Financial & Operating Highlights

The table below provides a summary of our financial and operating results for three month periods ended March 31, 2008 and 2007.

	Three Month Period Ended March 31		
($000s except where noted)	**2008**	2007	Change
Revenue, net[(1)]	**1,377,352**	1,025,512	34%
Cash From Operating Activities before changes in non-cash working capital and asset retirement obligations	**185,386**	213,941	(13%)
Per Trust Unit, basic	**$ 1.24**	$ 1.68	(26%)
Cash From Operating Activities	**128,119**	111,048	15%
Per Trust Unit, basic	**$ 0.85**	$ 0.87	(2%)
Per Trust Unit, diluted	**$ 0.83**	$ 0.84	(1%)
Net Income (Loss)[(2)]	**(346)**	69,850	(100%)
Per Trust Unit, basic	**$ -**	$ 0.55	(100%)
Per Trust Unit, diluted	**$ -**	$ 0.55	(100%)
Distributions declared	**135,167**	145,270	(7%)
Distributions declared, per Trust Unit	**$ 0.90**	$ 1.14	(21%)
Distributions declared as a percentage of Cash From Operating Activities before changes in non-cash working capital and asset retirement obligations	**73%**	68%	5%
Distributions declared as a percentage of Cash From Operating Activities	**106%**	131%	(25%)
Bank debt	**1,330,423**	1,363,222	(2%)
7 7/8% Senior Notes	**250,099**	279,612	(11%)
Convertible Debentures[(3)]	**628,929**	793,184	(21%)
Total long-term financial liabilities[(3)]	**2,209,451**	2,436,018	(9%)
Total assets	**5,574,528**	5,800,346	(4%)
UPSTREAM OPERATIONS			
Daily Production			
Light to medium oil (bbl/d)	**25,509**	27,034	(6%)
Heavy oil (bbl/d)	**12,980**	15,614	(17%)
Natural gas liquids (bbl/d)	**2,484**	2,496	-%
Natural gas (mcf/d)	**102,570**	101,282	1%
Total daily sales volumes (boe/d)	**58,067**	62,024	(6%)
Operating Netback ($/boe)	**45.34**	29.81	52%
Cash capital expenditures	**79,571**	148,487	(46%)
DOWNSTREAM OPERATIONS			
Average daily throughput (bbl/d)	**111,999**	113,711	(2%)
Aggregate throughput (mbbl)	**10,191**	10,234	-%
Average Refining Margin (US$/bbl)	**8.90**	11.85	(25%)
Cash capital expenditures	**6,027**	4,883	23%

(1) Revenues are net of royalties.
(2) Net Income (Loss) includes a future income tax recovery of $21.8 million (2007 – nil) and unrealized net loss from risk management activities of $60.9 million (2007–$14.1 million) for the three months ended March 31, 2008.
(3) Includes current portion of Convertible Debentures.

Q1 MESSAGE TO UNITHOLDERS

The first quarter of 2008 was a very strong operating period for Harvest, demonstrated by stable quarter-over-quarter production in the upstream business and improved performance of operating units in our downstream business. Supporting these successes were advancements we made on many of our key Sustainable Growth initiatives designed to strengthen Harvest's position for long term value creation.

We generated $185.4 million in cash flow or $1.24 per trust unit (prior to changes in non-cash working capital and asset retirement obligations) which reflects strong operating performance coupled with a robust commodity price environment, offset by realized price risk management losses. Based on a monthly distribution level of $0.30 per unit, the ratio of distributions to cash flow was 73% for the quarter before the impact of the Distribution Reinvestment Program. As we execute our Sustainable Growth strategy, Harvest continues to realize an improved balance between our sources and uses of cash, and as a result, have maintained the C$0.30 per unit distribution level for each of May, June and July.

Upstream
In our western Canadian oil and natural gas production business, our first quarter production volume averaged 58,067 barrels of oil equivalent per day (boe/d), which is effectively flat compared to the fourth quarter of 2007. During the quarter, our $79.6 million capital program was directed at maintaining our active and successful drilling program in southeast Saskatchewan, where we are targeting the Tilston, Souris Valley and Bakken plays. We invested $13.6 million in capital in Saskatchewan during the quarter resulting in the drilling of 16 horizontal wells with 100% success. Exploration activities in areas such as Chedderville, west central Alberta and Southern Alberta continued to generate attractive production rates supporting our overall volumes. To capitalize further on our success thus far, we have increased our 2008 upstream capital budget by $20 million, largely focused on continued development of oil opportunities in southern Alberta, the drilling of a Bakken well in southeast Saskatchewan, and natural gas drilling in response to stronger prices and good results in central Alberta. As a result of this increase, we now expect 2008 production to average between 55,000 and 56,000 boe/d.

A key element underpinning our sustainability is our attractive near and longer term enhanced oil recovery (EOR) projects. We made good progress on EOR projects being implemented in 2008, as well as some additional projects that may be undertaken within the next 12- 18 months. At Wainwright, we finalized the design of our Alkaline Surfactant Polymer flood during the quarter and will continue to procure equipment while aiming to commence polymer injection early in the fourth quarter. We received approvals for pipelines to proceed with our enhanced waterflood project at Bellshill Lake, designed to increase pressure support and 'push' more oil out of the reservoir. Equipment scoping and procurement for this project is expected to continue through the second quarter with commencement of pipeline construction expected to begin in the third quarter. At Suffield, we have completed the testing of the first injection well and finalized scoping of the second injection well, both of which will allow water transferred from our Batus pool to be re-injected into our Lark pool, improving pressure support and enhancing recovery. At Hay River, we completed and tied-in five water source wells resulting in a 20% increase in water injection into the Bluesky formation which is expected to support enhanced production levels achieved through optimization undertaken during the quarter.

Future EOR opportunities that could be implemented as early as 2009 have been identified in Hayter, Hay River, Kindersley and southeast Saskatchewan, while CO_2 flooding, oilsands and coal bed methane (CBM) represent longer term recovery opportunities for Harvest. At Hayter, a solvent/gas injection project resulted in incremental oil being produced from the injected well on a cyclic stimulation test with over 90% of the injected gas being recovered from the reservoir. At Hay River, we commenced reservoir simulation studies designed to optimize the impact on production and reserves of enhanced waterflooding to re-establish reservoir pressure, and to assess the potential impact of polymer/surfactant injection given the similarity of the Bluesky reservoir to our Wainwright Sparky reservoir. With completion of the all-season access road constructed last year, installation and commissioning of commercial power, and ample source water, we believe we have an ideal combination of factors to proceed with a polymer / surfactant pilot in the near future to further enhance recovery of this large, original oil in place pool.

Downstream
We were also very pleased with the operational performance of the refinery during the first quarter, as throughput averaged 111,999 bbl/d, with product output averaging approximately 42% distillate (ultra low sulphur diesel and jet fuel), 33% gasoline and 25% high sulphur fuel oil (HSFO). We realized benefits from significantly improved performance from the crude and vacuum tower units following successful completion of a maintenance turnaround in the fourth quarter of 2007. Although margins for gasoline and HSFO were weaker during the first quarter than the same period in prior years, distillate margins were stronger than they have been historically and helped to partially offset weakness in the other two product streams. As a result, North Atlantic realized an average gross margin of US$8.90/bbl for the quarter.

Into the second quarter, distillate margins have remained at very attractive levels, while gasoline margins have started to slowly improve heading into the summer driving season. Unfortunately, we are still realizing weak HSFO margins primarily due to excess supply entering North America, but the impact of this situation on margins is expected to be mitigated by an offsetting improvement in the discounts for medium gravity, sour crude oils.

We invested approximately $6.0 million in capital at the refinery in the first quarter, which included $1.7 million to further advance the visbreaker expansion project, with the balance allocated to other incremental discretionary improvements. We are pleased that the visbreaker project is proceeding on schedule and budget with expected installation and related outage planned for late in the third quarter / early in the fourth quarter. We have already ordered any materials requiring long lead times and the required soaker drum unit is being fabricated with expected delivery before the end of July, 2008.

Through the quarter, SNC Lavalin continued their study to identify and scope some of the longer term growth opportunities at the refinery. Presently, we are in the process of short-listing high value refinery configurations, primarily focused on a variety of upgrading technologies utilizing a mix of medium and heavy sour crudes which would reduce or eliminate the production of the low margin HSFO product. Such upgrading technologies include new and expanded visbreaking process technologies or delayed coking. We anticipate that a final report with recommendations will be available late in the second quarter, which will enable us to begin the next phase of planning and engineering.

Corporate

In keeping with our Sustainable Growth strategy, we successfully strengthened our debt position in the quarter with a $250 million convertible debenture offering which closed in April. This offering creates additional room on our committed bank line which better positions Harvest to take advantage of value added acquisitions or development project opportunities. Given the numerous attractive investment opportunities we have available to us both within our existing asset base as well as through potential acquisitions, maintaining greater flexibility is important.

As we move forward through 2008, we will continue to execute our Sustainable Growth strategy, including investigating viable alternatives and planning for restructuring prior to implementation of the Canadian government's trust tax in 2011. We believe we are well positioned to meet operational expectations in both business segments, and are excited about the potential growth projects we have available to us through our internal portfolio as well as through acquisitions. While staying true to our value principles, we believe there are improved opportunities to make acquisitions in western Canada, while also being able to profitably divest of some non-core assets. Finally, we are also committed to raising awareness about Harvest amongst existing and potential investors across North America and Europe.

In closing, we thank all of our stakeholders for your ongoing 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, 2007 and 2006, our MD&A for the year ended December 31, 2007 as well as our interim consolidated financial statements and notes for the three month period ended March 31, 2008 and 2007. The information and opinions concerning our future outlook are based on information available at May 7, 2008.

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.

In this MD&A, we use certain financial reporting measures that are commonly used as benchmarks within the petroleum and natural gas industry such as Earnings From Operations, Cash General and Administrative Expenses and Operating Netbacks and with respect to the refining industry, Earnings from Operations and Gross Margin which are each defined in this MD&A. These measures are not defined under Canadian generally accepted accounting principles ("GAAP") and should not be considered in isolation or as an alternative to conventional GAAP measures. Certain of these measures are not necessarily comparable to a similarly titled measure of another issuer. When these measures are used, they are defined as "Non-GAAP measures" and should be given careful consideration by the reader. Please refer to the discussion under the heading "Non-GAAP Measures" at the end of this MD&A for a detailed discussion of these measures.

FORWARD-LOOKING INFORMATION

This MD&A highlights significant business results and statistics from our consolidated financial statements for the three months ended March 31, 2008 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, capital taxes, 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.

Financial and Operating Highlights – First Quarter 2008

- Cash from operating activities of $128.1 million as compared to $111.0 million in the prior year.
- Upstream operating cash flow of $230.8 million reflecting strong commodity prices with average daily production of 58,067 boe/d as compared to 58,416 boe/d in the Fourth Quarter of 2007.
- Upstream capital spending of $79.6 million including the drilling of 86 gross (57.8 net) wells with a success ratio of 100% and the advancement of various enhanced recovery initiatives.

- Downstream operating cash flow of $24.5 million reflecting stable throughput volumes of 111,999 bbl/d with an improved yield of gasoline and distillate products, higher margins for distillates offset by weaker refining margins for gasoline and high sulphur fuel oil products, tighter differentials for medium gravity crude oil feedstock and higher costs for purchased energy to provide heat for the refinery processes.
- Maintained our monthly distributions of $0.30 per trust unit through the quarter resulting in distributions declared as a percentage of cash from operating activities of 106% for the quarter.
- Subsequent to the end of the quarter, balance sheet liquidity bolstered with the issuance of $250.0 million of principal amount of 7.5% Convertible Unsecured Subordinated Debentures with the net proceeds of $239.5 million used to repay bank indebtedness.

SELECTED INFORMATION

The table below provides a summary of our financial and operating results for three month periods ended March 31, 2008 and 2007.

	Three Month Period Ended March 31		
($000s except where noted)	**2008**	2007	Change
Revenue, net[(1)]	**1,377,352**	1,025,512	34%
Cash From Operating Activities	**128,119**	111,048	15%
Per Trust Unit, basic	**$ 0.85**	$ 0.87	(2%)
Per Trust Unit, diluted	**$ 0.83**	$ 0.84	(1%)
Net Income (Loss)[(2)]	**(346)**	69,850	(100%)
Per Trust Unit, basic	**$ -**	$ 0.55	(100%)
Per Trust Unit, diluted	**$-**	$ 0.55	(100%)
Distributions declared	**135,167**	145,270	(7%)
Distributions declared, per Trust Unit	**$ 0.90**	$ 1.14	(21%)
Distributions declared as a percentage of Cash From Operating Activities	**106%**	131%	(25%)
Bank debt	**1,330,423**	1,363,222	(2%)
7 7/8% Senior Notes	**250,099**	279,612	(11%)
Convertible Debentures[(3)]	**628,929**	793,184	(21%)
Total long-term financial liabilities[(3)]	**2,209,451**	2,436,018	(9%)
Total assets	**5,574,528**	5,800,346	(4%)
UPSTREAM OPERATIONS			
Daily Production			
Light to medium oil (bbl/d)	**25,509**	27,034	(6%)
Heavy oil (bbl/d)	**12,980**	15,614	(17%)
Natural gas liquids (bbl/d)	**2,484**	2,496	-%
Natural gas (mcf/d)	**102,570**	101,282	1%
Total daily sales volumes (boe/d)	**58,067**	62,024	(6%)
Operating Netback ($/boe)	**45.34**	29.81	52%
Cash capital expenditures	**79,571**	148,487	(46%)
DOWNSTREAM OPERATIONS			
Average daily throughput (bbl/d)	**111,999**	113,711	(2%)
Aggregate throughput (mbbl)	**10,191**	10,234	-%
Average Refining Margin (US$/bbl)	**8.90**	11.85	(25%)
Cash capital expenditures	**6,027**	4,883	23%

(1) Revenues are net of royalties.
(2) Net Income (Loss) includes a future income tax recovery of $21.8 million (2007 – nil) and unrealized net loss from risk management activities of $60.9 million (2007 – $14.1 million) for the three months ended March 31, 2008.
(3) Includes current portion of Convertible Debentures.

REVIEW OF OVERALL PERFORMANCE

Harvest is an integrated energy trust with our petroleum and natural gas business focused on the operations and further development of assets in western Canada ("upstream operations") and our refining and marketing business focused on the safe operation of a medium gravity sour crude hydrocracking refinery and a retail and wholesale petroleum marketing business both located in the Province of Newfoundland and Labrador ("downstream operations").

Cash from operating activities of $128.1 million is comprised of cash flow contributions of $230.8 million and $24.5 million from the Upstream and Downstream Operations, respectively, offset by $36.3 million of cash settlements from risk management activities, $35.9 million of financing and other costs and $55.0 million of non-cash working capital adjustments. The year-over-year increase in cash from operating activities of $17.1 million is primarily attributed to a $72.1 million improvement in upstream operations and a $45.8 million reduction to non-cash working capital adjustments offset by a $70.4 million drop in contribution from downstream operations and a $36.0 million increase in cash settlements from cash flow risk management activities.

Cash provided from Upstream Operations totaled $230.8 million during the First Quarter of 2008, as compared to the $158.7 million in the first three months of the prior year. The strength in Canadian crude oil prices during the First Quarter of 2008 reflected a 68% increase in the WTI benchmark price and tighter heavy oil differentials offset by a 17% strengthening in the Canadian dollar relative to the US dollar. During the first quarter of 2008, our realized price averaged $71.41/boe as compared to $52.15 in the prior year, a 37% improvement in price, while average daily production of 58,067 boe/d during the quarter was 6% less than the First Quarter of 2007. Relative to the Fourth Quarter of 2007, production is substantially unchanged. During the First Quarter of 2008, production benefited from our recent drilling success at Chedderville and Dobson adding a significant boost to natural gas production as well as natural gas liquids. Operating cost averaged $13.69 per boe during the First Quarter of 2008, an increase of 6% over the First Quarter of the prior year and essentially unchanged from the average for 2007. Our netback price averaged $45.34 per boe during the First Quarter of 2008, a 52% increase over the First Quarter of last year.

During the First Quarter of 2008, Downstream Operations provided cash from operations totaling $24.5 million as compared to $94.9 million in First Quarter of the prior year, a reduction of 74% year-over-year. This reduction is primarily the result of a $50.9 million decrease in refining margins which has been attributed to lower margins for gasoline products and high sulphur fuel oil ("HSFO") partially offset by higher distillate margins coupled with lower differentials for medium sour crude oil feedstocks and a $19.1 million increase in the cost of purchased energy to provide heat for the refinery processes. During the First Quarter of 2008, our average refining margin was US$8.90 per barrel of throughput, a US$2.95 drop as compared to US$11.85 per barrel in the First Quarter of 2007. Our refinery throughput averaged 111,999 bbls/d during the First Quarter of 2008 as compared to 113,711 bbls/d in the First Quarter of the prior year. Daily throughput in the First Quarter of 2008 generally averaged in excess of 116,000 bbls/d but an unplanned four day partial outage resulted in a lower than average throughput for the quarter.

Our monthly distributions were $0.30 per Trust Unit during the First Quarter of 2008 and we have declared monthly distributions of $0.30 per Trust Unit for April, May, June and July of 2008. Unitholder participation in our distribution reinvestment programs generated $35.9 million of equity capital reflecting a 27% average level of participation.

On April 25, 2008, Harvest improved its financial liquidity with the issuance of $250 million principal amount of 7.50% Convertible Unsecured Subordinated Debentures for net proceeds of $239.5 million. The net proceeds were used to reduce bank indebtedness under our $1.6 billion Extendible Revolving Credit Facility. At the end of the first quarter, our bank debt to twelve month trailing earnings before interest, taxes depreciation and amortization ("EBITDA") was 1.7 times and subsequent to the issuance of the debentures on April 25, 2008, this financial ratio was 1.4 times with approximately $500 million of undrawn commitments available under our credit facility.

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

	Three Month Period Ended March 31					
	2008			2007		
(in $000's)	**Upstream**	**Downstream**	**Total**	Upstream	Downstream	Total
Revenue(1)	**314,933**	**1,062,419**	**1,377,352**	241,467	784,045	1,025,512
Earnings From Operations(2)	**113,251**	**7,740**	**120,991**	41,852	75,356	117,208
Capital expenditures	**79,571**	**6,027**	**85,598**	148,487	4,883	153,370
Total assets(3)	**3,962,295**	**1,592,586**	**5,574,528**	4,053,682	1,729,069	5,800,346

(1) Revenues are net of royalties.
(2) These are non-GAAP measures; please refer to "Non-GAAP Measures" in this MD&A.
(3) Total Assets on a consolidated basis as at March 31, 2008 includes $19.6 million (2007 - $17.6 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

First Quarter Highlights

- Daily production of 58,067 boe/d, a decrease of 6% from the First Quarter of 2007 and 1% from the Fourth Quarter of 2007.
- Continued strength in commodity prices resulting in an average realized price for the quarter of $71.41/boe.
- Capital expenditures of $79.6 million, of which $56.4 million was spent drilling 86.0 gross wells and $16.4 million was spent on well equipment, pipelines and facilities including enhanced oil recovery projects.
- First Quarter 2008 Operating Netback of $45.34/boe, reflecting strong commodity prices offset by increased royalties and operating expenses.

Summary of Financial and Operating Results

	Three Month Period Ended March 31		
(in $000's)	**2008**	2007	Change
Revenues	**$ 377,333**	$ 291,116	30%
Royalties	**(62,400)**	(49,649)	26%
Net revenues	**314,933**	241,467	30%
Operating expenses	**72,323**	72,296	-%
General and administrative	**11,909**	10,104	18%
Transportation and marketing	**3,025**	2,812	8%
Depreciation, depletion, amortization and accretion	**114,425**	114,403	-%
Earnings From Operations[(1)]	**113,251**	41,852	171%
Cash capital expenditures (excluding acquisitions)	**79,571**	148,487	(46%)
Property and business acquisitions, net of dispositions	**185**	30,953	(99%)
Daily sales volumes			
Light to medium oil (bbl/d)	**25,509**	27,034	(6%)
Heavy oil (bbl/d)	**12,980**	15,614	(17%)
Natural gas liquids (bbl/d)	**2,484**	2,496	-%
Natural gas (mcf/d)	**102,570**	101,282	1%
Total (boe/d)	**58,067**	62,024	(6%)

(1) These are non-GAAP measures; please refer to "Non-GAAP Measures" in this MD&A.

