Harvest ENERGY


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OIL & NATURAL GAS PRODUCTION

Exploratory drilling & ongoing development supports our oil weighted production base


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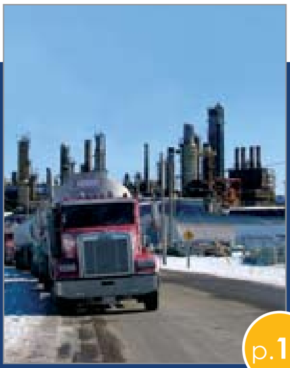
ENHANCED OIL RECOVERY (EOR)

Looking at three EOR projects planned for 2008 to improve the recovery of our large hydrocarbon pools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REFINING & MARKETING

An overview of near term margin improvements and longer term investment opportunities at North Atlantic

p.3 LETTER TO UNITHOLDERS

ENHANCING RETURNS | *An Integrated Approach*

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Harvest
ENERGY
sustainable growth

Harvest Energy is a significant operator in Canada's oil and natural gas industry offering Unitholders exposure to an integrated structure with upstream and downstream segments.

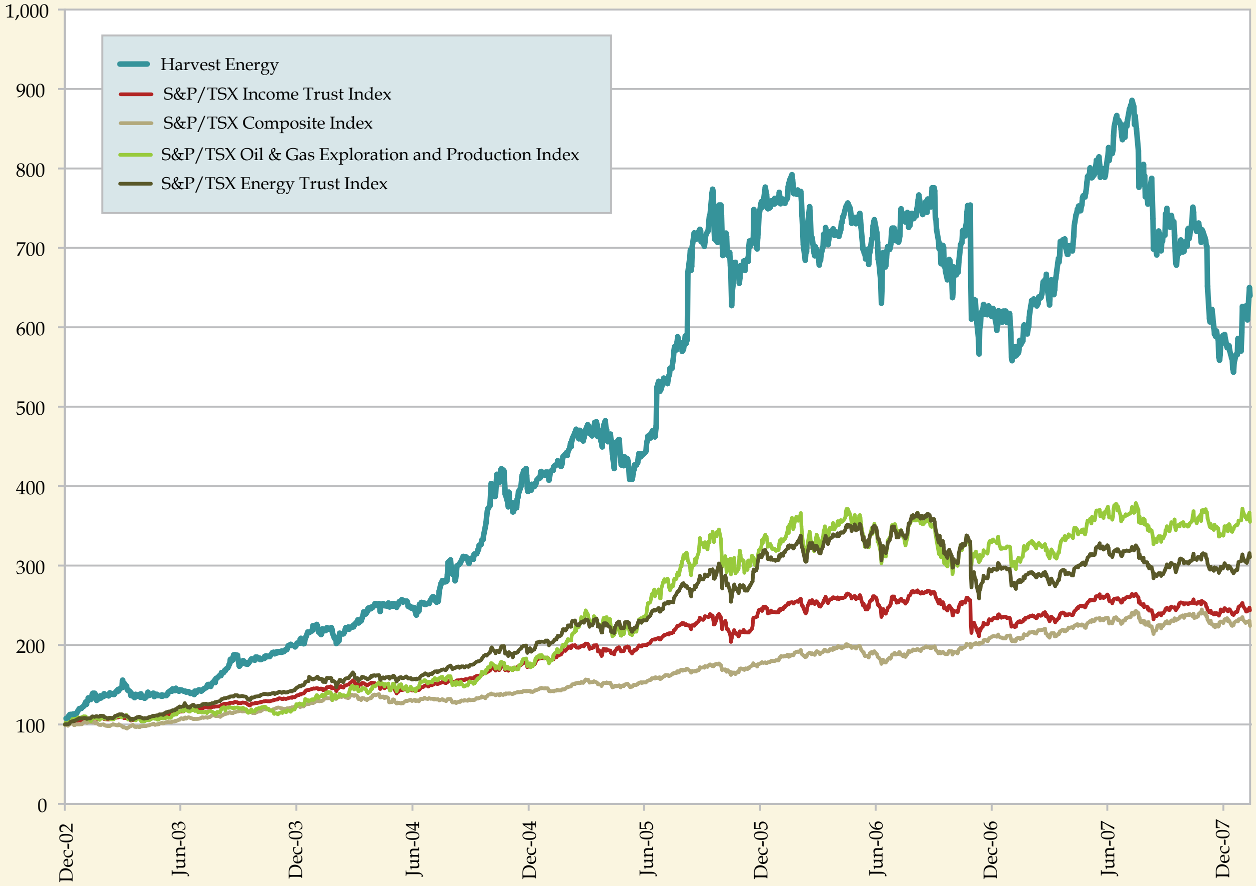
We focus on identifying opportunities to create and deliver value to Unitholders through monthly distributions and unit price appreciation. Given our size, liquidity and integrated structure, Harvest is well positioned to complement our internal portfolio with value-added acquisitions that help drive our Sustainable Growth strategy. Our upstream oil and gas production is weighted approximately 73% to crude oil and liquids and 27% to natural gas, and is complemented by our attractive, long-life refining and marketing business.

ANNUAL MEETING OF UNITHOLDERS

3:00 pm May 20, 2008 at the Metropolitan Centre in Calgary, AB.

TSX: **HTE.UN**
NYSE: **HTE**

Total Return Since Inception



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Highlights SELECTED ANNUAL INFORMATION

The table below provides a summary of our financial and operating results for years ended December 31, 2007, 2006 and 2005.

	Year Ended December 31			% Change
($000s except where noted)	2007	2006	2005	(2007 to 2006)
Revenue, net[1]	4,069,600	1,380,825	554,494	195%
Cash From Operating Activities	641,313	507,885	$ 283,178	26%
Per Trust Unit, basic	$ 4.63	$ 5.00	$ 6.08	(7%)
Per Trust Unit, diluted	$ 4.30	$ 4.84	$ 5.81	(11%)
Net Income (loss)[2]	(25,676)	136,046	104,946	(119%)
Per Trust Unit, basic	$ (0.19)	$ 1.34	$ 2.25	(114%)
Per Trust Unit, diluted	$ (0.19)	$ 1.33	$ 2.19	(114%)
Distributions declared	610,280	468,787	153,494	30%
Distributions declared, per Trust Unit	$ 4.40	$ 4.53	$ 3.20	(3%)
Distributions declared as a percentage of Cash From Operating Activities	95%	92%	54%	3%
Bank debt	1,279,501	1,595,663	13,869	(20%)
7 7/8% Senior Notes	241,148	291,350	290,750	(17%)
Convertible debentures[3]	651,768	601,511	44,455	8%
Total long-term financial liabilities[3]	2,172,417	2,488,524	349,074	(13%)
Total assets	5,451,683	5,745,558	1,308,481	(5%)
UPSTREAM OPERATIONS				
Daily Production				
Light to medium oil (bbl/d)	27,165	27,482	17,590	(1%)
Heavy oil (bbl/d)	14,469	13,904	13,747	4%
Natural gas liquids (bbl/d)	2,412	2,247	824	7%
Natural gas (mcf/d)	97,744	96,578	26,461	1%
Total daily sales volumes (boe/d)	60,336	59,729	36,571	1%
Operating Netback ($/boe)	29.89	30.54	32.01	(2%)
Cash capital expenditures	300,674	376,881	120,508	(20%)
DOWNSTREAM OPERATIONS[4]				
Average daily throughput (bbl/d)	98,617	86,890	-	13%
Aggregate throughput (mbbl)	35,995	6,343	-	467%
Average Refining Margin (US$/bbl)	10.05	9.32	-	8%
Cash capital expenditures	44,111	21,411	-	106%

(1) Revenues are net of royalties.
(2) Net Income includes a future income tax expense of $65.8 million (2006 – a recovery of $2.3 million; 2005 – a recovery of $32.4 million) and unrealized net losses on risk management contracts of $147.8 million (2006 – net gains of $52.2 million; 2005 – net losses of $45.1 million) for the year ended December 31, 2007. Please see Notes 16 and 18 to the Consolidated Financial Statements for further information.
(3) Includes current portion of convertible debentures.
(4) Downstream operations acquired on October 19, 2006.

Forecast prices & costs	As at December 31, 2007		As at December 31, 2006	
RESERVES (mmBOE)	Gross	Net	Gross	Net
Proved reserves	154.5	134.7	158.9	137.6
Probable reserves	66.5	57.6	61.0	52.3
Total proved plus probable (P+P) reserves	220.9	192.3	219.9	189.9
Total P+P Reserve Life Index		10.3 years		9.3 years

Message to Unitholders

"Our Sustainable Growth strategy will position Harvest for the long term as a significant operator in Canada's energy industry."

John Zahary
President & Chief Executive Officer

Against the backdrop of a constantly changing and rapidly evolving industry, Harvest remained focused on our core principles of value creation through 2007. Over the past few years, we have built an excellent portfolio of assets through acquisition and development. We are fortunate to have two strong business platforms – our upstream (oil and natural gas production) and downstream (refining and marketing). We capture the value of these assets for our shareholders through the dedicated efforts of our highly skilled employees.

During 2007, we refocused our upstream teams on longer term opportunities in our asset base. In western Canada, we complemented our ongoing drilling efforts with an increased focus on enhanced recovery of our very large fields, most of which have relatively low recovery of the original oil and gas in place. In the downstream, we continued striving to improve margins, strengthened the organization with some key hires, initiated a major profit improvement investment, and also began the process of looking at the very substantial growth opportunity embedded in that business.

We experienced challenges in 2007 with the continued effect of the Canadian trust tax situation, the royalty regime modifications in Alberta, a strong Canadian dollar, and an escalating cost environment. We also had some internal challenges in the upstream business with production volumes that we have since successfully overcome. These challenges reminded us that we cannot be static; we must continue to be nimble and adaptive in pursuit of the best courses of action for creating value for our unitholders. To that end, we advanced and formalized a Sustainable Growth strategy that will position Harvest for the long term as a significant operator in Canada's energy industry. This strategy includes a focused capital investment program that allows us to capture the value of our assets for shareholders, yet remain disciplined in our approach to this capital investment. To do this, we must maintain financial flexibility and an appropriate balance sheet. As a result, we have set a monthly distribution level of C$0.30 per unit with a goal to improve financial flexibility through debt reduction.

UPSTREAM SEGMENT

A key component of our Sustainable Growth strategy is positioning Harvest to maximize value from our assets over the long term. In keeping with this strategy, our teams are focused on methods to improve recovery of our large, original oil in place (OOIP) pools. We have an estimated 2 billion barrels of OOIP on our conventional lands, with another 1 billion barrels of OOIP on our oilsands lands. Having access to such large hydrocarbon pools with only approximately 20% overall recovery to date across the entire asset base provides us with significant short and longer term benefits.

An important part of managing our portfolio includes constantly high-grading and consolidating our assets. Consistent with this, we successfully added to some of our core areas during 2007 while also divesting of minor properties or interests for very attractive metrics. We successfully completed the acquisition of Grand Petroleum in mid-year, bolstering our already strong positions in southeast Saskatchewan and central Alberta. The Grand acquisition was completed at very attractive metrics of approximately $41,000 per barrel of oil equivalent per day (boepd), or about $23.00 per proved plus probable barrel of reserves.

The attractive royalty regime offered in Saskatchewan became even more relevant in the fall of 2007 as the Alberta government announced punitive changes to the existing royalty rates in the province, to become effective in 2009. This new royalty framework is very negative for an industry that is already struggling with a rising cost structure, a strong Canadian dollar and the challenges brought about by changes to the tax status for energy trusts. In a high commodity price environment, producers with higher productivity wells will be the most impacted by the new royalties. Our independent reserve evaluators completed a thorough

“We have an estimated 2 billion barrels of Original Oil in Place (OOIP) on our conventional lands, with another 1 billion barrels of OOIP on our oilsands lands.”

In addition to the Grand acquisition, we also strengthened our presence in southeast Saskatchewan through internal development, infill drilling, small land acquisitions, ongoing pool delineation and interest consolidation. This continues to be a key area for Harvest because it offers light oil production, excellent netbacks (averaging $44/boe in 2007), favorable royalty regime, new pool discoveries and the expansion of our focus from the Tilston / Souris Valley playtrends to include the Bakken. Since we first entered the area in 2003, we have successfully grown production, by drilling 118 wells. To further consolidate our position in southeast Saskatchewan, we divested of two small non-core properties late in 2007, for very attractive metrics averaging approximately $82,000/boepd.

analysis of the changes and confirmed that the impact to Harvest is likely to be less than 1% under the most likely scenario. This is because only 55% of our upstream production is derived from Alberta crown lands. Relative to our peers, Harvest would be one of the least impacted producers.

Despite experiencing some production challenges in our asset base in 2007, we believe that the potential of our asset base is enormous. We have a large portfolio with substantial resource in place and relatively low recovery. As commodity prices have improved, we see great economic and technical opportunity to increase recovery from these fields. If prices continue to improve, the potential in the future is even greater.

NEAR TERM ENHANCED OIL RECOVERY (EOR) PROJECTS

In 2008, we are implementing three enhanced oil recovery (EOR) initiatives, and will conduct the work needed for future projects in 2009 and beyond. At our Wainwright field, we are on schedule for fourth quarter 2008 implementation of an alkaline surfactant polymer (ASP) flood pilot project which could improve recovery factors by up to 15%. We are also launching two enhanced waterfloods at Bellshill Lake and Suffield, respectively, which will result

in produced water from one pool being reinjected into an adjacent pool to enhance reservoir pressure and 'push' more oil out. These projects require very modest capital investment but have the potential to add significant reserves, which is accretive to our net asset value, and also greatly improves our finding & development (F&D) costs. At current prices, the economics are very attractive and if successful could be replicated across the asset base in many of our other large OOIP fields. In our year end 2007 reserve bookings, our independent reserve evaluators gave us some recognition for the potential of these projects, and we would expect incremental additions to our reserve bookings in 2008.

While we are implementing these enhanced oil recovery projects in 2008, we will also be looking at other fields for the implementation of enhanced recovery in 2009 and beyond, including a super-saturated brine injection project in Kindersley, enhanced waterflooding in Hay River and acid gas/solvent injection in Hayter. These projects demonstrate the potential in our large asset base for enhanced recovery through design and implementation of optimal recovery schemes. In addition, since some of these projects can be implemented relatively quickly, we are able to benefit from impacts to production and cash flow in as little as 4 months of project initiation.

LONGER TERM PROJECTS

Given the maturity of the Western Canadian Sedimentary Basin coupled with the environmental concerns about greenhouse gases, producers in western Canada are increasingly looking at the potential opportunity that CO_2 injection represents. Based on independent engineering assessments, approximately 40% of Harvest's overall asset base is amenable to miscible or immiscible CO_2 flooding, positioning us very well should the logistical issues surrounding CO_2 sourcing and transportation in western Canada be resolved. We also have potential with our Coal Bed Methane (CBM) rights and substantial oil sands leases. With current and improving commodity prices, these assets show great economic potential given the substantial amount of resource on these lands. Harvest has the ability to hold these lands and develop their resource potential as commodity prices and the operating environment allow.

DOWNSTREAM SEGMENT

With the addition of our downstream segment, we have vertically integrated our business. This vertical integration is designed to enable Harvest to capture a greater share of the value chain for our investors, exploit the natural hedge that exists from producing and refining heavier crude oil, diversify our cashflows for enhanced sustainability and generate long-term value for shareholders.

As 2007 was the first full year for Harvest owning the refinery, we can now look back and reflect upon the successes we achieved and the areas in which we faced challenges. The strength of refining margins and the resultant cash flow generated by the refinery were very robust in the first half of 2007. This strength enabled us to bolster our balance sheet by adding $689.2 million to our equity from the conversion of convertible debentures and equity financing. In the second half of the year when margins are seasonally weaker, we took the opportunity to accelerate maintenance that was originally planned for the second quarter of 2008. We were pleased with the refinery's operational performance throughout the year although we have great confidence that we can do even better in future years with the focused strategies that we have to further improve operational performance.

Through our first year of owning the refinery, we were focused on activities to enhance margins and maximize the value of the business in the short term, while also positioning ourselves to improve margins over the long term. In the second quarter when gasoline cracks were near record highs, we were able to take advantage of this strength by adjusting our product mix to be more heavily weighted to gasoline. Although the natural markets for our refined products are the Boston and New York harbors, we have the option to sell into other markets that may prove more lucrative for us, which we successfully did in 2007. We sold distillate products in Europe, high sulfur fuel oil ("HSFO") in South Asia and gasoline and distillate products in South America. Each of these markets offered higher prices than our natural markets and we worked with our marketing agent to effect those transactions. In the fourth quarter, we entered into an exclusive agreement to sell all of our HSFO directly to a major global energy company, rather than go through our marketing agent. This will result in better realized pricing for our HSFO. We will continue to seek out and pursue similar opportunities that create incremental value for our unitholders.

Consistent with historical trends, when the summer driving season ended in the third quarter, the gasoline crack declined considerably and refining margins were much lower in the third quarter compared to the second quarter. This effect was magnified further for Harvest because we also experienced a short-term weakening of the price discounts of our sour crude oil feedstock. Lower product prices combined with higher input costs resulted in weaker than expected refining margins in the third quarter. However, this weak margin environment provided a good opportunity for us to accelerate into the fourth quarter of 2007 a turnaround and partial shut-down of the refinery from the second quarter of 2008 when margins are expected to be stronger. The turnaround was complete in early December and since then we have seen improved performance with strong throughput. We have also experienced a strengthening in product prices and crack spreads, as well as more normalized sour crude discounts.

We bolstered our North Atlantic business further by the appointment of a COO of Downstream, Brad Aldrich who brings many years of experience in improving, expanding and maximizing refineries globally. The expertise of Brad and the North Atlantic team was instrumental in ensuring that the accelerated turnaround was successfully completed without incident, on time and on budget, and that the refinery was back up and running to near capacity in the first week of December. Brad and his team's experience will be invaluable as we evaluate and pursue further capital investment opportunities at the refinery.

REFINERY CAPITAL INVESTMENT OPPORTUNITIES

During 2007, we started looking at the great uncaptured potential embedded in the North Atlantic refinery. The first step toward capturing some of this value was the sanctioning of a project to enhance the visbreaker unit. The visbreaker is a unit which takes low valued vacuum tower bottoms ("VTB's") and 'breaks the viscosity' of this product stream so that it may be sold into the higher valued HSFO market. This project, which is scheduled for commissioning in the fourth quarter of 2008, will result in an additional 1,500 bbl/d of high value distillate product being sold instead of being utilized in the process of blending HSFO.

In 2008, a third party global engineering firm will complete a detailed engineering study of the technical feasibility and construction timing and cost estimates of various enhancement opportunities at the refinery. One of the most significant projects under consideration is the addition of delayed coking capability to eliminate HSFO production, and convert approximately 30,000 bbl/d of negative margin products to higher value distillate and gasoline products. At the same time, there is a potential refinery expansion to increase throughput by 33% or more. Finally, we could also modify the refinery to enable us to purchase less expensive heavier and more sour crude oils, which would further improve margins. Given the refinery's supportive community, extensive land base, underutilized infrastructure, and cost advantages of off-shore unit assembly, these opportunities appear at this time to have very attractive investment return potential. The results of this engineering study will provide the basis for more definitive project scope selection and improved economic analyses. As in the upstream, these projects represent options that can be exercised as markets and other factors dictate.

ENVIRONMENT, HEALTH & SAFETY (EH&S)

Protecting our people, our partners, our stakeholders and the environment are key elements of our business. We are active throughout the organization and we never lose sight of the fact that safe and environmentally friendly business practices are critical to our social license to operate.

In our upstream segment, we are a participant in the Canadian Association of Petroleum Producers' (CAPP) Stewardship program, and achieved platinum level status in 2007 and each of the last 3 years. In 2007, we also achieved a lower total recordable injury frequency than the industry average, and received Worker's Compensation Board premium rebates because of our strong corporate performance and low claim costs. Going forward, we will continue pursuing excellence in our EH&S initiatives.

In the downstream segment, we have set new internal safety records approaching 1.8 million person-hours without a lost time accident to the end of February, 2008, and we scored top marks (97%) on a Newfoundland government safety audit in 2007. These achievements demonstrate the effectiveness of our integrated management system which incorporates environmental, health and safety considerations. The key components of this continuous improvement program include job safety analysis, incident investigations, risk management, detailed equipment inspections, work permitting, in-house government-certified inspectors and Canadian Registered Safety Professionals.

In all aspects of our business, we are committed to minimizing our environmental footprint, being a good and responsible corporate citizen, and conducting all of our affairs in an environmentally and socially responsible manner.

FUTURE OUTLOOK

Although the Canadian government's trust tax proposal was passed into law in the second quarter of 2007 and is scheduled to be implemented in 2011,

Harvest continues to investigate alternatives to its royalty trust structure that would accommodate an efficient distribution of cash to unitholders and enable us to maintain our sustainable growth strategy. Currently, our base case is to maintain our existing structure and then convert to a Canadian corporation. We anticipate that the conversion can be completed on a tax free basis for both Harvest and its unitholders. Throughout this transition period, we expect to be able to continue with our on-going business plans including property acquisitions and divestitures while we continue to distribute a significant portion of cash flow to our investors. We have a significant amount of "safe harbour" flexibility in delivering our business plan over this time period.We are investigating other opportunities that would improve the tax efficiency and valuation for our investors.

Harvest is well positioned as a major contributor to Canada's energy industry. We have assembled a very strong asset base loaded with optionality and brought together talented teams who are committed to identifying unique opportunities for value creation and risk management. I believe this organization has all the necessary elements for success and is well positioned to overcome challenges and deliver positive returns for our unitholders for many years to come.

Sincerely,

John Zahary,
President and Chief Executive Officer
March 12, 2008

Meet Our
Senior Management Team

John Zahary

President & Chief Executive Officer

- Responsible for Harvest's vision and overall executive leadership
- A Professional Engineer with 20+ years of operational and management experience
- Specific experience includes working on enhanced oil recovery projects such as hydrocarbon and carbon dioxide miscible floods, heavy oil and oilsands development, as well as other business aspects for integrated oil companies and upstream companies
- Broad range of industry experience including Chair of the Petroleum Technology Research Centre, Governor of the Canadian Association of Petroleum Producers, and ex-President of the Alberta Chamber of Resources

Robert Fotheringham

Chief Financial Officer

- Responsible for the oversight and management of all financial reporting and corporate finance aspects of Harvest's business
- A Chartered Accountant who brings more than 20 years of progressive experience in the energy industry
- Provides leadership in areas such as internal controls over financial reporting, compliance with security regulations, banking relationships, upstream marketing operations and cash flow forecasting, as well as treasury, risk management and tax planning

Rob Morgan

Chief Operating Officer, Upstream

- Responsible for the oversight and management of all aspects of Harvest's upstream oil and natural gas production and development
- A Professional Engineer with 20+ years of technical, operations and management experience in the oil and natural gas industry
- Proven expertise with exploiting large hydrocarbon reservoirs, including the use of innovative technologies in the planning and implementation of successful enhanced oil recovery projects in western Canada

Brad Aldrich

Chief Operating Officer, Downstream

- Responsible for the oversight and management of all aspects of Harvest's downstream refining and marketing business located in Newfoundland and Labrador
- Over 28 years of experience in petroleum refining, marketing, supply and trading, price risk management, transportation and distribution, and production planning
- Previously managed eleven refineries and petrochemical plants for Russia's largest oil company and was responsible for the operations of one of the largest independent refining and marketing companies in the US

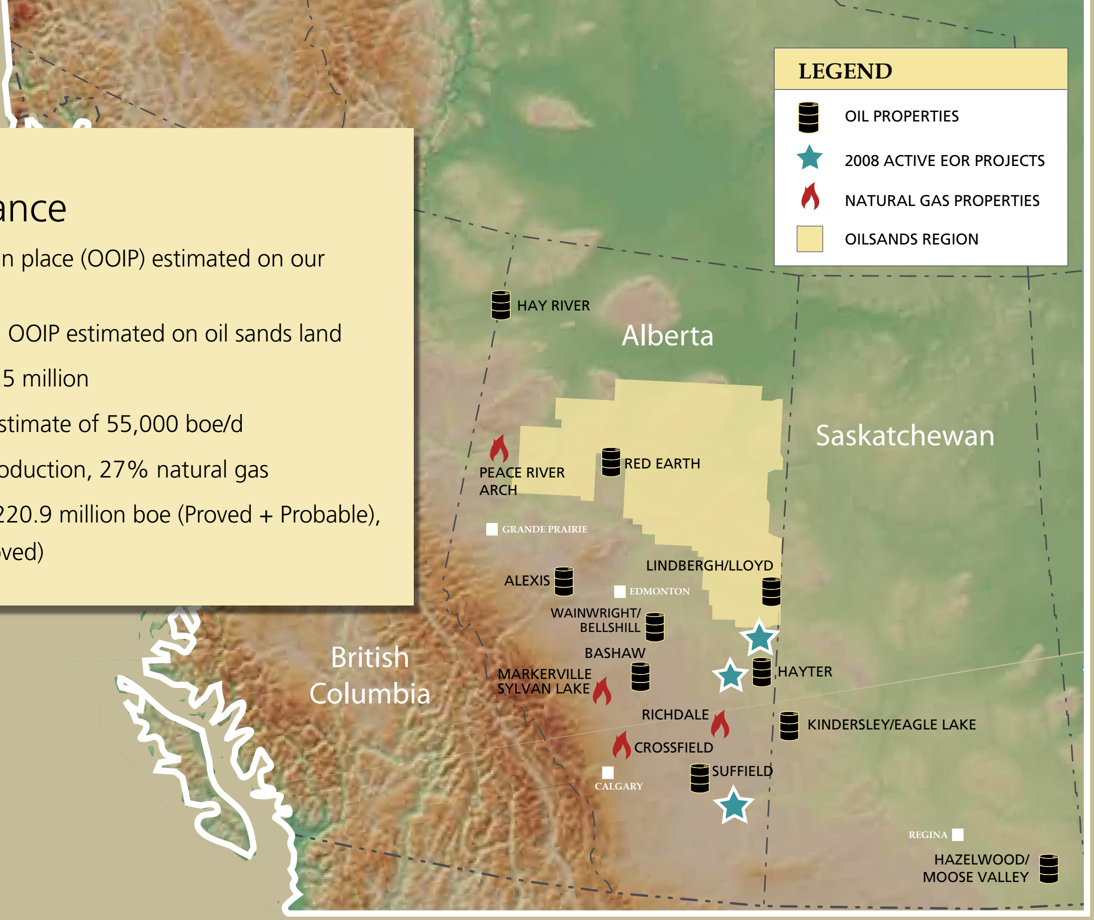
Jacob Roorda

Vice President, Corporate

- Responsible for business development and marketing initiatives for Harvest
- A Professional Engineer with over 28 years of technical engineering and management experience in the oil and natural gas industry, including 8 years experience in research and investment banking for Canadian financial services

Upstream at a Glance

- 2 billion boe of original oil in place (OOIP) estimated on our conventional lands
- 1 billion boe of incremental OOIP estimated on oil sands land
- 2008 capital budget of $225 million
- 2008 average production estimate of 55,000 boe/d
- 73% crude oil weighted production, 27% natural gas
- Year end 2007 reserves of 220.9 million boe (Proved + Probable), 154.5 million boe (Total Proved)



Upstream Operations

More Than Just Conventional

We have a number of assets where we are implementing and optimizing long-life primary and secondary recovery through more active reservoir management.

Since the formation of Harvest in 2002, we have followed our value principles and successfully assembled a unique suite of assets that would be very difficult, if not impossible, to replicate today. Further, we have structured our organization to benefit from vertical integration, and as a result, have a unique inventory of future internal development opportunities across the energy spectrum in which we can invest to generate attractive rates of return.

Harvest unitholders are well positioned to benefit from exposure to exploration and production activities, including significant enhanced oil recovery potential, and crude oil refining, product marketing and sales.

Our upstream asset base consists of large pools of light/medium and heavy crude oil which have significant opportunity for current and future development. With over 2 billion barrels of estimated conventional original-oil-in-place (OOIP) and an incremental 1 billion barrels of oil sands OOIP, we have identified over 1,000 drilling locations on our existing portfolio of properties. Based on current capital expenditure levels, this represents a 4-5 year development plan. Given our size, liquidity and integrated structure, we are well positioned to supplement our internal portfolio with value-added acquisitions that help drive Sustainable Growth.

We, in addition to our ongoing exploration and development activities, also have a number of assets where we are implementing and optimizing long-life primary and secondary recovery through more active reservoir management.

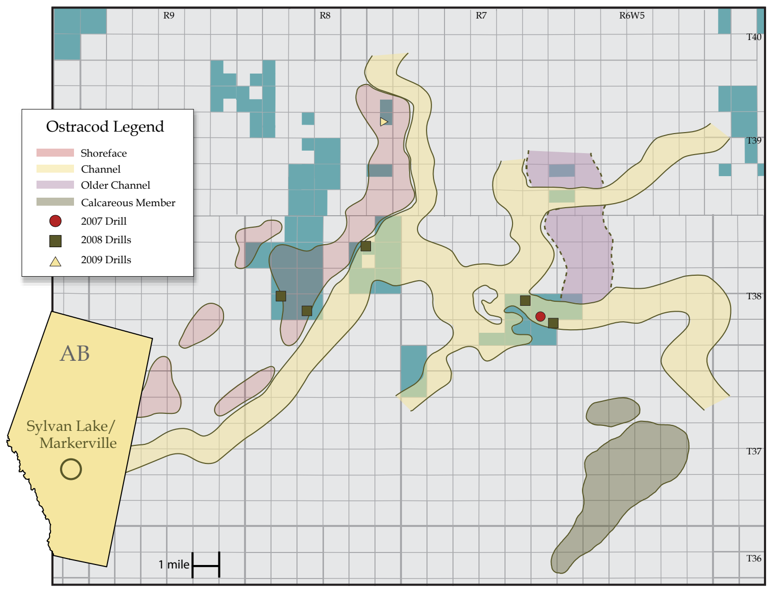
Exploration and Development Activities

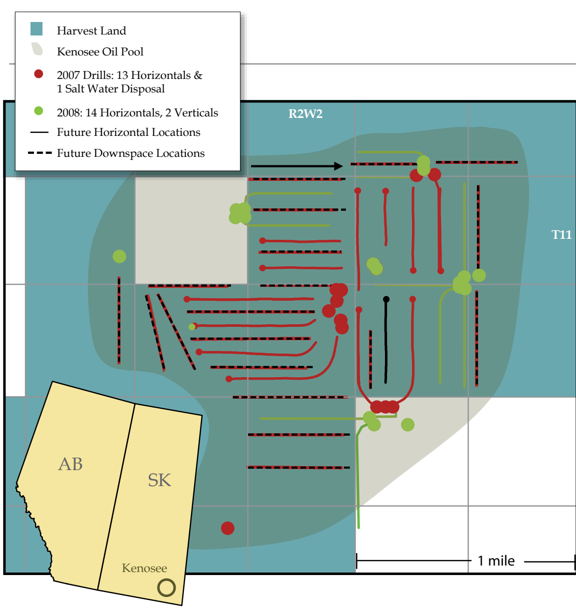
In addition to seeking new ways to maximize recovery from our existing pools, Harvest's upstream operating teams are focused on identifying new potential horizons or pools for future development.

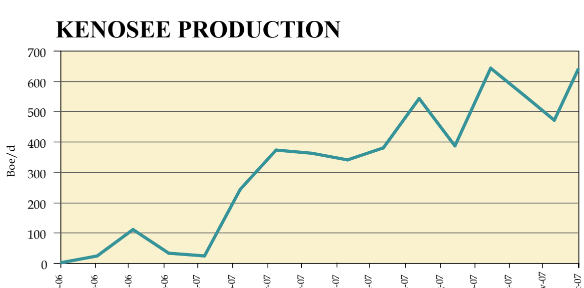
Our strong technical teams engage in exploration activities such as shooting seismic and drilling test wells that contribute to the identification and discovery of new pools. Three examples of our success in exploration are exploratory drilling success in Central Alberta (Cheddarville), a new pool discovery (Kenosee) in southeast Saskatchewan, and the Lloydminster heavy oil area.

2007 Exploratory Drilling Success at Cheddarville

In the third quarter 2007, Harvest drilled an exploratory well in our Cheddarville (Sylvan Lake/Markerville) area in Central Alberta. This exploratory well encountered significant net gas pay, and our initial test data indicated that the well had productive capability up to 800 boe/d including liquids. Harvest has a 100% working interest in this well, and we have identified at least one follow-up location to be pursued in 2008, with the potential to downspace further to maximize recovery.



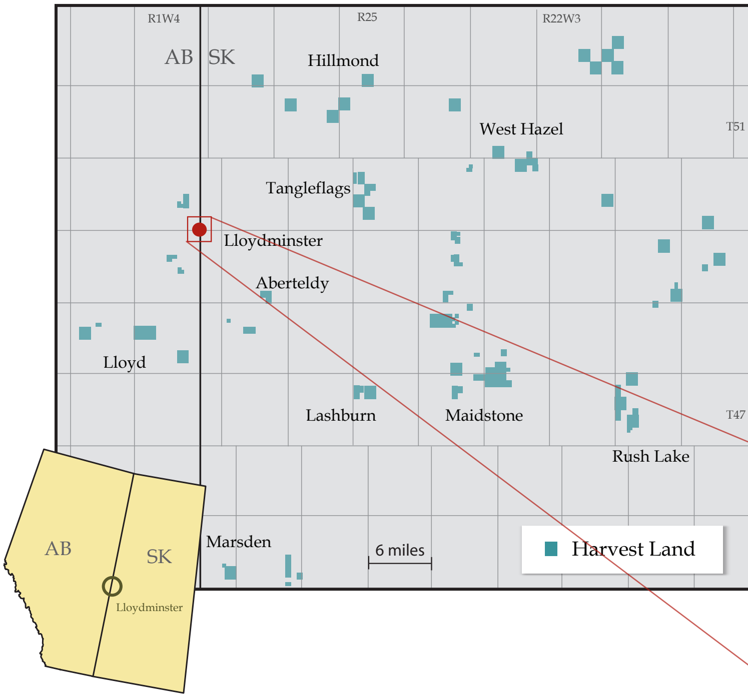




2006 New Pool Discovery at Kenosee, Saskatchewan

Southeast Saskatchewan has been a key area for Harvest since our initial acquisition of properties in October of 2003. Since then, we have assembled a significant land base with the acquisition of additional properties and crown land parcels. We have also shot extensive 3-D seismic, drilled exploratory wells and successfully identified new light oil pools at Hazelwood, Kennedy and Kenosee.

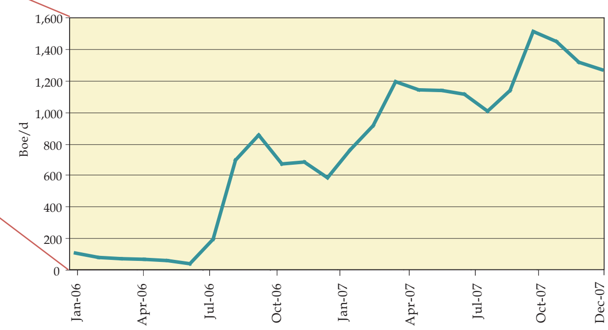
Our most recent discovery at Kenosee (2006) was producing in excess of 600 boe/d of 33° API light oil from 13 horizontal wells drilled to the end of 2007. In 2008, we plan to drill another 16 wells and invest approximately $19 million in capital.

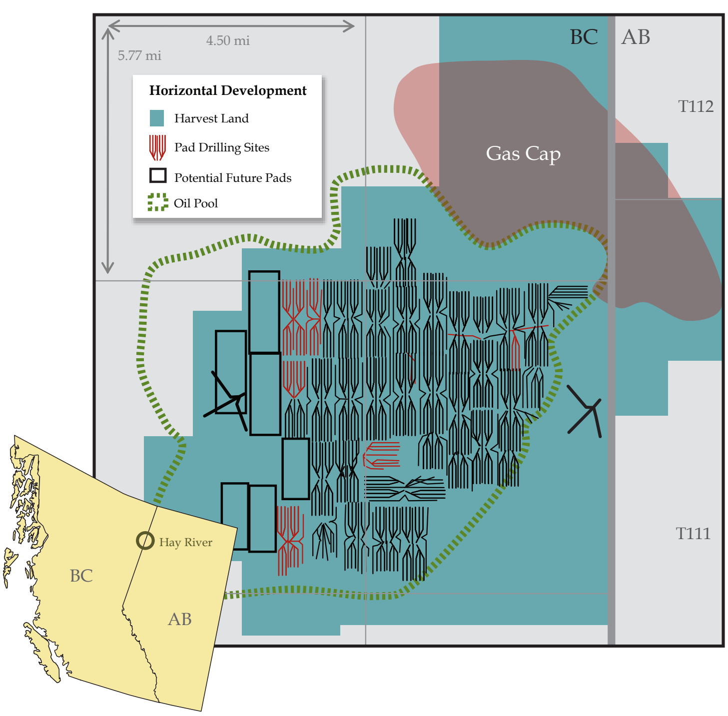


Lloydminster Saskatchewan / Alberta

A successful exploration well drilled in 2005 identified a Lloydminster heavy oil pool. To develop this new discovery, we have successfully drilled 27 horizontal wells through 2006 and 2007, which have resulted in current production of 1,300 boe/d.

