
$31.30 - $37.40	$18.18 - $27.84	1,334,983	24.01	1.6	-	-
$4.84 - $37.40	$0.01 - $27.84	7,584,973	$ 15.66	3.2	17,150	$ 0.28

(1) Based on weighted average Unit Appreciation Rights outstanding.
(2) Excludes unvested Unit Appreciation Rights and vested Unit Appreciation Rights that are out-of-the money at period end.

Unit Award Incentive Plan ("Unit Award Plan")

The following table summarizes the Trust Units reserved for issuance under the Unit Award Incentive Plan:

Number	Nine months ended September 30, 2009	Year ended December 31, 2008
Outstanding, beginning of period	**659,137**	348,248
Granted	**15,822**	390,274
Adjusted for distributions	**97,891**	75,310
Exercised	**(91,506)**	(121,776)
Forfeitures	**(27,675)**	(32,919)
Outstanding, end of period	**653,669**	659,137
Exercisable, end of period	**277,515**	238,817

Harvest has recognized a compensation expense of $0.6 million and $0.3 million (2008 – recovery of $6.5 million and expense of $1.6 million), including a non cash compensation expense of $0.6 million and $0.2 million (2008 – recovery of $6.7 million and expense of $0.6 million), for the three and nine months ended September 30, 2009 respectively, related to the Trust Unit Rights Incentive Plan and the Unit Award Plan and this is reflected in general and administrative expense in the consolidated statements of income.

13. Employee Future Benefit Plans

Defined Benefit Plans

The table below shows the components of the net benefit plan expense:

	Three months ended September 30, 2009		Three months ended September 30, 2008	
	Pension Plans	**Other Benefit Plans**	Pension Plans	Other Benefit Plans
Current service cost	**$ 296**	**$ 54**	$ 838	$ 92
Interest costs	**774**	**98**	668	87
Expected return on assets	**(660)**	**-**	(698)	-
Amortization of net actuarial gains	**(3)**	**-**	-	-
Net benefit plan expense	**$ 407**	**$ 152**	$ 808	$ 179

	Nine months ended September 30, 2009		Nine months ended September 30, 2008	
	Pension Plans	**Other Benefit Plans**	Pension Plans	Other Benefit Plans
Current service cost	**$ 887**	**$ 162**	$ 2,515	$ 276
Interest costs	**2,322**	**294**	2,003	261
Expected return on assets	**(1,981)**	**-**	(2,094)	-
Amortization of net actuarial gains	**(7)**	**-**	-	-
Net benefit plan expense	**$ 1,221**	**$ 456**	$ 2,424	$ 537

14. Financial Instruments and risk management contracts

Harvest is exposed to market risks resulting from fluctuations in commodity prices, currency exchange rates and interest rates in the normal course of operations. Harvest is also exposed, to a lesser extent, to credit risk on accounts receivable and counterparties to price risk management contracts and to liquidity risk relating to our debt. The Trust's financial risk exposure and risk management strategies have not changed significantly from those described in the consolidated financial statements for the year ended December 31, 2008 in Note 20 as filed on SEDAR at www.sedar.com.

Financial instruments of Harvest consist of cash, accounts receivable, accounts payable and accrued liabilities, cash distribution payable, a credit facility, risk management contracts, Convertible Debentures and the $7^{7/8}$% Senior Notes.

At September 30, 2009, the net fair value reflected on the balance sheet for all the risk management contracts outstanding at that date was approximately $8.6 million (December 31, 2008 - $35.9 million), which was included in the balance sheet as follows: fair value of risk management contracts (current assets) $9.5 million, fair value deficiency of risk management contracts (current liabilities) $0.9 million.

The following is a summary of Harvest's risk management contracts outstanding, along with their fair value at September 30, 2009:

Quantity	**Type of Contract**	**Term**	**Average Price**	**Fair value**
Currency Exchange Rate Risk Management				
$5,000,000/month	U.S./Cdn dollar exchange rate swap	Oct. 09 – Dec. 09	1.288 Cdn/U.S.	$ 3,264
$10,000,000/month	U.S./Cdn dollar exchange rate swap	Oct. 09 – Dec. 09	1.279 Cdn/U.S.	6,249
				$ 9,513
Natural Gas Price Risk Management				
251 GJ/d	Fixed price – natural gas contract	Oct. 09 – Dec. 09	Cdn $3.48[a]	**$ (7)**
Electricity Price Risk Management				
10 MWh	Electricity price swap contracts	Oct. 09 – Dec. 09	Cdn $61.90	$ (17)
25 MWh	Electricity price swap contracts	Jan. 10 – Dec. 10	Cdn $59.22	(902)
				$ (919)
Total net fair value of risk management contracts				**$ 8,587**

[a] *This contract contains an annual escalation factor such that the fixed price is adjusted each year.*

For the three and nine months ended September 30, 2009, the total unrealized losses recognized in the consolidated statement of income and comprehensive income was $2.1 million and $27.3 million respectively (2008 – gains of $359.7 million and losses of $6.3 million), which represents the change in fair value of financial assets and liabilities classified as held for trading. The realized gains and losses on all risk management contracts are included in the period in which they are incurred.