Commodity Price Environment

	Three Month Period Ended March 31		
Benchmarks	**2008**	2007	Change
West Texas Intermediate crude oil (US$ per barrel)	**97.90**	58.16	68%
Edmonton light crude oil ($ per barrel)	**97.35**	67.11	45%
Bow River blend crude oil ($ per barrel)	**77.72**	50.04	55%
AECO natural gas daily ($ per mcf)	**7.90**	7.40	7%
Canadian / U.S. dollar exchange rate	**0.996**	0.854	17%

The average First Quarter 2008 West Texas Intermediate ("WTI") benchmark price increased 68% over the First Quarter 2007 average price, reflecting a generally steady increase throughout the past twelve months. The average Edmonton light crude oil price ("Edmonton Par") has also increased steadily throughout the past twelve months, resulting in a First Quarter 2008 average price of $97.35, an increase of 45% over the First Quarter of the prior year. This increase has been less than that of the WTI benchmark price due to a strengthened Canadian dollar relative to the US dollar, which has increased 17% compared to the First Quarter of 2007.

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. In the First Quarter of 2008, very cold weather across Alberta contributed to heavy oil production disruptions, reducing supply and shrinking the differential relative to Edmonton Par to 20.2% as compared to 25.4% in the same period in the prior year.

	2008	2007				2006		
Differential Benchmarks	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Bow River Blend differential to Edmonton Par	**20.2%**	34.2%	30.0%	29.4%	25.4%	30.3%	25.8%	22.9%

The cold winter weather in Canada and the northern United States contributed to increased demand for natural gas which increased the average AECO daily natural gas price during the First Quarter of 2008 by 7% from $7.40/mcf in the prior year to $7.90/mcf.

Realized Commodity Prices(1)

The following table summarizes our average realized price by product for the three month periods ended March 31, 2008 and 2007.

	Three Month Period Ended March 31		
	2008	2007	Change
Light to medium oil ($/bbl)	**86.54**	58.90	47%
Heavy oil ($/bbl)	**69.04**	44.54	55%
Natural gas liquids ($/bbl)	**78.04**	52.78	48%
Natural gas ($/mcf)	**8.28**	8.05	3%
Average realized price ($/boe)	**71.41**	52.15	37%

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

In the First Quarter of 2008, our average realized price was 37% higher than the First Quarter of 2007, with every product realizing a higher average price than the comparative period in the prior year.

Our realized price for light to medium oil sales increased 47% in the first three months of 2008 compared to the same period in the prior year, reflecting the 45% increase in Edmonton Par pricing over the First Quarter of 2007 coupled with improved quality differentials realized on our light to medium oil production relative to the Edmonton Par price.

Harvest's heavy oil price increased 55% in the First Quarter of 2008 relative to the First Quarter of 2007, reflecting the 55% increase in the average posted Bow River price for the same periods. As Harvest's last significant heavy oil property acquisition took place in the First Quarter of 2007, the average API gravity of our heavy oil production has remained relatively unchanged in the past twelve months, typically resulting in realized prices of approximately 89% of the posted Bow River price.

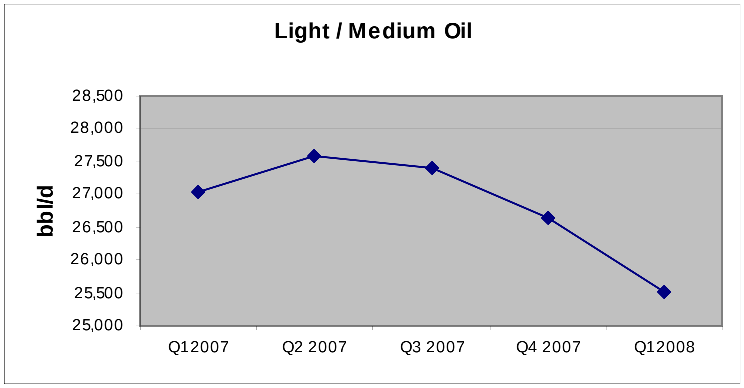
The average realized price for our natural gas production was 3% higher in the First Quarter of 2008 than in the First Quarter of 2007 despite an increase of 7% in AECO daily pricing over the same period. Throughout the First Quarter of 2007, we marketed approximately 60% of our natural gas production on the AECO daily price, 30% on the AECO monthly price and the remaining production was sold to aggregators. Commencing in January 2008, substantially all of our natural gas production was sold at the AECO daily price. This change in marketing arrangements has resulted in a lower increase in total realized natural gas pricing over the prior year. Our larger natural gas producing properties generally have a higher than average heat content, which realizes a premium in its pricing.

Sales Volumes

The average daily sales volumes by product were as follows:

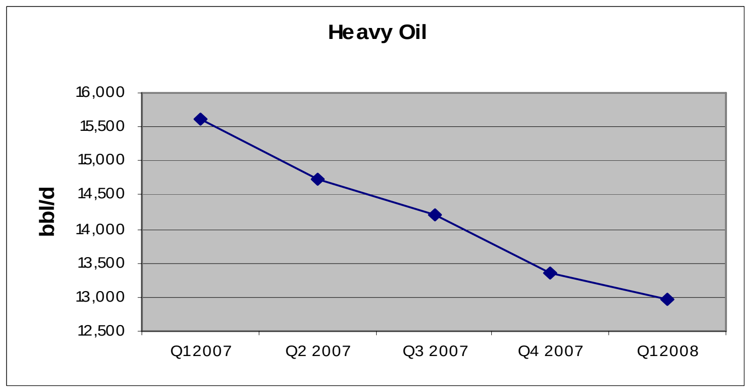
	Three Month Period Ended March 31				
	2008		2007		
	Volume	**Weighting**	Volume	Weighting	% Volume Change
Light to medium oil (bbl/d)(1)	**25,509**	**44%**	27,034	44%	(6%)
Heavy oil (bbl/d)	**12,980**	**22%**	15,614	25%	(17%)
Natural gas liquids (bbl/d)	**2,484**	**4%**	2,496	4%	-%
Total liquids (bbl/d)	**40,973**	**70%**	45,144	73%	(9%)
Natural gas (mcf/d)	**102,570**	**30%**	101,282	27%	1%
Total oil equivalent (boe/d)	**58,067**	**100%**	62,024	100%	(6%)

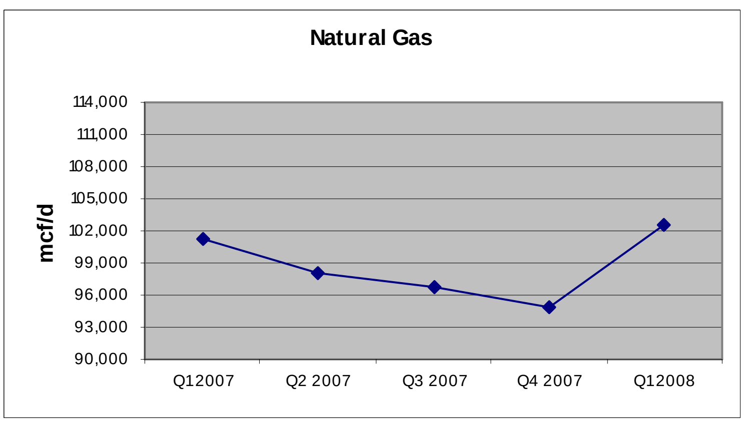
(1) Harvest classifies our oil production, except that produced from Hay River, as light to medium and heavy according to NI 51-101 guidance. The oil produced from Hay River has an average API of 24° (medium grade) and is classified as a light to medium oil, however, it benefits from a heavy oil royalty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



The First Quarter of 2008 light/medium oil production was 25,509 bbl/d, which is a 1,525 bbl/d decrease from the First Quarter of 2007 and a 1,131 bbl/d decrease from the Fourth Quarter of 2007. The decrease in production in the First Quarter of 2008 relative to the Fourth Quarter of 2007 is mainly attributed to the sale of approximately 280 bbl/d of assets in the southeast Saskatchewan area in the Fourth Quarter of 2007, low levels of capital drilling activity in the Fourth Quarter of 2007 resulting in incremental production insufficient to offset natural production declines, and production disruptions related to the cold weather experienced in January coupled with downtime associated with service work. Compared to the First Quarter of 2007, production was reduced by steeper than expected declines on our Hay River 2007 winter drilling program as well as the items noted above.

Our heavy oil production has decreased steadily over the past twelve months resulting in First Quarter 2008 production of 12,980 bbl/d compared to 15,614 bbl/d in the First Quarter of 2007, a reduction of 17% year-over-year. In December 2007, heavy oil production was approximately 13,000 bbl/d as production was lost due to increased water cuts in some larger producing wells as well as well servicing resulting in downtime. Throughout the First Quarter of 2008 this trend continued, despite bringing on additional production through the acquisition of some heavy oil properties late in December 2007 and service work completed in the Fourth Quarter of 2007, as production was lost due to operational problems resulting from cold weather and shut-in wells to accommodate nearby drilling activity.





Our First Quarter of 2008 natural gas production increased by 1% over the First Quarter of 2007, averaging 102,570 mcf/d. Relative to the Fourth Quarter of 2007, First Quarter of 2008 natural gas production has increased by 8%, primarily due to new wells drilled in 2007 and during the First Quarter of 2008 coupled with increased run time on some of our other wells. Throughout 2007, our natural gas production had been steadily declining as we faced higher than anticipated decline rates on properties acquired in 2006 as well as encountered disruptions from various third party processing facility turnarounds, one of which lasted for an extended period, reducing quarterly volumes by 1,600 mcf/d.

Revenues

	Three Month Period Ended March 31		
(000s)	**2008**	2007	Change
Light to medium oil sales	**$ 200,875**	$ 143,305	40%
Heavy oil sales	**81,552**	62,585	30%
Natural gas sales	**77,270**	73,370	5%
Natural gas liquids sales and other	**17,636**	11,856	49%
Total sales revenue	**377,333**	291,116	30%
Royalties	**(62,400)**	(49,649)	26%
Net Revenues	**$ 314,933**	$ 241,467	30%

Our revenue is impacted by changes to production volumes, commodity prices, and currency exchange rates. First Quarter of 2008 total sales revenue of $377.3 million is $86.2 million higher than the prior year, of which $101.0 million is attributed to higher realized prices offset by $14.7 million in respect of lower production volumes. The price increase reflects the 45% increase in Edmonton Par pricing in the First Quarter of 2008 as compared to the First Quarter of 2007, while our decreased production volume is attributed to the higher than anticipated decline rates experienced throughout 2007 coupled with various operational difficulties.

Light to medium oil sales revenue for the First Quarter of 2008 was $57.6 million higher than in the comparative period, due to a $64.2 million favourable price variance offset by a $6.6 million unfavourable volume variance. The price variance reflects a 45% increase in Edmonton par pricing relative to the First Quarter of the prior year plus improved differentials with a negative volume variance reflecting normal declines coupled with operational problems in the First Quarter of 2008.

First Quarter of 2008 heavy oil sales revenue of $81.6 million was $19.0 million higher than in the prior year due to a $28.9 million favourable price variance resulting from tighter heavy oil differentials relative to the First Quarter of 2007, offset by a $9.9 million unfavourable volume variance reflecting a natural decline rate.

Natural gas sales revenue increased by $3.9 million in the First Quarter of 2008 compared to the same period in 2007 due to a $2.1 million favourable price variance coupled with a $1.8 million favourable volume variance. The favourable price variance reflects the $0.23/mcf increase in our realized natural gas prices resulting from a 7% increase in the AECO daily price relative to the prior year coupled with a shift to market substantially all of our gas volumes at AECO daily pricing. The favourable volume variance is primarily attributed to the incremental gas production from new wells coming online in late December 2007 and early 2008 and a relative increase in run time from existing wells.

In the First Quarter of 2008, natural gas liquids and other sales revenue increased by $5.8 million compared to the First Quarter of the prior year resulting from a $5.7 million favourable price variance and a $0.1 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.

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.

Throughout the First Quarter of 2008 net royalties as a percentage of gross revenue were 16.5% (17.1% in the First Quarter of 2007) and aggregated to $62.4 million (2007 - $49.6 million). Our royalty rate for the First Quarter of 2008 was slightly lower than the expected rate of 17% due in part to over-delivery and low production credits received in the quarter as well as other minor prior period adjustments.

Operating Expenses

	Three Month Period Ended March 31				
	2008		2007		Per BOE
(000s except per boe amounts)	**Total**	**Per BOE**	Total	Per BOE	Change
Operating expense					
Power and fuel	**$ 18,500**	**$ 3.50**	$ 15,778	$ 2.83	24%
Well Servicing	**11,198**	**2.12**	17,209	3.08	(31%)
Repairs and maintenance	**11,686**	**2.21**	11,791	2.11	5%
Lease rentals and property taxes	**7,505**	**1.42**	3,740	0.67	112%
Processing and other fees	**2,207**	**0.42**	4,859	0.87	(52%)
Labour – internal	**6,322**	**1.20**	6,654	1.19	1%
Labour – contract	**3,901**	**0.74**	3,999	0.72	3%
Chemicals	**4,089**	**0.77**	3,557	0.64	20%
Trucking	**2,797**	**0.53**	3,047	0.55	(4%)
Other	**4,118**	**0.78**	1,662	0.29	169%
Total operating expense	**72,323**	**13.69**	72,296	12.95	6%
Transportation and marketing expense	**$ 3,025**	**$ 0.57**	$ 2,812	$ 0.50	14%

First Quarter 2008 operating costs totaled $72.3 million, unchanged from the operating costs incurred in the First Quarter of 2007. On a per barrel basis, our operating costs have increased to $13.69 in the first three months of 2008 compared to $12.95 during the same period in the prior year, a 6% increase as a result of reduced production volume. The largest components of operating expense are power and fuel costs, well servicing and repairs and maintenance costs. Well servicing and repairs and maintenance costs reflect the continued high demand for oilfield services, although with reduced activity compared to the same period in the prior year, we have seen reductions in the per barrel well servicing cost while repairs and maintenance costs have remained relatively stable. Lease rentals and property tax expenses have increased 112% to $1.42/boe in the First Quarter of 2008 relative to the First Quarter of 2007. Of this increase, approximately $1.0 million reflects increased rate estimates for the current year, mainly for property taxes and government fees. The remaining $2.8 million of the increase is a result of lower than average expense recorded in the First Quarter of 2007 coupled with additional costs recognized in the First Quarter of 2008 to more accurately provide for our 2008 expected lease rental and property tax costs.

Power and fuel costs, comprised primarily of electric power costs, represented approximately 26% of our total operating costs during the First Quarter of 2008. Electric power prices of $76.69/MWh in the First Quarter of 2008 were 21% higher than the First Quarter 2007 average of $63.62/MWh and this is reflected in Harvest's 24% increase in power and fuel costs over the prior year. To manage our exposure to electric power price fluctuations we have electric power price risk management contracts in place which resulted in a gain of $1.5 million in the First Quarter 2008 compared to a gain of $0.5 million in the same period of 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 Month Period Ended March 31		
(per boe)	**2008**	2007	Change
Electric power and fuel costs	**$ 3.50**	$ 2.83	24%
Realized gains on electricity risk management contracts	**(0.29)**	(0.09)	222%
Net electric power costs	**$ 3.21**	$ 2.74	17%
Alberta Power Pool electricity price (per MWh)	**$ 76.69**	$ 63.62	21%

Approximately 52% of our estimated Alberta electricity usage is protected by fixed price purchase contracts at an average price of $56.69 per MWh through December 2008. These contracts moderate the impact of future price swings in electric power as will capital projects undertaken that contribute to improving our efficient use of electric power.

First Quarter 2008 transportation and marketing expense was $3.0 million or $0.57 per boe, an increase of 14% per boe from $2.8 million or $0.50 per boe in the First Quarter of 2007. These 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 fluctuate in relation with our natural gas production volumes and the cost per boe is expected to remain relatively constant.

Operating Netback

	Three Month Period Ended March 31	
(per boe)	**2008**	2007
Revenues	**$ 71.41**	$ 52.15
Royalties	**(11.81)**	(8.89)
Operating expense	**(13.69)**	(12.95)
Transportation and marketing expense	**(0.57)**	(0.50)
Operating netback(1)	**$ 45.34**	$ 29.81

(1) These are non-GAAP measures; please refer to "Non-GAAP Measures" in this MD&A.

Our operating netback represents the net amount realized on a per boe basis after deducting directly related costs. In the First Quarter of 2008, our operating netback increased by $15.53/boe or 52% over the First Quarter of 2007. The increase in our operating netback is primarily attributed to a $19.26/boe increase in realized commodity prices, reflecting the increase in Edmonton Par and Bow River pricing over the prior year, offset by an increase in royalties of $2.92/boe resulting from higher realized prices and a $0.74/boe increase in operating expenses.

General and Administrative ("G&A") Expense

	Three Month Period Ended March 31		
(000s except per boe)	**2008**	2007	Change
Cash G&A	**$ 8,469**	$ 7,205	18%
Unit based compensation expense	**3,440**	2,899	19%
Total G&A	**$ 11,909**	$ 10,104	18%
Cash G&A per boe ($/boe)	**$ 1.60**	1.29	24%

For the three months ended March 31, 2008, Cash G&A costs increased by $1.3 million (or 18%) compared to the same period in 2007. Approximately $0.7 million of this increase is related to salaries and a further $0.4 million is related to increased consulting costs, reflecting the current tight market for technically qualified staff in the western Canadian petroleum and natural gas industry. Generally, approximately 75% of our Cash G&A expenses are related to salaries and other employee related costs.

Our unit based compensation plans provide the employee 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. The market price of our Trust Units was $20.63 at January 1, 2008 and on March 31, 2008, the price was $23.00. This increase in unit value coupled with an increasing number of outstanding awards becoming vested resulted in a First Quarter of 2008 unit based compensation expense of $3.4 million. Total unit based compensation expense increased $0.5 million in the First Quarter of 2008 compared to the same period in 2007 due to the increased number of awards vested.

Depletion, Depreciation, Amortization and Accretion Expense

	Three Month Period Ended March 31		
(000s except per boe)	**2008**	2007	Change
Depletion, depreciation and amortization	**$ 106,204**	$ 105,896	-%
Depletion of capitalized asset retirement costs	**3,624**	4,061	(11%)
Accretion on asset retirement obligation	**4,597**	4,446	3%
Total depletion, depreciation, amortization and accretion	**$ 114,425**	$ 114,403	-%
Per boe	**$ 21.65**	$ 20.49	6%

Our overall depletion, depreciation, amortization and accretion ("DDA&A") expense for the three months ended March 31, 2008 was substantially unchanged from the same period in the prior year, resulting from a reduced level of production offset by slightly higher finding and development costs that have increased our depletion rate compared to the same period of the prior year.

Capital Expenditures

	Three Month Period Ended March 31	
(000s)	**2008**	2007
Land and undeveloped lease rentals	**$ 985**	$ 160
Geological and geophysical	**3,136**	4,014
Drilling and completion	**56,376**	78,284
Well equipment, pipelines and facilities	**16,408**	63,345
Capitalized G&A expenses	**2,666**	2,553
Furniture, leaseholds and office equipment	**-**	131
Development capital expenditures excluding acquisitions and non-cash items	**79,571**	148,487
Non-cash capital additions (recoveries)	**543**	415
Total development capital expenditures excluding acquisitions	**$ 80,114**	$ 148,902

In the First Quarter of 2008, we incurred capital expenditures of $79.6 million to pursue drilling opportunities and advance a number of enhanced recovery initiatives.