LLOYDMINSTER PRODUCTION

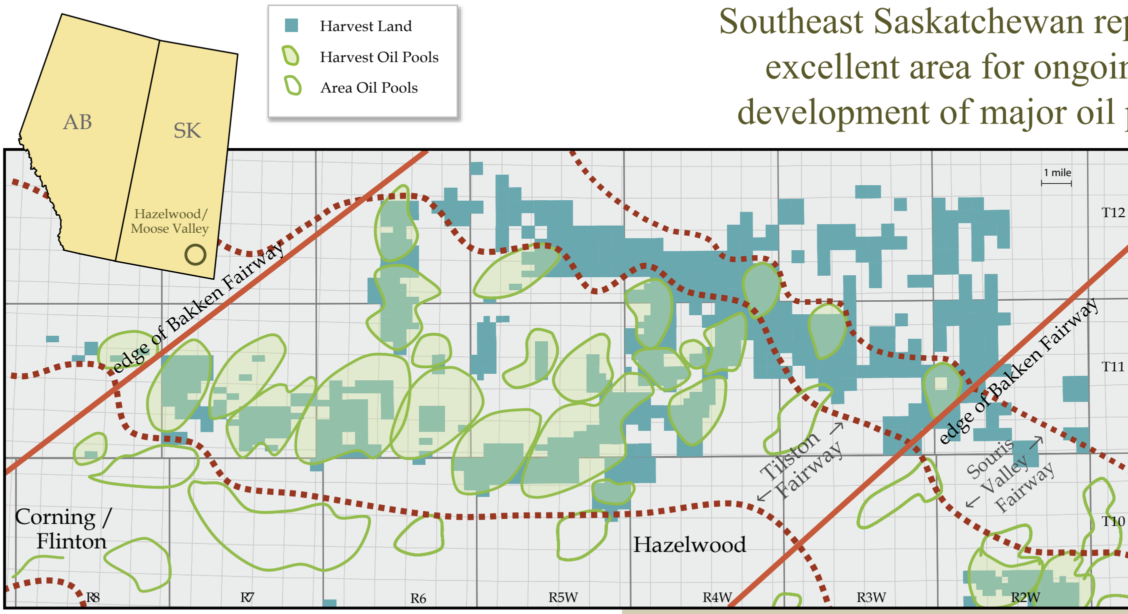




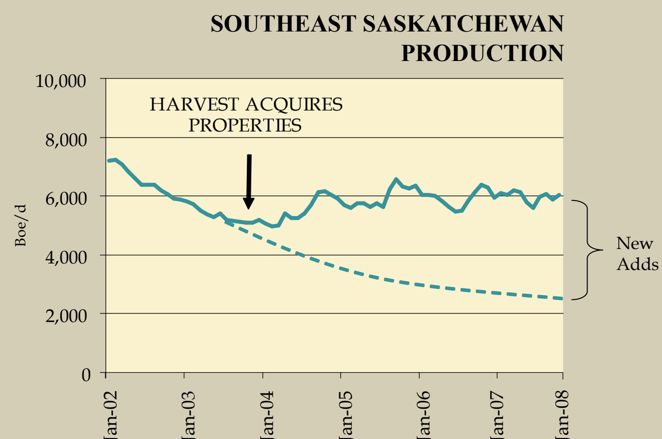
Hay River, British Columbia

Harvest acquired Hay River in August of 2005. This large OOIP bluesky pool has very low recovery to date (~8%) and produces a medium gravity crude oil which receives pricing based on a discount off of Edmonton Light crude oil (a more valuable benchmark), along with benefiting from discounted heavy oil royalty rates. Through the winters of 2005, 2006 and 2007 we undertook extensive drilling programs that involved pad drilling horizontal wells, pump replacement and upgrades, identification of viable electrical power sources, and the investigation of alternatives to develop the large gas cap which resides above the oil pool, all of which contribute to improved economics.

In 2008, we will execute a lower capital budget of $3 million focused on sourcing water to help maintain reservoir pressure. Given its very low recovery, Hay River offers significant future development and enhanced recovery potential. In the shorter term, our teams will concentrate on increasing water injection for voidage replacement, improved recovery, as well as plans for the 2009 and our longer term drilling program.



Southeast Saskatchewan represents an excellent area for ongoing development of major oil pools.



Ongoing Development in Southeast Saskatchewan

Not only has southeast Saskatchewan provided Harvest with successful exploratory drilling opportunities, but it also represents an excellent area for ongoing development of major oil pools. In keeping with our continued consolidation efforts, we acquired Grand Petroleum in mid-2007 for $41,000/boepd, or $23.00 per barrel of Proved plus Probable reserves, which is a very attractive metric.

Through our acquisition and development activities, Harvest has built a dominant position on the Tilston & Souris Valley playtrends. Our $49 million capital program for the area in 2008 is targeting to drill 40 new wells into these playtrends, as well as at least one well into the Bakken. Given that our production is predominantly light oil (33° API) and the region offers an attractive royalty regime, Harvest realizes very strong netbacks in Southeast Saskatchewan, which averaged $44/boe in 2007.

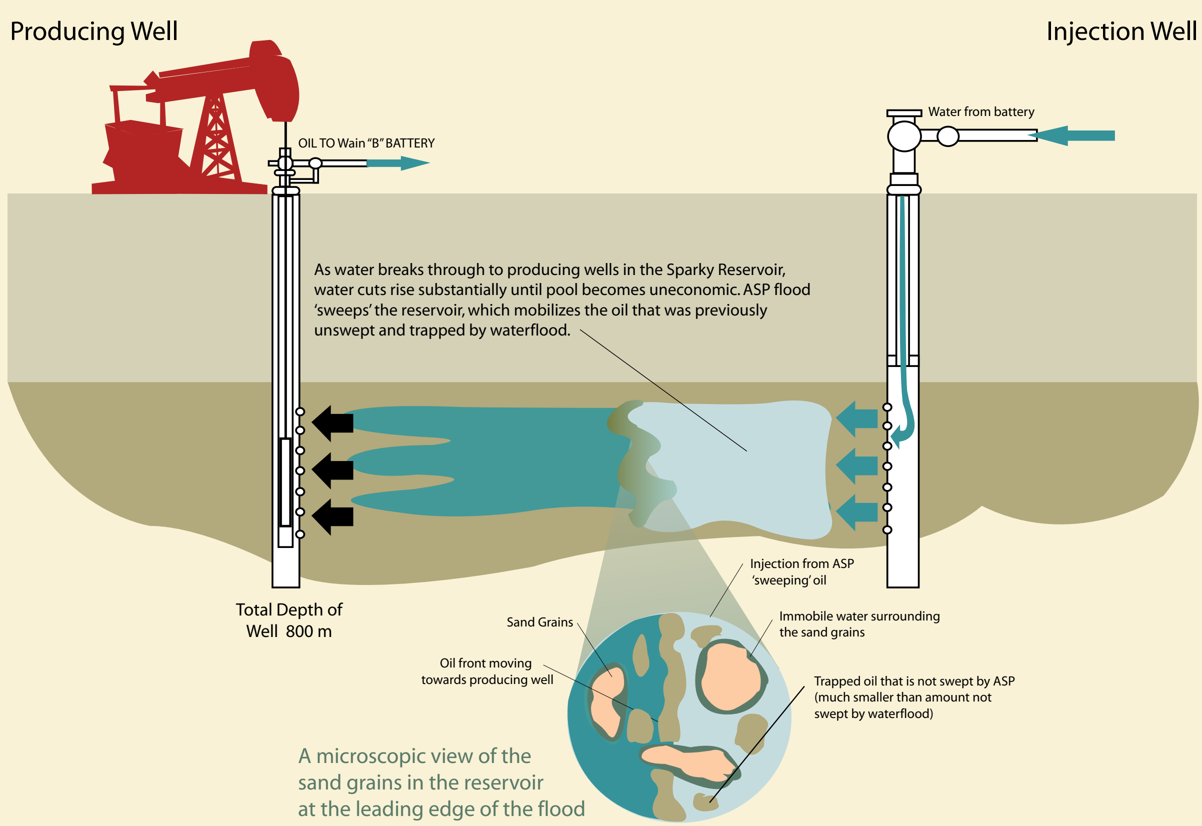
Planning for the Future

Longer Term Potential & Enhanced Oil Recovery (EOR)

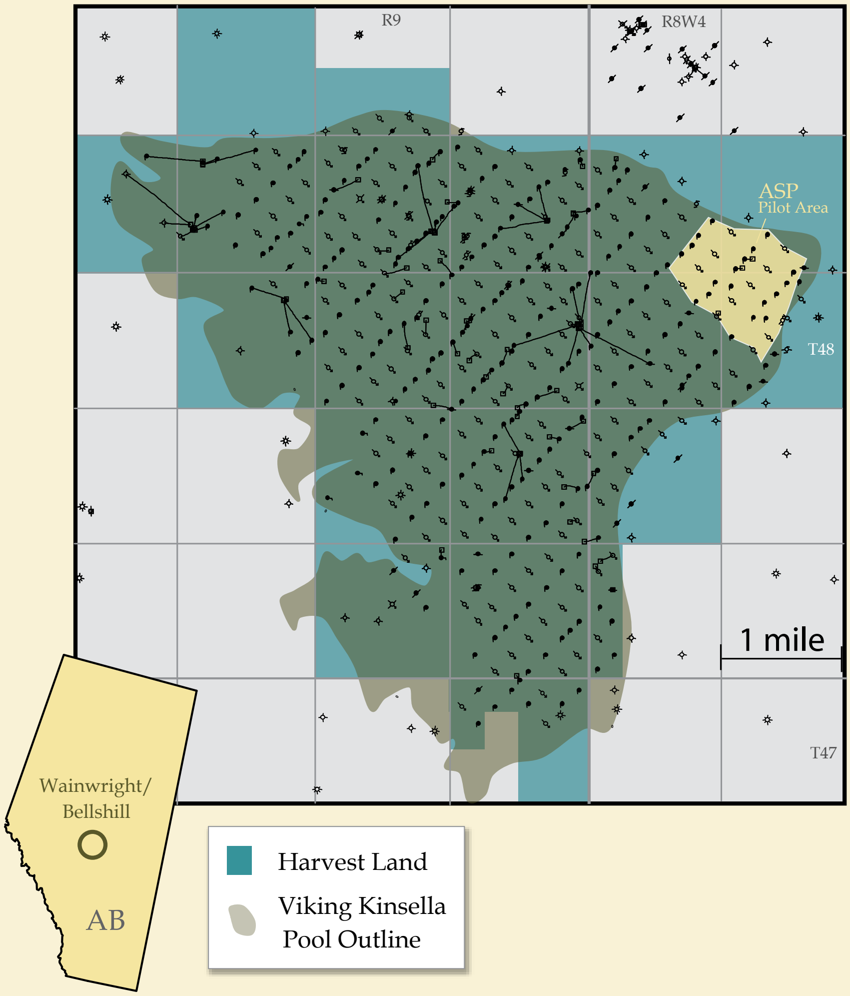
Harvest's upstream asset base offers improved recovery potential in both our conventional and oilsands opportunities. We are well positioned to realize significant short and longer term benefits by employing new technologies and methods to enhance recovery of our large hydrocarbon pools.

2008 Enhanced Oil Recovery Projects

Wainwright Alkaline Surfactant Polymer (ASP) Injection Increases Oil Sweep

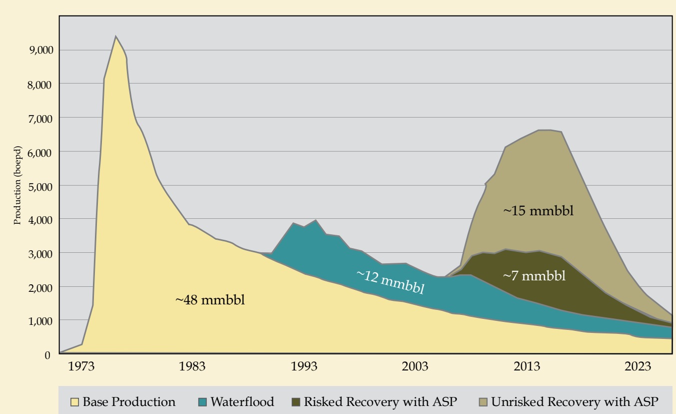


WAINWRIGHT B OIL POOL - ASP PILOT



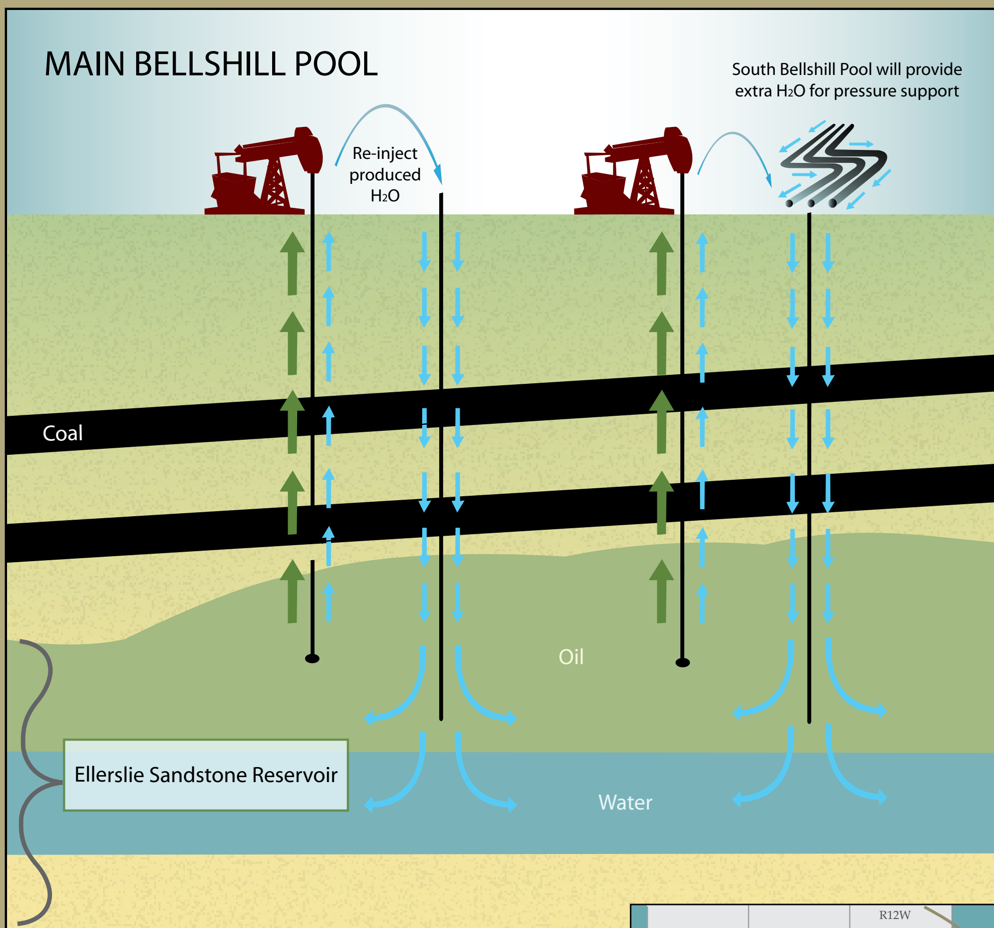
One of our 2008 EOR projects is scheduled to be implemented at Harvest's Wainwright property. We have a 100% working interest in the Wainwright B pool, a large Sparky medium gravity oil pool with an estimated 133 mmboe of net OOIP, and a recovery factor of only 35% to date. Our teams have completed a technical evaluation of a commercially viable EOR pilot project on this pool using an Alkaline Surfactant Polymer (ASP) flood, the economics of which are supported by the existing infrastructure in the area. Sourcing of necessary equipment is expected to be complete early in the second quarter of 2008, with full scale pilot implementation before the end of 2008, and initial results expected by the third quarter of 2009. Technical analysis and scaled laboratory tests indicate that the potential pool-wide recovery factors could range from 47% up to as much as 60%.

WAINWRIGHT PRODUCTION ASP EXTENDS FIELD LIFE

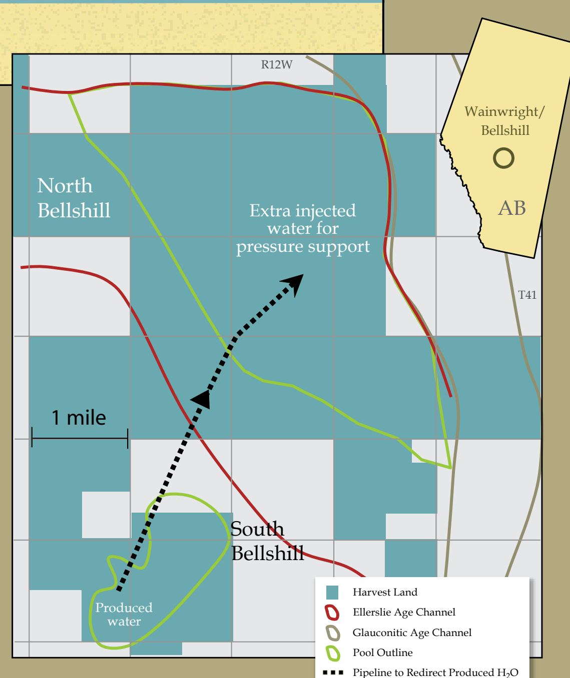


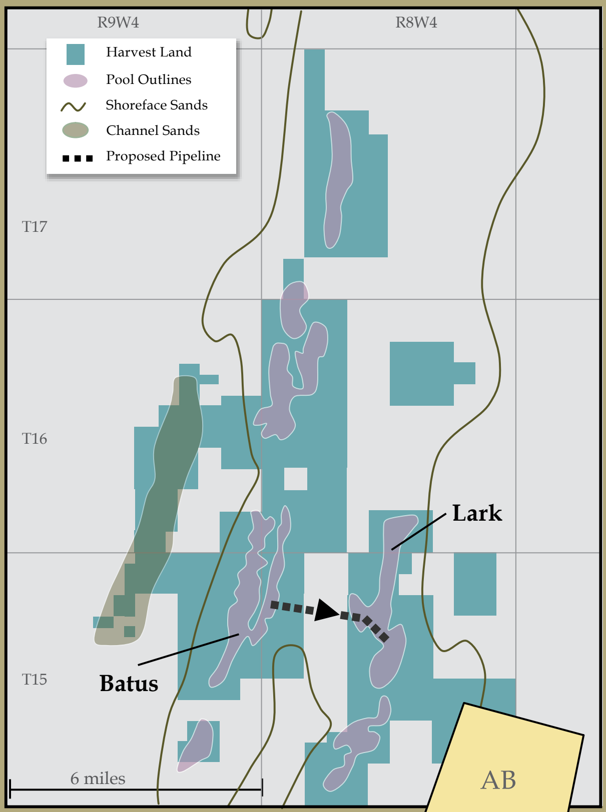
Enhanced Waterflood in Bellshill Lake, AB

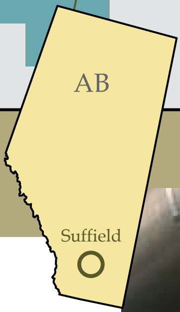
The second of Harvest's 2008 EOR initiatives is the implementation of a new water injection scheme in the Ellerslie Formation at Bellshill Lake, Alberta. We have a 99% working interest in the Bellshill Lake Ellerslie unit that contains an estimated 216 mmboe of OOIP (net to Harvest) with a recovery factor to date of approximately 50%.



This enhanced waterflood will redirect produced water from the over-injected South Bellshill pool to the currently under-injected main Bellshill pool adding pressure support. This project has a very modest capital cost of only $3 million for pipeline construction which will commence in the second quarter of 2008. Implementing this waterflood has the potential to add up to 7% over booked proved plus probable reserves as at December 31, 2007. In our year end 2007 reserve report, the independent evaluators did give us some recognition for this project, with incremental additions expected in 2008.







Enhanced Waterflood in Suffield, AB

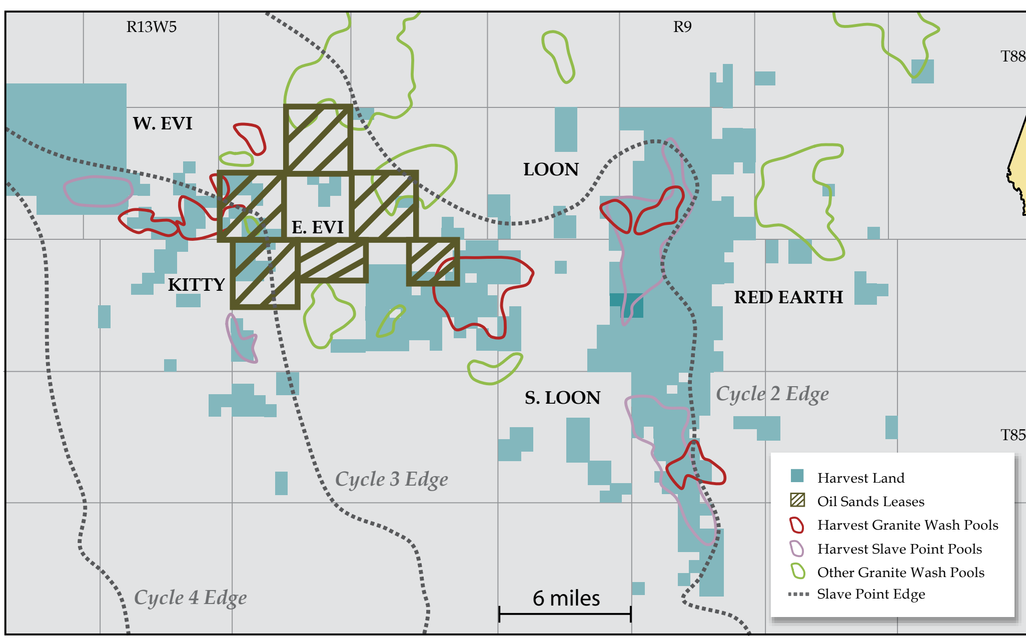
The last of Harvest's three EOR projects to be implemented in 2008 is a new water injection scheme into the Glauconitic Channel Sands at Suffield, a 156 mmbbl OOIP pool with only 11% recovery to date.

As a result of extensive upgrades to the water handling facilities completed in 2006, we can now achieve better water distribution to under-injected pools. The enhanced waterflood project has the potential to add an incremental 1-2% recovery. Capital costs associated with the pipeline construction needed to move water from the over-injected Batus pool to the under-injected Lark pool is budgeted at $3 million of our total $14 million capital program for Suffield in 2008. The balance of the capital to be invested will be focused on infill drilling.

There is an estimated 156 million barrels of Original Oil in Place at Suffield, and our 2008 enhanced waterflood project has the potential to improve recovery factors in the area by 1-2%.

Harvest's Identified Enhanced Oil Recovery Opportunities

Area	OOIP (MMBOE)	Technology	Estimated Ultimate Recovery Factor Improvement
Wainwright, AB	133	Polymer / ASP project	Improve recovery factor from 47% up to as much as 60% based on scaled laboratory tests
Bellshill Lake, AB	216	Enhanced waterflood	Potential for additional 7% recovery based on independent engineering study
Suffield, AB	156	Enhanced waterflood	Potential for additional recovery in Lark Field
Kindersley, SK	80	Enhanced waterflood (Brine injection)	Potential for additional 5-10% recovery
Hay River, BC	200	Enhanced waterflood	Potential for additional 5-10% recovery
Hayter, AB	138	Solvent, acid gas and/or enhanced water injection	Potential for additional 5-10% recovery
Various	800	CO_2 flooding	Potential for 10+% recovery improvement

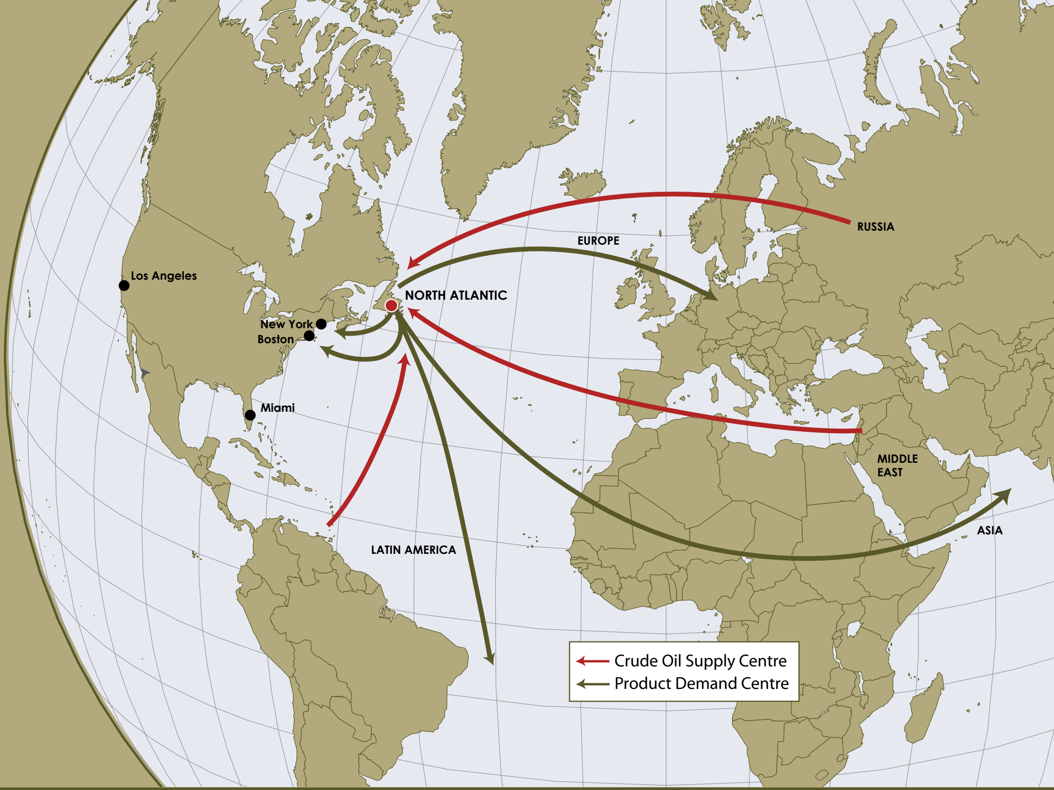


Oilsands at Red Earth, AB

In addition to our 13,000 net undeveloped acres in the Cold Lake oilsands area, Harvest also successfully acquired approximately 29,000 net undeveloped acres of oil sands leases at Red Earth, which falls within the Peace River oil sands region. We are very well positioned to develop this oil sands potential since we have existing infrastructure in the area, and also because we produce light oil and condensate at Red Earth that can be used for blending with the heavy oil to bring it up to pipeline specifications. We have drilled one strat test well designed to help us determine whether conventional cold production, thermal stimulation or some other technology represents the optimal development strategy to best exercise the value of this embedded option.

Our 2008 conventional oil production in Red Earth is expected to average approximately 2,800 boe/d, based on an annual capital budget of $20 million, focused on pool delineation, drilling and waterflooding.

Complementing our upstream oil and gas assets in western Canada is our very long-life downstream refining and marketing business, North Atlantic. This business, which is rich in opportunity, includes a 115,000 bbl per day medium sour hydrocracking refinery, 64 retail gas stations, a home heat division, marine terminaling and wholesale/ bunker capability.



Downstream Operations

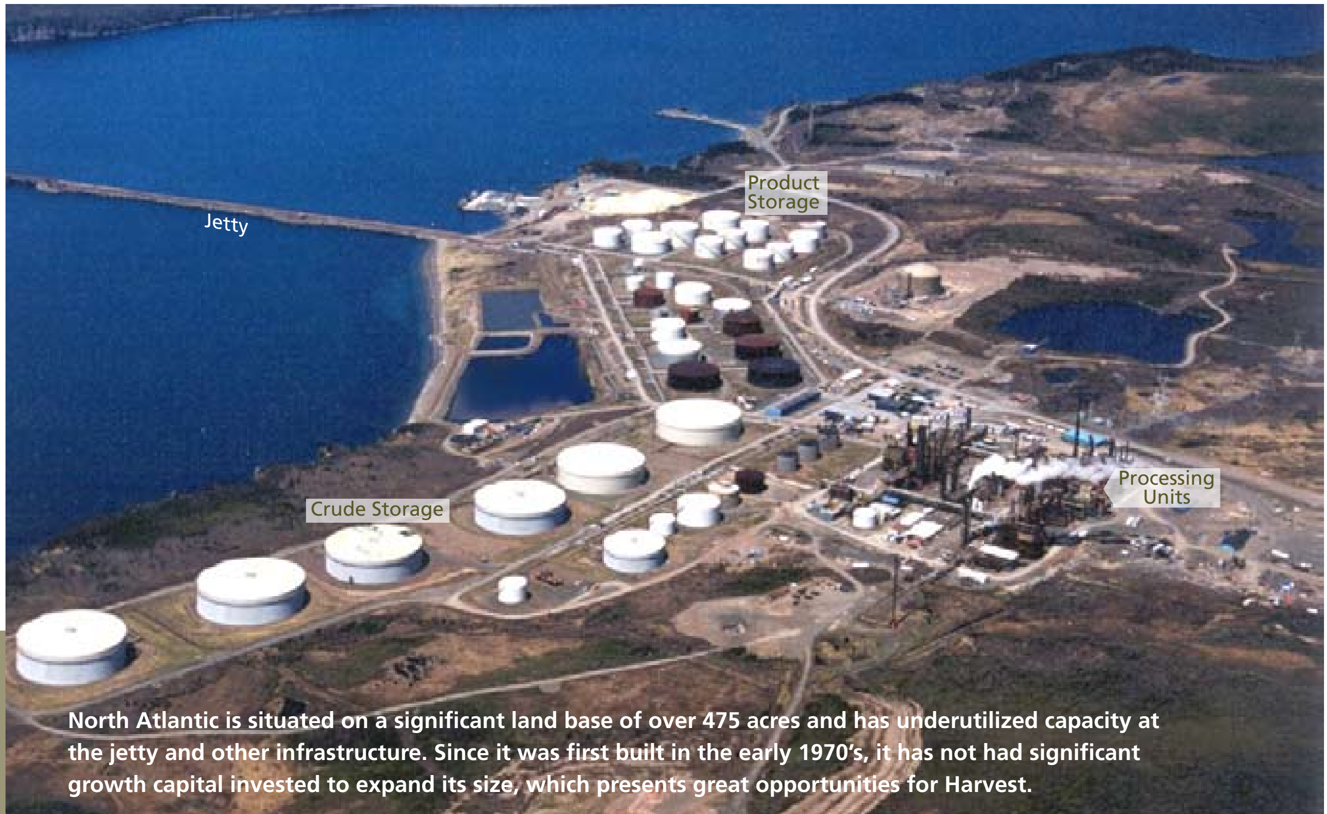
North Atlantic Refining

The North Atlantic refinery is one of the newest refineries in North America, and is situated on an ice-free, deep-water bay on the east coast of Canada. Since Newfoundland is an island, transportation of the crude oil feedstock and exported refined products is all done via ship, and because of its unique location, Very Large Crude Carriers (VLCC's) can dock right at our jetty, eliminating the need to trans-ship or offload off shore. Further, the refinery boasts an extensive land base which is conducive to expansion, and is well regarded by the local government, communities and employees.

The refinery purchases and processes a medium gravity, sour grade of crude oil which is very similar in quality to the oil that we produce in western Canada. This effectively vertically integrates our upstream and downstream businesses, and creates a natural financial hedge. Due to the type of oil we process, we can economically source crude oil and other feedstock from numerous locations, including the Middle East, Latin America and Russia. Since our gasoline and distillate products meet the world's highest specifications and because we have easy access to the ocean for shipping, there are numerous markets that can be supplied with our product, ensuring the best possible price.

With the successful integration and a year's worth of operations behind us, we are now focused on initiatives designed to reduce costs and improve margins. While continuing to work with our marketing agent, Vitol, we have been successful at directly sourcing crude supplies and selling refined product into new markets, resulting in an improved price and stronger margins for Harvest. Approximately 10% of our products are sold locally in Newfoundland (where we command more than 50% of the market share for jet fuel and heating oil), but on occasion, we have sold 100% of our product outside of Newfoundland into markets that need more stringent specifications and provide a better price.

Commencing in 2008, we negotiated an agreement to directly supply high sulfur fuel oil (HSFO) to a large purchaser in the New York Harbour market, which results in a better realized price for Harvest. Boston and New York harbors are two key markets for North Atlantic's products, but since purchasing the refinery



North Atlantic is situated on a significant land base of over 475 acres and has underutilized capacity at the jetty and other infrastructure. Since it was first built in the early 1970's, it has not had significant growth capital invested to expand its size, which presents great opportunities for Harvest.

in late 2006, we have also sold products in Europe, Chile, Singapore and California. Since the beginning of 2008, approximately 60% of our distillate sales outside of Newfoundland have gone to Europe.

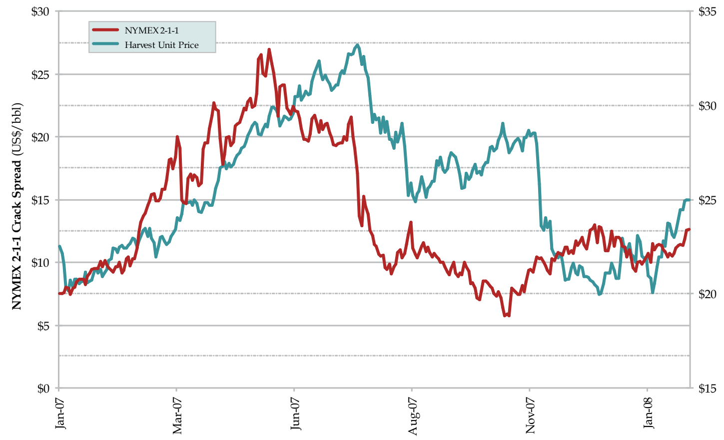
The broader energy industry, including the refining business, is subject to seasonality which results in commodity price variations throughout the year. This effect was evident in the third quarter, as refining margins and crack spreads fell considerably from levels experienced in the second quarter, impacting the cash flow contribution we realized from our North Atlantic business segment. Despite this impact, on a full year basis the refining business met our expectations both operationally and financially. Refining margins in 2007 averaged US$10.05 per bbl, which meets our original budget of approximately $9.00 to $10.00, despite a second half 2007 average of only US$4.16 per bbl. The weakness in the second half of the year was largely driven by a decrease in gasoline margins (representing just over 30% of our product slate) which historically occurs during the third quarter after driving season comes to an end.

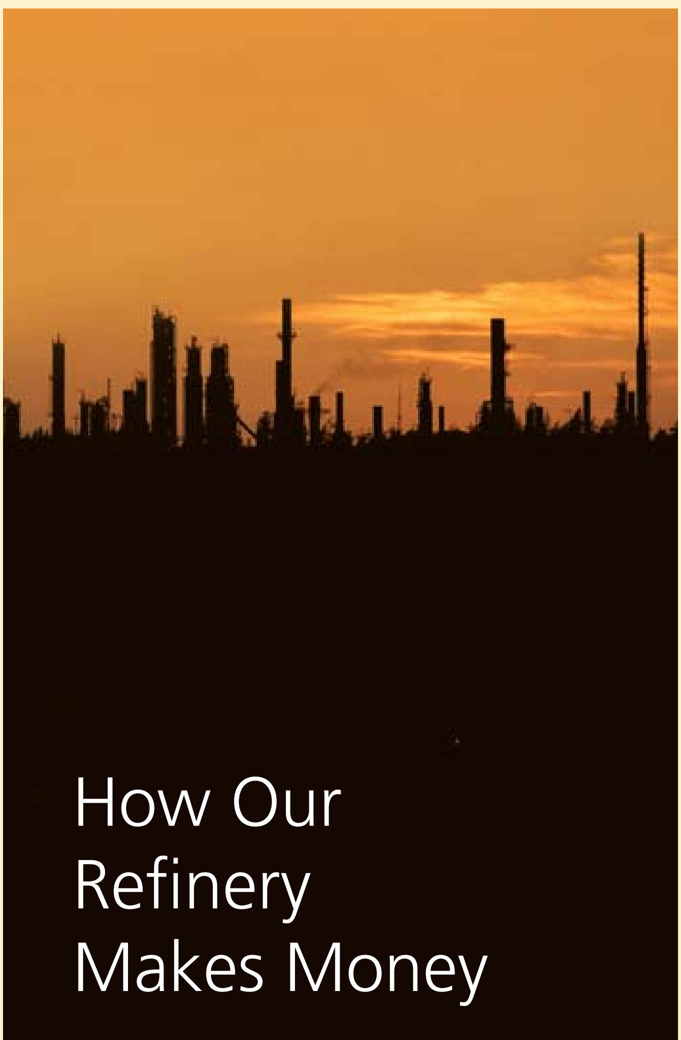
We were able to take advantage of the weak refining margins in the latter part of 2007 by accelerating a turnaround that was originally scheduled for the second quarter of 2008 (during the period when refining margins are historically strongest). With only approximately 8 weeks' notice, we successfully coordinated the logistics and assembled the necessary equipment and manpower to undertake the crude and vacuum unit turnaround. Through most of October and November, the refinery operated at reduced capacity while we performed the required maintenance on the units. The turnaround was completed on time, within budget and without any safety or environmental issues. By the first week in December, we had started the refinery back up, and throughput for the second half of 2007 averaged 82,849 bbl/d. Having completed this turnaround early, we have eliminated the need to perform any turnaround maintenance in 2008, which means the refinery will be running at close to full capacity for the entire year.

A significant benefit of holding a refining asset within a dividend paying structure is its relatively low annual capital maintenance (capex) requirements. Unlike an upstream business which can require maintenance capital of 50% or more of cash flow, a refinery only needs very modest annual cash flow reinvestment, which can be as low as 10%. The strong free cash flow generating characteristics of an infrastructure-type asset like a refinery further enhances the value of our integrated structure.

Consistent with historical trends in the first and second quarters, we are experiencing the seasonal recovery in distillate margins (just over 40% of our product slate) which is associated with the winter heating oil season, and also some strengthening of the gasoline cracks as well. We expect to see further strengthening in the first half of 2008 as the onset of the summer driving season improves gasoline cracks. We have supported our price realizations and protected the downside by entering into price risk management contracts on approximately 10% of our cash flow exposure related to crack spreads for 2008, and we have refined product and WTI pricing contracts that represent approximately 79% of our cash flow exposure in the first half of 2008 and 68% for the second half of 2008.

CRACK SPREAD SEASONALITY CREATES UNIQUE INVESTMENT OPPORTUNITIES





How Our Refinery Makes Money

Similar to any manufacturing business, the refinery makes money based on margins or 'crack spreads'. In simple terms, a crack spread is the difference between the cost to purchase a barrel of crude oil feedstock, and the revenue realized when selling a barrel of refined product. A common crack spread is the 2-1-1, which is the difference between buying 2 barrels of crude oil feedstock, and selling one barrel of diesel (or distillate) and one barrel of gasoline.

At North Atlantic, the feedstock we buy is a medium-sour crude oil, purchased at a discount to the light, sweet crude oil benchmark, West Texas Intermediate (WTI) of approximately US$8/bbl. We also purchase Vacuum Gas Oil (VGO) which is purchased at a discount to WTI of approximately US$1/bbl. After running the feedstock through the refinery, we end up with 3 primary product streams: approximately 40% Distillates, 32% RBOB Gasoline and 28% High Sulphur Fuel Oil (HSFO).

Opportunities for Future Investment

In 2008, a key focal area for us is further improving the performance of the refinery. One aspect of this will include cost reduction initiatives aimed at improving the efficiency of our overhead as well as our energy consumption and costs. The other component involves investigating growth opportunities. Although significant capital has been invested in the refinery over the years on clean fuels, safety and reliability, no substantial capital has been invested to grow or expand its capacity, and it remains at its original size of 115,000 bbl/d.