15. Segment Information

Harvest operates in Canada and has two reportable operating segments, Upstream and Downstream. Harvest's upstream operations consist of development, production and subsequent sale of petroleum, natural gas and natural gas liquids, while its downstream operations include the purchase of crude oil, the refining of crude oil, the sale of refined products including a network of retail operations and the supply of refined products to commercial and wholesale customers.

Results of Continuing Operations	Downstream[1] Three months ended Sep 30		Upstream[1] Three months ended Sep 30		Total Three months ended Sep 30	
	2009	2008	**2009**	2008	**2009**	2008
Revenue[2]	**$ 800,728**	$ 1,214,898	**$ 226,920**	$ 455,565	**$ 1,027,648**	$ 1,670,463
Royalties	**-**	-	**(35,794)**	(73,268)	**(35,794)**	(73,268)
Less:						
Purchased products for resale and processing	**731,872**	1,099,963	**-**	-	**731,872**	1,099,963
Operating	**52,868**	58,326	**60,330**	73,314	**113,198**	131,640
Transportation and marketing	**3,617**	8,560	**4,569**	3,855	**8,186**	12,415
General and administrative	**490**	345	**10,006**	2,148	**10,496**	2,493
Depletion, depreciation, amortization and accretion	**18,299**	17,195	**109,002**	107,600	**127,301**	124,795
Goodwill impairment[4]	**-**	-	**677,612**	-	**677,612**	-
	$ (6,418)	$ 30,509	**$ (670,393)**	$ 195,380	**(676,811)**	225,889
Realized net gains (losses) on risk management contracts					**8,046**	(94,498)
Unrealized net (losses) gains on risk management contracts					**(2,075)**	359,654
Interest and other financing charges on short term debt, net					**(3,394)**	(32)
Interest and other financing charges on long term debt					**(25,506)**	(38,063)
Currency exchange loss					**(2,450)**	(7,662)
Large corporations tax recovery (expense) and other tax					**530**	25
Future income tax expense					**(12,037)**	(149,525)
Net (loss) income					**$ (713,697)**	$ 295,788
Total Assets[3]	**$ 1,388,215**	$ 1,670,107	**$ 3,026,074**	$ 3,982,397	**$ 4,423,802**	$ 5,659,227
Capital Expenditures						
Development and other activity	**$ 7,945**	$ 17,199	**$ 12,455**	$ 69,098	**$ 20,400**	$ 86,297
Business acquisitions	**-**	-	**998**	36,756	**998**	36,756
Property acquisitions (dispositions), net	**-**	-	**(1,764)**	95,374	**(1,764)**	95,374
Total expenditures	**$ 7,945**	$ 17,199	**$ 11,689**	$ 201,228	**$ 19,634**	$ 218,427
Property, plant and equipment						
Cost	**$ 1,344,180**	$ 1,282,947	**$ 4,808,178**	$ 4,573,654	**$ 6,152,358**	$ 5,856,601
Less: Accumulated depletion, depreciation, and amortization	**(193,037)**	(125,674)	**(1,897,967)**	(1,457,849)	**(2,091,004)**	(1,583,523)
Net book value	**$ 1,151,143**	$ 1,157,273	**$ 2,910,211**	$ 3,115,805	**$ 4,061,354**	$ 4,273,078
Goodwill[4]						
Beginning of period	**$ -**	$ 181,025	**$ 677,612**	$ 676,795	**$ 677,612**	$ 857,820
Addition to goodwill	**-**	7,900	**-**	817	**-**	8,717
Impairment of goodwill	**-**	-	**(677,612)**	-	**(677,612)**	-
End of period	**$ -**	$ 188,925	**$ -**	$ 677,612	**$ -**	$ 866,537

(1) *Accounting policies for segments are the same as those described in the consolidated financial statements for the year ended December 31, 2008 in Note 2 as filed on SEDAR at www.sedar.com.*

(2) *Of the total downstream revenue for the three months ended September 30, 2009, two customers represent sales of $507.9 million and $140.7 million respectively (2008 - $769.9 million and $193.1 million). No other single customer within either division represents greater than 10% of Harvest's total revenue.*