In southeast Saskatchewan we drilled 16 gross (14.5 net) horizontal wells for a total expenditure of $13.6 million and continue to develop the Tilston and Souris Valley opportunities in our southeast Saskatchewan land holdings to take advantage of the strong oil prices on light oil production. Harvest also has access to approximately 11,000 gross acres of prospective Bakken mineral rights which we will be evaluating in the second quarter.

We drilled 12 gross (11.3 net) wells targeting light oil from the Slave Point and Granite Wash formations in the Red Earth area including the area's first horizontal well. This well is expected to access oil reserves in the tighter Slave Point reservoir matrix which may open significant undeveloped acreage to further development. We also completed some optimization projects including the installation of electric submersible pumps in existing wells to increase fluid production that will be handled at the newly expanded EVI 3 battery that was commissioned in the Fourth Quarter of 2007.

During the First Quarter of 2008, we commissioned electrical service for our wells and facilities at Hay River, allowing for increased water injection to enable improved recovery and optimize fluid production without drilling any new wells. We also commissioned a new gas plant at Hay River in the quarter, and expect to be selling additional gas that is currently being flared.

We continued to drill horizontal wells at Suffield and Lloydminster, continuing our ongoing exploitation of these larger oil pools with our economics enhanced by strong prices.

At Dobson, we followed up on an earlier gas find and drilled a 100% working interest well that tested at approximately 2,000 mcf/d. An additional 2 locations are planned for the remainder of 2008.

The Alkaline Surfactant Polymer pilot at Wainwright progressed with the ordering of necessary equipment, enabling the commencement of injection in the Fourth Quarter. We have received pipeline approvals for the enhanced water injection at Bellshill Lake and have also acquired the working interest of a minor owner increasing Harvest's ownership in the Bellshill Lake unit to 100%.

The following summarizes Harvest's participation in gross and net wells drilled during the first three month of 2008:

	Total Wells		Successful Wells		Abandoned Wells	
Area	**Gross[1]**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Hay River	-	-	-	-	-	-
Southeast Saskatchewan	16.0	14.5	16.0	14.5	-	-
Markerville	22.0	6.6	22.0	6.6	-	-
Lloydminster	6.0	6.0	6.0	6.0	-	-
Red Earth	12.0	11.3	12.0	11.3	-	-
Suffield	8.0	8.0	8.0	8.0	-	-
Hayter	-	-	-	-	-	-
Other Areas	22.0	11.4	22.0	11.4	-	-
Total	86.0	57.8	86.0	57.8	-	-

(1) Excludes 9 additional wells 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 as the expenditure occurs. 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 $1.7 million during the First Quarter of 2008 as a result of additional obligations incurred through our drilling activity throughout the period of $0.6 million and accretion expense of $4.6 million offset by $2.3 million of actual asset retirement expenditures incurred and a minor revision of $1.2 million to our estimated obligation.

DOWNSTREAM OPERATIONS

First Quarter Highlights

- Continued strong refinery operating performance with an improved yield of gasoline and distillate products while an increase in average daily processing offsets the impact of a four day unplanned partial outage.
- First Quarter of 2008 per barrel refining margin of US$8.90 is an increase of US$2.90 from the Fourth Quarter of 2008 and a US$2.95 shortfall as compared to the First Quarter of 2007 with price increases for refined products insufficient to offset the increases in the cost of feedstock.
- Operating costs remain relatively consistent at $2.10 per barrel of throughput compared to $2.06 in the prior year.
- Cost of purchased energy rises to $4.23 per barrel of throughput from $2.35 in the prior year reflecting a significantly higher commodity price environment.

Summary of Financial and Operational Results

(in $000's except where noted below)	**Three Month Period Ended March 31**	
	2008	2007
Revenues	**1,062,419**	784,045
Purchased feedstock for processing and products purchased for resale	**959,992**	632,296
Gross Margin(1)	**102,427**	151,749
Costs and expenses		
Operating expense	**25,895**	25,361
Purchased energy expense	**43,127**	24,000
Marketing expense	**8,597**	7,343
General and Administrative	**568**	300
Depreciation and amortization expense	**16,500**	19,389
Earnings (loss) from operations(1)	**7,740**	75,356
Cash capital expenditures	**6,027**	4,883
Feedstock volume (bbl/day)(2)	**111,999**	113,711
Yield (000's barrels)		
Gasoline and related products	**3,417**	3,310
Ultra low sulphur diesel and jet fuel	**4,261**	4,213
High sulphur fuel oil	**2,566**	2,745
Total	**10,244**	10,268
Average Refining Margin (US$/bbl)(3)	**8.90**	11.85

(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 margin is calculated based on per barrel of feedstock throughput

Overview of Downstream Performance

During the first quarter of 2008, cash flow from downstream operations totaled $24.5 million as compared to $94.9 million in the prior year, a drop of $70.4 million. This 74% reduction in cash flow in 2008 is primarily the result of a $50.9 million decrease in refining margins which has been attributed to lower margins for gasoline products and high sulphur fuel oil ("HSFO") partially offset by higher distillate margins and lower differentials for our medium sour feedstocks and a $19.1 million increase in the cost of purchased energy to provide heat for refinery processes. During the first quarter of 2008, our average refining margin was US$8.90 per barrel of throughput, a drop of US$2.95 per barrel as compared to US$11.85 per barrel for the first quarter of 2007.

Refinery throughput averaged 111,999 bbl/d during the first quarter of 2008 as compared to 113,711 bbl/d in the prior year. While the daily throughput in 2008 was generally in excess of 116,000 bbl/d, we experienced a four day unplanned partial outage in February which offset our higher daily rate. The outage was required to replace a worn pipe impacting the crude unit. Subsequent to the outage, throughput returned to an average daily rate in excess of 116,000 bbl/d.

Relative to the industry benchmark prices for RBOB gasoline, heating oil and HSFO, we realized premium prices for distillates and HSFO of US$5.99 per barrel and US$0.61 per barrel, respectively, while our prices for gasoline products were discounted by US$3.98 per barrel. The premium price for distillates reflects the low sulphur content of our regulatory compliant diesel fuels. As compared to the first quarter of 2007, the premiums we received for distillate and HSFO has improved while a slight premium for gasoline products in 2007 has eroded to a discount in 2008. On a year-over-year basis, the improvement in our realized prices relative to the various benchmark prices was not sufficient to offset a significantly less robust refining environment as the increase to sales prices for gasoline products, distillates and HSFO of 41%, 63% and 77%, respectively, were not enough to offset an 81% increase in the cost of feedstock.

During the first quarter of 2008, we shifted our slate of crude oil feedstock with an increase and diversification of Russian sourced crude and the addition of a second crude from Iraq to offset a reduction in Basrah Light. Our average cost for crude oil feedstock was a net discount of US$5.28 per barrel during the first quarter of 2008 as compared to a net discount of US$7.09 in the prior year, a US$1.81 per barrel change. In addition, our processing of purchased vacuum gas oil ("VGO") was reduced by 67,000 barrels during the first quarter of 2008 as compared to the prior year due a higher VGO cut attributed to the incremental Russian crude.

Except for the cost of purchased energy, our operating costs were essentially unchanged during the first quarter of 2008 as compared to the prior year, $25.9 million in 2008 and $25.4 million in 2007. However, our cost of purchased energy increased to $43.1 million as compared to $24.0 million in the prior year, a $19.1 million increase as a result of increased prices for purchased fuel oil to heat the refinery processes.

Refining Benchmark Prices

The North American refining industry has numerous pricing benchmarks against which to compare refinery gross margin performance. Typically, these gross margin indicators include prices for refined products such as Reformulated Blendstock for Oxygenate Blending gasoline ("RBOB gasoline") and heating oil. The New York Mercantile Exchange ("NYMEX") "2-1-1 Crack Spread" is such an indicator and is calculated assuming that the processing of two barrels of light sweet crude oil (defined as a WTI quality) yields one barrel of RBOB gasoline and one barrel of heating oil both of which are delivered to the New York market where product prices are set in relation to NYMEX RBOB gasoline and NYMEX heating oil prices. The following average prices, gross margin indicators and currency exchange rates are provided as reference points with which to index our refinery's performance:

	Three Month Period Ended March 31		
	2008	**2007**	**Change**
WTI crude oil (US$ per barrel)	**97.90**	58.16	68%
Brent crude oil (US$ per barrel)	**93.39**	58.63	59%
Basrah Official Sales Price ("OSP") (US$ per barrel)	**(7.78)**	(7.62)	2%
RBOB gasoline (US$ per barrel)	**104.36/2.48**	70.77/1.69	47%
Heating oil (US$ per barrel)	**115.10/2.74**	69.86/1.66	65%
High Sulphur Fuel Oil (US$ per barrel)	**70.43**	39.85	77%
2-1-1 Crack Spread (US$ per barrel)	**11.83**	12.14	(3%)
Canadian / US dollar exchange rate	**0.996**	0.854	17%

During the three month period ended March 31, 2008, the "2-1-1 Crack Spread" benchmark decreased US$0.31 per barrel as compared to the prior year period as a result of an increase in the WTI benchmark price of US$39.74 being only partially offset by a US$33.59 per barrel (US$0.80 per gallon) increase in the RBOB gasoline benchmark price and a US$45.24 per barrel (US$1.08 per gallon) increase in the heating oil benchmark price.

As compared to the "2-1-1 Crack Spread" indicator, our refinery's production differs in that it also produces approximately 25% to 30% HSFO not represented in the "2-1-1 Crack Spread" indicator. HSFO typically sells at a discount to the WTI benchmark price resulting in a negative contribution to our gross margin relative to the "2-1-1 Crack Spread." On the other hand, our refinery also processes a medium gravity sour crude oil rather than a WTI quality of light sweet crude oil which sells at a discount to the WTI benchmark price. To optimize the throughput of our Isomax hydrocracker unit, we typically purchase approximately 8,000 to 10,000 bbl/d of VGO which can sell at either a premium or discounted price to the WTI benchmark price which further complicates the comparison of our refining margin to the "2-1-1 Crack Spread."

Downstream Gross Margin

The following summarizes the downstream operations' gross margin contributions for each of the three month periods ended March 31, 2008 and 2007 segregated between refining activities and marketing and other related businesses.

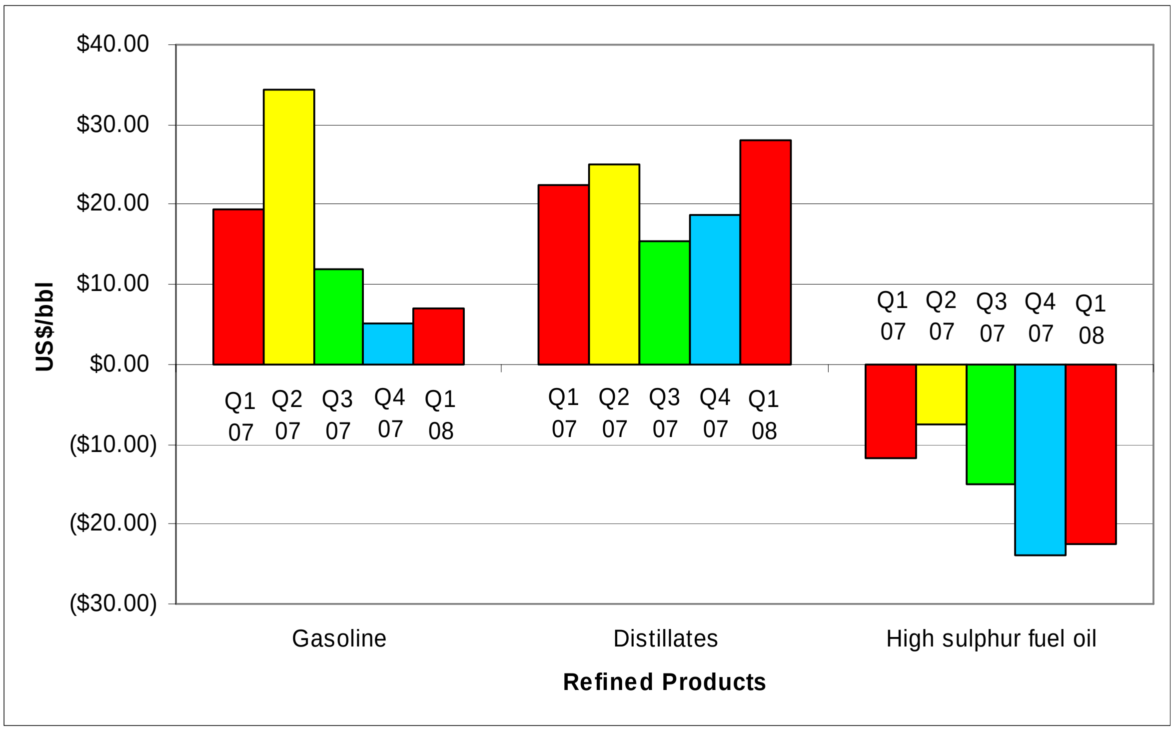
	Three Month Period Ended March 31					
	2008			2007		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	Refining	Marketing	Total
Sales revenue(1)	**1,036,631**	**144,006**	**1,062,419**	761,337	91,290	784,045
Cost of feedstock for processing and products for resale(1)	**945,599**	**132,611**	**959,992**	619,386	81,492	632,296
Gross margin(2)	**91,032**	**11,395**	**102,427**	141,951	9,798	151,749
Average Refining Margin (US$/bbl)	**$8.90**			$11.85		

(1) Downstream operations sales revenue and cost of products for processing and resale are net of inter-segment sales of $118,218,000 and $68,582,000, reflecting the refined products produced by the refinery and sold by Marketing Division for the three month periods ended March 31, 2008 and 2007, respectively.
(2) These are non-GAAP measures; please refer to "Non-GAAP Measures" in this MD&A.

The gross margin from refining operations totaled $91.0 million during the first quarter of 2008, a reduction of $50.9 million compared to the prior year, reflecting an average refining margin of US$8.90 per barrel of throughput in 2008 as compared to US$11.85 per barrel of throughput in 2007, a 25% decrease of US$2.95/bbl. During the first quarter of 2008, the average sales price of our refined products was US$102.17/bbl which as compared to the average WTI benchmark price of US$97.90 results in a US$4.27/bbl differential while in the prior year, our refined products received an average sales price of US$64.29/bbl as compared to a WTI price of US$58.16 and a US$6.13/bbl differential. Relative to the WTI benchmark price, the pricing differential of our refined products dropped by US$1.86 per barrel in 2008, a 30% reduction year-over-year.

The cost of refinery feedstock in the first quarter of 2008 averaged US$93.44/bbl, a US$4.46/bbl discount compared to the WTI benchmark price of US$97.90 while our average cost of US$51.73/bbl in the prior year represented a US$6.43/bbl discount off the WTI benchmark price of US$58.16. Year-over-year, the cost of feedstock relative to the WTI benchmark price has risen by US$1.97 reflecting a 31% reduction in the discount.

The following chart summarizes Harvest's refining margin by product per barrel over the past five quarters:



While our average sales price per barrel relative to the WTI benchmark price has dropped by US$1.86 and the cost of our feedstock relative to the WTI benchmark price has increased by US$1.97, our gross margin has only dropped by US$2.95 per barrel during the first quarter on a year-over-year basis. The US$0.88 per barrel discrepancy in this gross margin analysis is attributed to the year-over-year improvement in yield of distillates and gasoline products at the expense of lower priced HSFO as well as the reduced processing of purchased VGO.

Relative to the "2-1-1 crack spread" benchmark of US$11.83 during the first quarter of 2008, our refining margin of US$8.90/bbl reflects a differential of US$2.93/bbl as compared to a differential of US$0.29/bbl in the prior year. The reason for the increase in the differential is primarily the significant increase in the discount for our HSFO selling price in 2008 relative to the WTI benchmark price coupled with by a tightening of the discount in the cost of medium gravity sour crude oil feedstock. In the first quarter of 2008, the average selling price of our HSFO was US$71.04/bbl, a discount of US$26.86/bbl relative the WTI benchmark price as compared to an average selling price of US$40.08 and a discount of US$18.08 in the prior year.

The Marketing Division is comprised of the retail and wholesale distribution of gasoline, diesel, jet and other transportation fuels as well as home heating fuels and related appliances and the revenues from our marine services including tugboat revenues. During the first quarter of 2008, the gross margin contributed by our marketing division increased by 16% as compared to the prior year primarily due to a change in the internal transfer pricing between the refinery and the Marketing Division to reflect internal transfer pricing competitive with the pricing in the Supply and Offtake Agreement with Vitol Refining S.A. ("Vitol").

Refined Product Sales Revenue

All of our gasoline and distillate products are sold to Vitol pursuant to the Supply and Offtake Agreement with the exception of products sold in Newfoundland through our marketing division. Effective January 20, 2008, we commenced selling all of our HSFO to a wholly-owned affiliate of one of the world's largest integrated oil and natural gas producers. Prior to January 20, 2008, the HSFO had also been sold to Vitol. With the exception of the sales to Vitol, our refined products are sold at prices that reflect market prices at the time that the product is delivered to the purchaser. The Supply and Offtake Agreement has pricing terms that reflect market prices based on an average delay of ten days which results in our sales to Vitol and our cost of refinery feedstock purchased from Vitol being based on a slightly different time period than the prices at the time of delivery. For more information on the Supply and Offtake Agreement with Vitol, see the description of the Supply and Offtake Agreement in our Annual Information Form for the year ended December 31, 2007 as filed on SEDAR at www.sedar.com.

A comparison of our refinery yield, product pricing and revenue for each of the three month periods ended March 31, 2008 and 2007 is presented below.

	Three Month Period Ended March 31					
	2008			2007		
	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	**355,564**	**3,528**	**100.38/2.39**	277,227	3,333	71.03/1.69
Distillates	**512,586**	**4,216**	**121.09/2.88**	360,810	4,154	74.18/1.77
High sulphur fuel oil	**168,481**	**2,362**	**71.04**	123,300	2,627	40.08
	1,036,631	**10,106**		761,337	10,114	
Inventory adjustment		**138**			154	
Total production		**10,244**			10,268	
Yield (as a % of Feedstock) (2)		**101%**			100%	

(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

Our refinery sales revenue is dependent on the sales value of the refined products produced as well as the yield of refined products from the crude oil feedstock. We analyze sales relative to the premium (or discount) received as compared to industry benchmark prices which captures the quality differential and transportation costs as well as analyze sales relative to the sale value of our refined products to the WTI benchmark price. Although our yield can be altered slightly to react to market conditions and seasonal demand, product yields are primarily impacted by the type of crude oil feedstock processed as well as refinery performance. For the three month period ended March 31, 2008, our refinery yield was comprised of 33% gasoline products, 42% distillates and 25% HSFO as compared to 32%, 41% and 27%, respectively, for the same period in the prior year.