North Atlantic is situated on a significant land base of over 475 acres and has underutilized capacity at the jetty and in terms of its infrastructure. This gives our refinery distinct advantages over other proposed refinery projects. North Atlantic is also a large employer, well regarded in the province, and is supported by the surrounding communities, including maintaining cooperative working relationships with government and local regulatory bodies. These factors further underpin the very attractive economics for expansion. Given the limited refining capacity in the northeast part of North America (US PADD 1), there are numerous benefits to considering these investment opportunities.

Included in our $63 million capital budget for 2008 is the allocation of capital for discretionary modifications to the visbreaker unit, which will be undertaken concurrently with performing required scheduled maintenance on the visbreaker. Work is already underway on this project, which is expected to be complete in the fourth quarter of 2008. This visbreaker enhancement will effectively upgrade approximately 1,500 bbl/d of HSFO to ultra-low sulfur diesel (ULSD).

Approximately $3 million of our 2008 capital program has been allocated to the evaluation of further growth and margin improvement opportunities by an independent engineering firm. Three main concepts that have been identified are:

- Further resid upgrading to eliminate heavy fuel oil production – As a follow on project to the visbreaker enhancement, this would convert effectively all of the heavy fuel oil produced, and take approximately 30,000 bbl/d of a negative margin product that sells at a discount to WTI, into higher value ULSD / gasoline products (which sell at a premium to WTI).
- Major refinery expansion – Opportunities exist to increase refinery throughput, with the optimal size and refinery configuration to be determined based on the results of the engineering study.
- Conversion to enable heavier feedstock – Modifying various equipment in the refinery would enable us to purchase heavier and therefore less expensive feedstock to further enhance our margins.

Based on preliminary assumptions, each of the above improvement projects provide economic rates of return and provide an exciting range of options for investment for the future.

WHAT IS A VISBREAKER ?

A visbreaker is one of the units in a refinery designed to 'break the viscosity' of long hydrocarbon chains using heat. Shorter hydrocarbon chains are found in more valuable products like gasoline, diesel and jet fuel, while longer chains are found in less valuable, heavier products like resid or heavy fuel oil.

Reserves Disclosure

The information presented below summarizes certain information contained in Harvest's reserves report for the year ended December 31, 2007. Our reserves were evaluated in accordance with National Instrument 51-101 ("NI 51-101") by the independent reserve evaluators McDaniel & Associates Consultants Ltd. ("McDaniel") who evaluated approximately 35% and GLJ Petroleum Consultants Ltd. ("GLJ") who evaluated approximately 65%. The information and tables listed below for Harvest constitute a combined summary of the two separate reserve reports. Reserves data presented below is net of downhole abandonment costs. The complete reserves disclosure as required under NI 51-101, is contained in Harvest's 2007 Renewal Annual Information Form, filed on SEDAR and available on our website.

Oil equivalent amounts (boe) referenced in the following reserves disclosure have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. Boes may be misleading, particularly if used in isolation. This conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Unless otherwise indicated, all reserves stated herein are gross reserves (before royalty burdens and without including royalty interests), based on forecast prices and costs.

Harvest Reserves Summary as at December 31, 2007 – Forecast Prices and Costs

GROSS[1]

Reserves Category	Light & Medium Crude Oil (mmbbl)	Heavy Crude Oil (mmbbl)	Associated & Non-Associated Gas (Bcf)	Natural Gas Liquids (mmbbl)	Total Oil Equivalent[3] 2007 (mmboe)	Total Oil Equivalent[3] 2006 (mmboe)
Proved						
Developed Producing	58.0	34.0	197.1	6.7	131.5	136.5
Developed Non-Producing	1.3	2.1	19.2	0.3	6.9	10.6
Undeveloped	6.3	4.5	28.7	0.4	16.0	11.8
Total Proved	65.5	40.6	245.0	7.5	154.5	158.9
Probable	27.0	20.1	96.6	3.2	66.5	61.0
Total Proved Plus Probable	92.6	60.7	341.6	10.7	220.9	219.9

NET[2]

Reserves Category	Light & Medium Crude Oil (mmbbl)	Heavy Crude Oil (mmbbl)	Associated & Non-Associated Gas (Bcf)	Natural Gas Liquids (mmbbl)	Total Oil Equivalent[3] 2007 (mmboe)	Total Oil Equivalent[3] 2006 (mmboe)
Proved						
Developed Producing	52.8	30.8	162.3	5.0	115.6	119.3
Developed Non-Producing	1.2	1.7	16.1	0.2	5.8	8.7
Undeveloped	5.5	3.7	22.3	0.3	13.3	9.7
Total Proved	59.5	36.3	200.7	5.6	134.7	137.6
Probable	24.8	17.4	78.0	2.3	57.6	52.3
Total Proved Plus Probable	84.2	53.7	278.7	7.9	192.3	189.9

Notes:

(1) "Gross" reserves means the total working interest share of Harvest's remaining recoverable reserves before deductions of royalties payable to others.

(2) "Net" reserves means Harvest's gross reserves less all royalties payable to others.

(3) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. Boes may be misleading, particularly if used in isolation. This conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(4) Columns may not add due to rounding.

(5) The reserves attributable to Harvest's Hay River property, which is an area that produces medium gravity crude oil (average 24° API), are subject to a heavy oil royalty regime in British Columbia and would be required, under NI 51-101, to be classified as heavy oil for that reason. We have presented Hay River reserves as medium gravity crude in the following reserve tables as they would otherwise be classified in this fashion were it not for the lower rate royalty regime applied in British Columbia. If the Hay River reserves were included in the heavy crude oil category, it would increase the gross heavy oil reserves and reduce the light/medium oil reserves by the following amounts: PDP: 12.0 mmbbl, Proved Undeveloped: 2.8 mmbbl, Total Proved: 14.8 mmbbl, Probable: 3.6 mmbbl and P+P: 18.4 mmbbl, and would increase the net heavy oil reserves and reduce the light/medium oil reserves by the following amounts: PDP:10.5 mmbbl, Proved Undeveloped: 2.4 mmbbl, Total Proved: 13.0 mmbbl, Probable: 3.2 mmbbl, and P+P: 16.2 mmbbl.

We successfully replaced approximately 104% of our 2007 production on a P+P basis through acquisition and 12.7 mmboe in positive additions from our capital program, including 5.7 mmboe of additions related to our enhanced recovery programs at Wainwright, Bellshill and Suffield. Our Proved Developed Producing reserves continue to represent a high percentage (approximately 85%) of our total Proved reserves, which represent approximately 70% of our total P+P reserves.

Based on our 2007 average production of approximately 60,000 boe/d and our year end 2007 reserves, our P+P reserve life index (RLI) remains at approximately 10.3 years.

Harvest Net Present Value of Future Net Revenue of Reserves as at December 31, 2007 – Forecast Prices and Costs

Harvest's crude oil, natural gas and natural gas liquids reserves were evaluated using McDaniel's product price forecasts effective January 1, 2008 prior to provision for income taxes, interest, debt service charges and general and administrative expenses. Note that this presentation is on a before tax basis, and when the tax measures announced on October 31st and passed into law in 2007 become enacted in 2011 then the after tax values could be different than the pre-tax number presented herein. It should not be assumed that estimates of the discounted future net production revenue represent the fair market value of Harvest's reserves.

Reserves Category	0% ($millions)	5% ($millions)	10% ($millions)	15% ($millions)	20% ($millions)
Proved					
Developed Producing	3,909.2	3,086.2	2,583.2	2,242.8	1,996.1
Developed Non-Producing	191.9	139.0	110.0	91.2	77.8
Undeveloped	349.1	238.6	171.9	128.2	97.7
Total Proved	4,450.1	3,463.8	2,865.2	2,462.3	2,171.6
Probable	2,059.7	1,201.4	809.4	594.3	461.2
Total Proved Plus Probable	6,509.8	4,665.2	3,674.5	3,056.6	2,632.9

Note:
(1) Columns may not add due to rounding.

McDaniel & Associates Consultants Ltd. January 1, 2008 Price Forecast

A summary of the McDaniel price forecast as at January 1, 2008 that was used in the Harvest reserves evaluation is listed below. A complete listing of the price forecast is available on the McDaniel's website at the following link http://www.mcdan.com/pricing_forecasts.html.

Year	WTI Crude Oil $US/bbl[1]	Edmonton Light Crude Oil $C/bbl[2]	Alberta Bow River Hardisty Crude Oil $C/bbl[3]	Alberta Heavy Crude Oil $C/bbl[4]	Alberta AECO Spot Price $C/GJ	US/CAN Exchange Rate $US/$CAN
2008	90.00	89.00	64.70	55.30	6.45	1.000
2009	86.70	85.70	62.30	53.20	7.00	1.000
2010	83.20	82.20	59.70	50.50	7.00	1.000
2011	79.60	78.50	57.00	48.70	7.00	1.000
2012	78.50	77.40	56.20	48.00	7.10	1.000
2013	77.30	76.20	55.30	47.20	7.30	1.000
2014	78.80	77.70	56.40	48.10	7.55	1.000
2015	80.40	79.30	57.50	49.10	7.80	1.000
2016	82.00	80.80	58.70	50.10	8.00	1.000
2017	83.70	82.50	59.90	51.10	8.25	1.000
2018	85.30	84.10	61.10	52.10	8.45	1.000
2019	87.00	85.80	62.30	53.10	8.70	1.000
2020	88.80	87.50	63.60	54.20	8.95	1.000
2021	90.60	89.30	64.80	55.30	9.20	1.000
2022	92.40	91.10	66.10	56.40	9.40	1.000
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	1.000

Notes:
(1) West Texas Intermediate at Cushing Oklahoma 40° API/0.5% sulphur.
(2) Edmonton Light Sweet 40° API, 0.3% sulphur.
(3) Bow River at Hardisty Alberta (Heavy stream).
(4) Heavy crude oil 12° API at Hardisty Alberta (after deduction of blending costs to reach pipeline quality).

Harvest 2007 Reconciliation Table – Forecast Prices and Costs

	TOTAL BARREL OF OIL EQUIVALENT (boe)	
FACTORS	Gross Proved (mmboe)	Gross Proved Plus Probable (mmboe)
December 31, 2006	158.9	219.9
Technical Revisions	2.3	(7.5)
Extensions/Improved Recovery	8.6	19.5
Discoveries	0.3	0.4
Economic/PV accretion	0.2	0.3
Acquisitions/Divestitures	6.2	10.3
Production	(22.0)	(22.0)
December 31, 2007	154.5	220.9

Note:
(1) Columns may not add due to rounding.

As indicated in the table above, our P+P reserve additions (excluding acquisitions/ dispositions) totaled 12.5 mmboe, which includes approximately 5.7 mmboe of additions from our enhanced recovery program. The negative revisions we experienced were largely related to central Alberta properties acquired in mid-2006 which have not performed as expected.

Finding, Development & Acquisition Costs

In the interests of continuity and consistency, we have elected to present Finding and Development (F&D) and Finding, Development and Acquisition (FD&A) costs calculated both excluding and including Future Development Capital (FDC). The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

The F&D and FD&A costs below include negative revisions associated with the central Alberta properties acquired in mid-2006, and do not provide the best representation of the performance of our overall asset base. To provide some indication of the capital efficiencies we realized across the portfolio absent these specific revisions, our P+P F&D costs would have been $14.07 and $16.93 per boe, excluding and including FDC, respectively while our P+P FD&A costs would have been $13.97 and $16.82 per boe, excluding and including FDC, respectively. Based on our 2007 average operating netback of $29.89/boe, our P+P FD&A costs of $16.82/boe would translate to an attractive recycle ratio of 1.8.

		Total Proved		Proved Plus Probable
Development Capital Expenditures ($MM)	**$**	**297.6**	**$**	**$297.6**
Change in Future Development Capital (FDC) ($MM)	$	25.6	$	60.5
Total Development Capital ($MM)	$	323.2	$	358.1
Reserve Additions (mmboe)		11.4		12.7
F&D Costs ($/boe)	**$**	**28.44**	**$**	**28.10**
F&D Costs before Changes in FDC ($/boe)	**$**	**26.19**	**$**	**23.35**
Development & Acquisition Capital Expenditures ($MM)	**$**	**438.8**	**$**	**438.8**
Change in Future Development Capital (FDC) ($MM)	$	34.7	$	89.5
Total Development & Acquisition Capital ($MM)	$	473.5	$	528.3
Reserve Additions (mmboe)		17.6		23.0
FD&A Costs ($/boe)	**$**	**26.98**	**$**	**22.97**
FD&A Costs before Changes in FDC ($/boe)	**$**	**25.00**	**$**	**19.08**
Three Year Average F&D ($/boe)	$	23.75	$	22.46
Before FDC ($/boe)	$	21.54	$	19.51
Three Year Average FD&A ($/boe)	$	25.37	$	21.05
Before FDC ($/boe)	$	23.06	$	18.00

Corporate Governance

Harvest Energy believes in maintaining good corporate governance practices and understands that our reputation for honesty and integrity is critical to the success of our business. To that end, we require that our board of directors, officers and employees exhibit the highest standards of professional and ethical conduct.

Harvest complies with corporate governance guidelines established by the Canadian Securities Administrators under National Instrument 58-101, details of which are included in our 2008 Proxy Statement and Information Circular filed on SEDAR, EDGAR and posted on the Harvest website. We also comply with the relevant internal control and disclosure certification requirements of the US Sarbanes-Oxley Act, which ensures that we have processes and controls in place to promote sound business practices throughout the organization. Additional details and related documents pertaining to our corporate governance practices and compliance are available on our website.

Every employee at Harvest must read and sign our Corporate Code of Business Conduct and Ethics. This Code is a statement of principles to which Harvest is committed and which is designed to direct all employees, officers and directors of Harvest in determining ethical business conduct. It also reflects our commitment to a culture of honesty, integrity and accountability and outlines the basic principles and policies with which all employees are expected to comply.

BOARD OF DIRECTORS

The Board has responsibility for the overall stewardship of Harvest, including but not limited to the corporate planning process, risk management policies and programs, management development and succession planning, significant business development (including large acquisitions and major financing proposals such as the issuance of Trust Units or debt structuring), and the integrity of internal control and information systems.

Our Board is comprised of experienced individuals with integrity, core operational competencies, financial capabilities and the motivation needed to carry out their fiduciary duties in the best long term interests of the corporation and our unitholders. A majority of our Board members are independent, and our directors and officers collectively own approximately 5% of the Trust Units outstanding. As a result of their significant ownership stake, Harvest insiders are well aligned to effectively represent the interests of unitholders.

The Board has established three permanent committees, whose members and respective mandates are listed below.

AUDIT COMMITTEE

Members: Hector McFadyen (Chairman of the Committee), Verne Johnson and Dale Blue

The Audit Committee is responsible for reviewing all financial statements on a quarterly basis and making recommendations regarding approval to the full Board. In addition, it reviews annual financial statements independently with Harvest's auditors, prior to presentation of such statements to the Board for approval. This committee reviews the integrity of management's reporting systems, and with management and the Auditors' assistance, reviews management reporting, internal financial and operating controls, and policies and practices.

COMPENSATION / CORPORATE GOVERNANCE COMMITTEE

Members: M. Bruce Chernoff (Chairman of the Committee), John Brussa and William Friley

The Compensation / Corporate Governance Committee provides assistance to the Board with its oversight responsibility with respect to human resources policies, compensation, succession planning and proposing new board nominees and assessing directors. The Committee is also responsible to review and recommend to the Board management's succession plan including provisions for appointing, training and monitoring senior management, reviewing the effectiveness of the Board and its committees, and reviewing the appropriateness of the current and future organizational structure of the Trust.

RESERVES, SAFETY & ENVIRONMENT (RSE) COMMITTEE

Members: David Boone (Chairman of the Committee), Kevin Bennett and Verne Johnson

Harvest's RSE Committee has responsibility for the review of annual independent reserve engineering evaluation reports, including reviewing the qualifications, experience and independence of the independent reserve evaluators, and meeting with the individuals from those firms who prepare such reports. This Committee also assists directors in meeting their responsibilities (particularly for accountability) with respect to Harvest's legal, industry and community obligations pertaining to the areas of health, safety and environment, as well as the establishment and implementation of appropriate environment, health and safety policies and procedures.

Environment Health & Safety (EH&S)

As an integrated oil company, we are focused on the full spectrum of environmental, health and safety issues both in the upstream business and in the downstream. Each segment has its unique challenges and opportunities, but our overriding principles of safe operations with minimal impact to the environment are consistent across our entire business. We use responsible practices to ensure the protection of people and the environment. Safety is at the core of our operations and is of utmost importance as we strive to always protect our people, our neighbors and the environment that we all share.

Stewardship of our EH&S programs is the responsibility of our Reserves, Safety and Environment Committee of the board of directors, who review our performance on a quarterly basis. This committee is supported by our EH&S Management Committee, as well as our upstream and downstream teams of dedicated professionals who regularly monitor our performance to ensure that Harvest conducts business in accordance with all regulatory requirements and industry best practices.

Upstream EH&S

In western Canada, we maintain a proactive safety management program that defines key principles by which all work is to be conducted, and defines specific responsibilities for all levels of personnel in the upstream organization. All new employees and worksite supervisors are provided with safety orientation and training in identification, assessment and control of potential workplace hazards. We maintain comprehensive corporate and site specific emergency response plans, and test them regularly to ensure personnel are adequately trained to effectively handle emergencies and protect the public.

HIGHLIGHTS:

- As a platinum level participant in the Canadian Association of Petroleum Producers' (CAPP) Stewardship program, we regularly conduct both internal and independent external audits to measure the adequacy of our EH&S system and our performance. Harvest's EH&S Management Committee monitors the continuous improvement of our system and performance as recommended in our audit documents.
- In 2007, Harvest installed infrastructure for periodic acid gas re-injection at Hayter, and installed electrical infrastructure at Hay River. Both projects will reduce emissions and enhance project economics.
- Harvest undertook a fugitive emissions detection and control pilot study in 2007 that demonstrated positive economic results and significant emission reductions in the target facility. In 2008 and 2009, we plan to implement a company-wide fugitive emissions detection and control plan. We will also install infrastructure to reduce methane venting from conventional heavy oil production, evaluate several flaring and venting conservation projects, and pursue energy reduction options in both upstream and downstream operations.
- In 2009 and beyond, we will evaluate various potential initiatives such as CO_2 sequestration in reservoirs, and reduced electrical consumption through deep disposal of produced water.
- In early 2008, Harvest participated in an industry initiative called Safety Stand Down Week, in which senior executives and managers visited frontline workers at their worksites, and talked to them directly and informally about safety issues.

Approximately 20 of our senior executives and managers visited various worksites throughout western Canada to discuss safety initiatives and listen to potential concerns. Over 200 frontline workers were engaged during a one week period making it a very successful exercise.

- Harvest intends to meet the federal government's targets for emission reduction, including a 6% intensity improvement each year from 2007 to 2010, with a further 2% annual improvement thereafter, and a long term target of 70% reduction by 2050 from 2006 levels.

Downstream EH&S

The North Atlantic refinery has an integrated management system which incorporates environmental, health, and safety considerations. The key components of this continuous improvement program include job safety analysis, incident investigations, risk management, detailed equipment inspections, work permitting, as well as maintaining in-house government-certified inspectors and Canadian Registered Safety Professionals. Refinery employees receive regular training in first aid, fire prevention / protection, and oil spill and emergency response. We regularly perform stack sampling, soil, vegetation, and fresh and ocean water tests. We also have monitoring stations to record the air quality in three adjacent communities as well as at the refinery fence line.

North Atlantic externally reports environmental performance through periodic meetings and emails to the Community Liaison Committee (CLC), which represents all of the communities adjacent to the refinery, as well as government regulators.

HIGHLIGHTS

- In 2007, North Atlantic scored top marks (97%) on a Newfoundland government safety audit performed by the Workplace Health Safety and Compensation Commission (“WHSCC”). The audit verified compliance with the requirements of the WHSCC’s employer incentive program, PRIME. North Atlantic’s safety program formed the basis upon which the WHSCC established its workers’ compensation premium for the following year. The refinery rate is approximately 60% of the industry average in the province and North Atlantic has been advised by the WHSCC that our assessment rates will be reduced for a sixth year in a row due to our safety program and our low workers’ compensation claims history.
- As of December 31, 2007, North Atlantic refining employees set a new record by accumulating 1.4 million person hours (431 days) without a lost-time injury for a Lost Time Accident frequency of 0.0, which is also a new record. As of February 29, this record has been extended to almost 1.8 million person-hours.
- For the year, North Atlantic reported the lowest recordable injury rate in our history, at 1.47 for the refinery and 1.49 for the entire organization.
- North Atlantic has continued with its strong focus on Process Hazard Analysis studies. Six refinery units were analyzed in depth for process hazards in 2007. All major units have now been studied and we will be starting a five year review of this work in 2008 as per standard industry risk management practice.
- In 2007, our “incident cost per barrel”, a standardized measure of our ability to prevent or mitigate the effects of process related incidents, decreased by approximately 86% from 2006 results.
- There were no regulatory compliance issues such as air or effluent water quality violations at North Atlantic in 2007. Further, the refinery had a net reduction in National Pollutant Release Inventory reportable and Greenhouse Gas (GHG) emissions compared to the previous year.
- North Atlantic was once again voted by its employees to be one of the top 100 employers in Canada, chosen from 1,800 organizations across the country, and the only Newfoundland based business to make the list. Selection criteria included measures such as work and social atmosphere, employee training programs, and contribution to the community.

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. The information and opinions concerning our future outlook are based on information available at March 12, 2008.

When reviewing our 2007 results and comparing them to 2006, readers should be cognizant that the 2007 results include twelve months of operations from our acquisition of Viking Energy Royalty Trust ("Viking") in February 2006, Birchill Energy Ltd. ("Birchill") in August 2006 and North Atlantic Refining Ltd. ("North Atlantic") in October 2006 and five months from our acquisition of Grand Petroleum Inc. ("Grand") in August 2007 whereas the comparative results in 2006 include only eleven months of operations from our acquisition of Viking, five months of operations from our acquisition of Birchill and ten weeks of operations from our acquisition of North Atlantic. This significantly impacts the comparability of our operations and financial results for the year ended December 31, 2007 to the comparative period in the prior year.

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: 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 and without including any royalty interests, unless otherwise stated. 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 (loss) 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" 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 reporting measures.

FORWARD-LOOKING INFORMATION

This MD&A highlights significant business results and statistics from our consolidated financial statements for the year ended December 31, 2007 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 refinery 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 several 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.

2007 FINANCIAL AND OPERATING HIGHLIGHTS

- Cash from operating activities of $641.3 million, representing an increase of $133.4 million over the prior year primarily due to a full year of downstream operations, the realization of $53.6 million of currency exchange gains and a $39.4 million reduction in cash settlements on our crude oil pricing contracts.
- Upstream operations contributed $624.3 million of cash reflecting production of 60,336 boe/d with strong commodity prices offset by a strengthening of the Canadian dollar and higher operating costs.
- Acquired Grand Petroleum for total cash consideration of $139.3 million representing a cost of approximately $41,000 per flowing barrel and $23.00 per boe for proved and probable reserves complementing our existing oil operations in southeast Saskatchewan.
- Capital spending of $300.7 million in our upstream operations plus $138.2 million of net acquisitions replaced 2007 production with finding and development costs, including changes in future development costs of $28.10 per boe.
- Downstream operations contributed $165.0 million of cash in 2007 reflecting refining throughput of 114,646 bbl/d and refining margins of US$13.69 per barrel during the first half of the year with an acceleration of turnaround activities significantly reducing throughput and increasing costs during the second half of 2007.
- Increased credit facility to $1.6 billion and extended the maturity date to April 2010 while maintaining the cost of borrowing with a quality syndicate of Canadian and international financial institutions.
- Declared distributions totaling $610.3 million ($4.40 per Trust Unit) with 29% participation in our distribution reinvestment programs providing $178.5 million of additional equity.

SELECTED ANNUAL INFORMATION

The table below provides a summary of our financial and operating results for years ended December 31, 2007 and 2006.

	Year Ended December 31		
($000s except where noted)	2007	2006	Change
Revenue, net[1]	4,069,600	1,380,825	195%
Cash From Operating Activities	641,313	507,885	26%
Per Trust Unit, basic	$ 4.63	$ 5.00	(7%)
Per Trust Unit, diluted	$ 4.30	$ 4.84	(11%)
Net Income (loss)[2]	(25,676)	136,046	(119%)
Per Trust Unit, basic	$ (0.19)	$ 1.34	(114%)
Per Trust Unit, diluted	$ (0.19)	$ 1.33	(114%)
Distributions declared	610,280	468,787	30%
Distributions declared, per Trust Unit	$ 4.40	$ 4.53	(3%)
Distributions declared as a percentage of Cash From Operating Activities	95%	92%	3%
Bank debt	1,279,501	1,595,663	(20%)
$7^{7/8}$% Senior Notes	241,148	291,350	(17%)
Convertible debentures[3]	651,768	601,511	8%
Total long-term financial liabilities[3]	2,172,417	2,488,524	(13%)
Total assets	5,451,683	5,745,558	(5%)
UPSTREAM OPERATIONS			
Daily Production			
Light to medium oil (bbl/d)	27,165	27,482	(1%)
Heavy oil (bbl/d)	14,469	13,904	4%
Natural gas liquids (bbl/d)	2,412	2,247	7%
Natural gas (mcf/d)	97,744	96,578	1%
Total daily sales volumes (boe/d)	60,336	59,729	1%
Operating Netback ($/boe)	29.89	30.54	2%
Cash capital expenditures	300,674	376,881	(20%)
DOWNSTREAM OPERATIONS[4]			
Average daily throughput (bbl/d)	98,617	86,890	13%
Aggregate throughput (mbbl)	35,995	6,343	467%
Average Refining Margin (US$/bbl)	10.05	9.32	8%
Cash capital expenditures	44,111	21,411	106%

(1) Revenues are net of royalties.

(2) Net Income includes a future income tax expense of $65.8 million (2006 - a recovery of $2.3 million) and unrealized net losses on risk management contracts of $147.8 million (2006 - net gains of $52.2 million) for the year ended December 31, 2007. Please see Notes 16 and 18 to the Consolidated Financial Statements for further information.

(3) Includes current portion of Convertible Debentures.

(4) Downstream operations acquired on October 19, 2006.

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 (our "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 (our "downstream operations").

During 2007, there were two international trends that have significantly impacted Harvest: the appreciation of the Canadian dollar relative to the US dollar and the disruption of international capital markets due to the sub-prime mortgage crisis in the United States and the asset-backed commercial paper problem in Canada. The strengthening of the Canadian dollar tempers the impact of record setting prices for crude oil and refined products as the currency of these pricing benchmarks is denominated in US dollars. For example, the December 31, 2007 closing West Texas Intermediate benchmark price ("WTI") of US$95.98 and a noonday foreign exchange rate of US$1.0120 per Canadian dollar converts to a CDN$94.84 equivalent. This compares to a year earlier when the WTI price was US$61.05 with an exchange rate of US$0.8581 and converted to a CDN$71.15 equivalent resulting in a 57% year-over-year increase in WTI with an increase of only 33% in the Canadian dollar equivalent. The impact of a strengthening Canadian dollar for both our upstream business with $937.0 million of crude oil sales and our downstream business with $430.8 million of refining margin is discussed in their respective sections of this MD&A.

In early July 2007, the extent of the sub-prime lending in the United States and the subsequent asset-backed commercial paper problems in Canada severely impacted the non-investment grade debt markets with a tightening of the availability of credit and a re-pricing of credit. We discuss the ongoing impact of this in the Liquidity and Capital Resources section of this MD&A.

During 2007, cash from operating activities totaled $641.3 million, a $133.4 million improvement as compared to $507.9 million in the prior year. While cash generated from our upstream operations of $624.3 million in 2007 remained relatively stable as compared to $626.2 million in the prior year, the cash generated in our downstream operations of $165.0 million in the current year represents a $129.8 million improvement over the prior year reflecting a full year of operations and robust refining margins in the first half of 2007. The increase in contribution from our downstream operations should be considered in light of a $74.1 million increase in interest costs during 2007 also reflecting a full year of ownership. As the Canadian dollar strengthened during 2007, we converted US$654.7 million of US dollar bank loan borrowings to Canadian dollar borrowings crystallizing $47.1 million of currency exchange gains. Cash settlements for our crude oil price risk management contracts totaled $41.5 million in 2007 reflecting a US$57.18 per barrel price cap with 70% participation above the cap, which is a US$13.38 per barrel higher price cap coupled with a 10% increase in participation above the price cap as compared to 2006. The $39.4 million reduction in crude oil risk management losses in 2007 is a result of the US$13.38 higher price cap more than offsetting the US$6.07 increase in the average WTI benchmark price.

Our upstream operations reflected production of 60,336 boe/d in 2007 as compared to 59,729 boe/d in the prior year with the incremental production in 2007 from our 2006 acquisitions of Viking (one month) and Birchill (seven months) and the acquisition of Grand in mid-2007 along with the results of our 2007 capital spending more than offsetting the natural decline and operating disruptions of 2007. Our production decline in 2007 was higher than expected as the assets acquired in the Birchill acquisition included a number of recently completed wells with higher than expected decline rates and our drilling at Hay River in the winter of 2007 did not produce as anticipated resulting in our focus in this area shifting to a re-pressurization of the reservoir. In addition, our operating costs increased to $300.9 million, representing a 23% increase in per unit operating costs to $13.66 per boe reflecting an overheated Alberta oilfield services market. While the average WTI benchmark price increased 9%, our average realized price increased 5% reflecting generally higher discounts for heavy oil and a strengthening of the Canadian dollar.

In early August 2007, we completed our acquisition of Grand for aggregate cash consideration of $139.3 million and quickly integrated its operations into our organization limiting transition costs. At the time of its acquisition, Grand's production averaged approximately 3,400 boe/d comprised of approximately 68% oil and 32% natural gas resulting in the acquisition cost being approximately $41,000 per flowing barrel. In addition, the Grand assets included 46,000 net acres of undeveloped land with supporting seismic. Grand's principal oil producing assets are located in southeast Saskatchewan adjacent to our Hazelwood property with our combined production in this area totaling approximately 3,600 boe/d at year end. In 2008, we are planning to drill 40 wells in southeast Saskatchewan.

Reserve additions in our upstream operations more than replaced our production during 2007 with our proved plus probable reserves at December 31, 2007 totaling 220.9 million boe as compared to 219.9 million boe at the end of 2006. Including changes in future development costs, our 2007 finding and development costs averaged $28.10 per boe while our finding, development and acquisition costs averaged $22.97 per boe as compared to $26.04 per boe and $24.59 per boe, respectively, in the prior year. Included in the 2007 proved plus probable reserve additions are 14.0 million boe attributed to our 2007 capital program and enhanced recovery plans and a further 9.3 million boe for new proved undeveloped reserves which, when coupled with the 10.3 million boe acquired during the year more than offsets our 2007 production and revisions for underperforming properties. Relative to our 2007 netback price of $29.89, our finding and development costs represent a recycle ratio of 1.06 while our finding, development and acquisition costs represent a recycle ratio of 1.30.

During 2007, our downstream operations generated $165.0 million of cash with $233.1 million generated in the first six months offset by a $68.1 million cash consumption in the last six months. During the first half of 2007, throughput averaged 114,646 bbl/d with our refining margin averaging US$13.69 per barrel which exceeded our expectations. In the second half of the year, our results reflect a significantly reduced refining margin of US$4.16 and the impact of two planned shutdowns. With reduced refining margin appearing early in the third quarter, we accelerated our first shutdown by a few weeks to enable the acceleration of a second shutdown from the spring of 2008, as originally planned, to the fourth quarter of 2007. This acceleration of planned shutdowns better positions us to benefit from anticipated higher refining margins in 2008.

In February 2007, we raised $357.4 million of net proceeds with the issuance of $230 million of principal amount Convertible Debentures and 6,146,750 Trust Units with $289.7 million of the proceeds directed to the repayment of our Senior Secured Bridge Credit Facility and the balance applied to our Three Year Extendible Revolving Credit Facility. In April 2007, we increased our Three Year Extendible Revolving Credit Facility from $1.4 billion to $1.6 billion and by October, extended the maturity date of this facility from March 2009 to April 2010 and maintained our syndicate of quality lenders as well as the cost of our borrowing. As the disruptions in the capital markets continue, we are comfortable with the April 2010 maturity date for our credit facilities and may elect to defer further extending the maturity date until capital market conditions improve.

In 2007, we declared distributions to Unitholders totaling $610.3 million ($4.40 per Trust Unit) comprised of ten monthly distributions of $0.38 per Trust Unit and distributions for November and December of $0.30 per Trust Unit. We had maintained our $0.38 per Trust Unit monthly distribution since February 2006 and in light of the impact of a significant strengthening of the Canadian dollar on our crude oil sales revenue and refining margins and the continued high cost of operating in Alberta, we reduced our monthly distribution to $0.30 per Trust Unit effective November 2007 to better balance our cash from operating activities, distributions and capital spending. Unitholder participation in our distribution reinvestment programs generated $178.5 million of equity capital reflecting a 29% average level of participation.

Business Segments

Following our acquisition of North Atlantic in October of 2006, our business has two segments: the upstream operations in western Canada and the downstream operations in the Province of Newfoundland and Labrador. The following table presents selected financial information for our two business segments:

	Year Ended December 31					
	2007			2006		
(in $000s)	Upstream	Downstream	Total	Upstream	Downstream	Total
Revenue(1)	971,044	3,098,556	4,069,600	920,466	460,359	1,380,825
Earnings From Operations(2)	169,423	92,270	261,693	211,418	19,740	231,158
Capital expenditures	300,674	44,111	344,785	376,881	21,411	398,292
Total assets	3,968,779	1,482,903	5,451,683	4,017,761	1,727,797	5,745,558

(1) Revenues are net of royalties.

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

(3) 2006 downstream operations are for the period October 19, 2006 to December 31, 2006.

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 and related effects on unitholder distributions.

UPSTREAM OPERATIONS

Financial and Operating Results

Throughout 2007, our production mix was approximately 49% light to medium oil and natural gas liquids, 24% heavy oil and 27% natural gas with our core areas of production located in Alberta, Saskatchewan and British Columbia.

The following summarizes the financial and operating information of our upstream operations for the years ended December 31, 2007 and 2006:

	Year Ended December 31		
(in $000s)	2007	2006	Change
Revenues	$ 1,184,457	$ 1,120,575	6%
Royalties	(213,413)	(200,109)	7%
Net revenues	971,044	920,466	5%
Operating expenses	300,918	242,474	24%
General and administrative	34,615	28,372	22%
Transportation and marketing	11,946	12,142	(2%)
Transaction costs	-	12,072	n/a
Depreciation, depletion, amortization and accretion	454,142	413,988	10%
Earnings From Operations(1)	169,423	211,418	(20%)
Cash capital expenditures (excluding acquisitions)	300,674	376,881	(20%)
Property and business acquisitions, net of dispositions	138,158	2,467,097	(94%)
Daily sales volumes			
Light to medium oil (bbl/d)	27,165	27,482	(1%)
Heavy oil (bbl/d)	14,469	13,904	4%
Natural gas liquids (bbl/d)	2,412	2,247	7%
Natural gas (mcf/d)	97,744	96,578	1%
Total (boe/d)	60,336	59,729	1%

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

Commodity Price Environment

	Year Ended December 31		
Benchmarks	2007	2006	Change
West Texas Intermediate crude oil (US$ per barrel)	72.31	66.24	9%
Edmonton light crude oil ($ per barrel)	76.25	72.79	5%
Bow River blend crude oil ($ per barrel)	63.36	51.04	5%
AECO natural gas daily ($ per mcf)	6.45	6.53	(1%)
AECO natural gas monthly ($ per mcf)	6.61	6.98	(5%)
Canadian / US dollar exchange rate	0.935	0.882	6%

In general, the average West Texas Intermediate ("WTI") crude oil price has increased steadily throughout 2007, beginning the year at US$54.35/bbl and exiting the year with a December average price of US$91.74/bbl, resulting in a 2007 annual average price of US$72.31/bbl, a 9% increase over the prior year. The average Edmonton light crude oil price ("Edmonton Par") also increased steadily throughout 2007, however to a lesser extent than WTI due to the relative strengthening of the Canadian dollar. The Canadian dollar equivalent of WTI for the year ended December 31, 2007 of $77.34 would have been $81.98 (or $4.64 higher) had the Canadian/ US dollar exchange rate remained unchanged from the prior year.

Heavy oil differentials fluctuate based on a combination of factors including the level of heavy oil inventories, pipeline capacity to deliver heavy crude to US markets and the seasonal demand for heavy oil. Throughout 2007, heavy oil demand was impacted by planned maintenance shut downs and unplanned disruptions of heavy oil refineries in the United States as well as production from new oil sands projects, resulting in widening differentials. Heavy oil differentials for the last eight quarters are shown below.

	2007				2006			
Differential Benchmarks	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Bow River Blend differential to Edmonton Par	34.2%	30.0%	29.4%	25.4%	30.3%	25.8%	22.9%	42.0%

North American natural gas storage inventories throughout 2007 were higher than in prior years, and as a result the benchmark natural gas price fell by 5% compared to the prior year to an average of $6.61/mcf from $6.98/mcf in 2006.

Realized Commodity Prices

The following table provides our average realized price by product for 2007 and 2006.

	Year Ended December 31		
	2007	2006	Change
Light to medium oil ($/bbl)	64.09	59.82	7%
Heavy oil ($/bbl)	46.71	46.14	1%
Natural gas liquids ($/bbl)	62.26	58.54	6%
Natural gas ($/mcf)	6.94	6.76	3%
Average realized price ($/boe)	53.78	51.40	5%

In 2007 our average realized price was 5% higher than in the prior year, with every product realizing a higher average price than the prior year.

Our realized price for light to medium oil sales increased 7% in 2007 compared to the prior year, reflecting the 5% increase in Edmonton Par pricing over 2006 coupled with improved quality differentials realized on our light to medium oil production relative to the Edmonton Par price during 2007.

Harvest's heavy oil prices were relatively unchanged in 2007 from 2006, despite a 5% year-over-year increase in the Bow River price. This is a result of the relatively heavier gravity of production from two heavy oil acquisitions completed in December 2006 and March 2007.