(3) *Total Assets on a consolidated basis includes $9.5 million (2008 – $6.7 million) relating to the fair value of risk management contracts.*

(4) *A goodwill impairment charge of $677.6 million for the upstream segment was recognized at September 30, 2009 (see Note 7).*

(5) *There is no intersegment activity.*

Results of Continuing Operations	Downstream[1]		Upstream[1]		Total	
	Nine months ended Sep 30		Nine months ended Sep 30		Nine months ended Sep 30	
	2009	2008	**2009**	2008	**2009**	2008
Revenue[2]	**$ 1,742,513**	$ 3,504,443	**$ 631,955**	$ 1,304,664	**$ 2,374,468**	$ 4,809,107
Royalties	**-**	-	**(88,522)**	(212,482)	**(88,522)**	(212,482)
Less:						
Purchased products for resale and processing	**1,436,564**	3,220,513	**-**	-	**1,436,564**	3,220,513
Operating	**179,063**	182,864	**196,982**	218,729	**376,045**	401,593
Transportation and marketing	**9,718**	26,558	**11,085**	10,232	**20,803**	36,790
General and administrative	**1,365**	1,514	**26,274**	26,766	**27,639**	28,280
Depletion, depreciation, amortization and accretion	**59,559**	50,438	**343,633**	329,396	**403,192**	379,834
Goodwill impairment[4]	**206,465**	-	**677,612**	-	**884,077**	-
	$ (150,221)	$ 22,556	**$ (712,153)**	$ 507,059	**(862,374)**	529,615
Realized net gains (losses) on risk management contracts					**53,018**	(225,216)
Unrealized net losses on risk management contracts					**(27,265)**	(6,331)
Interest and other financing charges on short term debt, net					**(5,929)**	(233)
Interest and other financing charges on long term debt					**(85,082)**	(109,113)
Currency exchange gain (loss)					**6,442**	(22,372)
Large corporations tax recovery (expense) and other tax					**546**	(471)
Future income tax expense					**(1,968)**	(32,500)
Net (loss) income					**$ (922,612)**	$ 133,379
Total Assets[3]	**$ 1,388,215**	$ 1,670,107	**$ 3,026,074**	$ 3,982,397	**$ 4,423,802**	$ 5,659,227
Capital Expenditures						
Development and other activity	**$ 34,778**	$ 31,845	**$ 154,556**	$ 188,337	**$ 189,334**	$ 220,182
Business acquisitions	**-**	-	**998**	36,756	**998**	36,756
Property acquisitions (dispositions), net	**-**	-	**(62,492)**	90,825	**(62,492)**	90,825
Total expenditures	**$ 34,778**	$ 31,845	**$ 93,062**	$ 315,918	**$ 127,840**	$ 347,763
Property, plant and equipment						
Cost	**$ 1,344,180**	$ 1,282,947	**$ 4,808,178**	$ 4,573,654	**$ 6,152,358**	$ 5,856,601
Less: Accumulated depletion, depreciation, and amortization	**(193,037)**	(125,674)	**(1,897,967)**	(1,457,849)	**(2,091,004)**	(1,583,523)
Net book value	**$ 1,151,143**	$ 1,157,273	**$ 2,910,211**	$ 3,115,805	**$ 4,061,354**	$ 4,273,078
Goodwill[4]						
Beginning of period	**$ 216,229**	$ 175,983	**$ 677,612**	$ 676,795	**$ 893,841**	$ 852,778
Addition (reduction) to goodwill	**(9,764)**	12,942	**-**	817	**(9,764)**	13,759
Impairment of goodwill	**(206,465)**	-	**(677,612)**	-	**(884,077)**	-
End of period	**$ -**	$ 188,925	**$ -**	$ 677,612	**$ -**	$ 866,537

(1) *Accounting policies for segments are the same as those described in the consolidated financial statements for the year ended December 31, 2008 in Note 2 as filed on SEDAR at www.sedar.com.*

(2) *Of the total downstream revenue for the nine months ended September 30, 2009, two customers represent sales of $1,081.7 million and $293.5 million respectively (2008 - $2,397.0 million and $487.2 million). No other single customer within either division represents greater than 10% of Harvest's total revenue.*

(3) *Total Assets on a consolidated basis includes $9.5 million (2008 – $6.7 million) relating to the fair value of risk management contracts.*

(4) *A goodwill impairment charge of $206.5 million for the downstream segment was recognized at June 30, 2009 and $677.6 million for the upstream segment at September 30, 2009 (see Note 7).*