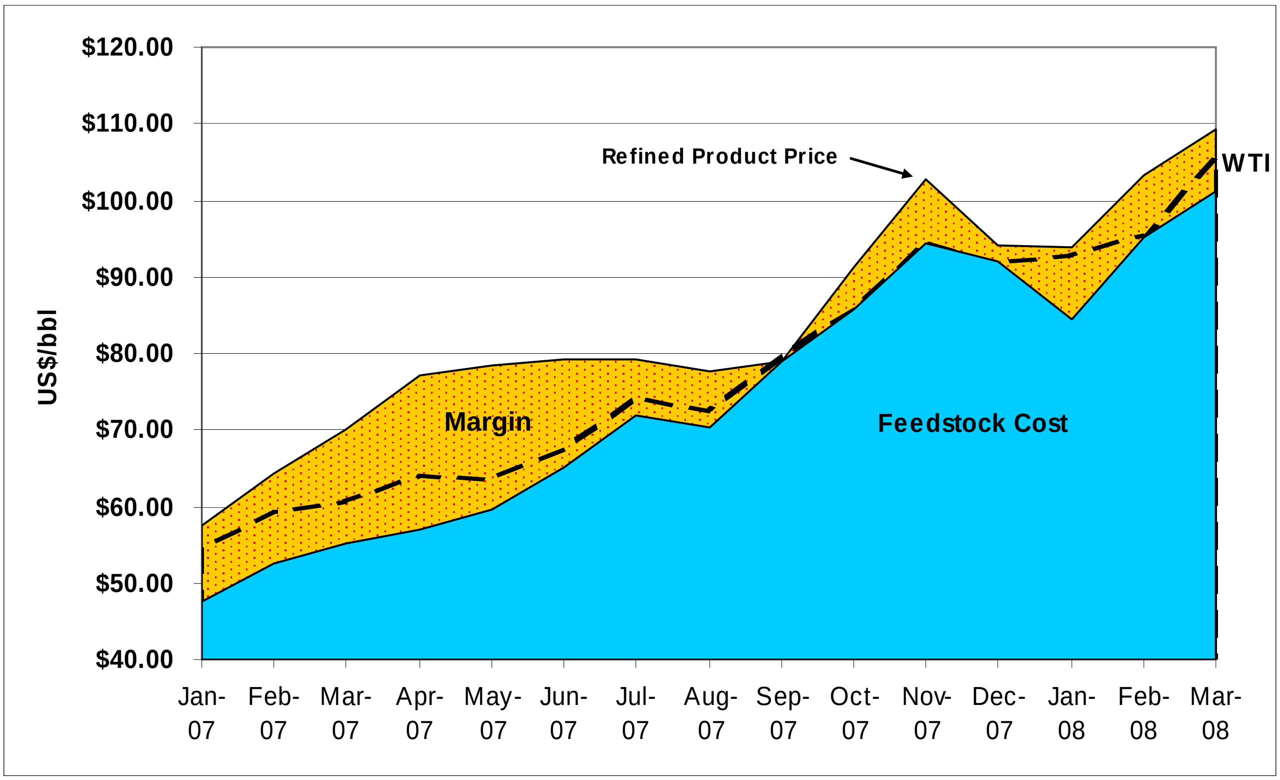
Relative to the NYMEX RBOB gasoline benchmark price, our gasoline products sold at a discount of US$3.98 per barrel (US$0.09 per gallon) during the first quarter of 2008 as compared to a premium of US$0.26 per barrel in the first quarter of 2007. For the 3,528,000 barrels of gasoline products sold during the first quarter of 2008, the change in pricing premium to a discount relative to the NYMEX RBOB gasoline benchmark price aggregates to a $15.0 million reduction in sales revenue and gross margin. This change in pricing is primarily attributable to the change in differential between the physical selling price for deliveries to the New York Harbour upon which the Supply and Offtake Agreement calculates our selling price and NYMEX benchmark price. During the first quarter of 2008, the discount between the physical selling price in New York Harbour and the NYMEX RBOB gasoline benchmark price averaged US$3.03 per barrel as compared to US$1.12 in the prior year. In addition, due to the 10 day delay in gasoline pricing pursuant to the Supply and Offtake Agreement, the First Quarter of 2008 gasoline price reflects a stable pricing environment compared to a rising price environment in the prior year.

During the first quarter of 2008, we received a premium of US$5.99 per barrel for our distillate relative to the NYMEX heating oil benchmark price as compared to a US$4.32 premium in the prior year. Relative to the 4,216,000 barrels of distillate sold during the first quarter of 2008, the improved pricing premium accounts for a $7.1 million increase in sales revenue and gross margin. The increased premium is primarily attributed to the 10 day delay in our pricing in a rising distillate price environment and to a lesser extent, our distillate products having a lower sulphur content than the benchmark heating oil product which is a higher valued product in the New York Harbour. In addition, approximately 1,724,000 barrels of distillate product were shipped to Europe during the first quarter of 2008 and we received $0.6 million of incremental revenue (US$0.34 per barrel) pursuant to our profit sharing arrangement in the Supply and Offtake Agreement in respect of such sales efforts beyond the East Coast markets.

We received an average of US$71.04 per barrel for our HSFO during the first quarter of 2008 reflecting an average premium of US$0.61 per barrel over the Platts HSFO benchmark price as compared to US$40.08/bbl received during the first quarter of 2007 being a US$0.23 per barrel premium to the same benchmark price. Relative to the 2,362,000 barrels of HSFO sold in the first quarter of 2008, the US$0.38 per barrel improved pricing over the benchmark represents $0.9 million of incremental sales revenue and gross margin. The improved pricing in 2008 is attributed to the new HSFO sales contract noted above.

Relative to the WTI benchmark price, the aggregate average sales price for our refined products was US$102.17/bbl during the First Quarter of 2008, representing an average refining margin of US$4.27/bbl as compared to US$64.29 realized in the prior year with a refining margin of US$6.13. This US$1.86/bbl year-over-year erosion in our refining margin relative to the WTI benchmark price aggregates a to $18.9 million reduction in sales revenue and gross margin. During the first quarter of 2008, the US$100.38/bbl average sales price for our gasoline products reflects a US$2.48 premium over the WTI benchmark price as compared to a US$12.87 premium in 2007. For distillates, our average sales price was US$121.09/bbl during the First Quarter of 2008, a US$23.19 premium over the WTI benchmark price as compared to a US$16.02 premium in the prior year. Similarly, the US$71.04/bbl average sales price of our HSFO reflects a US$26.86 discount to the WTI benchmark price as compared to a US$18.08 discount in 2007. Unfortunately, we do not produce a sufficient volume of distillates for the US$7.17 improvement in its pricing relative to the WTI benchmark price to offset the impact of the US$10.39 and US$8.78 erosion in the relative pricing for our gasoline products and HSFO, respectively.

The following summarizes our refining margin per barrel relative to our cost of feedstock and the WTI benchmark from the period January 2007 to March 2008:



Refinery Feedstock

We purchase our refinery feedstock from Vitol pursuant to the terms of the Supply and Offtake Agreement whereby the price of feedstock floats with the WTI benchmark price for the period from pricing through to the date it is charged to the refinery subject to an average ten day delay in pricing similar to the product sales pricing formulas. This pricing accelerates the impact of pricing trends on the cost of our feedstock and results in our costs being based on a slightly different time period than the monthly average WTI benchmark price.

A comparison of crude oil and VGO feedstock processed for three month periods ended March 31, 2008 and 2007 is presented below.

	Three Month Period Ended March 31					
	2008			2007		
	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)
Basrah Light	**394,635**	**4,407**	**89.19**	422,856	7,002	51.55
Hamaca	**140,944**	**1,507**	**93.15**	96,977	1,664	49.75
Urals	**134,519**	**1,409**	**95.09**	42,376	730	49.55
Kirkuk	**145,250**	**1,496**	**96.70**	-	-	-
Varandey	**60,649**	**601**	**100.51**	-	-	-
Crude Oil Feedstock	**875,997**	**9,420**	**92.62**	562,209	9,396	51.07
Vacuum Gas Oil	**80,077**	**771**	**103.45**	57,996	838	59.06
	956,074	**10,191**	**93.44**	620,205	10,234	51.73
Other costs	**(10,475)**			(819)		
	945,599			619,386		

(1) Cost of feedstock includes all costs of transporting the crude oil to refinery in Newfoundland

During the first quarter of 2008, our feedstock was comprised of 103,519 bbl/d of medium sour crude oil and 8,480 bbl/d of VGO as compared to 104,400 bbl/d of crude oil and 9,311 bbl/d of VGO in the prior year. While the daily volume of crude oil processed remained relatively unchanged year-over-year, the consumption of purchased VGO dropped by an average of 831 bbl/d. This 9% reduction in VGO consumption in 2008 is the result of a lower rate of flow through the Isomax unit during the month of January due to delays in receiving VGO shipments combined with the positive impact of an improved VGO cut from the Varandey crude processed in February.

The average cost of purchased VGO during the first quarter of 2008 was US$103.45/bbl representing a premium of US$5.55/bbl relative to the average WTI benchmark price as compared to US$59.06 and a US$0.90 premium, respectively, in the prior year. The increased premium in 2008 is attributed a third party refinery outage in late 2007 causing a continuing disruption in the very tightly balanced VGO market. Relative to the 771,000 barrels of VGO consumed during the first quarter of 2008, the US$4.65/bbl increase in price differential over the WTI benchmark price represents a $3.6 million increase in feedstock costs and similarly, a $3.6 million reduction in gross margin.

During the first quarter of 2008, we expanded our crude oil slate to include Kirkuk crude from Iraq and Varandey crude from Russia as well as increased our consumption of Urals crude. These changes were implemented to diversify our crude oil feedstock supply, optimize the refinery's yield of gasoline and distillate products as well as mitigate an expected shortage of Basrah Light crude during the month of February. The WTI benchmark price averaged US$92.93 for the month of January 2008, US$95.35 for February 2008 and US$105.42 for March 2008 as compared to the average for the three month period ended March 2008 of US$97.90. This volatility in the WTI benchmark price results in it being difficult to evaluate the economics of individual crude costs when our consumptions of crudes varies from month-to-month and the aggregation of feedstock costs, including their relative discount to the WTI benchmark price, is relative to the WTI Benchmark price ten days after consumption.

The cost of our crude oil feedstock averaged US$92.62/bbl during the first quarter of 2008 representing a US$5.28/bbl discount from the WTI benchmark price as compared to US$51.07 and a discount of US$7.09, respectively, in the prior year. While the US$1.81/bbl reduction in discount to the WTI benchmark price aggregates to a $17.1 million incremental increase in crude oil feedstock costs, the year-over-year US$39.74 increase in the WTI benchmark price represents a 68% increase in the benchmark price and added a further $375.9 million to our crude oil feedstock cost during the first quarter of 2008. In aggregate, the US$93.44/bbl average cost of feedstock during the first quarter of 2008 represents an 81% increase over the average cost in the prior year. The cost of feedstock reflect numerous factors beyond changes in the WTI benchmark price such as the Official Selling Price ("OSP") as set by the Oil Marketing Company of the Republic of Iraq, the costs of transporting the crude feedstock to our refinery and the ten day delay in pricing as a result of the Supply and Offtake pricing formula.

Operating Expenses

The following summarizes the operating costs from the refinery and marketing division for three month periods ended March 31, 2008 and March 31, 2007:

	Three Month Period Ended March 31					
	2008			2007		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	Refining	Marketing	Total
Operating expense	**21,375**	**4,520**	**25,895**	21,031	4,330	25,361
Purchased energy	**43,127**	**-**	**43,127**	24,000	-	24,000
	64,502	**4,520**	**69,022**	45,031	4,330	49,361

The largest component of refining operating expense is wages, salaries and benefits which totaled $13.2 million during the three month period ended March 31, 2008 (2007 - $12.9 million) while the other significant components were maintenance and repairs costs of $4.1 million (2007 - $3.1 million), insurance of $1.4 million (2007 - $1.8 million) and professional services of $1.0 million (2007 - $1.1 million). During the three month period ended March 31, 2008, refining operating expenses were $2.10 per barrel as compared to $2.06 per barrel in the three month period ended March 31, 2007 and were consistent with our expectations of approximately $2.10 to $2.20 per barrel. The Marketing Division's operating costs are consistent at approximately $4.5 million per quarter.

Purchased energy, consisting of low sulphur fuel oil and electric power, is required to provide heat and power to refinery operations. Our purchased energy for the three month period ended March 31, 2008 was $4.23 per barrel of throughput as compared to $2.35/bbl for the three month period ended March 31, 2007. In the first quarter of 2008, we purchased 498,326 barrels of fuel oil at an average price of US$80.94/bbl as compared to 474,462 barrels purchased in the first quarter of 2007 at an average price of US$38.28/bbl, which is the primary reason for the $19.1 million increase in the cost of purchased energy. Our electricity costs remained substantially unchanged during the first quarter of 2008 at $2.6 million as compared to $2.5 million in the prior year.

Marketing Expense

During the three month period ended March 31, 2008, marketing expense was comprised of $0.9 million of marketing fees (based on US $0.08 per barrel of feedstock) to acquire feedstock (2007 - $1.0 million) and $7.7 million of "Time Value of Money" charges (2007 - $6.3 million) both pursuant to the terms of the Supply and Offtake Agreement. The increased "Time Value of Money" charge is the result a larger crude oil inventory investment due to the higher WTI benchmark price during 2008.

Capital Expenditures

Capital spending for the three month period ended March 31, 2008 totaled $6.0 million and included approximately $1.7 million of an estimated $25 million to enhance our visbreaker capacity which is expected to be completed in the fourth quarter of 2008.

Depreciation and Amortization Expense

The following summarizes the depreciation and amortization expense for the first three months of 2008 and 2007:

	Three Month Period Ended March 31					
	2008			2007		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	Refining	Marketing	Total
Tangible assets	**14,479**	**553**	**15,032**	17,183	495	17,678
Intangible assets	**1,118**	**350**	**1,468**	1,304	407	1,711
	15,597	**903**	**16,500**	18,487	902	19,389

The process units are amortized over an average useful life of 20-30 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

As the refining assets are held in a self-sustaining subsidiary with a US dollar functional currency, the value of the goodwill is adjusted at the end of each accounting period to reflect the current US dollar exchange rate. We assess goodwill for impairment annually, or more frequently if events or changes in circumstances warrant. There has been no charge for impairment to goodwill since the date of acquisition.

RISK MANAGEMENT, FINANCING AND OTHER

Cash Flow Risk Management

Our MD&A for the year ended December 31, 2007 included a comprehensive discussion of our approach to analyzing cash flow at risk relative to changes in crude oil prices, natural gas prices, certain refined product prices and the US/Canadian dollar exchange rate. See "Cash Flow Risk Management" in our MD&A for the year ended December 31, 2007 filed on SEDAR at www.sedar.com. The details of our commodity price contracts outstanding at March 31, 2008 are included in the notes to our consolidated financial statements for the three month period ended March 31, 2008 and 2007 also filed on SEDAR at www.sedar.com.

The table below provides a summary of the net gains and (losses) realized on our price risk management contracts for the three month periods ended March 31, 2008 and 2007:

(000s)	Crude Oil	Refined Products	Natural Gas	Currency Exchange Rates	Electric Power	**Total**
Three Months Ended March 31, 2008	$ (8,579)	$ (31,816)	$ (101)	$ 2,654	$ 1,548	**$ (36,294)**
Three Months Ended March 31, 2007	$ 290	$ -	$ 161	$ (1,248)	$ 500	**$ (297)**

During the First Quarter of 2008, the net realized loss on price risk management contracts totaled $36.3 million, as compared to a modest loss of $0.3 million in the First Quarter of the prior year, primarily due to our crude oil and refined product pricing contracts. In the First Quarter of 2007, our crude oil price contracts had WTI benchmark price caps of US$55.67/bbl plus 73% participation on prices above US$55.67/bbl while the quarterly average WTI benchmark price was US$58.16/bbl. In contrast, our crude oil and refined product contracts for the First Quarter of 2008 have substantially higher price caps, however commodity prices have substantially exceeded these price caps as the WTI benchmark price increased by 68%, heating oil increased by 65% and HSFO increased by 77% over the First Quarter of the prior year.

For the First Quarter of 2008, we had crude oil price risk management contracts in place for 10,000 bbl/d with an average WTI benchmark floor price of US$60.00/bbl and participation in 73% of prices above US$60.00/bbl. The cash settlements of this obligation totaled $8.6 million. This WTI price contract continues for 10,000 bbl/d through to the end of June 2008.

In respect of refined products, we also had pricing contracts in place for 12,000 bbl/d of NYMEX heating oil and 8,000 bbl/d of Platts heavy fuel oil for the First Quarter of 2008 and realized losses of $32.0 million during the period. In addition, we had contracts in place on 6,000 bbl/d of NYMEX heating oil crack spreads and 2,000 bbl/d of Platts heavy fuel oil crack spreads which were settled with cash payments to Harvest of $0.2 million during the first quarter of 2008. As of March 31, 2008, we had the following refined product price contracts in place:

April 2008 through December 2008:

- 12,000 bbl/d of NYMEX heating oil
- 8,000 bbl/d of Platts heavy fuel oil
- 6,000 bbl/d of NYMEX heating oil crack spread
- 2,000 bbl/d of Platts heavy fuel oil crack spread

July 2008 through December 2008:

- 6,000 bbl/d of NYMEX RBOB gasoline comprised of an RBOB crack contract and a WTI price contract

January 2009 through June 2009:

- 12,000 bbl/d of NYMEX heating oil
- 8,000 bbl/d of Platts heavy fuel oil

With respect to currency exchange rates, we had contracted to fix the exchange rate during the first quarter of 2008 on US$8.3 million per month averaging Cdn$1.11 per US $1.00 and collared an exchange rate of Cdn$1.00 to Cdn$1.055 per US$1.00 on a further US$10 million per month. The settlement on the fixed rate contract resulted in Harvest receiving $2.7 million in the First Quarter of 2008 while the exchange rate collar settled with a nominal payment to Harvest. The fixed exchange rate contract continues through the end of June 2008 while the exchange rate collar extends through the end of December 2008.

During the First Quarter of 2008, the settlement of our fixed price power contracts for 35 MWh at $56.69 per MWh resulted in Harvest receiving $1.5 million as the Alberta electric power price averaged $76.69 per MWh during the period. This fixed price contract continues for 35 MWh through to the end of 2008.

At March 31, 2008, we had a modest 276 GJ/d of natural gas price contracts in place through December 2008.

At the end of 2007, the mark-to-market deficiency on our refined product and WTI price contracts was $138.8 million and $24.9 million, respectively, while the mark-to-market value of our currency exchange rate and electrical power price contracts aggregated to $14.0 million. At March 31, 2008, the mark-to-market deficiency on our refined product and WTI price contracts was $190.2 million and $29.5 million, respectively, while the mark-to-market value of our currency exchange rate and electrical power price contracts aggregated to $2.6 million and $6.8 million, respectively.

The following is a summary of net unrealized gains and losses recorded for our price risk management contracts for the three month periods ended March 31, 2008 and 2007 which reflects the change in the mark-to-market value or deficiency of our price risk management contracts during the respective periods:

(in 000s)	Crude Oil	Refined Products	Natural Gas	Currency Exchange Rates	Electric Power	**Total**
Three Months Ended March 31, 2008	$ (4,603)	$ (51,351)	$ (120)	$ (5,948)	$ 1,164	**$ (60,858)**
Three Months Ended March 31, 2007	$ (12,241)	-	$ (2,815)	$ 1,362	$ (427)	**$ (14,121)**

Subsequent to the end of the First Quarter of 2008, we have settled our April 2008 refined product and WTI price contract settlements with cash payments of $23.8 million and received cash payments totaling $2.8 million in respect of the April settlements of our currency exchange and Alberta electric power price contracts. We have not entered into any new price risk management contracts subsequent to March 31, 2008.

Interest Expense

	Three Month Period Ended March 31		
(000s)	**2008**	2007	Change
Interest on short term debt			
Bank loan	**$ -**	$ 1,170	(100%)
Convertible Debentures	**201**	646	(69%)
Amortization of deferred finance charges – short term debt	**-**	1,811	(100%)
	201	3,627	(94%)
Interest on long-term debt			
Bank loan	**16,060**	19,176	(16%)
Convertible Debentures	**13,062**	14,448	(10%)
7 7/8% Senior Notes	**5,306**	6,146	(14%)
Amortization of deferred finance charges – long term debt	**675**	679	(1%)
	35,103	40,449	(13%)
Total interest expense	**$ 35,304**	$ 44,076	(20%)

Interest expense, which includes the amortization of related financing costs, was $8.8 million lower for the three month period ended March 31, 2008 than the prior year. Of this decrease, $4.3 million is attributed to decreased short and long term bank loan interest as a result of having lower average bank borrowings outstanding. Interest expense on Convertible Debentures decreased by $1.8 million in 2008 compared to 2007 due to the reduced principal amount of Convertible Debentures outstanding and amortization of deferred financing costs decreased by $1.8 million. Interest expense on our 77/8% Senior Notes decreased by $0.8 million due to the strength of the Canadian dollar in the first quarter of 2008 as compared to the first quarter of the prior year.