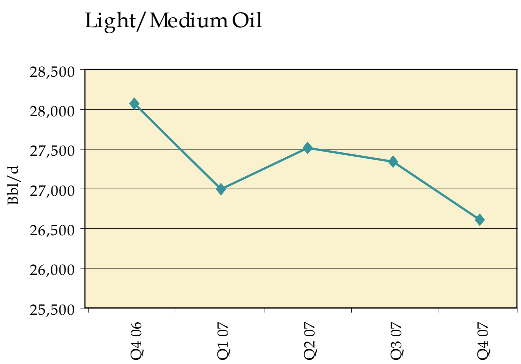
The average realized price for our natural gas production was 3% higher in 2007 than in 2006 compared to reductions of 1% in AECO daily pricing and 5% in AECO monthly pricing over the same period. The increase in our realized natural gas prices relative to 2006 is a result of consolidating our gas marketing arrangements with one third party marketer in late 2006. Throughout 2007 we sold approximately 60% of our natural gas off the AECO daily benchmark and approximately 30% off the AECO monthly benchmark with the remainder sold to aggregators. Additionally, the natural gas produced in our larger natural gas producing properties generally has a higher than average heat content, which realizes a premium in its pricing.

Sales Volumes

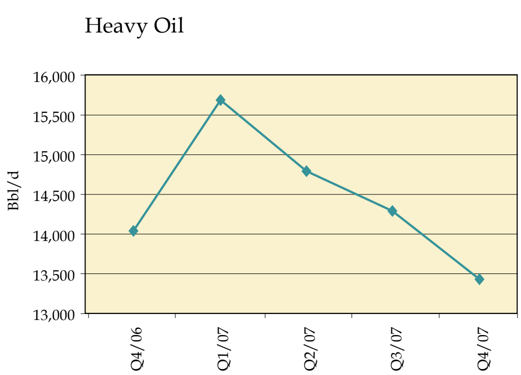
The average daily sales volumes by product were as follows:

	Year Ended December 31				
	2007		2006		
	Volume	Weighting	Volume	Weighting	% Volume Change
Light to medium oil (bbl/d)(1)	27,165	45%	27,482	46%	(1%)
Heavy oil (bbl/d)	14,469	24%	13,904	23%	4%
Natural gas liquids (bbl/d)	2,412	4%	2,247	4%	7%
Total liquids (bbl/d)	44,046	73%	43,633	73%	1%
Natural gas (mcf/d)	97,744	27%	96,578	27%	1%
Total oil equivalent (boe/d)	60,336	100%	59,729	100%	1%

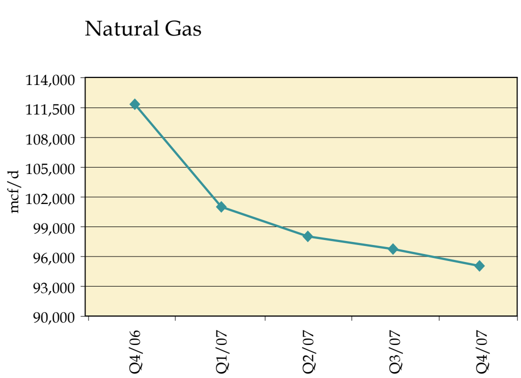
(1) Harvest classifies our oil production, except that produced from Hay River, as light to medium and heavy according to NI 51-101 guidance. The oil produced from Hay River has an average API of 24o (medium grade) and is classified as a light to medium oil, however, it benefits from a heavy oil royalty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



In 2007, our light/medium oil production has trended downward each quarter, except for the second quarter, resulting in an annual average production level of 27,165 bbl/d which is 317 bbl/d or 1% lower than the prior year. In the first quarter, production was disrupted due to a major drilling project at Hay River that produces about 15-20% of our total light/medium oil production. In the second quarter, Hay River production resumed, adding an incremental 1,200 bbl/d of initial production from the new wells. In the third quarter, however, steeper than expected declines were experienced in this property, reducing production by 1,750 bbl/d for the quarter which was offset by our August 1, 2007 acquisition of Grand that added approximately 1,100 bbl/d. In the fourth quarter, production declined a further 500 bbl/d due to continued declines in Hay River as well as normal declines and power outages at Hazelwood properties in southeast Saskatchewan and the disposals of some minor properties.



Our total heavy oil production increased by 4% in 2007 relative to 2006 for an average of 14,469 bbl/day. Despite this overall increase, our heavy oil production has actually been decreasing each quarter in 2007. Two heavy oil acquisitions, one in late in 2006 and one in March 2007 added approximately 1,055 incremental barrels per day of production for the first quarter, offsetting natural declines in other properties and production disruptions associated with "military lockouts" at our Suffield property where our operations are located on a Canadian Forces military base. In the second quarter, our production was 14,719 bbl/d, an 895 bbl/d reduction from the first quarter due to wet spring conditions with soft road conditions limiting the movement of well servicing equipment and again the military lockouts at Suffield. Production volumes declined further in the third and fourth quarters as a result of increased water cuts on various large producing wells in the west central Saskatchewan and Lloydminster areas as well as well servicing activities and normal declines.



Our 2007 natural gas production was relatively unchanged from the prior year, averaging 97,744 mcf/d. Our 2006 acquisitions of Birchill and Viking added incremental gas production with our fourth quarter 2006 production volume of 112,006 mcf/d. In 2007 we acquired approximately 7,000 mcf/d additional gas production with Grand in the third quarter and focused our capital program on tie-ins of wells drilled in 2006 and expected a downward trend in our natural gas production. While we experienced higher than expected production declines on a few of the Birchill properties acquired in the prior year our second and third quarter natural gas production was lower due to various third party processing facility turnarounds, specifically in our Crossfield area where quarterly production volumes were reduced by 1,600 mcf/d.

Revenues

	Year Ended December 31		
(000s)	2007	2006	Change
Light to medium oil sales	$ 635,470	$ 600,061	6%
Heavy oil sales	246,674	234,144	5%
Natural gas sales	247,499	238,367	4%
Natural gas liquids sales and other	54,808	48,003	14%
Total sales revenue	1,184,451	1,120,575	6%
Royalties	(213,413)	(200,109)	7%
Net Revenues	$ 971,038	$ 920,466	5%

Our revenue is impacted by changes to production volumes, commodity prices, and currency exchange rates. Our 2007 total sales revenue of $1,184.5 million is $63.9 million higher than the prior year, of which $54.9 million is attributed to higher realized prices and $9.0 million in attributed to increased production volumes. The price increase reflects the 5% increase in Edmonton Par pricing in 2007 compared to 2006, and our increased production volume is mainly attributed to the acquisitions that we have completed in late 2006 and throughout 2007 coupled with our 2007 capital spending program.

Light to medium oil sales revenue for 2007 was $35.4 million higher than in the comparative period, due to a $42.3 million favourable price variance offset by a $6.9 million unfavourable volume variance. Increased demand for Canadian light sweet crude oil has resulted in increased realized prices on our light to medium oil production and has had a positive impact on overall revenue while higher than expected decline rates in Hay River and delayed well servicing activity have contributed to an unfavourable volume variance between 2007 and 2006.

During 2007, our heavy oil sales revenue of $246.7 million was $12.5 million higher than in the prior year due to a $9.5 million favourable volume variance resulting from current year acquisitions of heavy oil properties and the incremental production from our drilling program and a $3.0 million favourable price variance reflecting the 5% year-over-year increase in Bow River benchmark pricing.

Natural gas sales revenue increased by $9.1 million in 2007 compared to 2006 due to a $6.2 million favourable price variance coupled with a $2.9 million favourable volume variance. The favourable price variance reflects the $0.18/mcf increase in our realized natural gas prices resulting from our consolidation of gas marketing arrangements to a single third party marketer and the favourable volume variance is primarily attributed to the incremental gas production from the acquisition of Birchill in August 2006 and Grand in August 2007.

During 2007, our natural gas liquids and other sales revenue increased by $6.8 million compared to the prior year, attributed to a $3.5 million favourable volume variance and a $3.3 million favourable price 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 2007 our net royalties as a percentage of gross revenue were 18.0% (17.9% in 2006) and aggregated to $213.4 million ($200.1 million in 2006). Our 2007 royalty rate is in line with expectations with additional crown royalties assessed on our Hay River properties in 2007, offset by reduced royalties due to increased gas cost allowance credits and crown royalty refunds on some of our shut-in gas-over-bitumen production. See "Changes in Regulatory Environment" section in this MD&A for further discussion on Alberta's New Royalty Framework.

Operating Expenses

	Year Ended December 31				
(000s except per boe amounts)	2007	Per BOE	2006	Per BOE	Per BOE Change
OPERATING EXPENSE					
Power	$ 56,427	$ 2.56	$ 61,056	$ 2.80	(9%)
Workovers	60,000	2.72	51,151	2.34	16%
Repairs and maintenance	62,260	2.83	38,969	1.79	58%
Labour – internal	13,887	0.63	20,719	0.95	(31%)
Processing fees	28,764	1.31	15,311	0.70	84%
Fuel	8,725	0.40	7,442	0.34	6%
Labour – external	15,641	0.71	13,012	0.60	18%
Land leases and property tax	21,262	0.97	19,319	0.89	9%
Other	33,952	1.53	15,495	0.71	115%
Total operating expense	300,918	13.66	242,474	11.12	23%
Transportation and marketing expense	$ 11,946	$ 0.54	$ 12,142	$ 0.56	(4%)

Our 2007 operating costs totaled $300.9 million as compared to the $242.5 million incurred in 2006. On a per barrel basis, our operating costs have increased to $13.66 in 2007 compared to $11.12 in 2006, representing a 23% increase over the prior year. The largest components of operating expense are workovers and repairs and maintenance costs, and these costs reflect the continued high demand for oilfield services that we experienced throughout the year, resulting in increased overall costs. Additionally, in the third quarter, an extended turnaround at a third-party processing plant in the Crossfield area accounted for a one-time $5.5 million increase in repairs and maintenance expense. The increase in processing fees are directly related to a greater proportion of non-operated properties as a result of the acquisition of Birchill. Generally, we incur higher processing fees on non-operated properties as we own an interest in the well, but may not own an interest in the processing plant and are usually charged a fee for processing which is higher than the per unit cost of operating the facility.

Our 2007 transportation and marketing expense was $11.9 million or $0.54 per boe and is relatively unchanged from $12.1 million or $0.56 per boe in 2006. 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.

Electric power costs represented approximately 19% of our total operating costs during 2007. Electric power prices of $66.84 per MWh in 2007 were 17% lower than the 2006 average of $80.48/MWh and Harvest recognized a $0.24 per boe reduction in power costs before gains on price risk management contracts as a result of this rate reduction. However, increased power consumption resulting from our acquisition of Birchill in August 2006 and our acquisition of Grand in August 2007 offset the full benefit of the reduction in price. In 2007, our electric power price risk management contracts resulted in a gain of $3.1 million compared to a gain of $11.6 million in the prior year which would be expected with lower power prices. The following table details the electric power costs per boe before and after the impact of our price risk management program.

	Year Ended December 31		
(per boe)	2007	2006	Change
Electric power costs	$ 2.56	$ 2.80	(9%)
Realized gains on electricity risk management contracts	(0.14)	(0.53)	(74%)
Net electric power costs	$ 2.42	$ 2.27	7%
Alberta Power Pool electricity price (per MWh)	$ 66.84	$ 80.48	(17%)

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 will 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.

Operating Netback

	Year Ended December 31	
(per boe)	2007	2006
Revenues	$ 53.78	$ 51.40
Royalties	(9.69)	(9.18)
Operating expense	(13.66)	(11.12)
Transportation and marketing expense	(0.54)	(0.56)
Operating netback[(1)]	$ 29.89	$ 30.54

(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 2007, our operating netback decreased by $0.65/boe or 2% relative to 2006. The decrease in our operating netback is primarily attributed to a 2.54/boe increase in operating expenses attributed to increased workover and maintenance activity throughout the year and to a lesser extent increased royalties resulting from higher realized prices. Offsetting these factors is a $2.38/boe increase in realized prices for our production compared to the prior year reflecting the increase in Edmonton Par and Bow River pricing throughout the year, as well as increased realized natural gas prices resulting from our change in marketing arrangements in late 2006.

General and Administrative ("G&A") Expense

	Year Ended December 31		
(000s except per boe)	2007	2006	Change
Cash G&A[1]	$ 31,892	$ 27,485	16%
Unit based compensation expense	2,723	887	207%
Total G&A	$ 34,615	$ 28,372	22%
Cash G&A per boe ($/boe)	$ 1.45	$ 1.26	15%
Transaction costs			
Unit based compensation expense	-	8,974	n/a
Severance and other	-	3,098	n/a
Total Transaction costs	$ -	$ 12,072	n/a

(1) Cash G&A excludes the impact of our unit based compensation expense and for 2006, $12.1 million of one time transaction costs.

For the year ended December 31, 2007, Cash G&A costs increased by $4.4 million (or 16%) compared to the same period in 2006. This increase is mainly related to salaries, which is attributed largely to increased staffing levels from our acquisition of Birchill in August 2006, with a nominal increase associated with our acquisition of Grand. Approximately 75% of our Cash G&A expenses are related to salaries and other employee related costs. Generally, the market for technically qualified staff in the western Canadian petroleum and natural gas industry continues to be tight.

Our unit based compensation plans provide the employee with the option of settling outstanding awards with cash. As a result, our 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. Our Trust Unit market price was $26.15 at January 1, 2007 and by December 31, 2007, our Trust Unit price had decreased to $20.63. This reduction in unit value was offset by an increasing number of outstanding awards becoming vested resulting in our 2007 unit based compensation expense of $2.7 million, including a $7.7 million recovery in the last six months of the year as our Trust Unit price decreased from $32.95 at June 30, 2007. Total unit based compensation expense increased $1.8 million 2007 compared to 2006 due to the increased amount of awards granted in 2007 and a larger recovery recorded in 2006 resulting from the changes in unit price. In 2006, we have recorded transaction costs of $12.1 million which represent one time costs incurred by Harvest as part of the acquisition of Viking in respect of Harvest's outstanding UARs vesting on February 3, 2006 and severance payments made to Harvest employees upon merging with Viking.

Depletion, Depreciation, Amortization and Accretion Expense

	Year Ended December 31		
(000s except per boe)	2007	2006	Change
Depletion, depreciation and amortization	$ 420,184	$ 381,085	10%
Depletion of capitalized asset retirement costs	15,621	16,950	(8%)
Accretion on asset retirement obligation	18,337	15,953	15%
Total depletion, depreciation, amortization and accretion	$ 454,142	$ 413,988	10%
Per boe	$ 20.62	$ 18.99	9%

Our overall depletion, depreciation, amortization and accretion ("DDA&A") expense for the year ended December 31, 2007 was $40.2 million higher than the prior year. The increased expense reflects increased production volumes resulting from our acquisitions coupled with higher finding and development costs that have increased our DDA&A rate.

Capital Expenditures

	Year Ended December 31	
(000s)	2007	2006
Land and undeveloped lease rentals	$ 2,785	$ 9,756
Geological and geophysical	6,058	6,709
Drilling and completion	146,941	214,964
Well equipment, pipelines and facilities	134,423	125,444
Capitalized G&A expenses	8,353	13,141
Furniture, leaseholds and office equipment	2,114	6,867
Development capital expenditures excluding acquisitions and non-cash items	300,674	376,881
Non-cash capital additions (recoveries)	371	(533)
Total development capital expenditures excluding acquisitions	$ 301,045	$ 376,348

In 2007, Harvest invested $300.7 million in development capital expenditures compared to $376.9 million in 2006. Approximately 49% of these expenditures were used to drill 182 gross wells with a success rate of 98%, compared to 252 gross wells with a success rate of 98% in 2006. While we continued to focus our drilling activity on oil opportunities (74% of the total net wells drilled) given the strong oil price environment, our central Alberta gas drilling resulted in some particularly successful wells. At Cheddarville, we drilled an Ostracod seismic anomally and discovered a large hydrocarbon charged porous interval. The well was tied-in late in 2007 and has been producing at approximately 700 boe/d of sweet natural gas and associated liquids. A second well at Markerville targeting the Ellerslie formation was found to have a productive capacity in the order of 500 boe/d.

Over 70% of our net drilling activity throughout the year took place in five major areas of Hay River, southeast Saskatchewan, Lloydminster, Suffield and Red Earth. In Hay River we drilled 31 wells and in 2008, we are focusing on additional water injection required to re-pressurize the reservoir. At Southeast Saskatchewan, a significant new light oil pool was discovered at Kenosee in 2006 and we drilled 13 gross horizontal wells to begin its exploitation, resulting in production in excess of 600 boe/d by the end of the year. Also at Southeast Saskatchewan we drilled a further 20 horizontal wells pursuing light oil accumulations in both the Souris Valley and Tilston formations with a 100% success rate. At Lloydminster and Suffield, we drilled 15 and 11 gross horizontal wells respectively, accessing heavy oil from the Lloydminster and Glauconitic sandstone formations. At Red Earth, we continued to pursue light oil opportunities in the Slave Point, Granite Wash, and Gillwood formations with a total of 12 gross wells drilled. In addition to our drilling activity we shot a large 3D seismic program on prospective lands acquired in 2006, and we added to our oilsands land inventory with the acquisition of 11,400 net acres bringing our total oilsands rights in the Red Earth area to 29,000 net acres. At Markerville, we drilled 22 gross wells pursuing shallow gas opportunities in the Edmonton Sands formation and liquids rich sweet natural gas in the Pekisko formation.

Our enhanced recovery projects continue to progress in 2007 as we plan the implementation phase for 2008. At Bellshill Lake, we have confirmed through an independent engineering study as well as field trials that increased water injection will translate to a reduction in our current decline rate and result in an improved recovery from this large medium gravity oil pool. At Wainwright, we completed the majority of our laboratory testing, and are in the final stages of equipment selection to begin construction on our ASP (Alkaline Surfactant Polymer) flood pilot that could access incremental medium oil if implemented field wide. A pilot will test this technology on an area representing approximately 10% of the pool starting in the 4th quarter of 2008. At Suffield, in 2008 we will launch an enhanced waterflood to increase the volume of water injection with expectation of a reduction in decline rates as well as an increase in recoverable reserves.

The $134.4 million of well equipment, pipelines and facilities expenditures during 2007 include a number of initiatives to improve the efficiency of our Hay River operations including the construction of an all season access road, the installation of natural gas infrastructure to eliminate flaring of produced natural gas, an electrical distribution system as well as well equipment required to bring new wells into production. Various other initiatives have been undertaken to improve overall efficiency in other areas, including an expansion of our oil processing facilities at Red Earth intended to optimize Slave Point light oil production and to provide the necessary infrastructure to accommodate our 2008 drilling program. An emulsion processing facility at Kenosee in southeast Saskatchewan has been constructed, also to accommodate the incremental production from our 2008 drilling program. Replacement of pipelines at Kilarney, Hayter and Bashaw are included as part of Harvest's capital maintenance program to maintain the integrity of our producing infrastructure.

The following summarizes Harvest's participation in gross and net wells drilled during 2007:

	Total Wells		Successful Wells		Abandoned Wells	
Area	**Gross[(1)]**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Hay River	31.0	31.0	31.0	31.0	-	-
Southeast Saskatchewan	33.0	29.0	33.0	29.0	-	-
Markerville	22.0	9.6	22.0	9.6	-	-
Lloydminster	15.0	15.0	15.0	15.0	-	-
Red Earth	12.0	8.5	12.0	8.5	-	-
Suffield	11.0	11.0	9.0	9.0	2.0	2.0
Hayter	7.0	5.3	7.0	5.3	-	-
Other Areas	51.0	22.2	49.0	21.6	2.0	0.6
Total	182.0	131.6	178.0	129.0	4.0	2.6

(1) Excludes 31 additional wells that we have an overriding royalty interest in.

Our 2007 capital program, along with our acquisitions and divestitures, more than replaced our production on a proved plus probable basis with 2007 year end reserves of 220.9 million boe, essentially unchanged from 219.9 million boe at the end of 2006. Including changes in future development costs, our 2007 finding and development cost averaged $28.10 per boe while our finding, development and acquisition costs averaged $22.97 per boe as compared to $26.04 per boe and $24.59 per boe, respectively, in the prior year. Based on the forecast prices and costs of our independent reservoir engineers as at December 31, 2007, the net present value of our future net revenues from proved reserves using a 10% discount rate is $2,865.8 million and $3,675.1 million from proved plus probable reserves. Relative to our 2007 netback price of $29.89/boe, our finding and development costs result in a recycle ratio of 1.06 while our finding, development and acquisition costs result in a recycle ratio of 1.30. Based on our 2007 production of 22.0 million boe, our 2007 year end proved reserves represent a reserve life index of 7 years while our proved plus probable reserves represent a reserve life index of 10 years.

CORPORATE ACQUISITIONS

Effective March 1, 2007, we acquired a private petroleum and natural gas corporation for cash consideration of $30.6 million which added approximately 1,500 bbl/d of western Saskatchewan heavy oil production which is adjacent to our existing operations in the area.

In early August 2007, we completed the acquisition of Grand for aggregate consideration of approximately $139.3 million, acquiring approximately 3,400 boe/d of production with proved plus probable (P+P) reserves of 6 million boe, composed of approximately 67% oil. The Grand assets include a significant presence in southeast Saskatchewan, the Sylvan Lake/Markerville area and eastern Alberta which are adjacent to existing Harvest operations with complementary drilling opportunities. We also acquired has 65,000 acres (46,000 net acres) of undeveloped land with supporting seismic data providing further development opportunities. This acquisition represents an acquisition cost of approximately $41,000 per flowing boe and $23.00 per boe of proved and probable reserves.

Goodwill

Goodwill is recorded when the purchase price of an acquired business exceeds the fair value of the net identifiable assets and liabilities of that acquired business. At December 31, 2006, we had recorded $656.2 million of goodwill related to our upstream segment, and during 2007 we added an additional $20.5 million of goodwill with our purchase of Grand. The goodwill balance is assessed annually for impairment or more frequently if events or changes in circumstances occur that would reasonably be expected to reduce the fair value of the acquired business to a level below its carrying amount. To date, no charge for impairment of this goodwill has been made.

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 $11.0 million in the year ended December 31, 2007. The increase is a result of additional obligations incurred through our corporate acquisitions and drilling activity throughout the year as well as accretion expense, offset by $13.1 million of actual asset retirement expenditures made during the period.

DOWNSTREAM OPERATIONS

Our downstream operations, operating under the North Atlantic trade name, are comprised of a medium gravity sour crude hydrocracking refinery with a 115,000 bbl/d nameplate capacity and a marketing division with 64 gasoline outlets, a home fuel business and a commercial and wholesale petroleum products business, all located in the Province of Newfoundland and Labrador. The sales volume of our marketing division represents approximately 20% of the Newfoundland market.

Since the acquisition of North Atlantic, our quarter-over-quarter operating results of our downstream business have not been very comparable due to planned shutdowns for refinery turnaround activities and the seasonal demand for refined products affecting throughput volumes and the volatility of refining margins, respectively. For the period ending December 31, 2006, our results reflect the impact of an extended turnaround commencing October 1, 2006 with the refinery returning to full operations near the end of November 2006 only to experience additional downtime in December 2006 due to a pipe rupture and a disruption in electric power service. Our operations for the first six months ended June 30, 2007 reflect solid operating performance with throughput of 114,646 bbl/d and robust refining margins generating $232.1 million of cash while the performance for the next six months reflect the impact of two planned shutdowns and substantially weaker refining margins. Accordingly, the analysis of our downstream operations will not be a comparison of one operating period with another but rather a review of the activities for each period and their impact on operating results.

The following summarizes our downstream financial and operational results for 2007 and 2006:

(in $000s except where noted below)	Six Months Ended June 30, 2007	Six Months Ended December 31, 2007	Year Ended December 31, 2007	For the Period October 19, 2006 to December 31, 2006
Revenues	1,684,432	1,414,124	3,098,556	460,359
Purchased feedstock for processing and products purchased for resale	1,340,938	1,326,776	2,667,714	386,014
Gross Margin[1]	343,494	87,348	430,842	74,345
Costs and expenses				
Operating expense	51,945	50,531	102,476	18,378
Purchased energy expense	42,337	49,991	92,328	15,685
Turnaround and catalyst expense	-	34,486	34,486	-
Marketing expense	16,402	18,568	34,970	5,060
General and Administrative	702	1,011	1,713	-
Depreciation and amortization expense	37,574	35,026	72,600	15,482
Earnings (loss) from operations[1]	194,534	(102,265)	92,269	19,740
Cash capital expenditures	14,754	29,357	44,111	21,411
Feedstock volume (bbl/day)[2]	114,646	82,849	98,617	86,890
Yield (000's barrels)				
Gasoline and related products	6,689	4,826	11,515	1,875
Ultra low sulphur diesel and jet fuel	8,233	6,173	14,406	2,624
High sulphur fuel oil	5,695	4,148	9,843	1,752
Total	20,617	15,147	35,764	6,251
Average Refining Margin (US$bbl)[3]	13.69	4.16	10.05	9.32

(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 throughput.

Overview of Downstream Financial Performance

During 2007, our downstream operations generated $165.0 million of cash with $233.1 million generated in the first six months offset by a $68.1 million cash deficiency in the last six months of the year. Earnings from operations of $92.3 million for 2007 comprised of earnings of $194.5 during the first six months and a loss of $102.3 million during the last six months. Our results for the first six months of 2007 reflect solid operating performance with throughput of 114,646 bbl/d and unit operating costs (operating expenses plus the cost of purchased energy) averaging $4.12 per barrel with an average refining margin of US$13.69 per barrel. During the first half of 2007, the sale of our refined products increased from US$71.03 per barrel to US$94.90 for gasoline and from US$74.18 per barrel to US$85.43 for distillate from the first quarter to second quarter, respectively, while the cost of our feedstock (crude oil and vacuum gas oil) increased from US$51.73 per barrel in the first quarter to US$60.46 in the second quarter resulting in robust refining margins during the first six months of 2007.

Our downstream operations during the last six months of 2007 reflect significantly reduced refining margins and two planned shutdowns. During the third quarter of 2007, increases in the cost of our crude oil feedstock were not accompanied with higher gasoline and distillate prices resulting in the significant erosion of our refining margin from US$15.64 per barrel of throughput in the second quarter to US$3.08 in the third quarter. Anticipating that refining margins were more likely to improve in the first half of 2008 than in the fourth quarter of 2007, we accelerated our first shutdown by a few weeks to enable the acceleration of a second shutdown from the spring of 2008, as originally planned, to the fourth quarter of 2007. During the first shutdown in September, we replaced and regenerated the catalyst in the Isomax and Platformer units, respectively, as well as completed routine inspection and maintenance on these units. Subsequent to the re-commissioning of the Isomax and Platformer units in mid-October, we initiated a shutdown of the crude and vacuum units and replaced catalyst in the distillate hydrotreater unit. In addition to advancing the re-certification of vessels in these units, the second shutdown included a significant improvement in our production of vacuum gas oil ("VGO") thereby reducing the amount of VGO required to be purchased in the future to optimize the Isomax throughput. By early

December, the refinery had returned to full operation with throughput averaging 109,611 bbl/d as compared to throughput of 90,440 bbl/d in September, 38,741 bbl/d in October and 35,981 bbl/d in November during the two shutdowns. This acceleration of planned shutdowns better positions us to benefit from anticipated higher margins in early 2008.

Comparatively, our refinery operating results for the period from October 19, 2006 through December 31, 2006 reflect the impact of an extended turnaround that commenced October 1, 2006 with the refinery returning to full operations near the end of November 2006. Our results for 2006 also include additional downtime in December as a result of a pipe rupture in the naphtha hydrotreater and a disruption in electric power service from the local utility which impacted the month's throughput by approximately 3,000 bbl/d.

Refining Benchmark Prices

The North American refining industry has numerous benchmark pricing indicators 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) produces one barrel of RBOB gasoline and one barrel of heating oil delivered to the New York market, where product prices are set in relation to NYMEX gasoline and NYMEX heating oil prices. The following average pricing indicators are provided as reference points with which to index our refinery's performance:

	Six Months Ended June 30, 2007	Six Months Ended December 31, 2007	Year Ended December 31, 2007	October 19, 2006 to December 31, 2006
West Texas Intermediate (US$ per barrel)	61.60	83.03	72.31	60.44
Brent (US$ per barrel)	63.65	81.69	72.67	60.74
RBOB gasoline (US$ per barrel)	82.62	91.10	86.86	66.78
Heating Oil (US$ per barrel)	75.15	96.15	85.65	71.82
High Sulphur Fuel Oil (US$ per barrel)	45.11	62.93	54.02	40.94
2-1-1 Crack Spread (US$ per barrel)	17.29	10.60	13.95	8.86
Canadian / US dollar exchange rate	0.881	0.988	0.935	0.883

During 2007, the seasonality of the North American refining industry was evident as the "2-1-1 Crack Spread" averaged US$17.29 for the first six months of the year and US$10.60 for the last six months. The robust crack spreads during the first half of 2007 also reflected the impact of numerous refinery outages and an extremely tight gasoline supply situation in the Midwest US markets. As compared to the October 19, 2006 through December 31, 2006 period, RBOB gasoline and heating oil prices increased by 24% and 5%, respectively, during the first six months of 2007 while the WTI benchmark price increased by a meager 2% resulting in a 95% increase in the "2-1-1 Crack Spread."

During the six months ended December 31, 2007, RBOB gasoline and heating oil prices increased an additional 10% and 28%, respectively, as compared to the first six months of 2007 while the WTI benchmark price increased by 35% and the "2-1-1 Crack Spread" narrowed by 39% to US$10.60. The squeezing of refining margins during the second half of 2007 reflects a balanced alignment of crude oil prices with refined product pricing as well as an increase in available refining capacity with the resolution of the outages encountered earlier in the year.

The significant strengthening of the Canadian dollar during the last six months of 2007 had a significant financial impact on the results of our downstream operations. The 12% change in the Canadian / US dollar exchange rate between the first six months of 2007 and the last six months of the year compounded the 39% drop in the "2-1-1 Crack Spread" in US dollar terms to a 45% drop if converted to a Canadian dollar equivalent.

As compared to the "2-1-1 Crack Spread" industry indicator, our refinery's production differs in that it also produces approximately 25% to 30% high sulphur fuel oil not represented in the "2-1-1 Crack Spread" indicator. High sulphur fuel oil typically sells US$15.00 to US$20.00 lower than the WTI benchmark price resulting in a negative contribution to our gross margin relative to the "2-1-1 Crack Spread." However, 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 and we purchase approximately 8,000 to 10,000 bbl/d of VGO to optimize the throughput of our Isomax unit at a premium price to the WTI benchmark price which further complicates comparison of our refining margin to the "2-1-1 Crack Spread."

Downstream Gross Margin

The downstream gross margin is comprised of the refining margins as well as the margin on our marketing and other related businesses. A comparison of the gross margin contribution from the refinery and marketing divisions for each of the first six months and last six months of 2007 is presented below:

	Six Months Ended June 30, 2007			Six Months Ended December 31, 2007		
(000s of Cdn dollars)	Refining	Marketing	Total	Refining	Marketing	Total
Sales revenue(1)	1,640,447	206,694	1,684,432	1,342,208	297,681	1,414,124
Cost of feedstock for processing and products for resale(1)	1,317,886	185,761	1,340,938	1,278,021	274,520	1,326,776
Gross margin(2)	322,561	20,933	343,494	64,187	23,161	87,348
Average Refining Margin (US$/bbl)	$ 13.69			$ 4.16		

(1) Downstream operations sales revenue and cost of products for processing and resale are net of inter-segment sales of $162,709,000 and $225,765,000, reflecting the refined products produced by the refinery and sold by Marketing Division for the six months ended June 30, 2007 and December 31, 2007, respectively.

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

During 2007, our gross margin from refining totaled $386.7 million comprised of $322.6 million earned in the first six months of 2007 and $64.2 million earned in last six months of the year with our average refining margin for the year of US$10.05 per barrel of throughput comprised of US$13.69 for the first six months and US$4.16 for the last six months. The review of our refining margins is a combination of two analysis: (1) a comparison of refined product prices relative to the North American crude oil benchmark price, WTI, and (2) an analysis of the cost of our crude oil feedstock as compared to the WTI price.

The Marketing Division of our downstream operations is comprised of both retail and wholesale distribution of gasoline, home heating fuels and related appliances as well as the revenues from marine services including tugboat revenues. The Marketing Division has provided relatively stable gross margins with $9.8 million, $11.1 million, $11.8 million and $11.4 million reported for the first, second, third and fourth quarters, respectively, with the aggregate gross margin for 2007 totaling $44.1 million.

Refined Product Sales Revenue

Our refinery sales revenue is dependent on our yield of refined products and their sales value. 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 as well as refinery performance. Our sales volume closely approximates our production as the Supply and Offtake Agreement requires that substantially all refined products produced be purchased by Vitol Refining S.A. as they leave the refinery with the exception of jet fuel and certain other products marketed by our downstream marketing division primarily in the Province of Newfoundland and Labrador. The Supply and Offtake Agreement includes pricing formulas for refined product purchases whereby the price for refined products delivered from one Wednesday to the next is determined using average benchmark prices for the period commencing on the following Monday through Friday adjusted for actual shipping and product quality differentials. This pricing, which is based on a subsequent period, accelerates the impact of pricing trends on our sales prices and results in our prices being based on a slightly different time period than the monthly average benchmark prices, but generally, our refined product sales prices reflect the cost of crude oil feedstock, a refining crack spread and a quality differential adjustment with each impacted by global supply and demand. For more information on the 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.

A comparison of our refinery product yield, pricing and revenue for each of the first six months and last six months of 2007 is presented below.

	Six Months Ended June 30, 2007			Six Months Ended December 31, 2007		
	Refinery Revenues	Volume	Sales Price[(1)]	Refinery Revenues	Volume	Sales Price[(1)]
	(000s of Cdn $)	(000s of bbls)	(US$ per bbl/ US$ per US gal)	(000s of Cdn $)	(000s of bbls)	(US$ per bbl/ US$ per US gal)
Gasoline products	611,618	6,543	82.35/1.96	476,597	5,183	90.85/2.16
Low & ultra low sulphur diesel & jet fuel	727,656	8,066	79.48/1.89	611,732	6,179	97.81/2.33
High sulphur fuel oil	301,173	5,693	46.61	253,879	4,047	61.98
	1,640,447	20,302		1,342,208	15,409	
Inventory adjustment		315			(262)	
Total production		20,617			15,147	
Yield (as a % of Feedstock)[(2)]		99%			99%	

(1) Average product sales prices are based on the deliveries at our refinery loading facilities.

(2) After adjusting for changes in inventory held for resale.

During 2007, gasoline product comprised 32% of our refinery output while ultra low sulphur diesel and jet fuel (or "distillates") accounted for 40% and our high sulphur fuel oil the residual 28%. Despite the two shutdowns in the last six months of 2007, our product yields during this period were substantially unchanged from the product slate produces during the first six months of the year. Our yield of 32% gasoline products and 40% distillates results in 72% of our production closely mirroring the "2-1-1 Crack Spread" benchmark.

Relative to the benchmark NYMEX RBOB gasoline price, our price for gasoline products closely mirrored the benchmark price with a minor difference of less than a US$0.01 per US gallon in both the first half and second half of 2007 compared to a US$0.11 per US gallon discount in the period from October 19, 2006 through December 31, 2006. During the 2006 period, commodity prices were relatively stable resulting in the discount approximating the expected shipping cost to the New York Harbour. While in 2007, the expected shipping costs were offset by the benefits of a 10 day delay in a rising price environment.

For our ultra low sulphur diesel and jet fuel products, we realized a US$0.05 per US gallon premium over NYMEX heating oil prices during 2007 which is primarily attributed to the 10 day delay in our pricing in a rising price environment and to a lesser extent, our distillate products being generally a mix of higher valued distillate products than the benchmark heating oil product offset by the expected shipping cost to the New York Harbour. In addition, from time-to-time, there will be modest differences in the differential between the physical selling prices for our refined products in the New York Harbour and the NYMEX benchmark prices. The US$0.05 per US gallon average premium for 2007 is comprised of a US$0.10 per US gallon premium for the first six months and a US$0.04 premium during the last six months of the year. During the period from October 19, 2006 through December 31, 2006, we realized a US$0.03 per US gallon premium over the NYMEX heating oil benchmark price.

Our high sulphur fuel oil was sold at an average discount of US$19.03 per barrel relative to the WTI benchmark price in 2007 reflecting the heavier gravity and higher sulphur content of our fuel oil product. During the first six months of 2007, our high sulphur fuel oil sold at an average discount of US$14.99 per barrel as compared to US$21.05 during the last six months of the year.

Overall, relative to the WTI benchmark price, our refined products received a net premium of US$5.78 per barrel during 2007 comprised of US$9.59 in the first six months and US$3.03 in the last six months of the year.

Refinery Feedstock

We purchase crude oil feedstock from Vitol Refining S.A. pursuant to the terms of the Supply and Offtake Agreement which includes financing and operational hedging of crude oil pricing commitments. This enables the price of our feedstock to float with the WTI benchmark price for the period from pricing through to the date it is charged to the refinery. The Supply and Offtake Agreement includes pricing formulas for feedstock purchases similar to the pricing for refined product sales whereby there is a 10 day delay in pricing. This pricing based on a subsequent period 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 feedstocks processed for each of the first six months and last six months of 2007 is presented below.

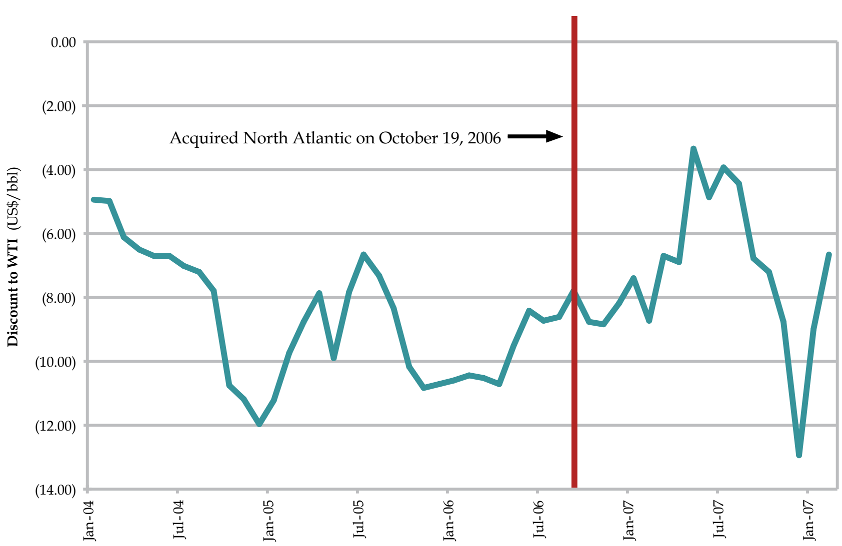
	Six Months Ended June 30, 2007			Six Months Ended December 31, 2007		
	Cost of Feedstock	Volume	Cost per Barrel[(1)]	Cost of Feedstock	Volume	Cost per Barrel[(1)]
	(000's of Cdn $)	(000s of bbls)	(US$/bbl)	(000's of Cdn $)	(000s of bbls)	(US$/bbl)
Basrah Light	859,308	13,795	54.88	749,048	9,435	78.44
Hamaca	172,501	2,879	52.79	190,367	2,301	81.74
Urals	152,007	2,246	59.63	85,442	1,121	75.30
Crude Oil Feedstock	1,183,816	18,920	55.12	1,024,857	12,857	78.76
Vacuum Gas Oil	134,347	1,831	64.64	220,511	2,387	91.27
	1,318,163	20,751	55.96	1,245,368	15,244	80.72
Other costs	(277)			32,653		
	1,317,886			1,278,021		

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

During 2007, our feedstock was comprised of 87,061 bbl/d of medium sour crude oil, (approximately 73% Basrah Light crude from Iraq, 16% Hamaca crude from Venezula and 11% Urals from Russia) and 11,555 bbl/d of VGO as compared to 80,767 bbl/d of crude oil (approximately 91% Basrah Light and 9% Hamaca), and 6,123 bbl/d of VGO in the prior year. We prefer to process Basrah Light feedstock due to its expected lower cost as compared to Hamaca and Urals while yielding a similar refined product slate and quality. The lower daily throughput during the period of October 19, 2006 to December 31, 2006 was the result of a turnaround that extended from the date of our acquisition of North Atlantic through to December 1, 2006. Similarly in 2007, daily throughput averaged 98,616 bbl/d for the year as two back-to-back shutdowns in the fourth quarter reduced the annual throughput which had averaged 111,052 bbl/d through the first nine months of the year.