(5) *There is no intersegment activity.*

16. Commitments, Contingencies and Guarantees

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

The following are the significant commitments and contingencies at September 30, 2009:

(a) *Canada Revenue Agency Assessment*
In January 2009, Canada Revenue Agency issued a Notice of Reassessment to Harvest Energy Trust in respect of its 2002 through 2004 taxation years claiming past taxes, interest and penalties totaling $6.2 million. The CRA has adjusted Harvest Energy Trust's taxable income to include their net profits interest royalty income on an accrual basis whereas the tax returns had reported this revenue on a cash basis. A Notice of Objection has been filed with CRA requesting the adjustments to an accrual basis be reversed. The Harvest Energy Trust 2005 tax return has also been prepared on a cash basis for royalty income with no taxes payable and, if reassessed by CRA on a similar basis, there would have been approximately $40 million of taxes owing. The Harvest Energy Trust 2006 tax return has been prepared on an accrual basis including incremental payments required to align the prior year's cash basis of reporting with no taxes payable. Management along with our legal advisors believe the CRA has not properly applied the provisions of the Income Tax Act (Canada) that entitle income from a royalty to be included in taxable income on a cash basis and that the dispute will be resolved with no taxes payable by Harvest Energy Trust. Harvest has filed a Notice of Objection with the CRA and filed a Notice of Appeal with the Tax Court. The CRA has advised that they will file their Reply/Statement of Defense shortly and Harvest has now scheduled examinations for discovery for December 2009.

The following is a summary of Harvest's contractual obligations and commitments as at September 30, 2009:

Payments Due by Period

	2009	2010	2011	2012	2013	Thereafter	Total
Debt repayments (1)	-	1,050,850	267,675	-	-	-	**1,318,525**
Debt interest payments(2)	24,879	90,283	79,305	60,838	44,548	27,299	**327,152**
Capital commitments(3)	13,623	-	-	-	-	-	**13,623**
Operating leases(4)	2,138	7,195	6,326	2,369	588	581	**19,197**
Pension contributions(5)	1,700	7,038	7,179	7,322	7,469	7,618	**38,326**
Transportation agreements(6)	869	2,911	889	408	189	-	**5,266**
Feedstock commitments(7)	523,906	-	-	-	-	-	**523,906**
Contractual obligations	**567,115**	**1,158,277**	**361,374**	**70,937**	**52,794**	**35,498**	**2,245,995**

(1) *Assumes that the outstanding Convertible Debentures either convert at the holders' option for Units or are redeemed for Units at Harvest's option.*
(2) *Interest determined on bank loan balance using the rate effective at period end and by using the period end U.S. dollar exchange rate for the Senior Notes.*
(3) *Relating to drilling contracts, AFE commitments, equipment rental contracts and environmental capital projects.*
(4) *Relating to building and automobile leases.*
(5) *Relating to expected contributions for employee benefit plans [see Note 13].*
(6) *Relating to oil and natural gas pipeline transportation agreements.*
(7) *Relating to crude oil feedstock purchases and related transportation costs. North Atlantic has a Supply and Offtake Agreement with Vitol Refining S.A. This agreement provides that the ownership of substantially all crude oil feedstock and refined product inventory at the refinery be retained by Vitol Refining S.A. and that Vitol Refining S.A. will be granted the right and obligation to provide crude oil feedstock for delivery to the refinery, as well as the right and obligation to purchase substantially all refined products produced by the refinery.*

17. Subsequent Events

Subsequent to September 30, 2009, Harvest declared a distribution of $0.05 per unit for Unitholders of record on October 22, 2009 payable on November 16, 2009.

On October 13, 2009, Harvest announced that, through its wholly owned subsidiary North Atlantic Refining Limited, it had revised the terms of the Supply and Offtake Agreement with Vitol and extended this agreement for two years beginning on November 1, 2009. The revised agreement contains more favorable financing charges, fees, and product sales prices. Vitol will also provide feedstock procurement and shipping, finished product marketing and shipping, price risk management, administrative and back office services. The new terms also include the marketing of high sulfur fuel oil inventories which, along with other amendments, will increase the amount of working capital financing provided by Vitol.

On October 21, 2009, Harvest announced that it received an offer from the Korea National Oil Corporation for the purchase of all the issued and outstanding Harvest Trust Units at a price of $10.00 per Unit for total cash consideration of approximately $1.8 billion plus the assumption of $2.3 billion of debt, subject to Unitholder approval.

Between October 1, 2009 and November 6, 2009, an additional $46.0 million was committed to the purchase of feedstock inventory under the Supply and Offtake Agreement held with Vitol Refining S.A. [see table in Note 16].

18. Comparatives

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