At March 31, 2008, we had drawn approximately $1,330.4 million of bank borrowings as compared to $1,279.5 million at December 31, 2007. Currently, the interest on our $1.6 billion Extendible Revolving Credit Facility is at a floating rate based on 75 basis points over bankers' acceptances for Canadian dollar borrowings and 75 basis points over the London Inter Bank Order Rate for US dollar borrowings. During the three month period ended March 31, 2008, interest charges on bank loans aggregated to $16.1 million, reflecting an effective interest rates of 4.83%. Further details on our credit facilities are included under "Liquidity and Capital Resources".

The interest on our Convertible Debentures totaled $13.3 million during the three month period ended March 31, 2008 and is based on the effective yield of the debt component of the Convertible Debentures. Details on the Convertible Debentures outstanding are fully described in Note 12 to the audited consolidated financial statements for the year ended December 31, 2007 filed on SEDAR at www.sedar.com. During the three month period ended March 31, 2008, there were $24.3 million of principal amount of Convertible Debentures converted to 1,169,370 Trust Units, including the settlement of $24.2 million principal amount of 10.5% Convertible Debentures that matured on January 31, 2008 with 1,166,593 Trust Units.

The interest on our 77/8% Senior Notes totaled $5.3 million for the three month period ended March 31, 2008. Similar to our Convertible Debentures, interest expense is based on the effective yield, and as a result, the interest expense recorded is greater than the cash interest paid. Due to the recent strength of the Canadian dollar relative to the U.S. dollar, our cash interest expense has been lowered as interest on these notes is paid in U.S. dollars.

Included in short and long term interest expense is the amortization of the discount on the 77/8% Senior Notes, the accretion on the debt component balance of the Convertible Debentures to face value at maturity, as well as the amortization of commitment fees and legal costs incurred for our credit facility, all totaling $0.7 million for the three month period ended March 31, 2008.

Currency Exchange

Currency exchange 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 77/8% Senior Notes as well as any other U.S. dollar cash balances. Since December 31, 2007, the Canadian dollar has modestly weakened compared to the U.S dollar, resulting in an unrealized foreign exchange loss on our 77/8% Senior Notes of $8.6 million during the three month period ended March 31, 2008. During the three month period ended March 31, 2008 we incurred unrealized foreign exchange losses and realized foreign exchange losses on downstream transactions of $0.5 million and $1.6 million, respectively.

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 First Quarter of 2008, the weakening of the Canadian dollar relative to the U.S. dollar resulted in a $50.5 million cumulative translation gain as the weaker Canadian dollar results in an increase in the relative value of the net assets in our downstream operations.

Future Income Tax

At the end of 2007, we had a net future income tax provision on our balance sheet totaling $86.6 million comprised of a $270.5 million provision for our mutual fund trust and other "flow through" entities and a net asset of $183.9 million for our corporate entities. In the First Quarter of 2008, we have reduced this provision by $21.8 million 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. 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 deficiency on our risk management contracts. Future income tax recoveries from of our corporate entities may fully offset the future income tax provision of our mutual fund trust and other "flow through" entities prior to 2011.

Contractual Obligations and Commitments

We have contractual obligations and commitments entered into in the normal course of operations including 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. We also have contractual obligations and commitments that are of a less routine nature as disclosed in the following table:

Annual Contractual Obligations *(000s)*		Maturity				
	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Long-term debt[(2)]	**$ 1,587,048**	$ -	$1,330,423	$ 256,625	$ -
Interest on long-term debt[(4)]	**191,602**	58,569	117,142	15,891	-
Interest on Convertible Debentures[(3)]	**240,639**	35,023	92,910	86,063	26,643
Operating and premise leases	**25,710**	5,564	12,628	7,270	248
Purchase commitments[(5)]	**39,573**	35,123	4,450	-	-
Asset retirement obligations[(6)]	**1,000,640**	22,364	17,350	27,437	933,489
Transportation [(7)]	**6,851**	2,197	3,337	1,270	47
Pension contributions	**31,074**	857	3,631	5,301	21,285
Feedstock commitments	**798,188**	798,188	-	-	-
Total	**$ 3,921,325**	$ 957,885	$1,581,871	$ 399,857	$ 981,712

(1) As at March 31, 2008, we had entered into physical and financial contracts for upstream production with average deliveries of approximately 8,000 bbl/d for the remainder of 2008. We have also entered into financial contracts for downstream production of refined products with average deliveries of approximately 32,000 bbl/d for the remainder of 2008 and 9,900 bbl/d in 2009. We have also entered into financial contracts to minimize our exposure to fluctuating electricity prices. Please see Note 12 to the consolidated financial statements for further details.
(2) Assumes that the outstanding Convertible Debentures either convert at the holders' option or are redeemed for Trust Units at our option.
(3) Assumes no conversions and redemption by Harvest for Trust Units at the end of the second redemption period. Only cash commitments are presented.
(4) Assumes constant foreign exchange rate.
(5) Relates to drilling commitments, AFE commitments and downstream purchase commitments.
(6) Represents the undiscounted obligation by period
(7) Relates to firm transportation commitment on the Nova pipeline.

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.

Related Party Transactions

During the First Quarter of 2008, Vitol purchased U.S. $67.8 million of Urals crude oil pursuant to the terms and conditions of the Supply and Offtake Agreement from a company in which a director of Harvest holds a minority equity interest. As at March 31, 2008, $1.7 million related to these purchases is included in Harvest's accounts payable and accrued liabilities, and $4.1 million is included in the total feedstock commitments disclosed at the end of March 2008. Subsequent to March 31, 2008, no further commitments have been incurred relating to crude oil purchases by Vitol from this private company.

CHANGE IN ACCOUNTING POLICIES

Effective January 1, 2008, we have adopted the requirements of the Canadian Institute of Chartered Accountants ("CICA") Section 3862 Financial Instruments – Disclosures, Section 3863 Financial Instruments – Presentation, and Section 1535 Capital Disclosures. The additional disclosures required as a result of adopting these new standards can be found in the notes to our consolidated financial statements for the three months ended March 31, 2008.

In June 2007, the CICA issued Section 3031 – Inventories, which replaces the existing standard for inventories. This new standard provides additional disclosure requirements for inventories, requiring that inventories be valued at the lower of cost and net realizable value. The standard is effective for Harvest beginning January 1, 2008. Application of this new standard did not have a material impact on our financial statements.

LIQUIDITY AND CAPITAL RESOURCES

During the First Quarter of 2008, cash from operating activities was $128.1 million, including a $55.0 million reduction in respect of changes in non-cash working capital. The non-cash working capital requirement is primarily due to a $95.2 million increase in accounts receivable and an $18.3 million increase in inventories offset by a $64.9 million increase in accounts payable. Cash from operating activities before changes in non-cash working capital and asset retirement expenditures totaled $185.4 million for the First Quarter of 2008. During the First Quarter of 2008, we declared distributions of $135.2 million, required $85.6 million to fund capital expenditures and raised $35.9 million with our distribution re-investment plans resulting in cash flow being balanced excluding working capital adjustments. The increase in bank borrowings totaled $50.9 during the first quarter of 2008 which closely approximates our increase in non-cash working capital requirements.

At the end of March 2008, we had $269.6 million of borrowing capacity available under our $1.6 billion Extendible Revolving Credit Facility as compared to $320.5 million at the beginning of the quarter. In late 2007, the much publicized sub-prime mortgage/asset backed commercial paper crisis had resulted in a tightening of credit availability and a general re-pricing of credit. As we do not generally maintain any surplus cash, we have no direct exposure to asset backed commercial paper. However, we have elected to defer our request to extend the maturity date of this Extendible Revolving Credit Facility from April 2010 to April 2011 in light of the current status of the worldwide credit markets.

Our cash flow risk management program includes entering into numerous pricing contracts. We have limited counterparties to the lenders in our syndicated credit facilities as the security provided in this credit agreement extends to our pricing contracts and this eliminates the potential requirement for margin calls and/or the pledging of collateral as well as limits the negotiation of events of default, all of which contribute to ensuring that these contracts improve our liquidity rather than exacerbate credit concerns.

The following table summarizes our capital structure as at March 31, 2008 and December 31, 2007:

(in millions) **DEBT**	**March 31, 2008**	December 31, 2007
Extendible Revolving Credit Facility	**$1,330.4**	$1,279.5
7 7/8 % Senior Notes Due 2011 (US$250 million)(1)	**256.6**	247.8
Convertible Debentures, at principal amount		
10.5% Debentures Due 2008	**-**	24.3
9% Debentures Due 2009	**1.0**	1.0
8% Debentures Due 2009	**1.7**	1.7
6.5% Debentures Due 2010	**37.1**	37.1
6.4% Debentures Due 2012	**174.6**	174.6
7.25% Debentures Due 2013	**379.3**	379.3
7.25% Debentures Due 2014	**73.2**	73.2
Total Convertible Debentures	**666.9**	691.2
Total Debt	**2,253.9**	2,218.5
TRUST UNITS		
151,135,724 issued at March 31, 2008	**3,803.5**	
148,291,170 issued at December 31, 2007		3,736.1
TOTAL OF DEBT AND TRUST UNITS	**$6,057.4**	$5,954.6

(1) Face value converted at the period end exchange rate.

Since December 31, 2007, the significant changes to our capital structure were:

- Issuance of 1,637,601 trust units pursuant to Harvest's Premium Distribution™, Distribution Reinvestment and Optional Trust Unit Purchase Plan (the "DRIP Plans") raising $35.9 million, and
- Issuance of 1,169,370 trust units on the conversion of $24.3 million of principal amount of Convertible Debentures including 1,166,593 in respect of the maturing of $24.2 million of principal amount of 10.5% convertible Debentures due January 31, 2008.

A full description of the terms and covenants of our $1.6 billion Extendible Revolving Credit Agreement, 77/8% Senior Notes and Convertible Debentures are contained in the notes to our audited consolidated financial statements for the year ended December 31, 2007 and the Liquidity and Capital Resources section of our MD&A for the year ended December 31, 2007 both of which are filed on SEDAR at www.sedar.com. The credit facility contains floating interest rates that are expected to range between 65 and 115 basis points over bankers' acceptance rates (currently 75 bps) depending on the ratio of our secured senior debt (excluding 77/8% Senior Notes and convertible debentures) to earnings before interest, taxes, depletion, amortization and other non-cash amounts ("EBITDA") with availability under this facility subject to:

Secured senior debt to EBITDA	3.0 to 1.0 or less
Total Debt to EBITDA	3.5 to 1.0 or less
Secured senior debt to capitalization	50% or less
Total Debt to capitalization	55% or less

At March 31, 2008, our Bank Debt to twelve-month trailing EBITDA was 1.7 to 1.0, Total Debt (excluding only the Convertible Debentures) to twelve-month trailing EBITDA was 2.0 to 1.0, while the Bank Debt to Total Capitalization was 29% and Total Debt to Total Capitalization was 34%.

The 7 7/8% Senior Notes contain certain covenants which among other things restrict our secured indebtedness to an amount less than 65% of the present value of future net revenues from our proved petroleum and natural gas reserves discounted at an annual rate of 10%. At the end 2007, 65% of the present value of the future net revenues from our proved petroleum and natural gas reserves discounted at an annual rate of 10% was approximately $1.85 billion.

Subsequent to March 31, 2008, we issued $250 million principal amount of 7.50% Convertible Debentures due May 31, 2015 for net proceeds of $239.5 million which were used to reduce bank borrowings, increasing Harvest's unused capacity in its credit facility to over $500 million. The most restrictive term of the Convertible Debentures limits the issuance of additional Convertible Debentures if 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. Subsequent to this issuance, the covenants of the Convertible Debentures will limit our issuance of additional convertible debentures to approximately $200 million based on current market capitalization.

Concurrent with the closing of the North Atlantic acquisition, we entered into a Supply and Offtake Agreement with Vitol, a third party related to the vendor of North Atlantic. The agreement provides for ownership of substantially all of the crude oil feedstock and refined product inventory at the refinery be retained by Vitol and that Vitol be granted the right and obligation to provide and deliver all feedstock to the refinery as well as the right and obligation to purchase all refined products produced by the refinery with the exception of certain excluded products. 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, 2007 filed on SEDAR at www.sedar.com. At the end of March 2008, we estimate that Vitol held inventories of VGO, crude oil feedstock (both delivered and in-transit) and refined products for resale valued at approximately $798.8 million which would have otherwise been assets of Harvest. Effective April 19, 2008, both Harvest and Vitol may terminate the Supply and Offtake Agreement by providing six month written notice. As of May 6, 2008, neither party has provided notice of its intent to terminate the agreement.

Year-to-date in 2008, the trading value of our Trust Units ranged from a high of $26.00 in February to a low of $20.48 in January. This volatility in our trading value is generally attributed to the seasonal decline in refining margins. At the end March 2008 approximately 67% of our Unitholders were non-residents of Canada which is up slightly from 66% at the end of 2007. The following summarizes the trading value of our trust units during 2008:

	Trading Price		
Month	**High**	**Low**	**Volume**
TSX Trading			
January 2008	$ 23.56	$ 20.48	10,474,631
February 2008	$ 26.00	$ 22.49	8,552,342
March 2008	$ 24.13	$ 22.00	9,638,750
April 2008	$ 24.94	$ 22.23	11,965,637
May 1 – 6, 2008	$ 23.23	$ 22.15	1,875,642
NYSE Trading (in US$)			
January 2008	$ 23.24	$ 20.00	18,167,009
February 2008	$ 25.70	$ 22.51	15,108,961
March 2008	$ 24.49	$ 21.44	17,099,323
April 2008	$ 24.82	$ 22.06	20,845,245
May 1 – 6, 2008	$ 23.07	$ 21.75	3,609,424

Through a combination of cash from operating activities, unused credit capacity and the working capital provided by the Supply and Offtake Agreement with Vitol, it is anticipated that we will have enough liquidity to fund future operations and forecasted capital expenditures although cash from operating activities used to fund ongoing operations may reduce the amount of future distributions paid to Unitholders.

Harvest is an integrated energy trust with a declining asset base in our upstream operations and a "near perpetual" asset in our downstream operations. The future of our upstream operations relies on the successful exploitation of existing reserves, future development activities and strategic acquisitions to replace existing production and add additional reserves, as well as future petroleum and natural gas prices. With a prudent maintenance program, our downstream assets are expected to have a long life with additional growth in profitability available by upgrading the heavy fuel oil currently produced and/or expanding our refining capacity. Future development activities and modest acquisitions in our upstream business as well as the maintenance program in our downstream business will likely be funded by cash from operating activities while we will generally rely on funding more significant acquisitions and growth initiatives from some combination of cash from operating activities, issuances of Trust Units and incremental debt. To the extent that we finance acquisitions and growth initiatives with cash from operating activities, the amount of our distributions to Unitholders may be reduced. Should equity capital markets or incremental debt not be available to us, our ability to make the necessary expenditures to maintain or expand our assets may be impaired and result in reductions to future distributions paid to Unitholders. In our upstream business, it is not possible to distinguish between expenditures to maintain productive capacity and spending to increase productive capacity due to the numerous factors impacting reserve reporting and the natural decline in reservoirs. Accordingly, maintenance capital is not disclosed separately.

Our distributions will generally exceed the net income reported in our financial statements as a result of significant non-cash charges. In the first quarter of 2008, we recorded a $60.9 million charge in respect of unrealized losses on price risk management contracts. In addition, we recorded a further $130.9 million provision in respect of depreciation and depletion based primarily on the historic costs of property, plant and equipment and this provision does not accurately represent the fair value or replacement cost of the assets, nor the cash generated in the current period. These charges result in significant changes to net income with no impact on cash from operating activities. Accordingly, we anticipate that over time, net income may fluctuate significantly from cash from operating activities as well as distributions to Unitholders. During the first quarter of 2008, distributions to Unitholders exceeded our net loss by $135.5 million as compared to the prior year when distributions to Unitholders exceeded net income of $69.9 million by $75.4 million. In instances where distributions exceed net earnings, a portion of the distribution may represent a return of capital rather than a distribution of earnings. For the first quarter of 2008, distributions declared totaled $135.2 million, representing 106% of cash from operating activities.

Management, together with the Board of Directors of Harvest, continually assess the level of our monthly distributions in light of commodity price expectations, currency exchange rates, production and throughput projections, operating cost forecasts, debt leverage and spending plans. Since November 2007, we have declared a monthly distribution of $0.30 per Trust Unit through July 2008, a level of distributions that reflects expectations of future commodity prices and currency exchange rates as well as our future production and throughput volumes and operating costs.

Prior to January 1, 2011, the Trust is subject to tax on its taxable income less the portion that is paid or payable to the Unitholders at the end of each taxation year. For 2008, we anticipate that distributions to Unitholders will be 100% taxable and that the Trust will have no taxable income. The following table summarizes the distributions declared, the proceeds from our distribution reinvestment programs as well as distributions as a percentage of cash from operating activities for the three months ended March 31, 2008 and 2007:

	Three Month Period Ended March 31		
(000s except per Trust Unit amounts)	**2008**	2007	Change
Distributions declared	**$ 135,167**	$ 145,270	(7%)
Per Trust Unit	**$ 0.90**	$ 1.14	(21%)
Distribution reinvestment proceeds	**$ 35,890**	$ 43,797	(18%)
Distributions as a percentage of cash from operating activities	**106%**	131%	(25%)

Throughout the first three months of 2008, we declared monthly distributions of $0.30 per Trust Unit to Unitholders, compared to a $0.38 per Trust Unit distribution for the same period in 2007. The total amount of distributions declared during the First Quarter of 2008 was $135.2 million, which is 106% of our cash from operating activities. The $10.1 million decrease in distributions declared during the First Quarter of 2008 relative to the First Quarter of 2007 is primarily due to the decrease of $0.08 in the distribution declared per Trust Unit, offset by an increase of approximately 21.1 million Trust Units outstanding.

OUTLOOK

Our 2008 business plan continues to focus on reservoir management in the upstream with reduced capital spending as compared to the $300.7 million of expenditures incurred in 2007 while our expectations for the downstream operations in 2008 anticipate no significant planned downtime for turnarounds with an improving yield of gasoline and distillate products attributed primarily to an increase in the refinery's visbreaker capacity. We are increasing our focus on drilling additional natural gas prospects in light of improved pricing and building on recent success at Cheddarville and Dobson.

We have added $20 million to our 2008 capital spending plans which brings the total for the year to $245 million and expect our annual upstream production will average approximately 55,000 to 56,000 boe/d. We are focusing on drilling in southeast Saskatchewan, Lloydminister, Red Earth and Hayter with our planned investment in infrastructure and workovers primarily relating to our reservoir management initiatives aggregating to approximately twenty five percent of our 2008 spending. Light and medium gravity oil, including natural gas liquids, is expected to represent approximately 48% of total production in 2008 with heavy oil and natural gas accounting for 23% and 29% respectively. Operating costs are expected to average $13.40/boe with electric power and well servicing representing approximately 50% of our costs. Power costs are significant as our field operations move and dispose of approximately 2 million bbl/d of water and accordingly, we have fixed price electric power contracts in place for approximately 50% of our expected 2008 Alberta power consumption at a price of $56.69 per MWh.

In our downstream operations, we are anticipating no planned shutdowns for the balance of 2008 except for the commissioning of our visbreaker expansion project in the Third Quarter. The turnaround of the crude unit and vacuum tower in late 2007 has resulted in a reduction in our purchases of vacuum gas oil from third parties in the First Quarter of 2008 and we anticipate this will continue with an annual cost saving estimated to be $40 million for the year. We are currently evaluating the alternatives to optimize our refinery profitability in light of the significant weakness in HSFO prices with alternatives including reduced rates of throughput and further shifts in our slate of crude oil feedstock. We expect that our operating costs will continue to average $2.10 to $2.20 per barrel of throughput. Our costs of purchased energy, primarily a lower sulphur fuel oil than we produce, are expected to range around $3.00 per barrel of throughput reflecting a significantly higher commodity price environment than anticipated at the beginning of 2008 and a reduced level of consumption for the balance of the year. Over the next few years, we expect to capture $10 million of operating cost reductions by improving energy efficiency and other operating measures. Capital spending expectations for our downstream operations are unchanged at $63 million. The cash flow contribution from our Marketing Division is expected to be $24 million, unchanged from our previous guidance.