Changes to our cost of feedstock reflect numerous factors beyond changes in the WTI benchmark price as our refinery competes for international waterborne barrels and the WTI benchmark price generally reflects a land-locked North American price with limited access to the Gulf Coast. The discount of Basrah Light relative to the WTI benchmark price is influenced by the quality of the crude as well as by the economics of other purchasers who may not be North American based nor deal in US dollars. On a monthly basis, the Oil Marketing Company of the Republic of Iraq announces its Official Selling Price ("OSP") which is expressed in US dollars as a discount to the WTI benchmark price for North American deliveries and at the time of announcement, is equivalent to the discount to the Brent benchmark price in Euros for deliveries to Europe. Since our acquisition of North Atlantic in October 2006, the OSP has fluctuated from a low of US$3.30 in May 2007 to a high of US$13.05 in December 2007. The following graph summarizes the OSP for Basrah Light since January 2004 which relative to our US$10.05 average refining margin for 2007 demonstrates the significance of OSP pricing to our downstream performance:

Basrah Official Selling Price (OSP)



Between the loading of the crude oil and its consumption, the OSP discount may change but for our load of Basrah Light, the OSP discount applicable at the time of loading does not change. For example, the OSP discount of US$6.90 in April 2007 was a component of the cost of our feedstock in June and July recognizing the 30 to 45 days to load in Iraq and ship to our refinery. While we are able to "operationally hedge" the WTI component of our feedstock costs between the date we commit to a purchase price and our processing of the crude, we are not able to effectively float the OSP component due to the lack of counterparty interest. As a result, the spike in the OSP discount in December 2007 to US$13.05 will significantly influence our refining margins in February and March 2008.

We also process Hamaca and Urals to complement our Basrah Light as a sufficient volume of Basrah Light is not always available and when other crudes are blended with Basrah Light, the blend may improve processing. During the first six months of 2007, we purchased Urals to ensure the refinery had ample crude oil feedstock and paid a premium as compared to Basrah Light. In July and August of 2007 when we processed the Urals, the WTI benchmark price was US$74.15 and US$72.36, respectively, which has resulted in our cost of Urals processed during the last six months of the year appearing to be lower than our cost of Basrah Light as the average WTI price for the last six months of 2007 of US$83.03 increased our cost of Basrah Light throughout the last half of the year. Typically, the price of Hamaca will closely track Basrah Light however the sharp increase in the OSP discount in late 2007 has resulted in the Hamaca crude becoming relatively more expensive.

In addition to VGO produced by our refinery, we purchase VGO as our Isomax unit's processing capacity exceeds the VGO provided by our refinery from feedstock. In addition, we purchased incremental VGO during the third quarter of 2007 as we stockpiled VGO for the Isomax unit during the shutdown of the crude unit and vacuum tower in the fourth quarter. During 2007, VGO comprised approximately 9% of our total feedstock during the first half of the year and approximately 16% of total feedstock for the last six months of the year. Typically, VGO trades at a US$3.00 to US$5.00 premium to WTI due to the limited amount of processing required to yield a substantial volume of gasoline and diesel. However in late 2007, the VGO market was disrupted due to a refinery outage in the US Gulf Coast and concurrently, a reduction in VGO exports from Europe which resulted in the tightly balanced VGO market temporarily falling out of balance and the VGO premium to WTI temporarily spiked for a few months.

The cost of our crude oil feedstock during 2007 averaged US$64.99 per barrel comprised of US$55.12 in the first six months of the year and US$78.76 during the last six months, while the WTI benchmark price averaged US$72.31 for the year reflecting US$61.60 during the first half of the year and US$83.03 during the last half. During the first half of 2007, our average crude oil feedstock cost was US$6.48 per barrel less than the WTI benchmark price whereas for the last six months, our crude oil feedstock costs were US$4.27 per barrel less than the WTI benchmark price, consistent with narrowing of the Basrah Light OSP discount during the year.

The price of VGO during 2007 averaged US$78.66 per barrel as compared to the WTI benchmark price of US$72.31, a premium of US$6.35 for the year and a premium during the first six months averaging US$3.04 and US$8.24 during the last six months of the year.

The average cost of our feedstock in 2007 was US$66.59 per barrel comprised of a US$5.64 discount to the WTI benchmark price in the first six months and a US$2.31 discount during the last six months of the year. The reduced average discount in the last half of the year reflects an increased consumption of premium priced VGO feedstock combined with the narrowing in the Basrah Light OSP.

Refining Gross Margin

Our refining gross margin for 2007 aggregated to $386.7 million being a combination of crack spreads from gasoline, distillates and high sulphur fuel oil comprised of $322.6 million earned in the first half of the year and $64.2 million in the last half. During the first six months of 2007, our gasoline and distillates crack spreads, relative to the WTI benchmark price, were US$20.75 and US$17.88 per barrel, respectively, aggregating to an average crack spread of US$19.32 per barrel as compared to the "2-1-1 Crack Spread" of US$17.29 for the same period. We would anticipate our average gasoline/distillate crack spread to be higher than the "2-1-1 Crack Spread" benchmark as our distillate sold at a US$0.10 per US gallon premium over the NYMEX heating oil benchmark during the first six months of 2007. During the first six months of 2007, our high sulphur fuel oil sold at a US$14.99 discount to the WTI benchmark price and our feedstock cost was US$5.64 per barrel lower than the WTI benchmark price.

During the last six months of 2007, our gasoline and distillates crack spreads, relative to the WTI benchmark price, were US$7.82 and US$14.78 per barrel, respectively, aggregating to an average crack spread of US$11.30 as compared to the "2-1-1 Crack Spread" of US$10.60 for the same period. As expected, our average gasoline/distillate crack spread was US$0.70 per barrel higher than the "2-1-1 Crack Spread" benchmark as our distillates sold at a premium over the respective NYMEX benchmark prices during this period but primarily due to the 10 day delay in pricing our refined products pursuant to the Supply and Offtake Agreement during a period when NYMEX gasoline and NYMEX heating oil price rose an average of 10% and 28%, respectively. During the last six months of 2007, our high sulphur fuel oil sold at a US$21.05 per barrel discount to the WTI benchmark price (a US$6.06 reduction in price as compared to the first six months of the year) and our feedstock cost was US$2.31 per barrel lower than the WTI benchmark price, an increase of US$3.33 per barrel in our feedstock costs relative to the WTI benchmark price.

During the first six months of 2007, robust refining margins combined with our refinery operating at near name plate capacity to generate $322.6 million of gross margin (US$13.69 per barrel of throughput) as compared to $64.2 million (US$4.16 per barrel of throughput) during the last six months of the year. The $258.4 million reduction in gross margin during the last six months of 2007 as compared to the first six months of the year is comprised of a $172.7 million variance attributed to reduced crack spreads and an $85.7 million unfavourable variance due to reduced throughput. Included in the reduced crack spreads is a $25.7 million unfavourable variance due to the strengthening of the Canadian dollar relative to the US dollar denominated crack spread pricing.

For the period from October 19, 2006 to December 31, 2006, our refining gross margin totaled $67.0 million comprised of $83.7 million from the sale of gasoline and distillate products refined from crude oil feedstock and $9.7 million from gasoline and distillate refined from VGO offset by a $26.4 million negative margin from the production of high sulphur fuel oil.

Operating Expenses

The following summarizes the operating costs from the refinery and marketing division for each of the first six months and last six months of 2007:

	Six Months Ended June 30, 2007			Six Months Ended December 31, 2007		
(000s of Canadian dollars)	Refining	Marketing	Total	Refining	Marketing	Total
Operating expense	43,153	8,792	51,945	40,782	9,749	50,531
Turnaround and catalyst	-	-	-	34,486	-	34,486
Purchased energy	42,337	-	42,337	49,991	-	49,991
	85,490	8,792	94,282	125,259	9,749	135,008

The largest component of our refining operating expense is wages and benefits which totaled $59.6 million during 2007 (2006 - $11.2 million) while the other significant components were maintenance and repairs costs of $14.6 million (2006 - $2.1 million), insurance of $7.0 million (2006 - $1.4 million) and professional services of $6.4 million (2006 - $0.8 million). During the year ended December 31, 2007 refining operating expenses were $2.33 per barrel as compared to $2.34 per barrel in the prior period consistent with our expectations of approximately $2.20 to $2.40 per barrel. The marketing division's operating costs run approximately $4.5 million per quarter aggregating to $18.5 million for 2007.

Turnaround and catalyst expenditures of $22.1 million and $12.4 million, respectively, were incurred during the two planned shutdowns in 2007. Catalyst expenditures include the planned biannual top-bed catalyst change-out on the hydrocracker unit and the replacement of the catalyst on the distillate hydrotreater unit. Turnaround expenditures include planned major maintenance completed simultaneously with the catalyst change-out on both the Isomax, and crude unit. The accelerated shutdown of the crude unit and vacuum tower, originally scheduled for the spring of 2008, contributed an incremental $17.0 million and $7.4 million to turnaround and catalyst expenditures, respectively.

Purchased energy, consisting of low sulphur fuel oil and electric power, is required to provide heat and power to refinery operations, respectively. Our purchased energy costs increased to $2.56 per barrel during 2007 as compared to $2.47 per barrel during 2006 as a result of the increased price of fuel oil.

Marketing Expense

During the year ended December 31, 2007 marketing expense, in conjunction with the Supply and Offtake Agreement, is comprised of $3.4 million of marketing fees (based on US $0.08 per barrel of feedstock) to acquire feedstock ($0.5 million in the period October 19, 2006 to December 31, 2006) and $31.6 million of "Time Value of Money" charges ($4.6 million in the period October 19, 2006 to December 31, 2006).

Capital Expenditures

Capital spending for the year ended December 31, 2007 totaled $44.1 million including $8.0 million for tank maintenance and recertification, $6.3 million to replace heat exchanger bundles, $4.8 million for re-piping of the crude unit and vacuum tower as well as approximately $2.0 million of an estimated $27 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 2007 and 2006:

(000s of Canadian dollars)	Year Ended December 31, 2007 Refining	Marketing	Total	For the Period October 19, 2006 to December 31, 2006 Refining	Marketing	Total
Tangible assets	64,251	2,071	66,322	13,833	410	14,243
Intangible assets	4,781	1,497	6,278	1,049	190	1,239
	69,032	3,568	72,600	14,882	600	15,482

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

On October 19, 2006, we recorded $203.9 million of goodwill with our acquisition of North Atlantic as the purchase price of the acquired business exceeded the fair value of the net identifiable assets and liabilities. 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.

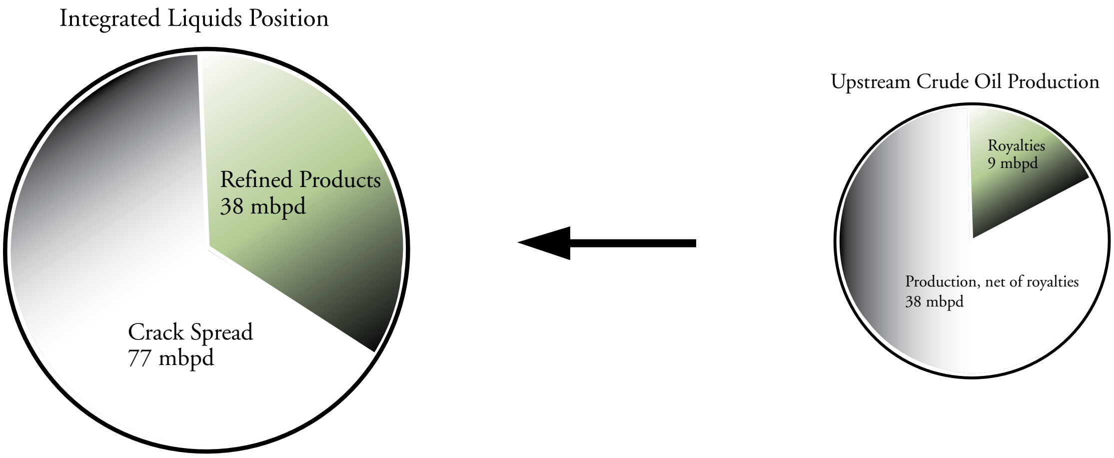
We assess goodwill for impairment annually, or more frequently if events or changes in circumstances warrant. We compare the fair value of our downstream assets and liabilities to their carrying value as well as evaluate the future cash flow projections of our downstream operations in light of the current outlook of the refining industry. Our assessment for the year ended December 31, 2007 concluded that the fair value of our downstream assets exceeds their carrying value and that future cash flows support the carrying value of the goodwill recorded in the accounts. For the year ended December 31, 2006, no charge for impairment was made.

RISK MANAGEMENT, FINANCING AND OTHER

Cash Flow Risk Management

Our cash flow risk management program includes a detailed analysis of the impact of changes in crude oil prices, natural gas prices, the US/Canadian dollar exchange rate and subsequent to acquiring the downstream operation in late 2006, certain refined product prices. While we anticipate our upstream operations will produce approximately 47,000 bbl/d of crude oil and 93,000 mcf/d of natural gas in 2008, our cash flow at risk is determined after deducting the royaltyholders' interest of approximately 9,000 bbl/d and 16,000 mcf/d, respectively. The crude oil produced by our upstream operations in western Canada does not physically flow to our refinery in the Province of Newfoundland and Labrador but for purposes of our cash flow at risk model, our cash flow from producing crude oil is financially integrated with our requirement to purchase crude oil feedstock for our downstream operations. As a result, our 2008 cash flow at risk is comprised of approximately 38,000 bbl/d of refined product prices and 77,000 bbl/d of refined product crack spreads as well as 77,000 mcf/d of western Canadian natural gas prices. Our refined product crack spread is the difference between the cost of our crude oil feedstock and the sales value of our refined products. Using forecast prices for 2008, our cash flow risk model projects 2008 net revenues will be comprised of 66% refined product revenues, 21% refined product crack spreads and 13% western Canadian natural gas prices. Prior to acquiring the downstream operations, our cash flow at risk was limited to western Canadian crude oil prices and natural gas prices as well as the US/Canadian dollar exchange rate.

2008 Integrated Liquids Position:



We enter into pricing contracts with financial counterparties for periods of up to two years whereby we receive a pre determined price as per the contract and the counterparty receives a market price over the term of the contract. Commencing in 2006, we have limited our counterparties to lenders in our syndicated credit facilities as the security provided under the credit agreement extends to our pricing contracts. This eliminates the requirement for margin calls and the pledging of collateral as well as enable the negotiation of a more limited number of events of default, all of which contribute to ensuring the contracts are in place for the contracted term and limit the potential for these contracts to exacerbate credit concerns. Typically, a significant mark-to-market deficiency in pricing contracts will heighten the counterparty's credit concerns: however, when the counterparty also participates in a related credit facility, the same commodity price increase giving rise to the mark-to-market credit concern should also provide offsetting credit comfort with respect to the credit facility as an increase in commodity prices should result in an appreciation in the value of the underlying assets securing the credit facility.

Prior to 2007, our pricing contracts were limited to WTI prices as publicly traded on the New York Merchantile Exchange ("NYMEX") and AECO natural gas prices as reported on the industry trading exchange. Commencing in 2007, the pricing terms of our refined product price contracts were limited to publicly traded benchmark prices on either the NYMEX or a Platts Index. By limiting the price basis to publicly traded benchmark prices, our price contracts should be sufficiently liquid as to enable an efficient unwinding of contracted positions should we encounter a disruption in production. Our execution of a refined product price contract combines the price protection of both the crude oil price (the "WTI" benchmark price) as well as the related refined product crack spread (either RBOB gasoline, heating oil or #6 fuel oil). The use of refined product price contracts consolidates credit requirements and results in combining the volatility of the WTI benchmark price with the volatility of the crack spread for refined product. In 2007, we have used a combination of "price collars" which provides a fixed floor price and price cap as well as a "three way" structure which provides a floor price with a premium over market price on the downside and a price cap. In the future, we may also use "fixed price swap" contracts which provide a "fixed price" and/or "participating swap" contracts which provide a firm floor price with a percentage participation in prices above the floor price. Details of our commodity price contracts outstanding at December 31, 2007 are included in Note 18 of our consolidated financial statements filed on SEDAR at www.sedar.com.

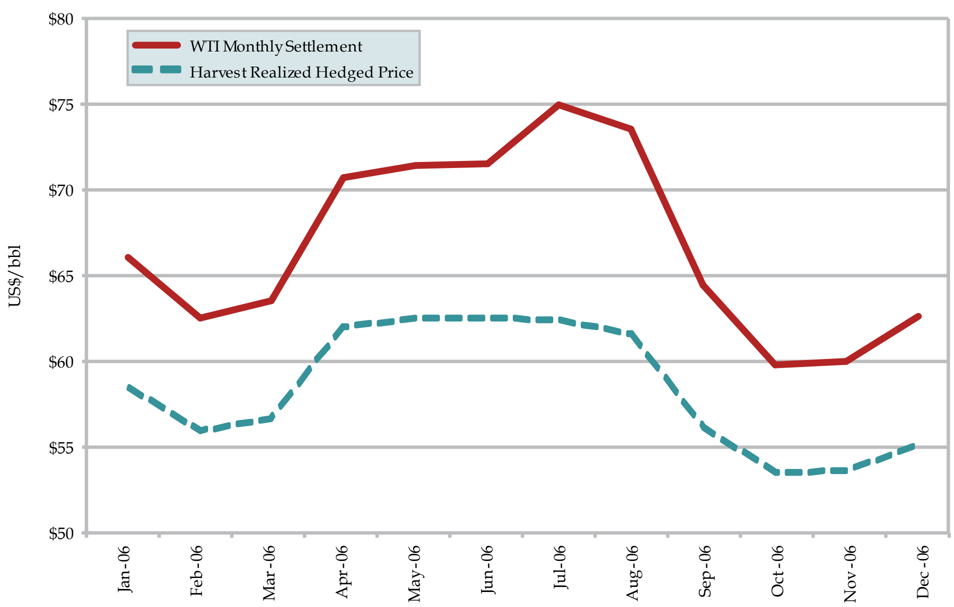
The table below provides a summary of the net gains and losses realized on our price risk management contracts for each of the years ended December 31, 2007 and 2006:

(in 000s)	Crude Oil	Natural Gas	Currency Exchange Rates	Electric Power	Total
Year ended December 31, 2007	$ (41,462)	$ 6,299	$ 5,725	$ 3,147	$ (26,291)
Year ended December 31, 2006	$ (80,832)	$ 4,838	$ 1,801[(1)]	$ 11,574	$ (62,619)

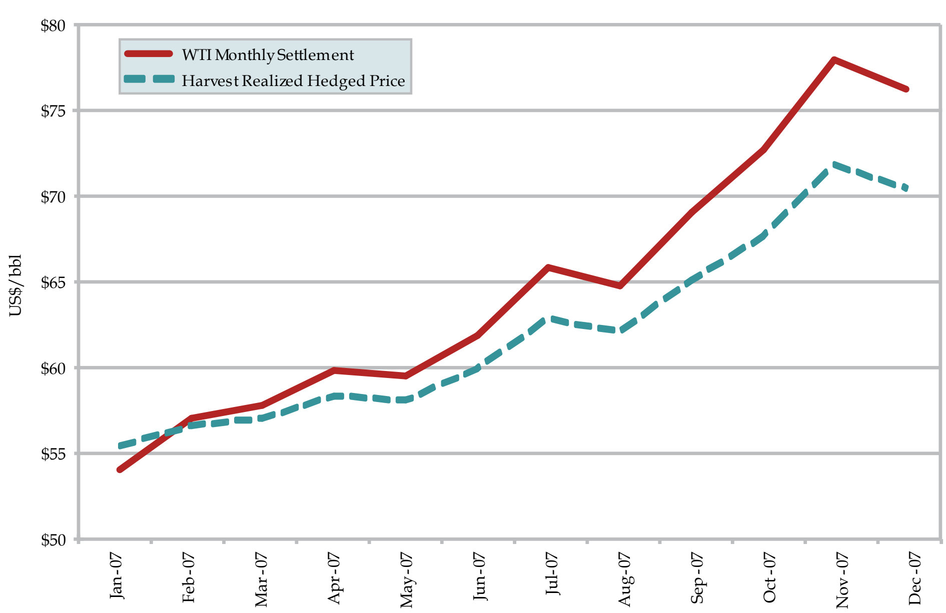
(1) Excludes $17.8 million realized on the series of US dollar forward purchase contracts entered into with respect to the purchase of North Atlantic.

During 2007, the net realized loss on price risk management contracts totaled $26.3 million, a $36.3 million reduction from the prior year substantially all related to our crude oil price contracts. The principal difference in our crude oil price contracts was the increase in the floor price to US$57.18 per bbl plus 70% participation on prices above US$57.18 in 2007 as compared to a floor price of US$43.80 plus 60% participation on prices above US$43.80 in 2006. With the average WTI price increasing US$6.07 from US$66.24 in 2006 and US$72.31 in 2007, the US$13.38 increase in our contracted floor price as well as the 10% higher participation level on prices in excess of the contracted floor price combined to reduce the losses realized on our crude oil contracts by $39.4 million in 2007 as compared to the prior year. The volume hedged averaged 23,750 bbl/d in 2006 and 27,500 bbl/d in 2007 which represented approximately 66% and 76% of our net production, respectively. The following charts present the average monthly WTI prices and the contracted crude oil price settlement in our oil pricing contracts for each of 2006 and 2007:

Year ended December 31, 2006



Year ended December 31, 2007



Typically, we enter into natural gas price contracts that provide a firm floor price in exchange for a price cap for the contract year (April through March of the following year) in anticipation of soft prices during the summer months. In 2007, we received $6.3 million primarily from our contracting for natural gas price protection on 30,000 GJ/d at a floor price equal to the greater of $7.00 per GJ or market price plus $2.00 for the period from April 2007 through March 2008 of which $5.5 million was received when we unwound the position in July 2007. In 2006, we had "price collar" contracts in place that provided floor prices on 25,000 GJ/d at $5.00 per GJ and with respect to a further 25,000 GJ/d, $7.00 per GJ. Substantially all of the $4.8 million gain in 2006 related to the natural gas price contract with the $7.00 floor price.

In 2007, the $5.7 million gain realized on our currency exchange rate contracts reflect the significant strengthening of the Canadian dollar relative to the US dollar from Cdn$1.1654 per US dollar at January 1, 2007 to Cdn$0.9913 on December 31, 2007. During 2007, we had US$8.7 million per month contracted at an exchange rate of Cdn$1.1228 per US dollar for the entire year which generated substantially all of the $5.7 million benefit while a further US$10 million contracted with a collar of Cdn$1.0000 and Cdn$1.0550 per US dollar added limited benefit. In addition, see Currency Exchange discussion in this MD&A.

We also enter into fixed price electric power contracts to provide protection from rising power prices in Alberta. In 2007, Alberta's electric power prices averaged $66.84 per megawatt hour as compared to $80.48 in 2006. Relative to our $11.6 million gain realized in 2006, the $3.1 million benefit received in the current year from our fixed price electric power contracts reflects generally lower prices as well as an increase in the contracted fixed price from $51.48 per MWh in 2006 to $56.69 in 2007. Typically, our fixed price electric power contracts represent approximately 50% of our anticipated electrical power consumption and for 2008, we have fixed price contracts for 35 MWh for the period from January 2008 through December 2008 at a price of $56.69.

During 2007, we entered into the following refined product price contracts:

For the period from January 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, and
- 2,000 bbl/d of Platts heavy fuel oil crack spread.

For the period from July 2008 through December 2008

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

For the period from January 2009 through June 2009

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

In addition, we have contracted for 10,000 bbl/d of WTI prices for the first half of 2008 with an average floor price of US$60.00 and participation in 73% of the upside above US$60.00 which was placed prior to our acquisition of the downstream business. In respect of our refined product price and WTI price exposures, these contracts represent approximately 79% of our exposure for the first half of 2008, 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, our contracts represent approximately 10% of our crack spread exposure for 2008.

The table below provides a summary of net unrealized gains and losses recorded for our price risk management contracts for each of the years ended December 31, 2007 and 2006 which reflects the change in period end unrealized gains and losses:

(in 000s)	Crude Oil	Refined Products	Natural Gas	Currency Exchange Rates	Electric Power	Total
Year ended December 31, 2007	$ (14,601)	$ (138,801)	$ (596)	$ 13,904	$ (7,687)	$ (147,781)
Year ended December 31, 2006	$ 53,820	-	$ (662)	$ (5,309)	$ 3,932	$ 51,781

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 natural gas, currency exchange rate and electrical power price contracts aggregated to $14.0 million. Our 2008 refined product contracts were placed in mid-2007 when the WTI benchmark price was approximately US$71.00 and the NYMEX price of heating oil and Platts Index for fuel oil were approximately US$2.00 per gallon and US$55.00 per barrel, respectively, as compared to the 2007 year end closing prices of US$95.98 for WTI, US$2.64 per gallon for NYMEX heating oil and US$75.15 per barrel for Platts fuel oil. While our contracted prices for 2008 are higher than prices received in 2007, the 2007 year end prices for WTI and refined products were higher still which has resulted in the significant mark-to-market deficiency. At the end of 2007, we had a modest 276 GJ/d of natural gas price contracts in place through December 2008.

While modest compared to our refined product position, we have contracted a fixed exchange rate on US$8.3 million per month for the period from January 2008 through June 2008 averaging Cdn$1.11 per US$1.00 and collared an exchange rate of Cdn$1.00 to Cdn$1.055 on a further US$10 million per month covering January 2008 through December 2008. These contracts had a mark-to-market value of $8.6 million at the end of 2007. For 2008, approximately 52% of our Alberta power consumption is price fixed at $56.69 and mark-to-market value of this contract was $5.6 million at the end of 2007.

Interest Expense

	Year Ended December 31		
(000s)	2007	2006	Change
Interest on short term debt			
Bank loan	$ 1,275	$ 1,489	(14%)
Convertible debentures	2,498	-	100%
Amortization of deferred finance charges – short term debt	1,811	3,375	(46%)
	5,584	4,864	15%
Interest on long-term debt			
Bank loan	70,204	30,967	127%
Convertible debentures	56,740	20,229	180%
$7^{7/8}$% Senior Notes	22,561	22,624	-%
Amortization of deferred finance charges – long term debt	2,696	5,073	(47%)
	152,201	78,893	93%
Total interest expense	$ 157,785	$ 83,757	88%

Interest expense, which includes the amortization of related financing costs, was $74.0 million higher in 2007 than the prior year. Of this increase, $39.0 million is attributed to increased short and long term bank loan interest resulting from the significant increase in bank debt to finance the acquisitions of North Atlantic in October 2006 and to a lesser extent, Grand in August 2007. An additional $39.0 million of interest expense was incurred in 2007 compared to 2006 due to the increased principal amount of Convertible Debentures outstanding, offset by a $3.9 million reduction in the amortization charge of deferred financing costs.

At December 31, 2007, we had drawn approximately $1,279.5 million of bank borrowings as compared to $1,595.7 million at December 31, 2006. During the First Quarter of 2007, our bank borrowings were reduced with the net proceeds of $357.4 million from our issuance of 6,146,750 Trust Units and $230 million principal amount of 7.25% Debentures due 2014. During the Second Quarter of 2007, our bank borrowings were reduced by a combination of net proceeds of $218.5 million from our issuance of 7,302,500 Trust Units and surplus cash from operating activities after capital spending and distribution requirements. In the Third Quarter of 2007, we increased our bank borrowings by $157.0 million, of which $139.3 million is attributed to the acquisition of Grand during the quarter. Our bank borrowings were further increased by $74.4 million in the Fourth Quarter, as our cash distributions and capital spending exceeded our cash flow from operating activities by $61.1 million. Currently, the interest on our Three Year Extendible Revolving Credit Facility is at a floating rate based on 70 basis points over bankers' acceptances for Canadian dollar borrowings and 70 basis points over the London Inter Bank Offer Rate for US dollar borrowings. During the year ended December 31, 2007, our interest charges on bank loans aggregated to $71.6 million, reflecting effective interest rates of 5.28% and 6.08% for the Canadian and US amounts drawn, respectively. Further details on our credit facilities are included under "Liquidity and Capital Resources".

The interest on our Convertible Debentures totaled $59.2 million during the year ended December 31, 2007, 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 year ended December 31, 2007, there were $161.1 million of principal amount of convertible debentures converted to 5,922,708 Trust Units.

The interest on our $7^{7/8}$% Senior Notes totaled $22.6 million for the year ended December 31, 2007. Like 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 US dollar, our cash interest expense has been lowered as interest on these notes is paid in US dollars, however our non-cash interest expense has increased due to the adoption of the revised standard on financial instruments. See Note 3 of the consolidated financial statements for the year ended December 31, 2007 filed on SEDAR at www.sedar.com.

Included in short and long term interest expense is the amortization of the discount on the $7^{7/8}$% 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 and bridge facilities, all totaling $4.5 million for the year ended December 31, 2007.

Currency Exchange

Currency exchange gains and losses are attributed to the changes in the value of the Canadian dollar relative to the US dollar on our US dollar denominated LIBOR bank loans, $7^{7/8}$% Senior Notes as well as any other US dollar cash balances. Since December 31, 2006, the Canadian dollar has strengthened significantly compared to the U.S dollar. As a result we have earned an unrealized foreign exchange gain on our $7^{7/8}$% Senior Notes of $42.3 million during the year ended December 31, 2007. In the Third Quarter of 2007, we repaid our US dollar denominated LIBOR bank loans that were incurred in connection with our purchase of North Atlantic, realizing a foreign exchange gain of $43.5 million in the quarter and $47.1 million year-to-date in respect of this loan. In addition, during the year ended December 31, 2007 we also incurred unrealized foreign exchange losses and realized foreign exchange gains on North Atlantic transactions of $10.6 million and $4.7 million, respectively.

Our downstream operations are considered a self-sustaining operation with a US dollar functional currency. The foreign exchange gains and losses incurred by our downstream operations relate to Canadian dollar transactions converted to US dollars as their functional currency is US dollars. The cumulative translation adjustment recognized in other comprehensive income represents the translation of our downstream operation's US dollar functional currency financial statements to Canadian dollars using the current rate method. In 2007, the strengthening of the Canadian dollar relative to the US dollar resulted in a $243.6 million cumulative translation loss as the stronger Canadian dollar results in a decrease in the relative value of our downstream net assets.

Future Income Tax

During 2007, there were two significant Canadian income tax changes that impacted our accounting for future income taxes. On June 22, 2007, Bill C-52 became law and on December 14, 2007, Bill C-28 became law. Bill C-52 contains provisions to implement the proposals to tax publicly traded income trusts and as a result, we recorded a $255.0 million future income tax charge during the second quarter of 2007 to apply an expected tax rate to the temporary differences between the book value and the tax basis of our assets held by our mutual fund trust and other "flow through" vehicles as forecasted on the effective date of the tax change, January 1, 2011. Concurrent with the recording of this non-cash future income tax expense, we also recorded an offsetting future income tax asset of $77.3 million to reflect the application of the current and expected future tax rates to the temporary differences between the book value and the tax basis of assets held by our corporate entities on June 30, 2007 which had not been previously reflected due to the lack of assurance that the benefit of this tax asset would be realized.

Bill C-28 contains the provisions to implement reductions in the federal corporate income tax rates. The federal corporate income tax rate will be reduced from 20.5% to 19.5% in 2008 with further reductions scheduled resulting in a 15% tax rate as of January 1, 2012. These rate reductions also apply to the expected tax rate applicable to our mutual fund trust and other "flow through" vehicles. Accordingly, in the fourth quarter of 2007, we adjusted our future income tax provision to reflect these reduced tax rates.

As at the end of 2007, we have 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. The net provision for our mutual fund trust and other "flow through" entities will be reviewed for changes in our forecasted temporary differences and 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.

In our current structure, payments in respect of net profits interests and interest on inter-entity debt are made between our operating entities and our mutual fund trust which ultimately transfers both taxable income and the income tax liability to the holders of our Trust Units. As a result, no cash income taxes have been paid by Harvest. However, effective January 1, 2011, Harvest will become subject to the provisions of Bill C-52 should Harvest remain in its current structure. At the end of 2007, we estimate our tax pools to be as follows:

Tax Classification (in millions)	Trust	Upstream Operations	Downstream Operations	Total
Canadian Oil & Gas Property Expenditures	$ 550	$ 310	$ -	$ 860
Canadian Development Expenditures	-	230	-	230
Unclaimed Capital Costs	-	500	420	920
Non-capital losses and other	40	570	150	760
Total	$ 590	$ 1,610	$ 570	$ 2,770

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:

		Maturity			
Annual Contractual Obligations (000s)	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Long-term debt(2)	1,527,326	-	1,279,501	247,825	-
Interest on long-term debt(4)	233,881	88,216	130,319	15,346	-
Interest on convertible debentures(3)	252,454	46,832	92,916	86,063	26,643
Operating and premise leases	27,362	7,572	12,397	7,145	248
Purchase commitments(5)	17,224	15,924	1,300	-	-
Asset retirement obligations(6)	1,002,893	24,617	17,350	27,437	933,489
Transportation(7)	6,110	2,249	2,953	861	47
Pension contributions	31,360	1,143	3,631	5,301	21,285
Feedstock commitments	843,583	843,583	-	-	-
Total	3,942,193	1,030,136	1,540,367	389,978	981,712

(1) As at December 31, 2007, we had entered into physical and financial contracts for production with average deliveries of approximately 8,000 bbl/d for 2008. We have also entered into financial contracts for our downstream production of refined products with average deliveries of approximately 34,000 bbl/d in 2008 and 10,000 bbl/d in 2009. We have also entered into financial contracts to minimize our exposure to fluctuating electricity prices. Please see Note 18 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 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 in place on 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.

Off Balance Sheet Arrangements

As at December 31, 2007, we have no off balance sheet arrangements in place.

Related Party Transactions

During the year ended December 31, 2007, Vitol Refining S.A. purchased US $388.8 million of Basrah Light 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 December 31, 2007, no amount related to these purchases is included in Harvest's accounts payable and accrued liabilities, and $68.0 million is included in the total feedstock commitments disclosed at the end of December 2007. Subsequent to December 31, 2007, no further commitments have been incurred relating to crude oil purchases by Vitol Refining S.A from this private company.

CHANGE IN ACCOUNTING POLICIES

Effective January 1, 2007, we have retrospectively without restatement adopted the new accounting standards of the Canadian Institute of Chartered Accountants respecting, "Financial Instruments – Recognition and Measurement"; "Comprehensive Income"; and "Financial Instruments – Disclosure and Presentation". The impact of adopting these new standards is reflected in our financial results for the year ended December 31, 2007 while the prior year comparative financial statements have not been restated. While the new standards change how we account for financial instruments, there were no material impacts on our results for the year ended December 31, 2007, with the most significant difference being that certain deferred charges previously presented as an asset are now netted against the respective debt and amortized to income using an effective interest rate. For a description of the new accounting standards and the impact on our financial statements of adopting such standards see Note 3 to the consolidated financial statements for the year ended December 31, 2007.

LIQUIDITY AND CAPITAL RESOURCES

During 2007, cash flow from operating activities was $641.3 million, including a reduction of $17.4 million in respect of non-cash working capital with the significant components of this being a $39.9 million reduction in accounts payable and a $34.5 million increase in downstream inventories offset by a $51.5 million reduction in accounts receivable. Cash flow from operating activities before changes in non-cash working capital totaled $658.7 million. We declared distributions of $610.3 million, required $344.8 million for capital expenditures and raised $178.5 million with our distribution re-investment plans. The net cash requirement of $135.3 million was funded with bank borrowings.

During the year, our net bank borrowings decreased by $316.2 million primarily from the $576.0 million of net proceeds from the issuance of $230.0 million of principal amount of Convertible Debentures and 13,499,250 Trust Units offset by the $135.3 million required for our capital expenditure program and $138.2 million for our property acquisition and disposition activity. Our upstream acquisition and disposition activity required funding as the $60.6 million of net proceeds we realized from the disposition of 885,000 barrels of proved reserves (at an average of $68.47 per boe) were more than offset by our investment of $198.7 million in an additional 7,283,000 barrels of proved reserves, including the acquisition of Grand Petroleum Inc., at an average cost of $27.29 per boe.

During the fourth quarter of 2007, cash flow from operating activities was $88.0 million, including $16.6 million of a reduction in non-cash working capital with the more significant components being a $26.9 million reduction in accounts payable offset by a $29.9 million reduction in accounts receivable and a $6.1 million reduction in downstream inventories. Cash flow from operating activities before changes in non-cash working capital totaled $71.4 million. We declared distributions of $144.7 million, required $47.5 million for capital expenditures and raised $43.1 million with our distribution re-investment plans. The net cash requirement of $61.1 million was funded by an increase in bank borrowings.

For the year ended December 31, 2006, cash flow from operating activities was $507.9 million, including a $28.2 million reduction in respect of non-cash working capital with the more significant components being a $55.5 million increase in accounts receivable offset by a $17.9 million increase in accounts payable and a $6.0 million increase in distributions payable. Cash flow from operating activities before changes in non-cash working capital totaled $536.0 million. We declared distributions of $468.8 million, required $398.3 million for capital expenditures and received $167.5 million from participation in our distribution re-investment plans. The net cash requirement of $191.7 million was funded with bank borrowings.