As referred to in the Cash Flow Risk Management section of this MD&A, we have not entered into any refined product and WTI pricing contracts since the end of 2007 and have approximately 79% of our WTI sensitive cash flow exposure in the second quarter of 2008 under contract as well as 68% for the second half of 2008 and 53% for the first half of 2009. With respect to our cash flow exposure related to refined product crack spreads, we have contracts in place for approximately 10% of our 2008 exposure. As our upstream operations continue to enjoy the unprecedented level of crude oil prices and our downstream operations experience more modest refining crack spreads as compared to 2007, our upside participation will be limited to an average US$78.81 of relative WTI pricing for the 20,000 bbls/d of contracted distillate and heavy fuel oil prices. We have currency exchange contracts on US$18.3 million per month through to December 2008, representing approximately 20% of our exposure to fluctuations in the US dollar relative to the Canadian dollar, prior to considering the offsetting exposure of our US dollar denominated 77/8% Senior Notes. We anticipate modest fluctuations from parity for the US/Canadian exchange rate. We have entered into electric power contracts to fix the price of 35 MWh through to the end of December 2008 at price of $56.69/MWh to reduce the volatility of our operating costs due to fluctuating electricity costs which typically represents approximately 25% of our upstream operating costs.

We continue to manage 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 77/8% Senior Notes and Convertible Debentures) carrying fixed rates of interest. Our short term financing consists of borrowings under our credit facilities totalling $1,090.9 million at March 31, 2008, after adjusting for the issuance of $250 million of convertible debentures on April 25, 2008, which represents approximately 48% of our total debt. As a result, approximately 48% of our interest rate exposure is floating and 52% is fixed. Currently, the most significant exposure to increasing interest rates is through the re-pricing of credit if we were to renew our credit facilities or enter into additional longer term financing. We have decided to defer extending the April 2010 maturity date on our $1.6 billion Extendible Revolving Credit Facility pending a general strengthening to the credit markets. With respect to further reducing our borrowings under our credit facility, we continue to monitor the high yield market as well as opportunities to issue additional Trust Units.

Upon maturity of our Convertible Debentures, we may elect to satisfy these obligations by issuing units rather than settling the obligations in cash. The maturity dates on the $916.9 million principal amount of Convertible Debentures outstanding after our recent $250 million issuance on April 25, 2008 are as follows: 2009 - $2.7 million; 2010 - $37.1 million; 2012 – $174.6 million; 2013 - $379.3 million; 2014 - $73.2 million and 2015 - $250 million. While this does not necessarily impact 2008, we anticipate that as these Convertible Debentures mature, or are converted into Trust Units before their maturity date, we will be able to retire $916.9 million of principal amount of unsecured debt with equity issuances.

Overall, we expect that based on current commodity price expectations, our 2008 cash from operating activities will be sufficient to fund our planned capital expenditures as well as maintain our present level of distributions. We expect that the participation level in our distribution re-investment programs will continue at approximately 30% with non-Canadian ownership of our Trust Units maintained at approximately 65% to 70%.

While we do not forecast commodity prices nor refining margins, we have entered into price risk management contracts to mitigate a substantial portion of the price volatility with the objective of stabilizing our 2008 cash from operating activities through a wide variety of pricing environments. The following table reflects the sensitivity of our 2008 operations to changes in the following key factors to our business over the remaining nine months of the year:

	Assumption	Change	Impact on Cash Flow
WTI oil price (US$/bbl)	$ 100.00	$ 5.00	$ 0.04 / Unit
CAD/USD exchange rate	$ 1.00	$ 0.05	$ 0.18 / Unit
AECO daily natural gas price (per mcf)	$ 9.00	$ 1.00	$ 0.14 / Unit
Refinery crack spread (US$/bbl)	$ 8.40	$ 1.00	$ 0.13 / Unit
Upstream Operating Expenses (per boe)	$ 13.35	$ 1.00	$ 0.10 / Unit

In our upstream business, we will continue to evaluate opportunities to acquire producing oil and/or natural gas properties as well as offer selected properties for divestment while striving to maintain or enhance productive capability and reduce operating costs per boe. In addition, we intend to be an active participant in the consolidation of the Canadian energy industry, including other royalty trusts.

In our downstream business, we continue to evaluate three potential enhancements to either expand or reconfigure the refinery with the assistance of SNC Lavalin. The options include a project to convert approximately 30,000 bbl/d of heavy fuel oil to higher valued refined products, a major expansion of processing capacity supported by existing infrastructure and enhancing our capability to refine a heavier and lower cost crude oil feedstock to improve margins. SNC Lavalin is expected to complete its study and provide a report by June 2008 and with projected costs of potential enhancements expected to exceed $1 billion, we will evaluate our financing options once the nature of the expansion project is more defined and the risks and benefits assessed. There are also economic gains to be had by upgrading our combustion technologies which will also reduce our greenhouse gas emissions.

As the changes to Canada's Income Tax Act to apply a 29.5% tax on distributions from publicly traded mutual fund trusts, including Harvest, have now been enacted with an effective date of January 1, 2011, we continue to search and validate various capital structures, balancing the benefits of the remaining years of tax efficient distributions against the longer term benefits of continuing with a growth strategy beyond the announced "normal growth" limitations.

SUMMARY OF QUARTERLY RESULTS

The following table and discussion highlights our First Quarter of 2008 relative to the preceding seven quarters:

		2008	2007				2006	
(000s except where noted)		**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Revenue, net of royalties	**$**	**1,377,352**	$879,124	$1,007,786	$ 1,133,450	$1,025,512	$682,744	$259,818	$257,103
Net income (loss)	**$**	**(346)**	$(113,585)	$11,811	$6,248	$69,850	$1,533	$107,768	$60,682
Per Trust Unit, basic[1]	**$**	**-**	$(0.77)	$0.08	$0.05	$0.55	$0.01	$1.01	$0.60
Per Trust Unit, diluted[1]	**$**	**-**	$(0.77)	$0.08	$0.05	$0.55	$0.01	$0.99	$0.60
Cash from operating activities	**$**	**128,119**	$87,998	$191,049	$251,218	$111,048	$140,543	$143,597	$135,581
Per Trust Unit, basic	**$**	**0.85**	$0.60	$1.31	$1.88	$0.87	$1.21	$1.35	$1.34
Per Trust Unit, diluted	**$**	**0.83**	$0.60	$1.22	$1.67	$0.84	$1.16	$1.31	$1.30
Distributions per Unit, declared	**$**	**0.90**	$0.98	$1.14	$1.14	$1.14	$1.14	$1.14	$1.14
Total long term financial liabilities	**$**	**2,209,451**	$2,172,417	$2,097,187	$1,987,352	$2,436,018	$2,488,524	$1,105,728	$746,840
Total assets	**$**	**5,574,528**	$5,451,683	$5,585,651	$5,613,333	$5,800,346	$5,745,558	$4,076,771	$3,455,918

(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. Accordingly, since the acquisition of the downstream operations in the Fourth Quarter of 2006, our revenues have increased substantially and then throughout 2007 have remained relatively stable until the Fourth Quarter of 2007 when the refinery throughput decreased due to a planned shutdown for more than half of the quarter. In the First Quarter of 2008, net revenues were the highest in Harvest's history due to strong commodity prices (for both the upstream and downstream operations) and increased throughput in our downstream operations.

The growth in cash from operating activities is closely aligned with the trend in net revenues and is attributed to the same factors as the growth in net revenues, reflecting the cyclical nature of the downstream segment in 2007. In the First Quarter of 2008, cash from operating activities had increased from the previous quarter as the Fourth Quarter of 2007 reflected weak refining margins and the effect of reduced refinery throughput and additional downstream costs resulting from the planned shutdowns. Additionally, First Quarter 2008 cash from operating activities reflects strong commodity prices from our upstream production offset by increased losses settled on our price risk management contracts.

Net 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 and losses on risk management contracts and Trust Unit right compensation expense cause net income to vary significantly from period to period. In the Second Quarter of 2007 Bill C-52 was substantively enacted, which imposed a new tax on distributions from publicly traded income trusts resulting in a large future income tax expense in the quarter. In the Fourth Quarter of 2007 Bill C-28 implemented reductions in the federal corporate income tax rates which will also apply to the tax on distributions from publicly traded mutual fund trusts, resulting in a significant future income tax recovery in the quarter. In the First Quarter of 2008, future income tax recovery of $21.8 million was recorded as a result of the excess depreciation expense recorded over the amount of tax pool claims to be made. Additionally, the volatility in net income (loss) over the preceding eight quarters has arisen from changes in the fair value of our risk management contracts. For these reasons, our net income (loss) does not reflect the same trends as net revenues or cash from operating activities, nor is it expected to.

Growth in total assets over the last eight quarters is directly attributed to our acquisition of Birchill in the Third Quarter of 2006 and North Atlantic in the Fourth Quarter of 2006. The changes in total long term financial liabilities is primarily due to the impact of our acquisitions, offset by the issuance of Trust Units and the net cash surplus of cash from operating activities over distributions to Unitholders.

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, 2007 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 months ended March 31, 2008 from those described in our annual MD&A.

RECENT CANADIAN ACCOUNTING AND RELATED PRONOUNCEMENTS

Convergence of Canadian GAAP with International Financial Reporting Standards
In early 2008, Canada's Accounting Standards Board ("AcSB") announced that Canadian public reporting issuers will be required to report under International Financial Reporting Standards ("IFRS") beginning January 1, 2011. The adoption of IFRS is intended to bring more transparency and a higher degree of global comparability as IFRS has been adopted in more than 100 countries. We are currently assessing the impact of adopting IFRS on our business and preparing for the upcoming transition.

In February 2008, the CICA issued Section 3064, Goodwill and Intangible Assets, replacing Section 3062 Goodwill and Other Intangible Assets and Section 3450, Research and Development Costs. The new Section will be effective on January 1, 2009. Section 3062 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. We are currently evaluating the impact of the adoption of this new section, however do not expect a material impact on our Consolidated Financial Statements.

OPERATIONAL AND OTHER BUSINESS RISKS

Our financial and operating performance is subject to risks and uncertainties which include, but are not limited to: upstream operations, downstream operations, reserve estimates, commodity prices, ability to obtain financing, environmental, health and safety risk, regulatory risk, disruptions in the supply of crude oil and delivery of refined products, employee relations, and other risks specifically discussed previously in this MD&A. We intend to continue executing our business plan to create value for Unitholders by paying stable monthly distributions and increasing the net asset value per Trust Unit. All of our risk management activities are carried out under policies approved by the Board of Directors of Harvest Operations, and are intended to mitigate the risks noted above as follows:

The following summarizes the more significant risks of our upstream and downstream operations. See our Annual Information Form for a full description of these risks as well as risks associated with our royalty trust structure.

Operation of oil and natural gas properties:

- Applying a proactive management approach to our properties;
- Selectively adding skilled and experienced employees and providing encouragement and opportunities to maintain and improve technical competence; and

Operation of a refining and petroleum marketing business

- Maintaining a proactive approach to managing the supply of feedstock and sale of refined products to ensure the continuity of supply of crude oil to the refinery and the delivery of refined products from the refinery;
- Allocating sufficient resources to ensure good relations are maintained with our non-unionized and unionized work force; and

- Selectively adding experienced refining management to further strengthen our "in-house" management team.

Estimates of the quantity of recoverable reserves:

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

Commodity price exposures:

- Maintaining a risk-management policy and committee to continuously review effectiveness of existing actions, identify new or developing issues and devise and recommend to the Board of Directors of Harvest Operations action to be taken;
- Executing risk management contracts with a portfolio of credit-worthy counterparties;
- Maintaining an efficient cost structure to maximize product netbacks; and
- Limiting the period of exposure to price fluctuations between crude oil prices and product prices by entering into contracts such that crude oil feedstock will be priced based on the price at or near the time of delivery to the refinery, which may be as much as 24 days subsequent to the time the feedstock is initially loaded onto the shipping vessel. Thereby, minimizing the time between the pricing of the feedstock and the refined products with the objective of maintaining margins.

Financial risk:

- Monitoring financial markets to ensure the cost of debt and equity capital is kept as low as reasonably possible;
- Retaining a portion of cash flows to finance capital expenditures and future property acquisitions; and
- Carrying adequate insurance to cover property and business interruption losses.

Environmental, health and safety risks:

- Adhering to our safety programs and keeping abreast of current industry practices for both the oil and natural gas industry as well as the refining industry; and
- Committing funds on an ongoing basis toward the remediation of potential environmental issues.

Changing government policy, including revisions to royalty legislation, income tax laws, and incentive programs related to the oil and natural gas industry:

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

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, 2007 as filed on SEDAR at www.sedar.com.

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 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 is also commonly used in the petroleum and natural gas and refining industries to reflect operating results before items not directly related to operations.

ADDITIONAL INFORMATION

Further information about us, 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)		**March 31, 2008**		December 31, 2007
Assets				
Current assets				
Cash	**$**	**-**	$	-
Accounts receivable and other		**311,029**		215,803
Fair value of risk management contracts *[Note 12]*		**19,647**		16,442
Prepaid expenses and deposits		**14,507**		15,144
Inventories		**77,276**		58,934
		422,459		306,323
Fair value of risk management contracts *[Note 12]*		**-**		-
Property, plant and equipment *[Note 3]*		**4,196,959**		4,197,507
Intangible assets *[Note 4]*		**96,083**		95,075
Goodwill		**859,027**		852,778
	$	**5,574,528**	$	5,451,683
Liabilities and Unitholders' Equity				
Current liabilities				
Accounts payable and accrued liabilities	**$**	**335,172**	$	270,243
Cash distribution payable		**45,340**		44,487
Current portion of convertible debentures *[Note 6]*		**-**		24,273
Fair value deficiency of risk management contracts *[Note 12]*		**165,159**		131,020
		545,671		470,023
Bank loan		**1,330,423**		1,279,501
$7^{7/8}$% Senior notes		**250,099**		241,148
Convertible debentures *[Note 6]*		**628,929**		627,495
Fair value deficiency of risk management contracts *[Note 12]*		**65,020**		35,095
Asset retirement obligation *[Note 5]*		**215,233**		213,529
Employee future benefits *[Note 11]*		**12,337**		12,168
Deferred credit		**657**		710
Future income tax		**64,806**		86,640
Unitholders' equity				
Unitholders' capital *[Note 7]*		**3,797,061**		3,736,080
Equity component of convertible debentures		**33,101**		39,537
Contributed surplus *[Note 8]*		**6,433**		-
Accumulated income		**246,519**		246,865
Accumulated distributions		**(1,475,515)**		(1,340,349)
Accumulated other comprehensive loss		**(146,246)**		(196,759)
		2,461,353		2,485,374
	$	**5,574,528**	$	5,451,683

Commitments, contingencies and guarantees [Note 14]
Subsequent events [Note 15]
See accompanying notes to these consolidated financial statements.

Approved by the Board of Directors:

((signed))
Hector J. McFadyen
Director

((signed))
Verne G. Johnson
Director

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

(thousands of Canadian dollars, except per Trust Unit amounts)		**Three months ended March 31, 2008**		Three months ended March 31, 2007
Revenue				
Petroleum, natural gas, and refined product sales	**$**	**1,439,752**	$	1,075,161
Royalty expense		**(62,400)**		(49,649)
		1,377,352		1,025,512
Expenses				
Purchased products for processing and resale		**959,992**		632,296
Operating		**141,345**		121,657
Transportation and marketing		**11,622**		10,155
General and administrative *[Note 10]*		**12,477**		10,404
Realized net losses on risk management contracts		**36,294**		297
Unrealized net losses on risk management contracts		**60,858**		14,121
Interest and other financing charges on short term debt, net		**201**		3,627
Interest and other financing charges on long term debt		**35,103**		40,449
Depletion, depreciation, amortization and accretion		**130,925**		133,792
Foreign exchange loss (gain)		**10,665**		(11,260)
Large corporations tax and other tax		**50**		124
Future income tax recovery		**(21,834)**		-
		1,377,698		955,662
Net (loss) income for the period		**(346)**		69,850
Cumulative Translation Adjustment		**50,513**		(16,140)
Comprehensive income for the period	$	**50,167**	$	53,710
Net income per trust unit, basic *[Note 7]*	**$**	**-**	$	0.55
Net income per trust unit, diluted *[Note 7]*	**$**	**-**	$	0.55

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	Accumulated Distributions	Accumulated Other Comprehensive (Loss) Income
At December 31, 2006	**$3,046,876**	**$ 36,070**	**$ -**	**$ 271,155**	**$ (730,069)**	**$ 46,873**
Adjustment arising from change in accounting policies	(49)	-	-	1,386	-	-
Issued for cash						
February 1, 2007	143,834	-	-	-	-	-
Equity component of convertible debenture issuances						
7.25% Debentures Due 2014	-	13,100	-	-	-	-
Convertible debenture conversions						
9% Debentures Due 2009	101	-	-	-	-	-
8% Debentures Due 2009	173	(2)	-	-	-	-
6.40% Debentures Due 2012	52	(4)	-	-	-	-
Exercise of unit appreciation rights and other	184	-	-	-	-	-
Issue costs	(7,841)	-	-	-	-	-
Foreign currency translation adjustment	-	-	-	-	-	(16,140)
Net income	-	-	-	69,850	-	-
Distributions and distribution reinvestment plan	43,797	-	-	-	(145,270)	-
At March 31, 2007	**$3,227,127**	**$ 49,164**	**$ -**	**$ 342,391**	**$ (875,339)**	**$ 30,733**
At December 31, 2007	**$3,736,080**	**$ 39,537**	**$ -**	**$ 246,865**	$ (1,340,349)	**$ (196,759)**
Convertible debenture conversions						
9% Debentures Due 2009	7	-	-	-	-	-
8% Debentures Due 2009	31	-	-	-	-	-
10.5% Debentures Due 2008	13	(3)	-	-	-	-
Redemption of convertible debentures						
10.5% Debentures Due 2008 *[Note 8]*	24,249	(6,433)	6,433	-	-	-
Exercise of unit appreciation rights and other	805	-	-	-	-	-
Issue costs	(14)	-	-	-	-	-
Foreign currency translation adjustment	-	-	-	-	-	50,513
Net income	-	-	-	(346)	-	-
Distributions and distribution reinvestment plan	35,890	-	-	-	(135,166)	-
At March 31, 2008	**$3,797,061**	**$ 33,101**	**$ 6,433**	**$ 246,519**	**$ (1,475,515)**	**$ (146,246)**

See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(thousands of Canadian dollars)	**Three months ended March 31, 2008**	Three months ended March 31, 2007
Cash provided by (used in)		
Operating Activities		
Net (loss) income for the period	**$ (346)**	$ 69,850
Items not requiring cash		
Depletion, depreciation, amortization and accretion	**130,925**	133,792
Unrealized foreign exchange loss (gain)	**9,866**	(10,736)
Non-cash interest expense	**1,836**	1,892
Amortization of deferred finance charges	**675**	2,481
Unrealized loss on risk management contracts *[Note 12]*	**60,858**	14,121
Future income tax recovery	**(21,834)**	-
Unit based compensation expense	**3,234**	2,430
Amortization of office lease premiums and deferred rent expense	**3**	3
Employee benefit obligation	**169**	108
Settlement of asset retirement obligations *[Note 5]*	**(2,253)**	(2,120)
Change in non-cash working capital	**(55,014)**	(100,773)
	128,119	111,048
Financing Activities		
Issue of Trust Units, net of issue costs	**(14)**	136,016
Issue of convertible debentures, net of issue costs	**-**	220,489
Bank borrowings (repayments), net	**50,922**	(225,371)
Financing costs	**-**	(273)
Cash distributions	**(98,423)**	(98,442)
Change in non-cash working capital	**67**	6,202
	(47,448)	38,621
Investing Activities		
Additions to property, plant and equipment	**(85,598)**	(153,370)
Business acquisitions	**-**	(30,264)
Property acquisitions (dispositions), net	**(185)**	(689)
Change in non-cash working capital	**5,646**	24,003
	(80,137)	(160,320)
Change in cash and cash equivalents	**534**	(10,651)
Effect of exchange rate changes on cash	**(534)**	645
Cash and cash equivalents, beginning of period	**-**	10,006
Cash and cash equivalents, end of period	**$ -**	$ -
Interest paid	**$ 24,041**	$ 15,843
Large corporation tax and other tax paid	**$ 50**	$ 124

See accompanying notes to these consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Period ended March 31, 2008
(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, 2007 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, 2008, Harvest adopted the following new Canadian Institute of Chartered Accountants ("CICA") accounting standards:

"Financial Instruments – Disclosure", section 3862 and "Financial Instruments – Presentation", section 3863. These new standards require increased disclosure on financial instruments, particularly with regard to the nature and extent of risks arising from financial instruments and how the entity manages those risks.