At the end of 2007, we had $320.5 million of unutilized borrowing capacity from our $1.6 billion Three Year Extendible Revolving Credit Facility as compared to $94.0 million of unutilized capacity under a $1.4 billion credit facility at the beginning of the year. In April 2007, we increased the facility from $1.4 billion to $1.6 billion and with the exception of $65 million of lending commitments which retained a March 2009 maturity date, extended the maturity date of our Three Year Extendible Revolving Credit Facility to April 2010. In October 2007, we re-assigned the $65 million of non-extending lender commitments to other lenders in our banking syndicate and concurrently extended the maturity date on this incremental commitment to April 2010. 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. As the disruptions in the capital markets continue, we are comfortable with the April 2010 maturity date for our credit facilities and may elect to defer extending the maturity date until capital market conditions improve.

Our cash flow risk management program includes our entering into numerous pricing contracts. We have limited our counterparties to the lenders in our syndicated credit facilities as the security provided in our credit agreement extends to our pricing contracts and this eliminates the requirement for margin calls and 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 for each of the years ended December 31, 2007 and 2006:

	As At December 31	
(in millions)	2007	2006
DEBT		
Credit Facilities		
- Three Year Extendible Revolving Credit Facility	$ 1,279.5	$ 1,306.0
- Senior Secured Bridge Facility	-	289.7
Total Bank Debt	1,279.5	1,595.7
$7^{7/8}$ % Senior Notes Due 2011 (US$250 million)[(1)]	247.8	291.4
Convertible Debentures, at principal amount		
10.5% Debentures Due 2008	24.3	26.6
9% Debentures Due 2009	1.0	1.2
8% Debentures Due 2009	1.7	2.2
6.5% Debentures Due 2010	37.1	37.9
6.4% Debentures Due 2012	174.6	174.8
7.25% Debentures Due 2013	379.3	379.5
7.25% Debentures Due 2014	73.2	-
Total Convertible Debentures	691.2	622.2
Total Debt	2,218.5	2,509.3
TRUST UNITS		
148,291,170 issued at December 31, 2007	3,736.1	
122,096,172 issued at December 31, 2006		3,046.9
TOTAL OF DEBT AND TRUST UNITS	$ 5,954.6	$ 5,556.2

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

During 2007, the significant changes to our capital structure were:

- Issuance of $230 million principal amount of 7.25% Debentures Due 2014 and 6,146,750 Trust Units in February with net proceeds of $357.4 million used to repay the Senior Secured Bridge Facility and reduced borrowings on our Three Year Extendible Revolving Credit Facility by $67.7 million,
- Extension of our Three Year Extendible Revolving Credit Facility's maturity date to April 2010 and a $200 million increase in the aggregate commitment to $1.6 billion,
- Issuance of a further 7,302,500 Trust Units in June to reduce borrowings on our Three Year Extendible Revolving Credit Facility by $218.5 million,
- Issuance of 5,922,708 Trust Units on the conversion of $161.1 million of principal amount of Convertible Debentures, and
- Issuance of 6,809,987 Trust Units pursuant to Harvest's Premium Distribution™, Distribution Reinvestment and Optional Trust Unit Purchase Plan (the "DRIP Plans") raising $178.5 million.

Concurrent with the closing of the Plan of Arrangement with Viking on February 3, 2006, we entered into a covenant-based Three Year Extendible Revolving Credit Agreement and have amended this agreement to extend the maturity to April 2010 and upsized the facility from an initial $750 million commitment to $1.6 billion. This facility is secured by a $2.5 billion first floating charge over all of our assets and generally contains typical covenants with the most restrictive being an aggregate limitation of $25 million on financial assistance and/or capital contributions to parties other than those included in the first floating charge debenture, a limitation to carrying on business in countries that are not members of the Organization of Economic Co-operation and Development and limitations on payments of distributions in certain circumstances such as an event of default. The credit facility contains floating interest rates that are expected to range between 65 and 115 basis points over bankers' acceptance rates (currently 70 bps) depending on the ratio of our secured senior debt (excluding $7^{7/8}$% 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 December 31, 2007, our Bank Debt to annualized EBITDA was 1.5 to 1.0, Total Debt (excluding Convertible Debentures) to annualized EBITDA was 1.8 to 1.0, while the Bank Debt to Total Capitalization was 29% and Total Debt to Total Capitalization was 34%. For a complete description of our covenant-based credit agreement, see Note 11 to our audited consolidated financial statements for the year ended December 31, 2007 filed on SEDAR at www.sedar.com.

In October 2004, Harvest Operations Corp., a wholly-owned subsidiary of Harvest, issued US$250 million of principal amount $7^{7/8}$% Senior Notes for net proceeds of $312.0 million Canadian dollars. These $7^{7/8}$% Senior Notes are unsecured, require semi-annual payments of interest and provide for the following permitted redemptions:

Beginning on October 15, 2007 at 103.938% of the principal amount[1];
After October 15, 2007 at 103.938% of the principal amount;
After October 15, 2009 at 101.969% of the principal amount; and,
After October 15, 2010 at 100% of the principal amount.

(1) Only permitted if necessary to prevent the Trust from being disqualified as a mutual fund trust for purposes of the Income Tax Act (Canada). Limited to 30% of the notes issued or less; otherwise 100% of the notes issued.

These $7^{7/8}$% Senior Notes contain certain covenants restricting, among other things, the sale of assets and the incurrence of additional indebtedness if such issuance would result in an interest coverage ratio, as defined, of less than 2.5 to 1.0 and 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% is approximately $1.86 billion.

At the end of 2007, we had $691.2 million of principal amount of Convertible Debentures issued in seven series with $64.0 million of principal amount due prior to 2012 and $627.2 million of principal amount due beyond 2011. Prior to maturity, these Convertible Debentures are convertible into Trust Units of Harvest, at the option of the holder, at the conversion price per Trust Unit specified for each series and may be redeemed at our option at a price equal to $1,050 per debenture during the first redemption period and $1,025 per debenture during a second redemption period. At maturity or upon redemption, the principal repayment obligation may be settled in the form of Trust Units at a price equal to 95% of the weighted average trading price for the preceding 20 consecutive trading days five days prior to the settlement. On January 31, 2008, we settled the maturity of $24.3 million principal amount of the 10.5% Convertible Debentures with the issuance of 1,116,593 Trust Units rather than settling the obligation with cash. 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. At December 31, 2007, we would be limited to an additional issuance of Convertible Debentures of approximately $325 million.

Concurrent with the closing of the North Atlantic acquisition, North Atlantic entered into a Supply and Offtake Agreement with Vitol Refining S.A. ("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 crude oil feedstock to the refinery as well as the right and obligation to purchase all refined products produced by the refinery. 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 2007, we estimate that Vitol held inventories of VGO, crude oil feedstock (both delivered and in-transit) and refined products for resale valued at approximately $818.1 million which would have otherwise been assets of Harvest.

During 2007, we issued a total of 26,194,998 Trust Units with 13,449,250 of those Trust Units issued in two public financings to raise $373.9 million at a weighted average price of $27.80 per Trust Unit, 5,922,708 Trust Units issued upon the conversion of Convertible Debentures, 6,809,987 Trust Units issued via a 29% level of participation in our distribution reinvestment programs and 13,053 Trust Units issued on the exercise of employee unit incentive plans. These issuances added $689.2 million to our equity bolstering our balance sheet ratios. In 2007, we have utilized our public financings to reduce bank borrowing incurred to fund the acquisition of North Atlantic in 2006 and Grand Petroleum in 2007 with the proceeds from the distribution reinvestment programs considered to be the balancing factor between our cash flow from operating activities, capital expenditure program and distributions.

During 2007, the trading value of our Trust Units ranged from a high of $34.97 in July to $19.75 in December. This volatility in our trading value is generally attributed to the seasonal fluctuation in refining margins and uncertainty created with the royalty review by the Province of Alberta offset by very strong crude oil prices. At the end of 2007 approximately 66% of our Unitholders were non-residents of Canada which is an increase from 54% at the end of 2006. We have experienced a reduction in the participation in our distribution reinvestment programs as the non-resident ownership of our Trust Units increases. We understand this is due to our Premium Distribution Re-investment Plan being very popular with our Unitholders resident in Canada. With the ownership of our Trust Units shifting to non-residents of Canada who are not eligible for the Premium Distribution Re-investment Plan, participation in our distribution reinvestment plans has diminished.

The following summarizes the trading value of our Trust Units during 2007 through to February 2008:

	Trading Price		
Month	**High**	**Low**	**Volume**
TSX Trading			
January 2007	$ 26.22	$ 23.20	12,822,502
February 2007	$ 27.49	$ 24.81	10,036,635
March 2007	$ 29.22	$ 25.90	11,430,584
April 2007	$ 31.10	$ 27.74	10,244,956
May 2007	$ 33.16	$ 30.25	13,984,905
June 2007	$ 34.48	$ 31.38	19,605,824
July 2007	$ 34.97	$ 29.50	19,478,671
August 2007	$ 31.52	$ 26.10	17,373,101
September 2007	$ 29.40	$ 25.18	15,463,720
October 2007	$ 28.39	$ 25.92	13,236,903
November 2007	$ 26.99	$ 20.42	12,281,080
December 2007	$ 22.22	$ 19.75	7,729,610
January 2008	$ 23.56	$ 20.48	10,474,631
February 2008	$ 26.00	$ 22.49	8,552,342
NYSE Trading (in US$)			
January 2007	$ 22.20	$ 19.70	16,693,600
February 2007	$ 23.55	$ 21.18	10,059,454
March 2007	$ 25.22	$ 21.97	12,316,050
April 2007	$ 28.07	$ 24.00	10,038,123
May 2007	$ 30.70	$ 27.05	14,253,739
June 2007	$ 32.46	$ 29.47	13,474,838
July 2007	$ 33.97	$ 27.15	17,505,628
August 2007	$ 29.74	$ 24.29	23,146,747
September 2007	$ 27.94	$ 25.15	19,625,622
October 2007	$ 29.11	$ 25.94	20,887,843
November 2007	$ 28.96	$ 20.50	27,496,352
December 2007	$ 22.20	$ 19.80	18,794,208
January 2008	$ 23.24	$ 20.00	18,167,009
February 2008	$ 25.70	$ 22.51	15,108,961

We are authorized to issue an unlimited number of Trust Units and as of March 7, 2008, we had 150,580,097 Trust Units outstanding, 5,394,230 of Unit Appreciation Rights outstanding (of which 3,691,600 were vested) and 498,772 awards issued under the Unit Awards Incentive Plan (of which 278,463 were vested). In addition, we have six series of Convertible Debentures outstanding that are convertible into 19,633,017 Trust Units. Additionally one issue, $24,258,000 principal amount of 10.5% debentures, matured in January 2008 which we settled with the issuance of 1,116,593 Trust Units.

Effective June 22, 2007 with the enacting of Bill C-52, our future issuance of Trust Units and Convertible Debentures will be limited by the "normal growth" guidelines contained therein. At the end of 2007, we estimate that we could issue approximately $550 million of Trust Units and Convertible Debentures in each of 2008, 2009 and 2010 with any unused "normal growth" available for use prior to 2011. In addition, we are entitled to issue approximately $590 million to replace debt held by the mutual fund trust on October 31, 2006. Trust Units issued pursuant to participation in our distribution reinvestment programs will be included as issuances in our "normal growth" limitation.

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. At the end of 2007, our weighted average cost of capital, including our current level of distributions and the recent trading value of our Trust Units, is approximately 11.25%.

Distributions to Unitholders and Taxability

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 successful exploitation of our 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 high sulphur fuel oil currently produced and/or expanding our refining capacity which is expected to provide favourable incremental economics from our existing infrastructure. 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 our cash generated 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 from 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 recorded in our income statement. In 2007, we recorded a $65.8 million charge in respect of future income tax expense and recognized a further $147.8 million in unrealized loss on price risk management contracts. In addition, we recorded a provision of $526.7 million in respect of depreciation and depletion which was based primarily on our historic costs of property, plant and equipment and does not accurately represent the fair value or replacement cost of the assets, nor does it affect 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 our net income may fluctuate significantly from our cash flow from operating activities as well as distributions to unitholders. During 2007, our distributions to unitholders exceeded our net loss of $25.7 million by $636.0 million as compared to the prior year where our distributions to unitholders exceeded our net income of $136.0 million by $332.7 million. In instances where our distributions exceed our net earnings, a portion of the distribution may represent a return of capital rather than a distribution of earnings. During 2007, our distributions declared totaled $610.3 million, representing 95% 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. We maintained a monthly distribution of $0.38 per Trust Unit from February 2006 through October 2007 and commencing in November 2007, have declared a monthly distribution of $0.30 per Trust Unit through April 2008, a level of distributions that reflects our expectations of future commodity prices and currency exchange rates as well as our future production and throughput volumes and operating costs.

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 past two years:

	Year Ended December 31		
(000s except per Trust Unit amounts)	2007	2006	Change
Distributions declared	$ 610,280	$ 468,787	30%
Per Trust Unit	$ 4.40	$ 4.53	(3%)
Distribution reinvestment proceeds	$ 178,489	$ 167,543	7%
Distributions as a percentage of cash from operating activities	95%	92%	3%

Throughout the first ten months of 2007, we declared monthly distributions of $0.38 per Trust Unit to Unitholders, and declared a monthly distribution of $0.30 per Trust Unit for the months of November and December 2007. The total distributions declared in 2007 was $610.3 million, which is 95% of our annual cash from operating activities. The $141.5 million increase in distributions declared during 2007 relative to 2006 is primarily due to the increase of approximately 26.2 million Trust Units outstanding following the acquisitions of Birchill and North Atlantic in 2006 along with issuances under our distribution re-investment plans and conversions of Convertible Debentures, offset by a reduction in the per Unit amount of distributions declared in November and December of 2007.

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 2007 and 2006, our distributions to Unitholders were 100% taxable and the Trust had no taxable income.

OUTLOOK

Our 2008 business plan includes two significant changes as compared to our 2007 operating results. In 2008, our upstream operations will increase its focus on enhanced oil recovery and longer term value creation with capital spending of $225 million planned as compared to $300.7 million in 2007 and $376.9 million in 2006. In 2008, our enhanced oil recovery efforts will focus on fluid management projects in several of our larger oil reservoirs which we expect will ultimately reduce overall decline rates for an extended period due to improved oil recovery rates. The anticipated improved recoveries are based on maintenance of reservoir pressure and the bolstering of traditional waterflood projects with the introduction of proven chemical enhancements, such as alkaline surfactant polymers. In our downstream operations, we are anticipating a robust year with no significant planned downtime for turnarounds and in the fourth quarter, an improved yield of gasoline and distillates attributed to an increase in the refinery's visbreaking capacity.

Our 2008 capital spending focuses on drilling programs in southeast Saskatchewan, Lloydminister, Red Earth, Suffield and Hayter with approximately 120 wells anticipated accounting for approximately 65% of our 2008 capital budget. Our planned investment in infrastructure and workovers primarily relates to our reservoir management initiatives and will account for approximately 25% of our 2008 spending including $8 million on the alkaline surfactant polymer project at Wainwright and a further $3 million investment in water handling capabilities at each of Bellshill Lake and Suffield to assist in re-pressurizing reservoirs. The balance of our capital program is allocated to projects necessary to maintain our existing infrastructure and does not increase production or reserves. The impact of increased focus on reservoir management and reduced drilling activity in the first quarter results in a more stable production profile throughout the year as compared to a front-end loaded production profile attributed to flush production from first quarter drilling activity, particularly in Hay River. Currently, our 2008 capital spending plans have a moderate natural gas focus which could change with a relative improvement in the outlook for natural gas prices as compared to oil prices. Our more significant natural gas investments in 2008 will build on significant 2007 discoveries in west central Alberta and the addition of processing capacity at existing facilities.

We anticipate that our upstream production will average approximately 40,000 bbl/d of liquids and 93,000 mcf/d of natural gas with a moderate declining production profile throughout the year. We anticipate production will be slightly front-end loaded in the first quarter due to drilling in southeast Saskatchewan and the tie-in of approximately 1,000 bbl/d of production from our 2007 drilling program. Light and medium gravity oil, including natural gas liquids, is expected to represent approximately 49% of our total production in 2008 with heavy oil and natural gas accounting for 23% and 28% respectively. We expect operating costs will continue to be a challenge in 2008 with approximately 40% of our costs attributed to electric power and well servicing. Power costs are significant for us as we move and dispose of approximately 2 million bbl/d of water to produce 40,000 bbl/d of oil and these costs will likely increase as we enhance our reservoir management focus. For 2008, we are projecting our operating costs to be approximately $13.00 per boe as compared to $13.66 in 2007 while our 2008 general and administrative costs are expected to average about $1.40 per boe.

In our downstream operations, we are not anticipating any planned shutdowns except for the shutdown of the visbreaker to enable the commissioning of our visbreaker upgrading project, and accordingly, are anticipating a 12% increase in throughput in 2008 to 112,900 bbl/d of feedstock. In 2007, we completed a turnaround of the crude vacuum units with the expectation that our purchases of vacuum gas oil from third parties would be reduced. For 2008, we anticipate a 4,800 bbl/d reduction in vacuum gas oil purchases at a cost saving of approximately $40 million. Currently, we expect that our operating costs and purchased energy costs will aggregate to $4.75 per bbl of throughput including the impact of a recently re-negotiated labour contract and a Canadian dollar at parity with the US dollar. We are also concentrating on capturing $10 million of operating cost reductions by improving energy efficiency and other operating measures which could reduce unit operating costs by $0.25 per barrel. Capital spending in our downstream operations is expected to total $63 million comprised of $22 million of mandatory/maintenance projects, $13 million discretionary projects, $25 million to complete the visbreaker project and $3 million on planning longer range refinery development projects. The cash flow contribution from our retail and wholesale marketing activities in the Province of Newfoundland and Labrador is expected to continue to add approximately $20 million of incremental cash flow to the downstream operations.

As discussed in the Cash Flow Risk Management section of this MD&A, we have refined product and WTI pricing contracts that represent approximately 79% of our cash flow exposure in the first half of 2008, 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. We also have a modest 276 GJ/d of natural gas fixed price contracts in place. Although we may enjoy unprecedented crude oil prices in 2008, our upside participation will be limited to an average WTI price of US$78.81/bbl within our 20,000 bbl/d of heating oil and fuel oil price risk management contracts. We have currency exchange contracts on US$18.3 million per month through to June 2008 with an average exchange rate of US$0.93 and an additional US$10.0 million per month through to December 2008 with an average exchange rate of US$0.95 representing approximately 20% of our exposure to fluctuations in the US dollar to Canadian dollar exchange rate, prior to considering the offsetting exposure of our US dollar denominated $7^{7/8}$% Senior Notes. We have also entered into contracts to fix the price of 35 MWh through to the end of December 2008 at a price of $56.69 with the objective of reducing the volatility of our operating costs to fluctuating electricity costs which represent approximately 20% of our upstream operating costs.

We manage our exposure to fluctuations in interest rates by maintaining a mix of short and longer term financing with the short term financing typically carrying floating interest rates and longer term financing (our $7^{7/8}$% Senior Notes and Convertible Debentures) carrying fixed rates of interest. Our short term financing consists of borrowings under our credit facilities, $1,279.5 million at December 31, 2007, which represents approximately 60% of our total debt. Accordingly, approximately 60% of our interest rate exposure is floating and 40% is fixed. Currently, our most significant exposure to increasing interest rates is through the re-pricing of credit as we extend (or renew) our credit facilities or enter into additional longer term financings. Prior to mid-2007, our short term interest rate was approximately 70 basis points over Bankers Acceptance rates while our long term rates based on the trading price of our $7^{7/8}$% Senior Notes was 250 basis points over the ten year US Treasury Bonds. As discussed in the Liquidity and Capital Resources section of this MD&A we may defer our credit facility extension request. With respect to further reducing our borrowings under this credit facility, we continue to monitor the high yield market as well as opportunities to issue additional Convertible Debentures and Trust Units.

On January 31, 2008, approximately $24.3 million of principal amount 10.5% convertible debentures matured and we elected to satisfy this obligation by issuing 1,116,593 Trust Units rather than settling the obligations in cash. This same option is available on all of the $666.9 million of principal amount of Convertible Debentures issued in six series with maturities in 2009, 2010, 2012, 2013 and 2014 as to $2.7 million, $37.1 million, $174.6 million, $379.3 million and $73.2 million, respectively. While not necessarily impacting 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 $666.9 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. In prior years, we have balanced our cash from operating activities and the funding of capital expenditures and distributions with reliance on proceeds from our distribution re-investment programs for shortfalls. The participation level in our distribution re-investment programs was 38% in 2006. However, as the ownership of our Trust Units by non-Canadian residents increased in 2007, the participation in our Premium Distribution Re-investment Plan™ has steadily diminished as non-residents of Canada do not qualify for this program which accounts for a substantial portion of the funding from our distribution re-investment programs. As of December 31, 2007, we estimate that 66% of our Unitholders are non-Canadian residents, a significant increase from 54% at the end of 2006 and 33% in February 2006 when Harvest and Viking merged.

While we do not forecast commodity prices nor refining margins, we have entered into price risk management contracts to mitigate a substantial portion of our price volatility with the objective of stabilizing our 2008 cash flow 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 including the impact of our price risk management contracts:

	Assumption	Change	Impact on Cash Flow
WTI oil price (US$/bbl)	$ 90.00	$ 5.00	$ 0.18/ Unit
CAD/USD exchange rate	$ 1.00	$ 0.05	$ 0.36 / Unit
AECO daily natural gas price ($/mcf)	$ 7.00	$ 1.00	$ 0.19 / Unit
Refinery crack spread (US$/bbl)	$ 9.00	$ 1.00	$ 0.27 / Unit
Upstream Operating Expenses (per boe)	$ 12.90	$ 1.00	$ 0.14/ 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 our productive capability and improve our unit operating costs. In addition, we intend to be an active participant in the consolidation of the Canadian energy industry, including royalty trusts.

In our downstream business, we are currently evaluating several opportunities to expand and/or reconfigure the refinery and have engaged SNC Lavalin to review the technical and economic feasibility of these options. The options include a project to convert approximately 30,000 bbl/d of high sulphur fuel oil to higher valued refined products, expand processing capacity supported by existing infrastructure and enhancing capability to refine a heavier and lower cost crude feedstock to improve margins. SNC Lavalin is expected to complete its study and provide its report by June 2008. With approval to proceed dependent on the outlook on worldwide growth in refining capacity, an expansion could boost throughput capacity and may take three to five years to complete. With costs expected to exceed $1 billion, we could either use our capital or a tolling processing arrangement from a producer seeking captive refining capacity to process its crude oil. There are also economic gains to be had by upgrading our combustion technologies.

The changes to Canada's Income Tax Act to apply a 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. On December 14, 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. See the Future Income Tax section in this MD&A for a more detailed discussion.

SUMMARY OF FOURTH QUARTER RESULTS

	Three months ended December 31						
	2007			2006			
	Upstream	Downstream	Total	Upstream	Downstream	Total	Change
Revenues	308,022	624,512	932,534	273,110	460,359	733,469	27%
Royalties	(53,410)	-	(53,410)	(50,725)	-	(50,725)	5%
Net revenues	254,612	624,512	879,124	222,385	460,359	682,744	29%
Purchased product for resale and processing	-	579,765	579,765	-	386,014	386,014	50%
Operating expenses	76,100	81,271	157,371	69,298	34,063	103,361	52%
General and administrative expenses	7,979	441	8,420	6,714	-	6,714	25%
Less: Unit based compensation expenses	(3,688)	48	(3,640)	(167)	-	(167)	2080%
Total cash general and administrative expenses	4,291	489	4,780	6,547	-	6,547	(27%)
Transportation and marketing	2,347	7,895	10,242	2,919	5,060	7,979	28%
Depreciation, depletion and accretion	115,176	17,746	132,922	116,262	15,482	131,744	1%
Net income per segment	56,698	(62,654)	(5,956)	27,359	19,740	47,099	(113%)
Realized losses (gains) on risk management contracts			17,375			5,996	190%
Unrealized losses (gains) on risk management contracts			122,739			(16,213)	857%
Interest and other financing charges			36,959			41,184	(10%)
Corporate costs[2]			(69,444)			14,599	(576%)
Net (loss) income			(113,585)			1,533	(7509%)
Per Trust Unit, basic			(0.77)			0.01	(7800%)
Per Trust Unit, diluted			(0.77)			0.01	(7800%)
Cash From Operating Activities			87,998			140,543	37%
Per Trust Unit, basic			0.60			1.21	(50%)
Per Trust Unit, diluted			0.60			1.16	(48%)
Distributions declared			144,681			134,974	(7%)
Distributions declared, per Trust Unit			0.98			1.14	(14%)
Distributions declared as a percentage of Cash From Operations			164%			96%	68%
UPSTREAM OPERATIONS							
Daily Production							
Light / medium oil (bbl/d)			26,640			28,152	(5%)
Heavy oil (bbl/d)			13,354			13,967	(4%)
Natural gas liquids (bbl/d)			2,595			2,649	(2%)
Natural gas (mcf/d)			94,961			112,006	(15%)
Total daily sales volume (boe/d)			58,416			63,436	(8%)
Operating Netback[1] ($/BOE)							
Revenue			57.32			46.80	22%
Royalties as percent of revenue			(9.94)			(8.69)	14%
Operating expense			(14.16)			(11.87)	19%
Transportation expense			(0.44)			(0.50)	(12%)
Operating Netback[1]			32.78			25.74	27%
Cash capital expenditures			30,643			90,358	(66%)
DOWNSTREAM OPERATIONS[3]							
Average daily throughput (bbl/d)			61,717			86,890	(29%)
Aggregate throughput (mbbl)			5,678			6,343	(10%)
Average Refining Margin (US$/bbl)			6.00			9.32	(36%)
Cash capital expenditures			16,889			21,411	(21%)

(1) This is a non-GAAP measure, please refer to "Non-GAAP Measure" in this MD&A.

(2) Includes foreign exchange losses, taxes and amounts realized on the series of US dollar forward purchase contracts entered into with respect to the purchase of North Atlantic.

(3) Downstream operations acquired on October 19, 2006.

Our 2007 fourth quarter results are not directly comparable to our 2006 fourth quarter results due to the acquisition of the North Atlantic during the fourth quarter of 2006, the turnaround activity at the refinery in the fourth quarter of both 2007 and 2006, and the acquisition of Grand Petroleum in the third quarter of 2007.

Upstream Operations

Our 2007 fourth quarter revenues increased $34.9 million over the same period in the prior year as a result of our realized commodity prices increasing by $10.52/boe (22%) due to significantly higher crude oil prices. Offsetting the increase in our realized commodity prices in the fourth quarter is a decrease in production volumes of 5,020 boe/d as compared to the prior period due to normal decline on our crude oil and natural gas production. Light / medium oil sales revenue for the three month period ended December 31, 2007 was $34.1 million (or 24%) higher than in same period in the prior year due to a favourable price variance of $41.6 million and an unfavourable volume variance of $7.5 million. Heavy oil revenues for the three months ended December 31, 2007 increased by $11.7 million (or 24%) due to a favourable price variance of $13.8 million and an unfavourable volume variance of $2.1 million. Natural gas sales revenue decreased by $15.9 million (or 22%) for the three months ended December 31, 2007 over the same period in 2006, which reflects an unfavourable price variance of $4.9 million and an unfavourable volume variance of $11.0 million.

For the three months ended December 31, 2007, our net royalties as a percentage of revenue were 17.3% ($53.4 million) as compared to 18.6% ($50.7 million) in the same period in 2006. The decrease in the royalty rate is mainly due to receiving crown royalty refunds on some of our shut in gas-over-bitumen production in the fourth quarter of 2007.

Operating expenses increased by $6.8 million (or 10%) for the three months ended December 31, 2007 compared to the same period in the prior year which reflects cost pressures in the western Canadian oil and natural gas sector.

For the three months ended December 31, 2007, Cash G&A increased by $1.3 million (or 19%) compared to the same period in the prior year. This increase is reflective of additional costs relating to consultant fees and generally higher costs to retain technically qualified staff in the western Canadian petroleum and natural gas industry.

After capital spending of $148.5 million, $48.2 million, and $73.3 million in the first, second and third quarters of 2007, respectively, capital spending in our upstream segment in the fourth quarter totaled $30.6 million which was mainly focused on tying-in our drilling results.

Downstream Operations

Our fourth quarter 2007 downstream operating results are not very comparable with the same period in the prior year, as the refinery was acquired midway through the fourth quarter of 2006 and during both periods the refinery undertook significant turnaround activity. Our operating results in the fourth quarter of 2007 reflect the impact of two planned shutdowns and weaker refining margins relative to the first and second quarters of 2007. By early December 2007, the refinery had returned to full operations with throughput averaging 109,611 bbl/d. For the fourth quarter 2006, our results reflect the impact of an extended turnaround commencing October 1, 2006 with the refinery returning to full operations near the end of November 2006 only to experience additional downtime in December 2006 due to a pipe rupture and a disruption in electric power service.

Corporate

Interest expense decreased by $4.2 million for the three months ended December 31, 2007 relative to the same period in the prior year due to a decrease in our total debt outstanding as a result of the issuance of $230.0 million of principal amount of Convertible Debentures and 13,499,250 Trust Units for total net proceeds of $576.0 million in the first half of 2007.

In the fourth quarter of 2007 we realized a $17.4 million loss and a $122.7 million unrealized loss on our risk management contracts as compared to a realized loss of $6.0 million and a $16.2 million unrealized gain in the same period in 2006. The significant unrealized loss in the fourth quarter of 2007 is due to our refined products and WTI price contracts as the refined product contracts were placed in mid-2007 when the WTI benchmark price was approximately US$71.00 and the NYMEX price for heating oil and Platts Index for fuel oil were approximately US$2.00 per gallon and US$55.00 per barrel, respectively, as compared to the 2007 year end closing prices of US$95.98 for WTI, US$2.64 per gallon for NYMEX heating oil and US$75.15 per barrel for Platts fuel oil.

SUMMARY OF QUARTERLY RESULTS

The table and discussion below highlight our fourth quarter 2007 performance over the preceding seven quarters on select measures:

	2007				2006			
(000s except where noted)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue, net of royalties	$ 879,124	$ 1,007,786	$ 1,133,450	$ 1,025,512	$ 682,744	$ 259,818	$ 257,103	$ 181,160
Net income (loss)	$ (113,585)	$ 11,811	$ 6,248	$ 69,850	$ 1,533	$ 107,768	$ 60,682	$ (33,937)
Per Trust Unit, basic(1)	$ (0.77)	$ 0.08	$ 0.05	$ 0.55	$ 0.01	$ 1.01	$ 0.60	$ (0.41)
Per Trust Unit, diluted(1)	$ (0.77)	$ 0.08	$ 0.05	$ 0.55	$ 0.01	$ 0.99	$ 0.60	$ (0.41)
Cash from operating activities	$ 87,998	$ 191,049	$ 251,218	$ 111,048	$ 140,543	$ 143,597	$ 135,581	$ 88,164
Per Trust Unit, basic	$ 0.60	$ 1.31	$ 1.88	$ 0.87	$ 1.21	$ 1.35	$ 1.34	$ 1.07
Per Trust Unit, diluted	$ 0.60	$ 1.22	$ 1.67	$ 0.84	$ 1.16	$ 1.31	$ 1.30	$ 1.07
Distributions per Unit, declared	$ 0.98	$ 1.14	$ 1.14	$ 1.14	$ 1.14	$ 1.14	$ 1.14	$ 1.11
Total long term financial liabilities	$ 2,172,417	$ 2,072,870	$ 1,961,748	$ 2,409,241	$ 2,488,524	$ 1,105,728	$ 746,840	$ 735,896
Total assets	$ 5,451,683	$ 5,585,651	$ 5,613,333	$ 5,800,346	$ 5,745,558	$ 4,076,771	$ 3,455,918	$3,470,653

(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 have generally increased steadily over the eight quarters with significantly higher revenue in the Second and Third Quarters of 2006 over the preceding quarters due to the incremental revenue from the Viking acquisition in February 2006 along with stronger commodity prices including narrowing crude oil differentials. In the Fourth Quarter of 2006, the significant increase in revenue over the prior quarter is attributed to the North Atlantic acquisition which is a margin business with significant revenues coupled with significant costs for crude oil feedstock. In the second half of 2007 net revenues decreased from the first half of 2007 due to the Refinery's lower realized prices and decreased throughput due to two planned shutdowns. The growth in cash from operating activities is closely aligned with the growth 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.

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. Additionally, the volatility in net income (loss) between quarters in 2006 and 2007 is due to the changes in the fair value of our risk management contracts and this is the primary reason why our net income (loss) does not reflect the same trends as net revenues or cash from operating activities.

Growth in total assets over the last eight quarters is directly attributed to our acquisition of Viking in the first quarter of 2006, Birchill in the Third Quarter of 2006 and North Atlantic in the Fourth Quarter of 2006. The changes in our total long term financial liabilities is primarily due to the impact of our acquisitions, offset by our issuance of Trust Units and the net cash surplus of cash from operating activities over our 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 take place and when these activities are reported. Changes in these estimates could have a material impact on our reported results.

Reserves

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. In the process of estimating the economically recoverable oil and natural gas reserves and related future net cash flows, we incorporate many factors and assumptions, such as:

- Expected reservoir characteristics based on geological, geophysical and engineering assessments;
- Future production rates based on historical performance and expected future operating and investment activities;
- Future oil and gas prices and quality differentials; and
- Future development costs.

We follow the full cost method of accounting for our oil and natural gas activities. All costs of acquiring oil and natural gas properties and related exploration and development costs, including overhead charges directly related to these activities, are capitalized and accumulated in one cost centre. Maintenance and repairs are charged against income, and renewals and enhancements that extend the economic life of the capital assets are capitalized. The provision for depletion and depreciation of petroleum and natural gas assets is calculated on the unit-of-production method, based on proved reserves as estimated by independent petroleum engineers.

Reserve estimates impact net income through depletion, the determination of asset retirement obligations and the application of an impairment test. Revisions or changes in the reserve estimates can have either a positive or a negative impact on net income, capital assets and asset retirement obligations.

Asset Retirement Obligations

In the determination of our asset retirement obligations, management is required to make a significant number of estimates with respect to activities that will occur in many years to come. In arriving at the recorded amount of the asset retirement obligation numerous assumptions are made with respect to ultimate settlement amounts, inflation factors, credit adjusted risk free discount rates, timing of settlement and expected changes in legal, regulatory, environmental and political environments. The asset retirement obligation also results in an increase to the carrying cost of capital assets. The obligation accretes to a higher amount with the passage of time as it is determined using discounted present values. A change in any one of the assumptions could impact the estimated future obligation and in return, net income. It is difficult to determine the impact of a change in any one of our assumptions. As a result, a reasonable sensitivity analysis cannot be performed.

Impairment of Capital Assets

Numerous estimates and judgments are involved in determining any potential impairment of capital assets. The most significant assumptions in determining future cash flows are future prices and reserves for our upstream operations and expected future refining margins for our downstream operations.

The estimates of future prices and refining margins require significant judgments about highly uncertain future events. Historically, oil, natural gas and refined product prices have exhibited significant volatility. The prices used in carrying out our impairment tests for each operating segment are based on prices derived from a consensus of future price forecasts among industry analysts. Given the number of significant assumptions required and the possibility that actual conditions will differ, we consider the assessment of impairment to be a critical accounting estimate.

If forecast WTI crude oil prices were to fall by 20%, the initial assessment of impairment of our upstream assets would not change; however, below that level, we would likely experience an impairment. Although oil and natural gas prices fluctuate a great deal in the short-term, they are typically stable over a longer time horizon. This mitigates potential for impairment. Similarly, for our downstream operations, if forecast refining margins were to fall by more than 25%, it is likely that our downstream assets would experience an impairment despite the expected seasonal volatility in earnings.

Reductions in estimated future prices may also have an impact on estimates of economically recoverable proved reserves.

Any impairment charges would reduce our net income.

It is difficult to determine and assess the impact of a decrease in our proved reserves on our impairment tests. The relationship between the reserve estimate and the estimated undiscounted cash flows is complex. As a result, we are unable to provide a reasonable sensitivity analysis of the impact that a reserve estimate decrease would have on our assessment of impairment.

Goodwill

Goodwill is recorded on a business combination when the total purchase consideration exceeds the fair value of the net identifiable assets and liabilities of the acquired entity. The goodwill balance is not amortized, however, must be assessed for impairment at least annually. Impairment is initially determined based on the fair value of a reporting unit compared to its book value. Any impairment must be charged to earnings in the period the impairment occurs. Harvest has a goodwill balance for each of our upstream and downstream operations. As at December 31, 2007, we have determined there was no goodwill impairment in either of our reporting units.

Employee Future Benefits

We maintain a defined benefit pension plan for the employees of North Atlantic. Obligations under employee future benefit plans are recorded net of plan assets where applicable. An independent actuary determines the costs of our employee future benefit programs using the projected benefit method. The determination of these costs requires management to estimate or make assumptions regarding the expected plan investment performance, salary escalation, retirement ages of employees, expected health care costs, employee turnover, discount rates and return on plan assets. The obligation and expense recorded related to our employee future benefit plans could increase or decrease if there were to be a change in these estimates. Pension expense represented less than 0.5% of our total expenses for 2007 (0.5% in 2006).

Purchase Price Allocations

Business acquisitions are accounted for by the purchase method of accounting. Under this method, the purchase price is allocated to the assets acquired and the liabilities assumed based on the fair values at the time of the acquisitions. The excess of the purchase price over the assigned fair values of the identifiable assets and liabilities is allocated to goodwill. In determining the fair value of the assets and liabilities we are often required to make assumptions and estimates about future events, such as future oil and gas prices, refining margins and discount rates. Changes in any of these assumptions would impact amounts assigned to assets and liabilities and goodwill in the purchase price allocation and as a result, future net earnings.

RECENT CANADIAN ACCOUNTING AND RELATED PRONOUNCEMENTS

Convergence of Canadian GAAP with International Financial Reporting Standards

In early 2007, Canada's Accounting Standards Board ("AcSB") issued a decision summary with respect to a previously issued strategic plan that will result in Canadian GAAP, as used by public companies, being converged with International Financial Reporting Standards ("IFRS"). In early 2008, it was confirmed by the AcSB that the transitions date from Canadian GAAP to IFRS will be January 1, 2011. We are currently evaluating our options with respect to this change and accordingly it is premature to assess the impact of the initiative, if any, on our financial statements at this time.

Financial Instruments – Disclosures and Presentation

On December 1, 2006, the AcSB issued the following two new standards regarding the disclosure and presentation of financial instruments with an implementation date for annual and interim financial statements beginning on or after October 1, 2007.

- Section 3862 – *Financial Instruments – Disclosures*

  This standard requires entities to provide disclosures in their financial statements that enable users to evaluate the significance of financial instruments to the entity's financial position and performance. It also requires that entities disclose the nature and extent of risks arising from financial instruments and how the entity manages those risks.

- Section 3863 – *Financial Instruments – Presentation*

  This standard establishes standards for presentation of financial instruments and non-financial derivatives and deals with the classification of financial instruments, from the perspective of the issuer, between liabilities and equity, the classification of related interest, dividends, losses and gains, and the circumstances in which financial assets and financial liabilities are offset.

Also on December 1, 2006, the AcSB issued a new standard regarding *Capital Disclosure* requiring 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. This standard also has an implementation date for annual and interim financial statements beginning on or after October 1, 2007.

In June 2007, the AcSB issued section 3031, Inventories, 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. This standard is to be adopted for fiscal years beginning on or after January 1, 2008. We do not expect the adoption of this section to have a material impact on our net income or financial position.

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 (including the Supply and Offtake Agreement with Vitol Refining S.A.) 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

On October 25, 2007, the Government of Alberta released its New Royalty Framework outlining changes that effective January 1, 2009 will increase the royalty rates on conventional oil and gas, oil sands and coalbed methane using a price-sensitive and volume-sensitive sliding rate formula for both conventional oil and natural gas. While there are considerable details to be provided, our preliminary assessment is that the impact of the changes on Harvest will be modest, as many of our oil and natural gas wells will be considered low productivity wells that continue to attract favourable royalty treatment. Based on the information available and assuming royalties will continue to be based on field gate prices realized by producers, our analysis indicates that if our field gate prices are less than $53.00, our oil royalties will be lower and if prices are higher, our royalties will increase and similarly for natural gas, if our gas plant prices are less than $7.00, our royalties will be lower and if prices are higher, our royalties will increase. Of particular concern is the royalty rates on natural gas where production from recently drilled wells may qualify as high productivity for a period of time and attract a royalty that is 15% to 20% higher than under the current royalty regime and this could significantly penalize the economics of our drilling natural gas wells. Generally, we will pay higher royalties if commodity prices are high and lower royalties on most of our wells as they will be considered to be low productivity wells.

In 2007, the Government of Alberta introduced the Climate Change and Emissions Management Amendment Act which intends to reduce greenhouse gas emissions intensity from large emitting facilities. On January 24, 2008, the Government of Alberta announced their plan to reduce projected emissions in the province by 50% under the new climate change plan by 2050. This will result in real reductions of 14% below 2005 levels. The Government of Alberta stated they will form a government-industry council to determine a go-forward plan for implementing technologies, which will significantly reduce greenhouse gas emissions by capturing air emissions from industrial sources and locking them permanently underground in deep rock formations.

In 2002, the Government of Canada ratified the Kyoto Protocol which calls for Canada to reduce its greenhouse gas emissions to specified levels. On April 26, 2007, the Government of Canada released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "Action Plan") which includes a regulatory framework for air emissions. This Action Plan is to regulate the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy-using products. On March 10, 2008, the Government of Canada released "Turning the Corner" outlining additional details to implement their April 2007 commitment to cut greenhouse gas emissions by an absolute 20% by 2020. "Turning the Corner" sets out a framework to establish a market price for carbon emissions and sets up a carbon emission trading market to provide incentives for Canadians to reduce their greenhouse gas emissions. In addition, the regulations include new measures for oil sands developers that require an 18% reduction from 2006 levels by 2010 for existing operations and for oil sands operations commencing in 2012, a carbon capture and storage capability. There is no mention of targeting reductions for unintentional fugitive emissions for conventional producers. Companies will be able to choose the most cost effective way to meet their emissions reduction targets from in-house reductions, contributions to time-limited technology funds, domestic emissions trading and the United Nations' Clean Development Mechanism. Companies that have already reduced their greenhouse gas emissions prior to 2006 will have access to a limited one-time credit for early adoption. Giving the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, and the lack of detail in the Government of Canada's announcement, it is not possible to assess the impact of the requirements on our operations and financial performance.

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.

Disclosure Controls and Procedures and Internal Control over Financial Reporting

Under the supervision of our Chief Executive Officer and Chief Financial Officer, we have evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2007 as defined under the rules adopted by the Canadian securities regulatory authorities and the US Securities and Exchange Commission. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that as of December 31, 2007, our disclosure controls and procedures were effective to ensure that information required to be disclosed by Harvest in reports it files or submits to Canadian and US securities authorities was recorded, processed, summarized and reported within the time period specified in Canadian and US securities laws and was accumulated and communicated to Harvest's management, including its Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosures.

Management is responsible for establishing and maintaining internal control over our financial reporting. Our internal control is designed to provide reasonable assurance regarding the reliability of financial reporting and preparation of financial statements for external purposes in accordance with Canadian Generally Accepted Accounting Principles. Management, with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated in the effectiveness of our internal control over financial reporting as of December 31, 2007. The evaluation was based on the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, management has concluded that as of December 31, 2007, we had effective internal control over financial reporting.

The effectiveness of our internal control over financial reporting as of December 31, 2007 was audited by KPMG, an independent registered public accounting firm, as stated in their report, which is included in our audited consolidated financial statements for the year ended December 31, 2007.

During the year ended December 31, 2007, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting except for the appointment of a Chief Operating Officer – Downstream. The appointment enhanced our oversight of these operations.

Based on their inherent limitations, disclosure controls and procedures and internal controls over financial reporting may not prevent or detect misstatements, errors or fraud. Control systems, no matter now well conceived or operated, can provide only reasonable, but not absolute, assurance that the objectives of the control systems are met.

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.

MANAGEMENT'S REPORT

In management's opinion, the accompanying consolidated financial statements of Harvest Energy Trust (the "Trust") have been prepared within reasonable limits of materiality and in accordance with Canadian generally accepted accounting principles. Since a precise determination of many assets and liabilities is dependent on future events, the preparation of financial statements necessarily involves the use of estimates and approximations. These have been made using careful judgment and with all information available up to March 12, 2008. Management is responsible for all information in the annual report and for the consistency, therewith, of all other financial and operating data presented in this report.

To meet its responsibility for reliable and accurate financial statements, management has established and monitors systems of internal control which are designed to provide reasonable assurance that financial information is relevant, reliable and accurate, and that assets are safeguarded and transactions are executed in accordance with management's authorization.

Under the supervision of our Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). We have concluded that as of December 31, 2007, our internal controls over financial reporting were effective.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

The consolidated financial statements and the Trusts' internal control over financial reporting have been examined by KPMG LLP, Independent Registered Public Accountants. Their responsibility is to express a professional opinion on the fair presentation of the consolidated financial statements in accordance with Canadian generally accepted accounting principles. The Independent Registered Public Accountants Report outlines the scope of their examination and sets forth their opinion.

The Audit Committee, consisting exclusively of independent directors, has reviewed these statements with management and the Independent Registered Public Accountants and has recommended their approval to the Board of Directors. The Board of Directors has approved the consolidated financial statements of the Trust.

J Zahary

John E. Zahary
President and Chief Executive Officer

R Fotheringham

Robert W. Fotheringham
Chief Financial Officer

Calgary, Alberta
March 12, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Harvest Operations Corp. on behalf of Harvest Energy Trust and the Unitholders of Harvest Energy Trust

We have audited Harvest Energy Trust's ("the Trust") internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Trust's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report. Our responsibility is to express an opinion on the Trust's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

An entity's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. An entity's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the entity; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the entity are being made only in accordance with authorizations of management and directors of the entity; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the entity's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have conducted our audits on the consolidated financial statements in accordance with Canadian generally accepted auditing standards. With respect to the years ended December 31, 2007 and 2006, we also have conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our report dated March 12, 2008, expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

KPMG LLP
Chartered Accountants
Calgary, Canada
March 12, 2008

AUDITORS' REPORT

To the Unitholders of Harvest Energy Trust

We have audited the consolidated balance sheets of Harvest Energy Trust (the "Trust") as at December 31, 2007 and 2006 and the consolidated statements of income and comprehensive (loss) income, unitholders' equity and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. With respect to the consolidated financial statements for the years ended December 31, 2007 and 2006, we also conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2007 and 2006 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Trust's internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 12, 2008 expressed an unqualified opinion on the effectiveness of the internal control over financial reporting.

KPMG LLP

KPMG LLP
Chartered Accountants
Calgary, Canada
March 12, 2008

COMMENTS BY AUDITORS FOR UNITED STATES READERS ON CANADA – UNITED STATES REPORTING DIFFERENCES

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the Trust's financial statements, such as the change described in note 3 to the consolidated financial statements as at December 31, 2007 and 2006 and for the years then ended. Our report to the unitholders dated March 12, 2008, is expressed in accordance with Canadian reporting standards, which do not require a reference to such a change in accounting principles in the auditors' report when the change is properly accounted for and adequately disclosed in the financial statements.

KPMG LLP

KPMG LLP
Chartered Accountants
Calgary, Canada
March 12, 2008

CONSOLIDATED BALANCE SHEETS

As at December 31

(thousands of Canadian dollars)		2007		2006
ASSETS				
Current assets				
Cash	$	-	$	10,006
Accounts receivable and other		215,803		257,131
Fair value of risk management contracts *[Note 18]*		16,442		17,914
Prepaid expenses and deposits		15,144		12,713
Inventories *[Note 5]*		58,934		23,792
		306,323		321,556
Deferred charges and other non-current assets *[Note 8]*		-		25,067
Fair value of risk management contracts *[Note 18]*		-		9,843
Property, plant and equipment *[Note 6]*		4,197,507		4,400,552
Intangible assets *[Note 7]*		95,075		122,362
Goodwill *[Note 4]*		852,778		866,178
	$	5,451,683	$	5,745,558
LIABILITIES AND UNITHOLDERS' EQUITY				
Current liabilities				
Accounts payable and accrued liabilities *[Note 9]*	$	270,243	$	294,582
Cash distribution payable		44,487		46,397
Current portion of convertible debentures *[Note 12]*		24,273		-
Fair value deficiency of risk management contracts *[Note 18]*		131,020		26,764
		470,023		367,743
Bank loan *[Note 11]*		1,279,501		1,595,663
$7^{7/8}$% Senior notes *[Note 13]*		241,148		291,350
Convertible debentures *[Note 12]*		627,495		601,511
Fair value deficiency of risk management contracts *[Note 18]*		35,095		2,885
Asset retirement obligation *[Note 10]*		213,529		202,480
Employee future benefits *[Note 17]*		12,168		12,227
Deferred credit		710		794
Future income tax *[Note 16]*		86,640		-
Unitholders' equity				
Unitholders' capital *[Note 14]*		3,736,080		3,046,876
Equity component of convertible debentures		39,537		36,070
Accumulated income		246,865		271,155
Accumulated distributions		(1,340,349)		(730,069)
Accumulated other comprehensive (loss) income *[Note 3]*		(196,759)		46,873
		2,485,374		2,670,905
	$	5,451,683	$	5,745,558

Commitments, contingencies and guarantees [*Note 20*].
Subsequent events [*Note 22*].
See accompanying notes to these consolidated financial statements.

Approved by the Board of Directors:

Hector J. McFadyen
Director

Verne G. Johnson
Director

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

For the Years Ended December 31

(thousands of Canadian dollars, except per Trust Unit amounts)		2007		2006
REVENUE				
Petroleum, natural gas, and refined product sales	$	4,283,013	$	1,580,934
Royalty expense		(213,413)		(200,109)
		4,069,600		1,380,825
EXPENSES				
Purchased products for processing and resale		2,667,714		386,014
Operating		530,208		276,537
Transportation and marketing		46,916		17,202
General and administrative *[Note 15]*		36,328		28,372
Transaction costs		-		12,072
Realized net losses on risk management contracts		26,291		44,808
Unrealized net losses (gains) on risk management contracts		147,781		(52,179)
Interest and other financing charges on short term debt, net		5,584		4,864
Interest and other financing charges on long term debt		152,201		78,828
Depletion, depreciation, amortization and accretion		526,741		429,470
Foreign exchange loss (gain)		(109,316)		21,100
Large corporations tax and other tax		(974)		(9)
Future income tax expense (recovery) *[Note 16]*		65,802		(2,300)
		4,095,276		1,244,779
NET INCOME (LOSS) FOR THE YEAR		(25,676)		136,046
Cumulative Translation Adjustment		(243,632)		-
COMPREHENSIVE INCOME (LOSS) FOR THE PERIOD *[Note 3]*	$	(269,308)	$	136,046
Net income per Trust Unit, basic *[Note 14]*	$	(0.19)	$	1.34
Net income per Trust Unit, diluted *[Note 14]*	$	(0.19)	$	1.33

See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY

For the Years Ended December 31

(thousands of Canadian dollars)	Unitholders' Capital	Equity Component of Convertible Debentures	Accumulated Income	Accumulated Distributions	Accumulated Other Comprehensive (Loss) Income *[Note 3]*	Total
At December 31, 2005	**$ 747,312**	**$ 2,639**	**$ 135,665**	**$ (261,282)**	**$ -**	**$ 624,334**
Issued in exchange for assets of Viking *[Note 4(e)]*	1,638,131	-	-	-	-	1,638,131
Issued for cash						
August 17, 2006	230,118	-	-	-	-	230,118
November 22, 2006	258,848	-	-	-	-	258,848
Equity component of convertible debenture issuances						
10.5% Debentures Due 2008	-	9,301	-	-	-	9,301
6.40% Debentures Due 2012	-	14,822	-	-	-	14,822
7.25% Debentures Due 2013	-	11,800	-	-	-	11,800
Convertible debenture conversions						
9% Debentures Due 2009	551	-	-	-	-	551
8% Debentures Due 2009	1,550	(12)	-	-	-	1,538
6.5% Debentures Due 2010	3,563	(223)	-	-	-	3,340
10.5% Debentures Due 2008	10,761	(2,238)	-	-	-	8,523
6.40% Debentures Due 2012	231	(19)	-	-	-	212
Exchangeable share retraction	2,648	-	(556)	-	-	2,092
Exercise of unit appreciation rights and other	12,034	-	-	-	-	12,034
Issue costs	(26,414)	-	-	-	-	(26,414)
Foreign currency translation adjustment	-	-	-	-	46,873	46,873
Net income	-	-	136,046	-	-	136,046
Distributions and distribution reinvestment plan	167,543	-	-	(468,787)	-	(301,244)
At December 31, 2006 *[Note 3]*	**3,046,876**	**36,070**	**271,155**	**(730,069)**	**46,873**	**2,670,905**
Adjustment arising from change in accounting policies *[Note 3]*	(49)	-	1,386	-	-	1,337
Issued for cash						
February 1, 2007	143,834	-	-	-	-	143,834
June 1, 2007	230,029	-	-	-	-	230,029
Equity component of convertible debenture issuances						
7.25% Debentures Due 2014	-	13,100	-	-	-	13,100
Convertible debenture conversions						
9% Debentures Due 2009	250	-	-	-	-	250
8% Debentures Due 2009	513	(4)	-	-	-	509
6.5% Debentures Due 2010	882	(55)	-	-	-	827
10.5% Debentures Due 2008	2,999	(627)	-	-	-	2,372
6.40% Debentures Due 2012	122	(10)	-	-	-	112
7.25% Debentures Due 2013	244	(8)	-	-	-	236
7.25% Debentures Due 2014	157,139	(8,929)	-	-	-	148,210
Exercise of unit appreciation rights and other	658	-	-	-	-	658
Issue costs	(25,906)	-	-	-	-	(25,906)
Foreign currency translation adjustment	-	-	-	-	(243,632)	(243,632)
Net income	-	-	(25,676)	-	-	(25,676)
Distributions and distribution reinvestment plan	178,489	-	-	(610,280)	-	(431,791)
At December 31, 2007	**$3,736,080**	**$ 39,537**	**$ 246,865**	**$(1,340,349)**	**$ (196,759)**	**$ 2,485,374**

See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31

(thousands of Canadian dollars)	2007	2006
Cash provided by (used in)		
OPERATING ACTIVITIES		
Net (loss) income for the year	$ (25,676)	$ 136,046
Items not requiring cash		
Depletion, depreciation, amortization and accretion	526,741	429,470
Unrealized foreign exchange loss (gain)	(55,725)	23,956
Non-cash interest expense	7,534	1,577
Amortization of deferred finance charges	4,509	8,432
Unrealized loss (gain) on risk management contracts *[Note 18]*	147,781	(52,179)
Future income tax expense (recovery)	65,802	(2,300)
Non-controlling interest	-	(65)
Unit based compensation expense	743	775
Amortization of office lease premiums and deferred rent expense	139	(161)
Employee benefit obligation	(61)	(328)
Settlement of asset retirement obligations *[Note 10]*	(13,090)	(9,186)
Change in non-cash working capital	(17,384)	(28,152)
	641,313	507,885
FINANCING ACTIVITIES		
Issue of Trust Units, net of issue costs	354,549	463,160
Issue of convertible debentures, net of issue costs *[Note 12]*	220,488	363,742
Redemption of exchangeable shares	-	(1,022)
Bank borrowings (repayments), net *[Note 11]*	(291,947)	1,452,138
Financing costs	(273)	(13,071)
Cash distributions	(433,699)	(273,391)
Change in non-cash working capital	(1,223)	(12,604)
	(152,105)	1,978,952
INVESTING ACTIVITIES		
Additions to property, plant and equipment	(344,785)	(398,292)
Business acquisitions	(170,782)	(2,044,640)
Property acquisitions	(27,943)	(65,773)
Property dispositions	60,569	20,856
Increase in other non-current assets	-	(165)
Change in non-cash working capital	(14,710)	10,886
	(497,651)	(2,477,128)
Change in cash and cash equivalents	(8,443)	9,709
Effect of exchange rate changes on cash	(1,563)	297
Cash and cash equivalents, beginning of year	10,006	-
Cash and cash equivalents, end of year	$ -	$ 10,006
Interest paid	$ 130,990	$ 53,434
Large corporation tax and other tax paid	$ 442	$ 862

See accompanying notes to these consolidated financial statements.

Notes To Consolidated Financial Statements

December 31, 2007 and 2006

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

1. STRUCTURE OF THE TRUST

Harvest Energy Trust (the "Trust") is an open-ended, unincorporated investment trust established under the laws of the Province of Alberta on July 10, 2002 and is governed pursuant to the Amended and Restated Trust Indenture dated February 3, 2006 between Harvest Operations Corp. ("Harvest Operations"), a wholly owned subsidiary and manager of the Trust, and Valiant Trust Company as Trustee (the "Trust Indenture"). The purpose of the Trust is to indirectly exploit, develop and hold interests in petroleum and natural gas properties and refining and marketing assets through investments in the securities of its subsidiaries and net profits interests in petroleum and natural gas properties. The beneficiaries of the Trust are the holders of its Trust Units (the "Unitholders") who receive monthly distributions from the Trust's net cash flow from its various investments after the provision for interest due to the holders of convertible debentures. Pursuant to the Trust Indenture, the Trust is required to distribute 100% of its taxable income to its Unitholders each year and to comply with the mutual fund trust requirements of the Income Tax Act (Canada). The Trusts' activities are limited to holding and administering permitted investments and making distributions to its Unitholders.

The business of the Trust is carried on by Harvest Operations and other operating subsidiaries of the Trust, including North Atlantic Refining Limited Partnership. The activities of Harvest Operations and the Trust's subsidiaries are financed through interest bearing notes from the Trust, net profit interests issued to the Trust, and third party debt such as the bank debt and the $7^{7/8}$% senior notes.

The net profit interests are determined pursuant to the terms of each respective net profit interest agreement. The Trust is entitled to net profit interests equal to the amount by which 99% of the gross proceeds from the sale of production from petroleum and natural gas properties exceed 99% of certain deductible expenditures. Under the terms of the net profits interests agreements, deductible expenditures may include discretionary amounts to fund capital expenditures, to repay third party debt and to provide for working capital required to carry out the operations of the operating subsidiaries.

References to "Harvest" refers to the Trust on a consolidated basis. References to "North Atlantic" refers to North Atlantic Refining Limited Partnership and it subsidiaries, all of which are 100% owned by Harvest.

2. SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). These principles differ in certain respects from accounting principles generally accepted in the United States of America ("US GAAP") and to the extent that the differences materially affect Harvest, they are described in Note 21.

(a) Consolidation

These consolidated financial statements include the accounts of Harvest and its subsidiaries. All inter-entity transactions and balances have been eliminated upon consolidation.

(b) Use of Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenues and expenses during the period. Specifically, amounts recorded for depletion, depreciation, amortization and accretion expense, asset retirement obligations, fair value of risk management contracts, employee future benefits and amounts used in the impairment tests for intangible assets, goodwill, inventory and property, plant and equipment are based on estimates. These estimates include petroleum and natural gas reserves, future petroleum and natural gas prices, future interest rates and future costs required to develop those reserves as well as other fair value assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future years could be material.

(c) *Revenue Recognition*

Revenues associated with the sale of crude petroleum, natural gas, natural gas liquids and refined products are recognized when title passes to customers and payment has either been received or collection is reasonably certain. Concurrent with the recognition of revenue from the sale of refined products and included in purchased products for resale and processing are associated transportation charges. Revenues for retail services are recorded when the services are provided.

The sales price of residential home heating fuels and automotive gasoline and diesel within the Province of Newfoundland and Labrador is subject to regulation under the Petroleum Products Act. The Petroleum Products Pricing Commissioner sets the maximum wholesale and retail prices that a wholesaler and a retailer may charge and sets the maximum mark-up between the wholesale price to the retailer and the retail price to the consumer. Prices are set biweekly using a price adjustment formula based on an allowable premium above Platt's with an interruption formula. The full effect of rate regulation is reflected in the product sales revenue as recorded by Harvest.

(d) *Inventories*

Inventories are carried at the lower of cost or net realizable value. The costs of in process inventory are determined using the weighted average cost method. The costs of purchased goods and petroleum products held for resale are determined under the first in, first out method. The costs of parts and supplies inventories are determined under the average cost method.

(e) *Joint Venture and Partnership Accounting*

The subsidiaries of Harvest conduct substantially all of their petroleum and natural gas production activities through joint ventures and through partnerships. The consolidated financial statements reflect only Harvest's proportionate interest in such activities.

(f) *Property, Plant, and Equipment*

Petroleum and Natural Gas

Harvest follows the full cost method of accounting for its petroleum and natural gas activities. All costs of acquiring petroleum and natural gas properties, whether productive or unproductive, related development costs, and overhead charges directly related to these activities, are capitalized and accumulated in one cost centre. Maintenance and repair costs that do not extend or enhance the recoverable reserves are charged against income.

Proceeds from the sale of petroleum and natural gas properties are applied against capital costs. Gains and losses are not recognized on the disposition of petroleum and natural gas properties unless that disposition would alter the rate of depletion and depreciation by 20% or more.

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

Harvest places a limit on the aggregate carrying amount of property, plant and equipment associated with petroleum and natural gas activities which may be amortized to depletion and depreciation in future periods. Impairment is recognized when the carrying amount of the petroleum and natural gas assets exceeds the sum of the undiscounted future cash flows expected from the proved reserves.

To recognize impairment, Harvest would then measure the amount of impairment by comparing the carrying amounts of the petroleum and natural gas assets to an amount equal to the estimated net present value of future cash flows from proved plus probable reserves using Harvest's risk-free discount rate. Any excess carrying amount above the net present value of Harvest's future cash flows would be a permanent impairment and reflected as a charge to net income for the period.

Cash flows are calculated based on future price estimates, adjusted for Harvest's contractual arrangements related to pricing and quality differentials.

The cost of unproved properties is excluded from the impairment test calculation described above and subject to a separate impairment test. An impairment of unproved properties is recognized when the cost base exceeds the fair value determined by a reference to market prices, historical experience or a third party independent evaluator. There were no impairment write downs for petroleum and natural gas assets for the years ended December 31, 2007 and 2006.

Refining and Marketing

Property, plant and equipment related to the refining assets are recorded at cost. Depreciation of recorded cost less salvage value is provided on a straight-line basis over the estimated useful life of the assets as set out below. Any gains or losses on disposal of individual assets are recognized in the year of disposal.

Asset	Period
Refining and production plant:	
Processing equipment	5 – 25 years
Structures	15 – 20 years
Catalysts	2 – 5 years
Tugs	25 years
Vehicles	2-5 years

Maintenance and repair costs including major maintenance activities, are expensed as incurred. Improvements that increase or prolong the service life or capacity of an asset are capitalized.

Property, plant and equipment related to refining assets are tested for recovery whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Property, plant and equipment related to refining assets are not recoverable if their carrying amounts exceed the sum of the undiscounted cash flows expected to result from their use and eventual disposition. If property, plant and equipment related to refining assets are not recoverable, an impairment loss is recognized in an amount by which their carrying amount exceed their fair value, with fair value determined based on discounted estimated net cash flows. There was no impairment write-down for refining assets for the years ended December 31, 2007 and 2006.

(g) Goodwill and Other Intangible Assets

Goodwill is recognized when the purchase price of an acquired business exceeds the fair value of the net identifiable assets and liabilities of the acquired business. Goodwill is carried at cost less impairment and is not amortized. The carrying amount of goodwill is assessed for impairment annually at year-end, or more frequently if events occur that could result in an impairment. The goodwill impairment test is a two step test. In the first step, the carrying amount of the assets and liabilities, including goodwill, is compared to the fair value of the reporting unit. The fair value of a reporting unit is determined by calculating the present value of the expected future cash flows from the reporting unit. If the fair value is less than the carrying amount of the reporting unit, a potential impairment of goodwill may exist requiring the second test to be performed. Impairment is measured by allocating the fair value of the reporting unit, as determined in the first test, over the identifiable assets and liabilities. The excess of the fair value of the reporting unit over the fair value of the identifiable assets and liabilities represents the fair value of goodwill. The excess of the book value of goodwill over this implied fair value is then recognized as an impairment and charged to income in the period in which it occurs. There were no impairment write-downs for each of the years ended December 31, 2007 and 2006.

Intangible assets with determinable useful lives are amortized using the straight line method over the estimated lives of the assets, which range from 5–20 years. The amortization methods and estimated service lives are reviewed annually. The carrying amounts of intangible assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying amounts may not be recoverable. Intangibles are not recoverable if their carrying amounts exceed the sum of the undiscounted cash flows expected to result from their use and eventual disposition. If intangibles are not recoverable, an impairment loss is recognized in an amount by which their carrying amount exceeds their fair value, with fair value determined based on discounted estimated net cash flows. There was no impairment write-down for the years ended December 31, 2007 and 2006.

(h) Asset Retirement Obligations

Harvest recognizes the fair value of any asset retirement obligations as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development, and normal use of the assets. Harvest uses a credit-adjusted risk free discount rate to estimate this fair value. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset and depleted and depreciated using the method described under “Property, Plant and Equipment”. Subsequent to the initial measurement of the asset retirement obligation, the obligation is adjusted at the end of each subsequent period to reflect the passage of time and changes in the timing and amount of estimated future cash flows underlying the obligation. Actual costs incurred upon settlement of the retirement obligation are charged against the obligation to the extent of the liability recorded.

(i) Income Taxes

Under the Income Tax Act (Canada) the Trust and its trust subsidiary entities are taxable only on income that is not distributed or distributable to their Unitholders. As both the Trust and its Trust subsidiaries distribute all of their taxable income to their respective Unitholders pursuant to the requirements of their trust indentures, neither the Trust nor its trust subsidiaries are currently subject to income tax. However, pursuant to newly enacted legislation in 2007, the Trust and its flow-through subsidiaries will become subject to a distribution tax beginning in 2011, provided that Harvest maintains its current structure. Harvest now makes provisions for future income taxes to reflect this new legislation.

Harvest follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements of the corporate subsidiaries and their respective tax bases, using enacted or substantively enacted income tax rates. The effect of a change in income tax rates on future tax liabilities and assets is recognized in income in the period in which the change occurs. A valuation allowance is recorded against any future income tax asset if it is more likely than not that the asset will not be realized.

(j) Unit-based Compensation

Harvest determines compensation expense for the Trust Unit Rights Incentive Plan ("Trust Unit Incentive Plan") and the Unit Award Incentive Plan ("Unit Award Incentive Plan") by estimating the intrinsic value of the rights at each period end and recognizing the amount in income over the vesting period. After the rights have vested, further changes in the intrinsic value are recognized in income in the period of change.

The intrinsic value is the difference between the market value of the Units and the exercise price of the right in the case of the Trust Unit Incentive Plan, and in the case of the Unit Award Incentive Plan the market value of the Units represents the intrinsic value of the Award. Under the Trust Unit Incentive Plan, the intrinsic value method is used as participants in the plan have the option to either purchase the Units at the exercise price or to receive a cash payment or Trust Unit equivalent, equal to the excess of the market value of the Units over the exercise price. Under the Unit Award Incentive Plan participants have the option upon exercise to receive a cash payment or Trust Unit equivalent, equal to the value of awards outstanding, which is equivalent to the market value of the Units.

(k) Employee Future Benefits

North Atlantic maintains defined benefit and defined contribution plans and provides certain post-retirement health care benefits, which cover the majority of its employees and their surviving spouses.

(i) Defined Contribution Plan

Under the defined contribution plan, the annual contribution of each participating employee's pensionable earnings is as follows:

Employee category	
Permanent	5.0%
Part-time	2.5%

The contributions associated with the defined contribution plan is expensed as incurred.

(ii) Defined Benefit Plans

The cost of providing the defined benefits and other post-retirement benefits is actuarially determined based upon an independent actuarial valuation using management's best estimates of discount rates, rate of return on plan assets, rate of compensation increase, retirement ages of employees, and expected health care costs. The cost of pensions earned by employees is actuarially determined using the projected benefit method prorated on credited service. Funding of the defined benefit pension plans complies with Canadian federal and provincial regulations, and requires contributions to the plans be made based on independent actuarial valuation. Pension plan assets are measured at fair values with the difference between the fair value of the plan assets and the total employee benefit obligation recorded on the balance sheet. For the purpose of calculating the expected return on assets, the fair value of the plan assets is used.

The defined benefit plans provide benefits based on length of service and the best five years of the last ten years' average earnings. There is no recognition or amortization of actuarial gains or losses less than 10% of the greater of the accrued benefit obligations and the fair value of plan assets for the defined benefit pension plans. Actuarial gains and losses over 10% are amortized on a straight-line basis over the average remaining service period of the plan participants. Actuarial gains or losses related to the other post-retirements benefits are recognized in income immediately. Past service costs are amortized on a straight-line basis over the expected average remaining service life of plan participants.

(l) Currency Translation

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

Harvest's investment in a subsidiary with a functional currency denominated in a currency other than the Canadian dollars is translated using the current rate method as the subsidiary is considered a self-sustaining operation. Gains and losses resulting from this translation are recorded in the cumulative translation adjustment in unitholders' equity.

(m) Rate Regulation

The sales price of residential home heating fuels and automotive gasoline and diesel within the Province of Newfoundland and Labrador is subject to regulation under the Petroleum Products Act. The Petroleum Products Pricing Commissioner sets the maximum mark-up between the wholesale price to the retailer and the retail price to the consumer. The full effect of rate regulation is reflected in the product sales revenue as recorded.

3. CHANGE IN ACCOUNTING POLICY

Financial Instruments and Comprehensive Income

Effective January 1, 2007, Harvest adopted three new and revised Canadian accounting standards as issued by the Canadian Institute of Chartered Accountants respecting "Financial Instruments – Recognition and Measurement", "Financial Instruments – Presentation and Disclosure" and "Comprehensive Income".

Financial Instruments

The revised standard on financial instruments provides new guidance on how to recognize and measure financial instruments. It requires all financial instruments to be recorded at fair value when initially recognized. Subsequent measurement is either at fair value or amortized cost, depending on the classification of the financial instrument. Financial assets and liabilities that are held-for-trading are measured at fair value with changes in those fair values recognized in net income. Available-for-sale financial assets are measured at fair value with unrealized gains or losses recognized in other comprehensive income. Held-to-maturity assets, loans and receivables and other liabilities are all measured at amortized cost with any related expenses or income recognized in net income. Price risk management contracts are classified as held-for-trading and are measured at fair value at initial recognition and at subsequent measurement dates. Any derivatives embedded in other financial or non-financial contracts that were entered into on or after January 1, 2001 must also be measured at fair value and recorded in the financial statements if the embedded derivative is not closely related to the host contract. Fair value of financial instruments is based on market prices where available, otherwise it is calculated as the net present value of expected future cash flows. For those items measured at amortized cost, interest expense is calculated using an effective interest rate that accretes any discount or premium over the life of the instrument so that the carrying value equals the face value at maturity.

Harvest does not have any financial assets classified as available-for-sale or held-to-maturity. The only items on Harvest's balance sheet that are classified as held-for-trading and subsequently measured at fair value are cash and our price risk management contracts. The remainder of the financial instruments are measured at amortized cost. As well, there are no significant embedded derivatives that need to be recorded in the financial statements.

Transaction costs relating to financial instruments classified as held-for-trading are expensed in net income in the period that they are incurred. Harvest has elected to add all other transaction costs that are directly attributable to the acquisition or issue of a financial asset or liability to the amount of the financial asset or liability that is recorded on initial recognition.

The transitional provisions of the financial instruments standard require retrospective adoption without restatement of prior period financial statements. The provisions also require all financial instruments to be remeasured using the criteria of the new standard and any change in the previous carrying amount to be recognized as an adjustment to retained earnings on January 1, 2007. As our price risk management contracts were already measured at fair value, the most significant change for Harvest was reclassifying the deferred charges relating to our senior notes and convertible debentures and netting these amounts against the respective liability. These charges are then amortized to income using an effective interest rate. The effect of applying this new standard on January 1, 2007 was to reduce the carrying value of the following accounts as indicated with an offsetting reduction to deferred charges:

Deferred charges	$	(25,067)
$7^{7/8}$% Senior notes		(9,522)
Convertible debentures		(16,882)
Unitholders' capital		(49)
Accumulated income		1,386

See Note 18 for the additional presentation and disclosure requirements for Financial Instruments.

Other Comprehensive Income

The new standards introduce the concept of comprehensive income, which consists of net income and other comprehensive income. Other comprehensive income represents changes in Unitholders' equity during a period arising from transactions and other events with non-owner sources. The transitional provisions of this section require that the comparative statements are restated to reflect the application of this standard only on certain items.

For Harvest, the only such item is the unrealized foreign currency translation gains or losses arising from our downstream operations, which is considered a self-sustaining operation with a US dollar functional currency. As the cumulative translation adjustment was presented as a separate component of Unitholders' equity already, this restatement simply required the cumulative translation adjustment to be reclassified to accumulated other comprehensive income on the balance sheet and statement of Unitholders' equity.

Future Accounting Changes

The AcSB issued new accounting standards on December 1, 2006 that 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. This standard has an implementation date for annual and interim financial statements beginning on or after October 1, 2007.

Also on December 1, 2006, the AcSB issued a new standard regarding Capital Disclosure requiring 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. This standard also has an implementation date for annual and interim financial statements beginning on or after October 1, 2007.

In June 2007, the AcSB issued section 3031, Inventories, 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. This standard is to be adopted for fiscal years beginning on or after January 1, 2008. We do not expect the adoption of this section to have a material impact on our net income or financial position.

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.

4. BUSINESS ACQUISITIONS

(a) Grand Petroleum Inc. ("Grand")

Pursuant to its cash offer of $3.84 for each issued and outstanding common share of Grand, Harvest acquired control of Grand with its acquisition of 21,310,419 Grand common shares for cash consideration of $81.8 million on July 26, 2007. Subsequent to this acquisition of 74.6% of the issued and outstanding common shares of Grand, Harvest acquired the remaining 7,251,604 common shares of Grand for an additional $27.8 million by extending its offer to purchase to August 9, 2007 and thereafter pursuant to the compulsory acquisition provisions of the Business Corporations Act (Alberta). The aggregate consideration for the Grand acquisition consists of the following:

	Amount
Cash paid	$ 109,678
Assumption of bank debt	28,798
Acquisition costs	785
	$ 139,261

This acquisition has been accounted for using the purchase method, whereby the assets acquired and the liabilities assumed are recorded at their fair values with the excess of the aggregate consideration over the fair value of the identifiable net assets allocated to goodwill. As of the acquisition date, Grand's operating results have been included in Harvest's revenues, expenses and capital spending. The following summarizes the allocation of the aggregate consideration for the Grand acquisition.

		Amount
Net working capital	$	(3,451)
Property, plant and equipment		147,420
Goodwill		20,546
Asset retirement obligation		(4,416)
Future income tax		(20,838)
	$	139,261

Amendments may be made to the purchase equation as the cost estimates and balances are finalized.

(b) *Private petroleum and natural gas corporation*

On March 1, 2007, Harvest acquired all of the issued and outstanding shares of a private petroleum and natural gas corporation for $30.6 million net of working capital adjustments and transaction costs. The results of operations of this acquisition have been included in the consolidated financial statements since its acquisition date. An officer of Harvest was a director of this private corporation and received proceeds that are considered to be insignificant to both the officer and Harvest.

(c) *North Atlantic Refining Limited*

On October 19, 2006, Harvest acquired all of the issued and outstanding shares of North Atlantic Refining Limited for $1.6 billion plus certain working capital and other adjustments. The principal asset of North Atlantic Refining Limited is a medium gravity, sour-crude hydrocracking refinery. North Atlantic Refining Limited also operates a marketing division which includes gas stations, a retail heating fuels business and other ancillary services. The results of operations of North Atlantic have been included in the consolidated financial statements since its acquisition on October 19, 2006.

The aggregate consideration for the acquisition of North Atlantic consists of the following:

		Amount
Cash paid	$	1,592,793
Acquisition costs		4,331
	$	1,597,124

This transaction has been accounted for using the purchase method whereby the assets acquired and the liabilities assumed are recorded at their fair values with the excess of the aggregated consideration over the fair value of the identifiable net assets allocated to goodwill. These amounts are estimates made by management based on currently available information. The following summarizes the aggregate consideration for the North Atlantic acquisition:

		Amount
Net working capital (including cash of $22,464)	$	2,863
Inventory		36,137
Property, plant and equipment		1,254,696
Intangible assets (Note 7)		111,977
Long-term receivables		2,729
Goodwill		200,925
Funding deficiency of pension and other benefit plans		(12,203)
	$	1,597,124

During 2007 the acquisition costs were reduced by $0.7 million and net working capital was increased by $2.9 million, with a corresponding decrease in goodwill, as certain accrued liabilities that were estimated at the time of purchase did not materialize subsequent to the acquisition.