"Capital Disclosures", section 1535 requires the disclosure of information about an entity's objectives, policies and processes for managing capital; quantitative data about what the entity regards as capital; whether the entity has complied with any externally imposed capital requirements; and if it has not complied, the consequences of such non-compliance.

"Inventories", section 3031, which replaces the existing inventories standard. This new standard provides additional guidance with respect to the measurement and disclosure requirements for inventories, requiring inventories to be valued at the lower of cost and net realizable value. The adoption of this section did not have any impact on our financial statements.

3. Property, Plant and Equipment

	March 31, 2008			December 31, 2007		
	Upstream	**Downstream**	**Total**	Upstream	Downstream	Total
Cost	**$ 4,327,478**	**$ 1,211,860**	**$ 5,539,338**	$ 4,247,819	$ 1,164,310	$ 5,412,129
Accumulated depletion and depreciation	**(1,252,173)**	**(90,206)**	**(1,342,379)**	(1,142,345)	(72,277)	(1,214,622)
Net book value	**$ 3,075,305**	**$ 1,121,654**	**$ 4,196,959**	$ 3,105,474	$ 1,092,033	$ 4,197,507

General and administrative costs of $3.2 million (2007 – $2.7 million) have been capitalized during the three month period ended March 31, 2008, of which $0.7 million (2007 - $0.5 million) relate to the Trust Unit Incentive Plan and the Unit award incentive plan.

4. Intangible Assets

	March 31, 2008			December 31, 2007		
	Cost	**Accumulated Amortization**	**Net book value**	Cost	Accumulated Amortization	Net book value
Engineering drawings	**$ 91,358**	**$ 6,662**	**$ 84,696**	$ 88,227	$ 5,330	$ 82,897
Marketing contracts	**6,354**	**1,399**	**4,955**	6,136	1,099	5,037
Customer lists	**3,847**	**561**	**3,286**	3,714	449	3,265
Fair value of office lease	**931**	**484**	**447**	931	428	503
Financing costs	**12,113**	**9,414**	**2,699**	12,113	8,740	3,373
Total	**$ 114,603**	**$ 18,520**	**$ 96,083**	$ 111,121	$ 16,046	$ 95,075

5. 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 $1,001 million which will be incurred between 2008 and 2057. 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:

	Three Months ended March 31, 2008	Year Ended December 31, 2007
Balance, beginning of period	**$ 213,529**	$ 202,480
Incurred on acquisition of a private corporation	**-**	1,629
Incurred on acquisition of Grand	**-**	4,416
Liabilities incurred	**590**	9,553
Revision of estimates	**(1,230)**	(6,088)
Liabilities settled through disposition	**-**	(3,708)
Liabilities settled	**(2,253)**	(13,090)
Accretion expense	**4,597**	18,337
Balance, end of period	**$ 215,233**	$ 213,529

Harvest has undiscounted asset retirement obligations of approximately $14.7 million relating to the refining and marketing assets. The fair value of this obligation cannot be reasonably determined because the assets currently have an indeterminate life.

6. Convertible Debentures

At March 31, 2008, Harvest had six 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, 2007.

The following table summarizes the face value, carrying amount and fair value of the convertible debentures:

	March 31, 2008			December 31, 2007	
	Face Value	**Carrying Amount(1)**	**Fair Value**	Face Value	Carrying Amount(1)
9% Debentures Due 2009	$ 969	$ 957	$ 1,667	$ 976	$ 962
8% Debentures Due 2009	1,697	1,666	2,461	1,728	1,692
6.5% Debentures Due 2010	37,062	34,830	36,877	37,062	34,653
10.5% Debentures Due 2008	-	-	-	24,258	24,273
6.40% Debentures Due 2012	174,626	168,598	160,638	174,626	168,325
7.25% Debentures Due 2013	379,256	355,960	354,604	379,256	355,145
7.25% Debentures Due 2014	73,222	66,918	71,025	73,222	66,718
	$666,832	**$628,929**	**$627,272**	$ 691,128	$ 651,768

(1)Excluding the equity component.

On January 31, 2008, the 10.5% debenture matured and Harvest elected to settle the obligation by issuing 1,166,593 Trust Units rather than settling the obligation in cash.

7. Unitholders' Capital

(a) *Authorized*

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

(b) *Number of Units Issued*

	Three month period ended March 31, 2008	2007
Outstanding, beginning of period	**148,291,170**	122,096,172
Issued for cash		
February 1, 2007	**-**	6,146,750
Convertible debenture conversions		
9% Debentures Due 2009	**505**	7,508
8% Debentures Due 2009	**1,928**	11,137
10.5% Debentures Due 2008	**344**	-
6.40% Debentures Due 2012	**-**	1,086
Redemption of convertible debentures		
10.5% Debentures Due 2008	**1,166,593**	-
Distribution reinvestment plan issuance	**1,637,601**	1,802,681
Exercise of unit appreciation rights and other	**37,583**	6,959
Outstanding, end of period	**151,135,724**	130,072,293

(c) *Per Trust Unit Information*

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

Net income adjustments	**March 31, 2008**	March 31, 2007
Net (loss) income, basic	**$ (346)**	$ 69,850
Interest on convertible debentures and other	**-**	77
Net income, diluted(1)	**$ (346)**	69,927
Weighted average Trust Units adjustments	**March 31, 2008**	March 31, 2007
Number of Units		
Weighted average Trust Units outstanding, basic	**149,899,484**	126,987,698
Effect of convertible debentures and other	**-**	220,870
Effect of Employee Unit Incentive Plans	**-**	253,032
Weighted average Trust Units outstanding, diluted(2)	**149,899,484**	127,461,600

(1) Net income, diluted excludes the impact of the conversions of certain of the convertible debentures of $13,264,000 for the three month period ended March 31, 2008 (three month period ended March 31, 2007 - $15,017,000), as the impact would be anti-dilutive.

(2) Weighted average Trust Units outstanding, diluted for the three month period ended March 31, 2008 does not include the unit impact of 20,031,150 for certain of the convertible debentures (three month period ended March 31, 2007 – 23,258,373) and 121,294 (three month period ended March 31, 2007 – nil) for the Employee Unit Incentive Plans, as the impact would be anti-dilutive.

8. Contributed Surplus

Contributed surplus of $6.4 million has been recorded during the three month period ended March 31, 2008 due to the maturity of the 10.5% Debentures Due 2008 and the resulting expiration of the conversion option which was previously recorded in equity component of convertible debentures.

9. Capital Structure

Harvest's primary objective in its management of capital resources is to ensure sufficient financial flexibility to access capital to fund its financial obligations as well as to fund future growth. Harvest considers its capital structure to comprise its credit facilities, 77/8% Senior Notes, convertible debentures and unitholders' equity.

Harvest monitors its capital structure using the following non-GAAP financial ratios: bank debt to Twelve Month Trailing Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA"), secured debt to net present value of our proved petroleum and natural gas reverses discounted at 10% and total debt to total debt plus unitholders' equity. Total debt includes borrowings under credit facilities plus our 77/8% Senior Notes and principal amount of convertible debentures and Unitholders' equity is adjusted to remove the equity component of convertible debentures.

Harvest's capital management strategy with regards to our bank debt is to maintain a bank debt to EBITDA ratio between 1.0 and 2.5 times. This ratio is calculated as follows:

	March 31, 2008	December 31, 2007
Cash provided by operating activities	**$ 658,384**	$ 641,313
Settlement of asset retirement obligations	**13,223**	13,090
Change in non-cash working capital	**(28,375)**	17,384
Interest paid	**138,830**	145,740
Large Corporations Tax and other taxes paid	**(1,048)**	(974)
Total EBITDA	**$ 781,014**	$ 816,553
Bank debt	**$ 1,330,423**	$ 1,279,501
Bank debt to EBITDA	**1.70**	1.57

With respect to its senior debt, Harvest's strategy is to target a ratio of secured debt to 65% of the net present value of its proved petroleum and natural gas reserves discounted at 10% (as determined on an annual basis) of less than 0.9 times. This is calculated as follows:

	March 31, 2008	December 31, 2007
Secured debt (borrowings under Credit Facilities)	**$ 1,330,423**	$ 1,279,501
Proved petroleum and natural gas reserves (January 1, 2008 Net Present Value discounted at 10%)	**$ 2,865,200**	$ 2,865,200
65% of Proved petroleum and natural gas reserves	**$ 1,862,380**	$ 1,862,380
Secured debt to 65% of proved petroleum and natural gas reserves	**0.71**	0.69

Harvest targets its total debt to total debt plus unitholders' equity to be a ratio between 0.25 and 0.55 times calculated as follows:

	March 31, 2008	December 31, 2007
Bank debt	**$ 1,330,423**	$ 1,279,501
7⁷/⁸% Senior Notes	**250,099**	241,148
Principal amount of convertible debentures	**666,832**	691,128
Total Debt	**2,247,354**	2,211,777
Unitholders' equity (less equity component of convertible debentures)	**2,428,252**	2,445,837
Total debt plus unitholders' equity	**$ 4,675,606**	$ 4,657,614
Total debt to total debt plus unitholders' equity	**0.48**	0.47

Harvest's capital structure is limited by a covenant in its Convertible Debenture Indenture which currently restricts the issuance of additional convertible debentures to approximately $200 million. In addition, although Harvest's Trust Unit Indenture provides for the issuance of an unlimited number of Trust Units, the "normal growth guidelines" contained in Bill C-52 issued by the Government of Canada limits the future issuance of convertible debentures and Trust Units at March 31, 2008 to approximately $550 million in each of 2008, 2009 and 2010 with any unused normal growth available for use prior to 2011. Harvest is also entitled to issue approximately $590 million to replace debt held by the Trust on October 31, 2006.

Harvest monitors its capital structure and makes adjustments according to market conditions to remain flexible while meeting its objectives as outlined above. Accordingly, Harvest may adjust its capital spending programs, adjust the amount of distributions paid to Unitholders, issue new Trust Units, convertible debentures or senior notes or repay existing debt. Harvest's capital management targets have remained unchanged during the three month period ended March 31, 2008.

10. Employee Unit Incentive Plans

Trust Unit Rights Incentive Plan

As at March 31, 2008, a total of 5,306,980 (3,823,683 – December 31, 2007) Unit Appreciation Rights were outstanding under the Trust Unit Rights Incentive Plan at an average exercise price of $24.36 ($25.74 – December 31, 2007).

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

	Three months ended March 31, 2008		Year ended December 31, 2007	
	Unit Appreciation Rights	**Weighted Average Exercise Price**	Unit Appreciation Rights	Weighted Average Exercise Price
Outstanding beginning of period	**3,823,683**	**$ 30.74**	3,788,125	$ 30.81
Granted	**1,679,722**	**23.61**	576,383	29.03
Exercised	**(36,875)**	**25.47**	(92,775)	21.88
Forfeited	**(159,550)**	**29.97**	(448,050)	31.10
Outstanding before exercise price reductions	**5,306,980**	**28.54**	3,823,683	30.74
Exercise price reductions	**-**	**(4.18)**	-	(5.00)
Outstanding, end of period	**5,306,980**	**24.36**	3,823,683	$ 25.74
Exercisable before exercise price reductions	**509,650**	**$ 25.33**	138,350	$ 22.72
Exercise price reductions	**-**	**(6.45)**	-	(9.38)
Exercisable, end of period	**509,650**	**$ 18.88**	138,350	$ 13.34

The following table summarizes information about Unit appreciation rights outstanding at March 31, 2008.

		Outstanding			**Exercisable**	
Exercise Price before price reductions	**Exercise Price net of price reductions**	**At March 31, 2008**	**Weighted Average Exercise Price net of price reductions(1)**	**Remaining Contractual Life (1)**	**At March 31, 2008**	**Weighted Average Exercise Price net of price reductions(1)**
$13.15-$14.99	$1.38-$4.31	22,750	$ 3.52	1.1	22,750	$ 3.52
$18.90-$25.30	$8.30-$25.06	1,828,847	22.44	4.7	116,700	14.75
$26.09-$28.41	$21.10-$26.53	1,579,150	21.40	3.8	362,600	21.14
$28.59-$37.56	$20.18-$31.87	1,876,233	28.99	3.2	7,600	20.26
$13.15-$37.56	$1.38-$31.87	5,306,980	$ 24.36	3.9	509,650	$ 18.88

(1) Based on weighted average Unit appreciation rights outstanding.

Unit Award Incentive Plan("Unit Award Plan")
At March 31, 2008, 391,683 Units were outstanding under the Unit Award Incentive Plan.

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

Number	**March 31, 2008**	December 31, 2007
Outstanding, beginning of period	**348,248**	306,699
Granted	**91,751**	56,132
Adjusted for distributions	**12,685**	48,280
Exercised	**(54,746)**	(37,072)
Forfeitures	**(6,255)**	(25,791)
Outstanding, end of period	**391,683**	348,248
Exercisable, end of period	**179,737**	168,401

Harvest has recognized compensation expense of $3.6 million for the three month period ended March 31, 2008 ($2.9 million - three month period ended March 31, 2007), including non cash compensation expense of $3.1 million for the three month period ended March 31, 2008 ($2.4 million - three month period ended March 31, 2007), related to the Trust Unit Incentive Plan and the Unit Award Plan and this is reflected in general and administrative expense in the consolidated statements of income.

11. Employee Future Benefit Plans

Defined Contribution Pension Plan

Total expense for the defined contribution plan is equal to Harvest's required contributions and was $0.2 million for the three month period ended March 31, 2008 (three month period ended March 31, 2007 - $0.2 million)

Defined Benefit Plans

Estimated pension and other benefit payments to plan participants, which reflect expected future service, expected to be paid from 2008 to 2017 are summarized in the commitment table [see Note 14].

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

	Three month period ended March 31, 2008		Three month period ended March 31, 2007	
	Pension Plans	**Other Benefit Plans**	Pension Plans	Other Benefit Plans
Current service cost	**$ 839**	**$ 92**	$ 761	$ 92
Interest costs	**667**	**87**	593	79
Expected return on assets	**(698)**	**-**	(666)	-
Amortization of net actuarial losses	**-**	**-**	-	-
Net benefit plan expense	**$ 808**	**$ 179**	$ 688	$ 171

12. Financial Instruments and risk management contracts

Financial instruments of Harvest consist of cash, accounts receivable, long-term receivables, accounts payable and accrued liabilities, cash distribution payable, bank loan, risk management contracts, convertible debentures and the 77/8% Senior Notes. The carrying value and fair value of these financial instruments at March 31, 2008 is disclosed below by financial instrument category, as well as any related gains or losses and interest income or expense for the three month period ended March 31, 2008:

	Carrying Value	**Fair Value**	**Gains/ (Losses)**	**Interest Income/ (Expense)**	**Other Income/ (Expense)**
Loans and Receivables					
Accounts receivable	$ 311,029	$ 311,029	$ -	$ 43 (2)	$ -
Liabilities Held for Trading					
Net fair value of risk management contracts	210,532	210,532	(97,152) (3)	-	-
Other Liabilities					
Accounts payable	335,172	335,172	-	-	-
Cash distribution payable	45,340	45,340	-	-	-
Bank loan	1,330,423	1,330,423	-	(16,060) (4)	(675) (4)
$7^{7/8}$% Senior Notes	250,099 (1)	236,376	-	(5,306) (5)	-
Convertible debentures	$ 628,929	$ 627,272	$ -	$ (13,263) (5)	$ -

(1) The face value of the $7^{7/8}$% Senior Notes at March 31, 2008 is $256.6 million (U.S. $250 million).
(2) Included in petroleum, natural gas, and refined product sales in the statement of income and comprehensive income.
(3) Included in risk management contracts - realized and unrealized gains/(losses) in the statement of income and comprehensive income.
(4) Included in interest and other financing charges on short term/long term debt in the statement of income and comprehensive income. The amortization of financing fees related to this liability is included in Amortization of deferred finance charges in the statement of cash flows.
(5) Included in Interest and other financing charges on short term/long term debt in the statement of income and comprehensive income. The non-cash interest expense relating to the accretion of premiums, discounts or transaction costs that are netted against these liabilities are included in non-cash interest in the statement of cash flows.

The fair values of the convertible debentures and the 77/8% Senior Notes are based on quoted market prices as at March 31, 2008. The risk management contracts are recorded on the balance sheet at their fair value, accordingly, there is no difference between fair value and carrying value. The bank loan is recorded at amortized cost, but as there are no transaction costs associated with our bank debt and the financing costs are included in intangible assets, there is no difference between the carrying value and the fair value. Due to the short term nature of accounts receivable, accounts payable and cash distribution payable, their carrying values approximate their fair values.

(a) Risk Exposure

Harvest is exposed to market risks resulting from fluctuations in commodity prices, foreign 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.

(i.) Credit Risk

Upstream Accounts Receivable

Accounts receivable in our upstream operations are due from crude oil and natural gas purchasers as well as joint venture partners. These balances are due from companies in the petroleum and natural gas industry and are subject to normal industry credit risks. Concentration of credit risk is mitigated by having a broad customer base, which includes a significant number of companies engaged in joint operations with Harvest. Harvest periodically assesses the financial strength of its crude oil and natural gas purchasers and will adjust its marketing plan to mitigate credit risks. This assessment involves a review of external credit ratings; however, if external ratings are not available, Harvest requests a guarantee from the parent company that does have a credit rating. If this is not possible, Harvest performs an internal credit review based on the purchaser's past financial performance. The credit risk associated with joint venture partners is mitigated by reviewing the credit history of partners and requiring some partners to provide cash prior to incurring significant capital costs on their behalf. As well, most agreements have a provision that enables us to use the proceeds from the sale of production that would otherwise be taken in kind by the partner to offset against amounts owing from the partner that are in default. Generally, the only instances of impairment are when a purchaser or partner is facing bankruptcy or extreme financial distress.

Risk Management Contract Counterparties

Harvest is also exposed to credit risk from the counterparties to our risk management contracts. This risk is managed by diversifying Harvest's risk management portfolio among a number of counterparties and limiting those counterparties to lenders in our syndicated credit facilities; we have no history of impairment with these counterparties.

Downstream Accounts Receivable

The Supply and Offtake Agreement entered into in conjunction with the purchase of the refinery exposed Harvest to the credit risk of Vitol Refining S.A. ("Vitol") as all feedstock purchases and the majority of product sales are made with Vitol under this agreement. Harvest mitigates this risk by requiring that Vitol maintain a minimum B+ credit rating as assessed by Standard and Poors. If the credit rating falls below this line, additional security is required to be supplied to Harvest. This credit risk is also mitigated by the amounts owing to Vitol for feedstock purchases that are offset against amounts receivable from Vitol for product sales with the balance being net settled. Harvest is in a net payable position with Vitol at March 31, 2008 and accordingly the outstanding balance is included in current trade accounts payable in the liability liquidity table below.

Harvest's policy is to manage its credit risk by dealing with only financially sound customers, based on an evaluation of the customer's financial condition. At March 31, 2008, Harvest had an accounts receivable balance with one customer of approximately $21 million resulting from the sale of refined product, representing approximately 20% of total downstream accounts receivable. This customer is an integrated multinational oil and gas company and the credit risk associated with this balance is low.

Our maximum exposure to credit risk relating to the above classes of financial assets at March 31, 2008 is the carrying value of accounts receivable. The table below provides an analysis of our current financial assets and the age of our past due but not impaired financial assets by type of credit risk.

	Current AR	Overdue AR			
		≤ 30 days	> 30 days, ≤ 60 days	> 60 days, ≤ 90 days	> 90 days
Upstream Accounts Receivable	$ 158,564	$ 4,231	$ 957	$ 2,361	$ 29,805
Risk Management Contract Counterparties	1,632	-	-	-	-
Downstream Accounts Receivable	89,886	18,344	1,059	548	3,642
Total	**$ 250,082**	**$ 22,575**	**$ 2,016**	**$ 2,909**	**$ 33,447**

(ii.) Liquidity Risk

Harvest is exposed to liquidity risk due to our borrowings under our credit facilities and 77/8% Senior Notes with repayment requirements. This risk is mitigated by managing the maturity dates on our obligations, complying with covenants and managing our cash flow by entering into price risk management contracts. Additionally, when we enter into price risk management contracts we select counterparties that are also lenders in our syndicated credit facility, using the security provided in our credit agreement to extend to our risk management contracts eliminating the requirement for margin calls and the pledging of collateral.

The following table provides an analysis of our financial liability maturities based on the remaining terms of our liabilities as at March 31, 2008 and includes the related interest charges:

	≤1 year	>1 year ≤3 years	>4 years ≤5 years	>5 years	Total
Trade accounts payable	$ 335,172	$ -	$ -	$ -	$ 335,172
Distributions payable	45,340	-	-	-	45,340
Settlements of risk management contracts(1)	186,081	24,275	-	-	210,356
Bank loan and interest	43,384	1,407,147	-	-	1,450,531
Convertible debentures interest(2)	35,023	92,910	86,063	26,643	240,639
Senior notes and interest	15,185	40,418	272,516	-	328,119
Pension contributions	857	3,631	5,301	21,285	31,074
Asset retirement obligations	22,364	17,350	27,437	933,489	1,000,640
Total	**$683,406**	**$1,585,731**	**$391,317**	**$ 981,417**	**$3,641,871**

(1) This value is determined using the relevant forward prices as of March 31, 2008. Additionally, only those contracts that are currently in a deficiency position are presented herein and the offsetting effect of contracts that are in an asset position is not reflected.

(2) Convertible debentures are typically converted into Trust Units prior to maturity or are redeemed for Trust Units at maturity by Harvest; therefore, only the interest portion is represented in the table above.

(iii.) Market Risks and Sensitivity Analysis

Harvest is exposed to three types of market risks: interest rate risk, foreign currency exchange rate risk and commodity price risk. How these risks arise, how they are managed and how Harvest's net income and other comprehensive income could be affected by changes in the underlying risk variables are presented below.

We have performed sensitivity analysis on the three types of risks identified, assuming that the volatility of the risks over the next quarter will be similar to that experienced in the past year. Harvest has determined that a reasonably possible price or rate variance over the next reporting period for a given risk variable can be estimated by calculating two standard deviations for each three month period in the last year for the relevant daily price/rate settings and using an average of the standard deviation as a reasonable estimate of the expected variance. This variance is then applied to the relevant period end rate or price to determine a reasonable percentage increase and decrease in the risk variable which can then be applied to the outstanding risk exposure at period end. Using 12 months of data, we factor in the seasonality of our business and the price volatility therein. At this time, we have not adjusted the data for any unusual or extreme situations but should one arise, the data would be adjusted accordingly.

Interest rate risk

Harvest is exposed to interest rate risk on its bank borrowings as interest rates are determined in relation to floating market rates plus an incremental charge based on secured debt to EBITDA. Harvest's convertible debentures and 77/8% Senior Notes have fixed interest rates and therefore do not have any additional interest rate risk. Harvest manages its interest rate risk by targeting appropriate levels of debt relative to its expected cash flow from operations.

At March 31, 2008, if interest rates had decreased by 10% with all other variables held constant, after-tax net income for the period would have been $2.9 million higher, as a result of lower interest expense on variable rate borrowings. If interest rates had increased by 10%, with all other variables held constant, the after-tax net income would have been $0.7 million higher. This unexpected increase in net income despite an increase in the period end interest rate results from the decrease in the Prime lending rate that occurred late in the first three months of 2008, resulting in a forward interest rate that is less than Harvest's effective interest rate throughout the period.

Foreign currency exchange rate risk

Harvest is exposed to the risk of changes in the U.S. dollar exchange rate on its U.S. dollar denominated revenues as well as Canadian dollar revenues that are based on a U.S. dollar commodity price. In addition, Harvest's 77/8% Senior Notes are denominated in U.S. dollars (U.S.$250 million) and interest on these notes is payable semi-annually in U.S. dollars and accordingly the principal and any interest payable at the balance sheet date are also subject to currency exchange rate risk. Harvest is also exposed to currency exchange rate risk on its net investment in a self sustaining subsidiary that uses a U.S. dollar functional currency. Harvest manages these exchange rate risks by occasionally entering into fixed rate currency exchange contracts on future U.S. dollar payments and U.S. dollar sales.

At March 31, 2008, if the U.S. dollar strengthened or weakened by 5% relative to the Canadian dollar, the impact on net income and other comprehensive income due to the translation of monetary financial instruments would be as follows:

			Impact on	
		Net Income	**Other Comprehensive Income**	
U.S. Dollar Exchange Rate - 5% increase	$	(12,959)	$	(7,813)
U.S. Dollar Exchange Rate - 5% decrease	$	12,959	$	7,813

As mentioned above, Harvest's wholly owned subsidiary North Atlantic Refining LP operates with a U.S. dollar functional currency which gives rise to currency exchange rate risk on North Atlantic's Canadian dollar denominated monetary assets and liabilities, such as Canadian dollar bank accounts and accounts receivable and payable, as follows:

			Impact on	
		Net Income	**Other Comprehensive Income**	
Canadian Dollar Exchange Rate - 5% increase	$	(5,402)	$	-
Canadian Dollar Exchange Rate - 5% decrease	$	5,402	$	-

Commodity Price Risk

Harvest uses price risk management contracts to manage a portion of its crude oil, natural gas and refined product sales price exposure and power costs. As many of these contracts are denominated in U.S. dollars, we also enter into fixed rate currency exchange contracts. These contracts are recorded on the balance sheet at their fair value as of the balance sheet date, with changes from the prior period's fair value recorded in net income for the period. These fair values are generally determined as the difference between the stated fixed price of the contract and an expected future price of the underlying asset. Variances in expected future prices expose us to commodity price risk as changes will result in a gain or loss that we will realize on settlement of these contracts. This risk is mitigated by continuously monitoring the effectiveness of these contracts.

If the following changes in expected forward prices were applied to the fair value of risk management contracts in place at March 31, 2008, net income would be impacted as follows:

			Impact on NI		
Contract	**% Change**		**Due to % increase**		**Due to % decrease**
Heating Oil NYMEX	10%	$	(66,865)	$	66,865
Heating Oil NYMEX - Crack	15%		(5,386)		5,386
RBOB Gasoline NYMEX – Crack	50%		(2,754)		2,754
#6 (1%) HFO Platts	10%		(28,120)		28,120
#6 (1%) HFO Platts – Crack	20%		2,823		(2,823)
West Texas Intermediate	10%		(13,724)		13,724
Alberta Power Pool	40%		7,956		(7,956)
Currency Forwards	5%		(3,607)		3,283
Total		**$**	**(109,677)**	**$**	**109,353**

(b) Fair Values

At March 31, 2008, the net fair value deficiency reflected on the balance sheet for all the risk management contracts outstanding at that date was approximately $210.5 million ($16.0 million – March 31, 2007), which was included in the balance sheet as follows: fair value of risk management contracts (current assets) $19.6 million, fair value deficiency of risk management contracts (current liabilities) $165.2 million and fair value deficiency of risk management contracts $65.0 million.

The following is a summary of Harvest's risk management contracts outstanding, along with their fair value at March 31, 2008:

Quantity	Type of Contract	Term	Average Price	Fair value
Crude Oil Price Risk Management				
10,000 bbl/d	WTI Participating swap	Apr. 08 – Jun. 08	US$60.00(b)	(13,629)
6,000 bbl/d	WTI 3-way contract	Jul. 08 – Dec. 08	US$62.00 - $87.53 ($72.00)(c)	(15,862)
				$ (29,491)
Refined Product Price Risk Management				
10,000 bbl/d	NYMEX heating oil 3-way contract	Apr. 08 – Dec. 08	US$60.90 - $93.31 ($81.06)(e)(k)	$ (78,907)
6,000 bbl/d	Platt's fuel oil 3-way contract	Apr. 08 – Dec. 08	US$43.00 - $63.21 ($51.67)(f)	(19,579)
2,000 bbl/d	NYMEX heating oil collar	Apr. 08 – Dec. 08	US$79.80 - $91.35(g) (k)	(16,779)
2,000 bbl/d	Platt's fuel oil collar	Apr. 08 – Dec. 08	US$51.00 - $58.68(h)	(8,869)
12,000 bbl/d	NYMEX heating oil 3-way contract	Jan. 09 – Jun. 09	US$72.59 - $98.73 ($86.52)(i) (k)	(47,398)
8,000 bbl/d	Platt's fuel oil 3-way contract	Jan. 09 – Jun. 09	US$49.75 - $65.89 ($57.38)(j)	(17,622)
				$(189,154)
Natural Gas Price Risk Management				
276 GJ/d	Fixed price – natural gas contract	Apr. 08 – Dec. 08	Cdn$4.16(d)	**$ (330)**
Electricity Price Risk Management				
35 MWh	Electricity price swap contracts	Apr. 08 – Dec. 08	Cdn $56.69	**$ 6,795**
Refined Product Crack Spread Risk Management				
2,000 bbl/d	Platt's fuel oil crack swap	Apr. 08 – Dec. 08	US($16.50)	$ 4,944
6,000 bbl/d	NYMEX heating oil crack swap	Apr. 08 – Dec. 08	US$14.63	(11,204)
6,000 bbl/d	NYMEX RBOB crack swap	Jul. 08 – Dec. 08	US$10.00	5,262
				$ (998)
Foreign Currency Exchange Rate Risk Management				
$8,333,333/month	U.S./Cdn dollar exchange rate swap	Apr. 08 – Jun. 08	1.1099 Cdn/US	2,311
$10,000,000/month	U.S./Cdn dollar collar	Apr. 08 – Dec. 08	1.000 Cdn/US- 1.055 Cdn/US(a)	335
				$ 2,646
Total net fair value deficiency of risk management contracts				**$ (210,532)**

(a) If the market price is below $1.000, price received is $1.000; if the market price is between $1.000 and the ceiling of $1.055, the price received is market price; if the market price is over the ceiling of $1.055, price received is the stated ceiling price.

(b) This is the average price of the price floors. Harvest realizes this price plus 67-79%, or an average of 73%, of the difference between spot price and the given floor price.

(c) If the market price is below $62.00, price received is market price plus $10.00; if the market price is between $62.00 and $72.00, the price received is $72.00; if the market price is between $72.00 and the ceiling of $87.53, the price received is market price; if the market price is over the ceiling of $87.53, price received is $87.53.

(d) This contract contains an annual escalation factor such that the fixed price is adjusted each year.

(e) If the market price is below $60.90, price received is market price plus $20.16; if the market price is between $60.90 and $81.06, the price received is $81.06; if the market price is between $81.06 and the ceiling of $93.31, the price received is market price; if the market price is over the ceiling of $93.31, price received is $93.31.

(f) If the market price is below $43.00, price received is market price plus $8.67; if the market price is between $43.00 and $51.67, the price received is $51.67; if the market price is between $51.67 and the ceiling of $63.21, the price received is market price; if the market price is over the ceiling of $63.21, price received is $63.21.

(g) If the market price is below $79.80, price received is $79.80; if the market price is between $79.80 and $91.35, the price received is market price; if the market price is over the ceiling of $91.35, price received is $91.35.

(h) If the market price is below $51.00, price received is $51.00; if the market price is between $51.00 and the ceiling of $58.68, the price received is market price; if the market price is over the ceiling of $58.68, price received is $58.68.

(i) If the market price is below the floor price of $72.59, price received is market price plus $13.93; if the market price is between the floor price of $72.59 and $86.52, the price received is $86.52; if the market price is between $86.52 and the ceiling of $98.73, the price received is market price; if the market price is over the ceiling of $98.73, price received is $98.73.

(j) If the market price is below the floor of $49.75, price received is market price plus $7.63; if the market price is between the floor price of $49.75 and $57.38, the price received is $57.38; if the market price is between $57.38 and the ceiling of $65.89, the price received is market price; if the market price is over the ceiling of $65.89, price received is $65.89.

(k) Heating oil contracts are contracted in U.S. dollars per U.S. gallon and are presented in this table in U.S. dollars per barrel for comparative purposes (1 barrel equals 42 U.S. gallons).

For the three month period ended March 31, 2008, the total unrealized loss on risk management contracts recognized in the consolidated statement of income and comprehensive income was $60.9 million (three month period ended March 31, 2007 - $14.1 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.

13. 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 the refined products including a network of retail operations and the supply of refined products to commercial and wholesale customers.

	Downstream(1) Three months ended March 31,		Upstream(1) Three months ended March 31,		Total Three months ended March 31,	
	2008	2007	**2008**	2007	**2008**	2007
Results of Continuing Operations						
Revenue(2)	**$ 1,062,419**	$ 784,045	**$ 377,333**	$ 291,116	**$ 1,439,752**	$ 1,075,161
Royalties	**-**	-	**(62,400)**	(49,649)	**(62,400)**	(49,649)
Less:						
Purchased products for resale and processing	**959,992**	632,296	**-**	-	**959,992**	632,296
Operating	**69,022**	49,361	**72,323**	72,296	**141,345**	121,657
Transportation and marketing	**8,597**	7,343	**3,025**	2,812	**11,622**	10,155
General and administrative	**568**	300	**11,909**	10,104	**12,477**	10,404
Depletion, depreciation, amortization and accretion	**16,500**	19,389	**114,425**	114,403	**130,925**	133,792
	$ 7,740	$ 75,356	**$ 113,251**	$ 41,852	**120,991**	117,208
Realized net losses on risk management contracts					**(36,294)**	(297)
Unrealized net losses on risk management contracts					**(60,858)**	(14,121)
Interest and other financing charges on short term debt, net					**(201)**	(3,627)
Interest and other financing charges on long term debt					**(35,103)**	(40,449)
Foreign exchange gain (loss)					**(10,665)**	11,260
Large corporations tax and other tax					**(50)**	(124)
Future income tax					**21,834**	-
Net (loss) income					**$ (346)**	$ 69,850
Total Assets(3)	**$ 1,592,586**	$ 1,729,069	**$ 3,962,295**	$ 4,053,682	**$ 5,574,528**	$ 5,800,346
Capital Expenditures						
Development and other activity	**$ 6,027**	$ 4,883	**$ 79,571**	$ 148,487	**$ 85,598**	$ 153,370
Business acquisitions	**-**	-	**-**	30,264	**-**	30,264
Property acquisitions (dispositions), net	**-**	-	**185**	689	**185**	689
Total expenditures	**$ 6,027**	$ 4,883	**$ 79,756**	$ 179,440	**$ 85,783**	$ 184,323
Property, plant and equipment						
Cost	**$ 1,211,860**	$ 1,306,618	**$ 4,327,478**	$ 3,981,413	**$ 5,539,338**	$ 5,288,031
Less: Accumulated depletion and depreciation	**(90,206)**	(31,942)	**(1,252,173)**	(816,497)	**(1,342,379)**	(848,439)
Net book value	**$ 1,121,654**	$ 1,274,676	**$ 3,075,305**	$ 3,164,916	**$ 4,196,959**	$ 4,439,592
Goodwill						
Beginning of period	**$ 175,984**	$ 209,930	**$ 676,794**	$ 656,248	**$ 852,778**	$ 866,178
Addition (reduction) to goodwill	**6,249**	(1,946)	**-**	-	**6,249**	(1,946)
End of period	**$ 182,233**	$ 207,984	**$ 676,794**	$ 656,248	**$ 859,027**	$ 864,232

(1) *Accounting policies for operating segments are the same as those described in the Significant Accounting Policies*

(2) *Of the total downstream revenue for the three month period ended March 31, 2008, $800.9 million is from one customer (three month period ended March 31, 2007 - $733.6 million). No other single customer within either division represents greater than 10% of Harvest's total revenue.*

(3) *Total Assets on a consolidated basis as at March 31, 2008 includes $19.6 million (2007 - $17.6 million) relating to the fair value of risk management contracts.*

(5) *There is no intersegment activity.*

14. 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 March 31, 2008:

(a) 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 for a minimum period of up to two years 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. As such, at March 31, 2008, North Atlantic had commitments totaling approximately $798.2 million ($798.5 million – March 31, 2007) in respect of future crude oil feedstock purchases and related transportation from Vitol Refining S.A.

(b) In January 2008 Vitol entered into a six month term contract with Iraq's State Oil Marketing Organization ("SOMO") for 33,000 bbl/day of Basrah crude oil at market prices on behalf of Harvest per the Supply and Offtake Agreement. Approximately two thirds of this commitment has either already been delivered or is scheduled for delivery and is included in the total feedstock commitment disclosed below. The remaining 2.0 million barrels was scheduled for delivery subsequent to March 31, 2008 and is included in the $377.7 million disclosed in Note 15.

The following is a summary of Harvest's contractual obligations and commitments as at March 31, 2008:

	Payments Due by Period						
	2008	2009	2010	2011	2012	Thereafter	Total
Debt repayments (1)	$ -	$ -	$1,330,423	$ 256,625	$ -	$ -	$ 1,587,048
Capital commitments(2)	35,123	4,450	-	-	-	-	39,573
Operating leases(3)	5,564	6,699	5,929	5,403	1,867	248	25,710
Pension contributions(4)	857	1,583	2,048	2,454	2,847	21,285	31,074
Transportation agreements(5)	2,197	1,864	1,473	770	500	47	6,851
Feedstock commitments(6)	798,188	-	-	-	-	-	798,188
Contractual obligations	**$ 841,929**	**$ 14,596**	**$1,339,873**	**$ 265,252**	**$ 5,214**	**$ 21,580**	**$ 2,488,444**

(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) *Relating to drilling contracts, AFE commitments, equipment rental contracts and environmental capital projects.*
(3) *Relating to building and automobile leases.*
(4) *Relating to expected contributions for employee benefit plans [see Note 11].*
(5) *Relating to oil and natural gas pipeline transportation agreements.*
(6) *Relating to crude oil feedstock purchases and related transportation costs [see Note 14 (a) above].*

15. Subsequent Events

Subsequent to March 31, 2008, Harvest declared a distribution of $0.30 per unit for Unitholders of record on May 15, 2008, June 16, 2008, and July 15, 2008.

Between April 1, 2008 and May 8, 2008, an additional $377.7 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 14].

On April 25, 2008, Harvest issued $250 million principle amount of convertible debentures for total net proceeds from the issue of $239.5 million.

16. Related Party Transactions

During the three month period ended March 31, 2008, in the normal course of operations, Vitol Refining S.A. purchased $67.8 million of Russian crude oil through the Supply and Offtake Agreement at fair market value for processing, which has been sourced from a private corporation of which a director of Harvest is also a director and holds a minority ownership interest. As at March 31, 2008, $1.7 million related to these transactions is included in accounts payable and accrued liabilities and $4.1 million is included in feedstock commitments for the purchase of Russian crude oil [See Note 14]. None of the $377.7 million committed to the purchase of feedstock inventory under the Supply and Offtake Agreement held with Vitol Refining S.A. between April 1, 2008 and May 8, 2008 [see Note 15] was purchased from this private corporation. During the three month period ended March 31, 2007, there were no related party transactions.

17. Comparatives

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