(d) *Birchill Energy Limited ("Birchill")*

On July 26, 2006, Harvest signed a binding agreement to purchase all of the issued and outstanding shares of Birchill on August 15, 2006 for $446.8 million net of working capital adjustments and transaction costs. The results of operations of Birchill have been included in the consolidated financial statements since the time of effective control, July 26, 2006.

The aggregate consideration for the acquisition of Birchill consists of the following:

		Amount
Cash paid, net of expected working capital recoveries	$	447,511
Acquisition costs		267
	$	447,778

This transaction has been accounted for using the purchase method whereby the assets acquired and the liabilities assumed are recorded at their fair values with the excess of the aggregate consideration over the fair value of the identifiable net assets allocated to goodwill. The following summarizes the allocation of the aggregate consideration for the Birchill acquisition.

		Amount
Net working capital deficiency (including nil cash)	$	(14,755)
Property, plant and equipment		463,752
Asset retirement obligation		(1,219)
	$	447,778

During 2007 the cash paid for Birchill was increased by $1.9 million while the acquisition costs were decreased by $1.0 million with the corresponding net increase of $0.9 million reflected in property, plant and equipment. The increase in cash paid is due to additional assets that could not be valued at the time of acquisition and were therefore subsequently valued and settled, while the reduction in acquisition costs relates to certain accrued liabilities that were estimated at the time of purchase and did not materialize subsequent to the acquisition.

(e) Viking Energy Royalty Trust ("Viking")

On February 3, 2006, the unitholders of Harvest and Viking voted to approve a resolution to effect the Plan of Arrangement (the "Plan of Arrangement") by which unitholders of Viking received 0.25 Harvest Trust Units for every Viking Trust Unit held, and Harvest acquired all of the assets and assumed all of the liabilities of Viking for total consideration of approximately $1,638.1 million plus assumption of debt. This amount consisted of the issuance of 46,040,788 Trust Units [Note 14(b)] at an ascribed value of $35.58 per Trust Unit, based on the weighted average trading price of the Harvest Trust Units before and after the announcement date of November 28, 2005. Pursuant to the terms and conditions of Vikings' convertible debenture indenture, Harvest's acquisition of Viking's net assets resulted in Harvest assuming the obligations of Viking's convertible debentures, including the adjustment of the conversion ratio to reflect the 0.25 Harvest Trust Unit for each Viking Trust Unit exchange ratio.

The aggregate consideration for the acquisition of Viking consists of the following:

		Amount
Ascribed value of Trust Units issued	$	1,638,131
Bank debt assumed		106,247
Convertible debentures assumed		-
Debt component		202,232
Equity component		24,123
Acquisition costs		4,600
	$	1,975,333

This transaction has been accounted for using the purchase method whereby the assets acquired and the liabilities assumed are recorded at their fair values with the excess of the aggregate consideration over the fair value of the identifiable net assets allocated to goodwill. The following summarizes the allocation of the aggregate consideration for the Viking acquisition.

		Amount
Net working capital deficiency (including nil cash)	$	(31,297)
Property, plant and equipment		1,455,000
Fair value deficiency of risk management contracts		(1,224)
Fair value of office lease (Note 6)		931
Goodwill		612,416
Asset retirement obligation		(60,493)
	$	1,975,333

Effective February 3, 2006, the results of Viking have been included in the consolidated financial statements.

5. INVENTORIES

	December 31, 2007	December 31, 2006
Petroleum products	$ 55,036	$ 19,513
Parts and supplies	3,898	4,279
Total inventories, net	$ 58,934	$ 23,792

6. PROPERTY, PLANT AND EQUIPMENT

	December 31, 2007			December 31, 2006		
	Upstream	Downstream	Total	Upstream	Downstream	Total
Cost	$ 4,247,819	$ 1,164,310	$ 5,412,129	$ 3,801,054	$ 1,320,698	$ 5,121,752
Accumulated depletion and depreciation	(1,142,345)	(72,277)	(1,214,622)	(706,540)	(14,660)	(721,200)
Net book value	$ 3,105,474	$ 1,092,033	$ 4,197,507	$ 3,094,514	$ 1,306,038	$ 4,400,552

General and administrative costs of $9.2 million (2006 – $12.1 million) have been capitalized during the year ended December 31, 2007, of which $0.6 million (2006 - $3.0 million) relate to the Trust Unit Incentive Plan and the Unit Award Incentive Plan.

All costs, except those associated with undeveloped properties, major spare parts inventory and assets under construction, are subject to depletion and depreciation at December 31, 2007 including future development costs of $325.4 million (2006 – $289.2 million). No amounts for undeveloped properties were excluded from the asset base subject to depletion for the years ended December 31, 2007 and 2006. Downstream major parts inventory of $6.1 million were excluded from the asset base subject to depreciation at December 31, 2007 (2006 - $6.7 million). Downstream assets under construction of $7.4 million were excluded from the asset base subject to depreciation at December 31, 2007 (2006 - $5.5 million).

The petroleum and natural gas future prices used in the impairment test for petroleum and natural gas assets were obtained from third party engineers and were adjusted for contractual arrangements relating to pricing and quality differentials specific to Harvest. Based on these assumptions, the undiscounted future net revenue from Harvest's proved reserves exceed the carrying amount of its petroleum and natural gas assets as at December 31, 2007 and 2006, and therefore no impairment was recorded in either of the periods ended on these dates.

Benchmark prices and US$/Cdn.$ exchange rate assumptions reflected in the impairment test as at December 31, 2007 were as follows:

Year	WTI Oil[1] (US$/barrel)	Foreign Exchange Rate	Edmonton Light Crude Oil[1] (CDN$ barrel)	AECO Gas[1] (CDN$/Gigajoule)
2008	90.00	1.00	89.00	6.45
2009	86.70	1.00	85.70	7.00
2010	83.20	1.00	82.20	7.00
2011	79.60	1.00	78.50	7.00
2012	78.50	1.00	77.40	7.10
Thereafter (escalation)	2%	0%	2%	2%

(1) Actual prices used in the impairment test were adjusted for commodity price differentials specific to Harvest.

7. INTANGIBLE ASSETS

	December 31, 2007			December 31, 2006		
	Cost	Accumulated Amortization	Net book value	Cost	Accumulated Amortization	Net book value
Engineering drawings	$ 88,227	$ 5,330	$ 82,897	$ 103,721	$ 1,080	$ 102,641
Marketing contracts	6,136	1,099	5,037	7,214	105	7,109
Customer lists	3,714	449	3,265	4,368	92	4,276
Fair value of office lease	931	428	503	931	205	726
Financing costs	12,113	8,740	3,373	11,840	4,230	7,610
Total	$ 111,121	$ 16,046	$ 95,075	$ 128,074	$ 5,712	$ 122,362

8. OTHER NON-CURRENT ASSETS

	December 31, 2007	December 31, 2006
Deferred charges, net of amortization *[Note 3]*	$ -	$ 23,659
Discount on senior notes, net of amortization *[Note 3]*	-	1,408
Total	$ -	$ 25,067

9. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	December 31, 2007	December 31, 2006
Trade accounts payable	$ 100,265	$ 111,837
Accrued interest	15,779	14,367
Trust Unit Incentive Plan and Unit Award Incentive Plan *[Note 15]*	7,218	6,442
Other accrued liabilities	146,981	161,936
Total	$ 270,243	$ 294,582

10. 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 $1,003 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:

	December 31, 2007	December 31, 2006
Balance, beginning of year	$ 202,480	$ 110,693
Incurred on acquisition of a private corporation	1,629	-
Incurred on acquisition of Grand	4,416	-
Incurred on acquisition of Viking	-	60,493
Incurred on acquisition of Birchill	-	1,219
Liabilities incurred	9,553	2,763
Revision of estimates	(6,088)	20,544
Liabilities settled through disposition	(3,708)	-
Liabilities settled	(13,090)	(9,186)
Accretion expense	18,337	15,954
Balance, end of year	$ 213,529	$ 202,480

Harvest has gross 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.

11. BANK LOAN

At December 31, 2007, Harvest had $1,279.5 million drawn under its $1.6 billion Three Year Extendible Revolving Credit Facility ("Credit Facility"). At December 31, 2006, Harvest had $1,306.0 million drawn under the Credit Facility, of which $763.0 million was payable in US dollars, and $289.7 million drawn under its $350 million Senior Secured Bridge Facility.

The Credit Facility was established on February 3, 2006 and subsequently amended on October 19, 2006 to accommodate the purchase of North Atlantic. This amendment increased the borrowing capacity to $1.4 billion and established a $350 million Senior Secured Bridge Facility. The maturity date of this facility was March 31, 2009, but could be extended on an annual basis for an additional 364 days with the consent of the lenders. The credit facility is secured by a $2.5 billion first floating charge over all of the assets of Harvest's operating subsidiaries plus a first mortgage security interest on the refinery assets of North Atlantic. Amounts borrowed under this facility bear interest at a floating rate based on bankers' acceptances plus a range of 65 to 115 basis points depending on Harvest's ratio of senior debt (excluding convertible debentures) to its earnings before interest, taxes, depletion, amortization and other non-cash amounts ("EBITDA"). An additional fee of 15 basis points was applicable so long as the Senior Unsecured Bridge Facility was outstanding. Availability under this facility is subject to the following quarterly financial covenants:

Senior debt to EBITDA	3.0 to 1.0 or less
Total debt to EBITDA	3.5 to 1.0 or less
Senior debt to Capitalization	50% or less
Total debt to Capitalization	55% or less

The $350 million Senior Secured Bridge Facility provided Harvest with a single draw on this facility within five days of the closing of its acquisition of North Atlantic and required repayments equivalent to the net proceeds from an issuance of equity or equity like securities including convertible debentures and, in all events, repayment in full within 18 months of the initial draw.

On February 1, 2007, Harvest issued 6,146,750 Trust Units and 200,000 convertible debentures for total net proceeds of $328.6 million which was used to fully repay the remaining $289.7 million outstanding on the Senior Secured Bridge Facility with the remainder applied to the Credit Facility.

On May 7, 2007, Harvest and its lenders amended the Credit Facility to increase the aggregate commitment amount from $1.4 billion to $1.6 billion and extend the maturity date of the facility from March 31, 2009 to April 30, 2010 with respect to $1,535 million of the aggregate commitment amount. Effective May 7, 2007, the Credit Facility consisted of $1,535 million of commitments with a maturity date of April 30, 2010 and $65 million of commitments with a maturity date of March 31, 2009.

On October 1, 2007, two of Harvest's existing lenders agreed to assume $50 million of the $65 million commitment to mature on March 31, 2009 and concurrently extended the maturity to April 30, 2010. On November 1, 2007, another of Harvest's existing lenders agreed to assume the remaining $15 million of credit commitments to mature on March 31, 2009 and similarly extended the maturity to April 30, 2010. Subsequent to these reassignments, the entire $1.6 billion of the Credit Facility matures on April 30, 2010.

On October 19, 2006, North Atlantic entered into an amended and restated credit agreement that provided for a $10 million demand operating line of credit to finance its receivables and inventory in the Province of Newfoundland and Labrador as well as support periodic cash management market transactions. This facility is secured by a guarantee from Harvest Operations Corp. with amounts borrowed bearing interest at the bank's prime lending rate.

For the year ended December 31, 2007 Harvest paid interest at an average rate of 5.28% (2005 – 4.86%) and 6.08% (2005 – 6. 07%) for the Canadian and U.S amounts drawn, respectively.

12. CONVERTIBLE DEBENTURES

Harvest has seven series of convertible unsecured subordinated debentures outstanding. Interest on the debentures is payable semi-annually in arrears in equal installments on dates prescribed by each series. The debentures are convertible into fully paid and non-assessable Trust Units, at the option of the holder, at any time prior to the close of business on the earlier of the maturity date and the business day immediately preceding the date specified by Harvest for redemption. The conversion price per Trust Unit is specified for each series and may be supplemented with a cash payment for accrued interest and in lieu of any fractional Trust Units resulting from the conversion.

The debentures may be redeemed by Harvest at its option in whole or in part prior to their respective maturity dates. The redemption price for the first redemption period is at a price equal to $1,050 per debenture and at $1,025 per debenture during the second redemption period. Any redemption will include accrued and unpaid interest at such time. Harvest may elect to settle the principal due at maturity or on redemption and periodic interest payments in the form of Trust Units at a price equal to 95% of the weighted average trading price for the preceding 20 consecutive trading days, 5 days prior to settlement date.

The following is a summary of the seven series of convertible debentures:

Series		Conversion price / Trust Unit	Maturity	First redemption period	Second redemption period
9% Debenture Due 2009	$	13.85	May 31, 2009	Jun. 1/07-May 31/08	Jun. 1/08-May. 30/09
8% Debenture Due 2009	$	16.07	Sept. 30, 2009	Oct. 1/07-Sept. 30/08	Oct. 1/08-Sept. 29/09
6.5% Debenture Due 2010	$	31.00	Dec. 31, 2010	Jan. 1/09-Dec. 31/09	Jan. 1/10-Dec. 30/10
10.5% Debenture Due 2008	$	29.00	Jan. 31, 2008	Feb. 1/06-Jan. 31/07	Feb. 1/07-Jan. 30/08
6.40% Debenture Due 2012(1)	$	46.00	Oct. 31, 2012	Nov. 1/08-Oct. 31/09	Nov. 1/09-Oct. 31/10
7.25% Debenture Due 2013(1)	$	32.20	Sept. 30, 2013	Oct. 1/09-Sept. 30/10	Oct. 1/10-Sept. 30/11
7.25% Debenture Due 2014(1)	$	27.25	Feb. 28, 2014	Mar. 1/10-Feb. 28/11	Mar. 1/11-Feb. 29/12

(1) These series of convertible debentures may also be redeemed by Harvest at a price of $1,000 per debenture after the second redemption period until maturity.

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

	December 31, 2007			December 31, 2006	
	Face Value	Carrying Amount(1)	Fair Value	Face Value	Carrying Amount(1)
9% Debentures Due 2009	$ 976	$ 962	$ 1,806	$ 1,226	$ 1,226
8% Debentures Due 2009	1,728	1,692	2,022	2,239	2,229
6.5% Debentures Due 2010	37,062	34,653	35,950	37,929	35,988
10.5% Debentures Due 2008	24,258	24,273	24,258	26,621	26,824
6.40% Debentures Due 2012	174,626	168,325	148,432	174,743	167,401
7.25% Debentures Due 2013	379,256	355,145	344,895	379,500	367,843
7.25% Debentures Due 2014	73,222	66,718	65,892	-	-
	$ 691,128	$ 651,768	$ 623,255	$ 622,258	$ 601,511

(1) Excluding the equity component.

On January 31, 2008, the 10.5% Debentures due 2008 matured and Harvest elected to settle the obligation by issuing 1,116,593 Trust Units rather than settling the obligation in cash.

13. 7 7/8% SENIOR NOTES

On October 14, 2004, Harvest Operations Corp., a wholly owned subsidiary of Harvest, issued US$250 million of 7 7/8% Senior Notes for cash proceeds of $311,951,000. The 7 7/8% Senior Notes are unsecured, require interest payments semi-annually on April 15 and October 15 each year and mature on October 15, 2011. Prior to maturity, redemptions are permitted as follows:

- Beginning on October 15, 2007 at 103.938% of the principal amount(1)
- After October 15, 2008 at 103.938% of the principal amount
- After October 15, 2009 at 101.969% of the principal amount
- After October 15, 2010 at 100% of the principal amount

(1) Only permitted if necessary to prevent the Trust from being disqualified as a trust for the purpose of the Income Tax Act. Limited to 35% of the notes issued or less; otherwise 100% of the notes issued.

The 7 7/8% Senior Notes contain certain covenants restricting, among other things, the sale of assets and the incurrence of additional indebtedness if such issuance would result in an interest coverage ratio, as defined, of less than 2.5 to 1. The covenants of the 7 7/8% Senior Notes also restrict Harvest's secured indebtedness to an amount less than 65% of the present value of the future net revenues from its proven petroleum and natural gas reserves discounted at an annual rate of 10%. In addition, the 7 7/8% Senior Notes restrict Harvest's ability to pay distributions to an amount equal to 80% of the cumulative net proceeds from the issuance of Trust Units plus the cash flows from operations, before settlement of asset retirement obligations and changes in non-cash working capital, both calculated from the date of issuance of the 7 7/8% Senior Notes. An excess carryforward balance of approximately Cdn$1.5 billion exists as at December 31, 2007.

The 7 7/8% Senior Notes are unconditionally guaranteed by Harvest and all of its wholly-owned subsidiaries. The fair value of the 7 7/8% Senior Notes at December 31, 2007 was US$232.6 million (2006 - $236.3 million).

14. UNITHOLDERS' CAPITAL

(a) *Authorized*

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

(b) *Number of Units Issued*

	Year ended December 31, 2007	2006
Outstanding, beginning of year	122,096,172	52,982,567
Issued in exchange for assets of Viking *[Note 4(e)]*	-	46,040,788
Issued for cash		
August 17, 2006	-	7,026,500
November 22, 2006	-	9,499,000
February 1, 2007	6,146,750	-
June 1, 2007	7,302,500	-
Convertible debenture conversions		
9% Debentures Due 2009	18,047	39,777
8% Debentures Due 2009	31,790	96,252
6.5% Debentures Due 2010	27,967	114,313
10.5% Debentures Due 2008	81,478	290,919
6.40% Debentures Due 2012	2,542	4,825
7.25% Debentures Due 2013	7,574	-
7.25% Debentures Due 2014	5,753,310	-
Exchangeable share retraction	-	184,809
Distribution reinvestment plan issuance	6,809,987	5,464,450
Exercise of unit appreciation rights and other	13,053	351,972
Outstanding, end of year	148,291,170	122,096,172

On August 17, 2005, Harvest implemented a premium distribution reinvestment plan. The premium distribution program enables investors to receive a cash payment equal to 102% of the regular distribution amount. The impact to Harvest is the same as the regular distribution reinvestment plan whereby it settles distributions with units rather than cash, at a discount to the current market price of the Units.

(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	December 31, 2007	December 31, 2006
Net (loss) income, basic	$ (25,676)	$ 136,046
Interest on convertible debentures and other	-	310
Net income, diluted(1)	$ (25,676)	$ 136,356
Weighted average Trust Units adjustments	**December 31, 2007**	**December 31, 2006**
Number of Units		
Weighted average Trust Units outstanding, basic	138,440,869	101,590,850
Effect of convertible debentures and other	-	322,793
Effect of Employee Unit Incentive Plans	-	268,518
Weighted average Trust Units outstanding, diluted(2)	138,440,869	102,182,161

(1) Net income, diluted excludes the impact of the conversions of certain of the convertible debentures of $59,238,000 for the year ended December 31, 2007 (2006 - $19,855,000), as the impact would be anti-dilutive.

(2) Weighted average Trust Units outstanding, diluted for the year ended December 31, 2007 does not include the unit impact of 23,636,000 for certain of the convertible debentures (2006 – 6,980,000) and 682,000 (2006 – nil) for the Employee Unit Incentive Plans, as the impact would be anti-dilutive.

15. EMPLOYEE UNIT INCENTIVE PLANS

Trust Unit Rights Incentive Plan

Harvest is authorized to grant non-transferable Unit appreciation rights to directors, officers, consultants, employees and other service providers to an aggregate of a rolling maximum of 7% of the outstanding Trust Units and the number of Trust Units issuable upon the exchange of any outstanding exchangeable shares. The initial exercise price of rights granted under the plan is equal to the market price of the Trust Units at the time of grant and the maximum term of each right is five years. The rights vest equally over four years commencing on the first anniversary of the grant date. The exercise price of the rights may be reduced by an amount up to the amount of cash distributions made on the Trust Units subsequent to the date of grant of the respective right, provided that Harvest's net operating cash flow (on an annualized basis) exceeds 10% of Harvest's recorded cost of property, plant and equipment less all debt, working capital deficiency (surplus) or debt equivalent instruments, accumulated depletion, depreciation and amortization charges, asset retirement obligations, and any future income tax liability associated with such property, plant and equipment. Any portion of a distribution that does not reduce the exercise price on exercised rights is paid to the holder in a lump sum cash payment after the rights have been exercised.

Upon the exercise of unit appreciation rights the holder has the sole discretion to elect to receive cash or units. As a result, Harvest recognizes a liability on its consolidated balance sheet associated with the rights reserved under the plan. This obligation represents the difference between the market value of the Trust Units and the exercise price of the vested Unit rights outstanding under the plan. As such, an obligation of $1.4 million (2006 - $2.8 million) has been recorded in accounts payable and accrued liabilities for the graded vested portion of the 3,823,683 (2006 – 3,788,125) Trust Units outstanding under the plan at December 31, 2007. For accounting purposes, vesting is deemed to occur on a pro rata basis throughout the year, rather than at a vesting date which only occurs on the anniversary date of the grant.

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

	Year ended December 31, 2007		Year ended December 31, 2006	
	Unit Appreciation Rights	Weighted Average Exercise Price	Unit Appreciation Rights	Weighted Average Exercise Price
Outstanding beginning of year	3,788,125	$ 30.81	1,305,143	$ 19.72
Granted	576,383	29.03	3,924,300	31.92
Exercised	(92,775)	21.88	(1,039,018)	18.58
Forfeited	(448,050)	31.10	(402,300)	37.25
Outstanding before exercise price reductions	3,823,683	30.74	3,788,125	30.81
Exercise price reductions	-	(5.00)	-	(1.67)
Outstanding, end of year	3,823,683	$ 25.74	3,788,125	$ 29.14
Exercisable before exercise price reductions	138,350	$ 22.72	266,125	$ 24.18
Exercise price reductions	-	(9.38)	-	(5.37)
Exercisable, end of year	138,350	$ 13.34	266,125	$ 18.81

The following table summarizes information about Unit appreciation rights outstanding at December 31, 2007.

		Outstanding			Exercisable	
Exercise Price before price reductions	Exercise Price net of price reductions	At December 31, 2007	Weighted Average Exercise Price net of price reductions(1)	Remaining Contractual Life(1)	At December 31, 2007	Weighted Average Exercise Price net of price reductions(1)
$12.19-$13.15	$0.87-$2.20	6,250	$ 1.93	0.9	6.250	$ 1.93
$13.75-$14.99	$2.99-$5.13	18,250	4.95	1.5	18,250	4.95
$18.90-$25.05	$9.12-$22.58	183,650	17.51	3.2	113,850	15.31
$26.09-$28.41	$21.92-$27.35	1,669,300	22.21	4.0	-	-
$28.59-$37.56	$21.00-$32.69	1,946,233	29.81	3.4	-	-
$12.19-$37.56	$0.87-$32.69	3,823,683	$ 25.74	3.6	138,350	$ 13.34

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

Unit Award Incentive Plan ("Unit Award Plan")

The Unit Award Plan authorizes Harvest to grant awards of Trust Units to directors, officers, employees and consultants of Harvest and its affiliates (to an aggregate of a rolling maximum of 0.5% of the outstanding Trust Units and the number of Trust Units issuable upon the exercise of any outstanding exchangeable shares). Subject to the Board of Directors' discretion, awards vest annually over a two to four year period and, upon vesting, entitle the holder to elect to receive the number of Trust Units subject to the award or the equivalent cash amount. The number of Units to be issued is adjusted at each distribution date for an amount approximately equal to the foregone distributions. Harvest recognizes a liability on its consolidated balance sheet associated with the awards granted under the plan. This obligation represents the fair value of the vested Trust Units granted under the Unit Award Plan. As such, an obligation of $5.8 million (2006 - $3.6 million) has been recorded in accounts payable and accrued liabilities for the graded vested portion of the 348,248 (2006 – 306,699) Unit Awards outstanding under the plan at December 31, 2007. For accounting purposes, vesting is deemed to occur on a pro rata basis throughout the year, rather than at a vesting date.

Number	December 31, 2007	December 31, 2006
Outstanding, beginning of year	306,699	35,365
Granted	56,132	320,905
Adjusted for distributions	48,280	27,879
Exercised	(37,072)	(41,530)
Forfeitures	(25,791)	(35,920)
Outstanding, end of year	348,248	306,699
Exercisable, end of year	168,401	67,428

Upon closing of the Viking Plan of Arrangement all awards and rights issued under Harvest's employee unit incentive plans vested and additional rights and awards were issued under both plans.

Harvest has recognized compensation expense of $2.7 million (2006 – $9.9 million), including non cash compensation expense of $0.6 million (2006 - $0.8 million), for the year ended December 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.

16. INCOME TAXES

The future income tax provision reflects the net tax effects of temporary differences between the carrying amounts of assets and liabilities of the Trust and their corresponding income tax bases as at that date. Changes in the temporary differences are reflected in future income tax expense or recovery.

In the second quarter of 2007, the Canadian government enacted legislation to apply a 31.5% tax to distributions from Canadian publicly traded income trusts. In the fourth quarter of 2007, the tax rate for trust distributions was reduced to 29.5% for 2011 and to 28% for 2012 and subsequent years. The new tax is not expected to apply to Harvest until 2011, as a transition period has been established for publicly traded trusts that existed prior to November 1, 2006. This portion of the Trust's future income tax liability represents its tax-effected temporary differences that it estimates will exist on January 1, 2011, pursuant to the current legislation and Harvest's current structure.

Concurrent with the tax rate reductions referred to above, further reductions in Federal corporate income tax rates were enacted. Under the legislation, Federal corporate rates will decline until 2012, resulting in an effective tax rate for the Trust's corporate entities of approximately 26%, which is the rate applied to the temporary differences in the future income tax calculation based on when these differences are expected to reverse.

The provision for future income taxes varies from the amount that would be computed by applying the relevant Canadian income tax rates to reported income before taxes as follows:

	Year ended December 31	
	2007	2006
Income before taxes	$ 39,152	$ 133,737
Combined Canadian Federal and Provincial statutory income tax rate	32.7%	35.3%
Computed income tax expense at statutory rates	12,803	47,209
Income earned by flow through entities	(179,750)	(136,452)
Loss in corporate entities	(166,947)	(89,243)
Increased expense (recovery) resulting from the following:		
Initial recognition of trust temporary differences	271,705	
Benefit of future tax deductions (recognized) not recognized	(72,073)	62,384
Difference between current and expected tax rates	44,547	10,465
Non-taxable portion of capital (gain) loss	(20,515)	1,789
Change in estimates	8,860	-
Non-deductible expenses	225	3,228
Non-deductible crown charges in excess of resource allowance	-	9,077
Future income tax expense (recovery)	65,802	(2,300)

The components of the future income tax liability (asset) are as follows:

	December 31, 2007	December 31, 2006
Net book value of petroleum and natural gas assets in excess of tax pools	$ 333,466	$ 29,896
Net book value of intangible assets in excess of tax pools	13,998	-
Asset retirement obligation	(56,066)	(17,641)
Net unrealized losses related to risk management contracts and foreign exchange positions – current	(38,642)	(3,818)
Net unrealized losses related to risk management contracts and foreign exchange positions – long-term	304	(1,266)
Non-capital loss carry forwards for tax purposes	(161,706)	(40,412)
Deferral of taxable income in partnership	1,492	1,483
Future employee retirement costs	(3,607)	-
Working capital and other items	(2,599)	(2,787)
Valuation allowance	-	34,545
Future income tax liability (asset), net	$ 86,640	$ -

Canada Revenue Agency ("CRA") Assessment

In 2002, the CRA assessed, as a $30 million forgiveness of debt, a 1994 share issue in connection with the acquisition of North Atlantic in 1994 by a Vitol Refining S.A. affiliate. North Atlantic disagrees with the CRA's position and believes that the value of the common shares issued in 1994 was equal to the value of the debt exchanged and has filed a Notice of Objection to the CRA's Notice of Reassessment. There are no contingent amounts accrued related to this matter in these financial statements. Harvest is indemnified by the vendor of North Atlantic in respect of this contingent liability.

17. EMPLOYEE FUTURE BENEFIT PLANS

Defined Contribution Pension Plan

Total expense for the defined contribution plan is equal to Harvest's required contributions and was $0.7 million for the year ended December 31, 2007 (2006 – $0.1 million).

Defined Benefit Plans

The measurement of the accrued benefit obligation and annual expense for the defined benefit plans requires actuarial calculations and several assumptions. These assumptions, set annually on December 31, are as follows;

	December 31, 2007		December 31, 2006	
	Pension Plans	Other Benefit Plans	Pension Plans	Other Benefit Plans
Discount rate	5.0%	5.0 %	5.0%	5.0 %
Expected long-term rate of return on plan assets	7.0%	-	7.0%	-
Rate of compensation increase	3.5%	-	3.5%	-
Employee contribution of pensionable income	6.0%	-	6.0%	-
Annual rate of increase in covered health care benefits	-	11.0%	-	12.0%
Expected average remaining service lifetime (years)	11.7	10.8	11.7	11.1

The assets of the defined benefit plan are invested and maintain the following asset mix:

	December 31, 2007	December 31, 2006
Bonds/fixed income securities	32%	32%
Equity securities	68%	68%

The expected long-term rates of return are estimated based on many factors, including the expected forecast for inflation, risk premiums for each class of asset, and current and future financial market conditions.

The defined benefit pension plans were subject to an actuarial valuation on December 31, 2005 and the next valuation report is due no later than December 31, 2008. The post-retirement health care benefits plan was last subject to an actuarial valuation on December 31, 2006.

	December 31, 2007		December 31, 2006	
	Pension Plans	Other Benefit Plans	Pension Plans	Other Benefit Plans
Employee benefit obligation, beginning of year	$ 43,101	$ 6,027	$ 38,754	$ 5,315
Current service costs	3,043	369	648	88
Interest	2,357	316	546	74
Actuarial losses	1,409	162	3,422	601
Plan amendment	-	-	-	-
Benefits paid	(828)	(221)	(269)	(51)
Impact of foreign exchange on translation	-	-	-	-
Employee benefit obligation, end of year	49,082	6,653	43,101	6,027
Fair value of plan assets, beginning of year	36,576	-	31,878	-
Actual return on plan assets	(1,682)	-	3,181	-
Employer contributions	3,428	221	1,306	51
Employee contributions	1,409	-	480	-
Benefits paid	(828)	(221)	(269)	(51)
Impact of foreign exchange on translation	-	-	-	-
Fair value of plan assets, end of year	38,903	-	36,576	-
Funded status	(10,179)	(6,653)	(6,525)	(6,027)
Unamortized balances:				
Net actuarial losses	4,664	-	325	-
Past services	-	-	-	-
Carrying amount	$ (5,515)	$ (6,653)	$ (6,200)	$ (6,027)

	December, 31, 2007	December 31, 2006
Summary:		
Pension plans	$ 5,515	$ 6,200
Other benefit plans	6,653	6,027
Carrying amount	$ 12,168	$ 12,227

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 20].

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

	Year ended December 31, 2007		Year ended December 31, 2006	
	Pension Plans	Other Benefit Plans	Pension Plans	Other Benefit Plans
Current service cost	$ 3,043	$ 369	$ 648	$ 88
Interest costs	2,357	316	546	74
Expected return on assets	(2,657)	-	(563)	-
Amortization of net actuarial losses	-	101	-	588
Net benefit plan expense	$ 2,743	$ 786	$ 631	$ 750

A 1% change in the expected health care cost trend rate would have the following annual impacts as at December 31, 2007:

	1% Increase	1% Decrease
Impact on post-retirement benefit expense	$ 1	$ (2)
Impact on projected benefit obligation	9	(11)

18. 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 senior notes. The carrying value and fair value of these financial instruments at December 31, 2007 is disclosed below by financial instrument category, as well as any related gains or losses and interest income or expense for the year ended December 31, 2007:

Financial Instrument	Carrying Value	Fair Value	Gains/ (Losses)	Interest Income/ (Expense)	Other Income/ (Expense)
Loans and Receivables					
Accounts receivable	212,271	212,271	-	-	-
Lease payments receivable	3,532(1)	3,532	-	201(2)	-
Liabilites Held For Trading					
Net fair value of risk management contracts	149,673	149,673	(174,072)(3)	-	-
Other Liabilities					
Accounts payable	270,243	270,243	-	-	-
Cash distribution payable	44,487	44,487	-	-	-
Bank loan	1,279,501	1,279,501	-	(71,477)(4)	(4,509)(4)
$7^{7/8}$% Senior Notes	241,148(6)	232,646	-	(22,561)(5)	-
Convertible debentures	651,768	623,255	-	(59,238)(5)	-

(1) Included in accounts receivable on the balance sheet.
(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.
(6) The face value of the $7^{7/8}$% Senior Notes at December 31, 2007 is $247.8 million (US $250 million).

The fair value of the lease payments receivable is the present value of expected future cash flows. The fair values of the convertible debentures and the $7^{7/8}$% Senior Notes are based on quoted market prices as at December 31, 2007. 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 there are no transaction costs associated with this and the financing costs are included in intangible assets; therefore, there is no difference between the carrying value and the fair value. Due to the short term nature of cash, 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, we try to obtain a guarantee from the parent company. If this is not possible, we perform our own internal credit review based on the purchaser's past financial performance. The credit risk associated with our joint venture partners is mitigated by reviewing the credit history of partners and requiring some partners to provide cash upfront in the form of cash calls for significant capital projects. As well, most agreements have a net off provision that enables us to use the proceeds from the sale of production that would otherwise be taken in kind by the partner to net off amounts owing from the partner that are in default. Historically, the only instances of impairment have been when a purchaser or partner has gone bankrupt.

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 by dealing with investment grade financial institutions. We have no history of impairment with these counterparties and therefore no impairment is recorded at December 31, 2007 or 2006.

Supply and Offtake Agreement Accounts Receivable (Vitol)

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 substantially all product sales are made with Vitol. 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.

Other Accounts Receivable

Harvest does not have any significant exposure to any individual customer in its downstream operations and its policy is to manage its credit risk by dealing with only financially sound customers. Credit is extended based on an evaluation of the customer's financial condition. The carrying amount of accounts receivable reflects management's assessment of the associated credit risks.

Harvest is also exposed to credit risk from customers due to the lease payments receivable relating to our net investment in vehicle and equipment leases. As some of the counterparties to these leases are employees or distributors, any over due amounts can be deducted from wages or commissions and therefore, the credit risk is low.

(ii.) Liquidity Risk

Harvest is exposed to liquidity risk mainly due to our outstanding bank balances and $7^{7/8}$% Senior Notes with repayment requirements. This risk is mitigated by managing the maturity dates on our obligations and complying with the covenants.

(iii.) Market Risk

Harvest is exposed to three types of market risks: interest rate risk, foreign currency exchange rate risk and commodity price risk.

Interest Rate Risk

Harvest is exposed to interest rate risk on its bank loans as interest rates are determined in relation to floating market rates. Harvest's convertible debentures and $7^{7/8}$% Senior Notes have fixed interest rates and therefore do not create an interest rate risk. Harvest manages its exposure to interest rate risk by maintaining its debt in a combination of floating rate debt denominated in Canadian dollars and bearing interest relative to the Canadian interest rate benchmark, and fixed rate debt denominated in US dollars.

In addition, Harvest manages its interest rate risk by targeting appropriate levels of debt relative to its expected cash flow from operations.

Foreign Currency Exchange Rate Risk

Harvest is exposed to the risk of changes in the Canadian/US dollar exchange rate on its US dollar denominated revenues and in respect of its refinery crude oil purchases and sales of refined products. In addition, Harvest's $7^{7/8}$% Senior Notes are denominated in US dollars (US$250 million). Interest is payable semi-annually in US dollars on the notes; therefore, any interest payable at the balance sheet date is also subject to currency exchange rate risk. Harvest manages these exchange rate risks by occasionally entering into fixed rate currency exchange contracts on future US dollar payments and US dollar sales.

Commodity Price Risk

Harvest uses price risk management contracts for a portion of its crude oil, natural gas and refined product sales to manage its commodity price exposure and power costs. 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 some expected future price of the underlying asset. Variances in expected future prices expose us to commodity price risk as they will change the gain or loss that we ultimately realize on these contracts. This risk is mitigated by continuously monitoring the effectiveness of these contracts and other risk management actions.

(b) Fair Values

At December 31, 2007, the net fair value deficiency reflected on the balance sheet for all the risk management contracts outstanding at that date was approximately $149.7 million ($1.9 million – December 31, 2006), which was included in the balance sheet as follows: Fair value of risk management contracts (current assets) $16.4 million, fair value deficiency of risk management contracts (current liabilities) $131.0 million and fair value deficiency of risk management contracts $35.1 million.

The following is a summary of Harvest's risk management contracts outstanding, along with their fair value at December 31, 2007:

Quantity	Type of Contract	Term	Average Price	Fair value
Crude Oil Price Risk Management				
10,000 bbl/d	WTI Participating swap	Jan. 08 – Jun. 08	US$60.00(b)	(15,873)
6,000 bbl/d	WTI 3-way contract	Jul. 08 – Dec. 08	US$62.00 - $87.53 ($72.00)(c)	(9,015)
				$ (24,888)
Refined Product Price Risk Management				
10,000 bbl/d	NYMEX heating oil 3-way contract	Jan. 08 – Dec. 08	US$60.90 - $93.31 ($81.06)(e)(k)	$ (56,929)
6,000 bbl/d	Platt's fuel oil 3-way contract	Jan. 08 – Dec. 08	US$43.00 - $63.21 ($51.67)(f)	(25,196)
2,000 bbl/d	NYMEX heating oil collar	Jan. 08 – Dec. 08	US$79.80 - $91.35(g)(k)	(12,513)
2,000 bbl/d	Platt's fuel oil collar	Jan. 08 – Dec. 08	US$51.00 - $58.68(h)	(11,203)
12,000 bbl/d	NYMEX heating oil 3-way contract	Jan. 09 – Jun. 09	US$72.59 - $98.73 ($86.52)(i)(k)	(21,840)
8,000 bbl/d	Platt's fuel oil 3-way contract	Jan. 09 – Jun. 09	US$49.75 - $65.89 ($57.38)(j)	(13,255)
				$ (140,936)
Natural Gas Price Risk Management				
276 GJ/d	Fixed price – natural gas contract	Jan. 08 – Dec. 08	Cdn$4.16(d)	**$ (210)**
Electricity Price Risk Management				
35 MWH	Electricity price swap contracts	Jan. 08 – Dec. 08	Cdn $56.69	**$ 5,631**
Refined Product Crack Spread Risk Management				
2,000 bbl/d	Platt's fuel oil crack swap	Jan. 08 – Dec. 08	US($16.50)	$ 1,815
6,000 bbl/d	NYMEX heating oil crack swap	Jan. 08 – Dec. 08	US$14.63	30
6,000 bbl/d	NYMEX RBOB crack swap	Jul. 08 – Dec. 08	US$10.00	290
				$ 2,135
Foreign Currency Exchange Rate Risk Management				
$8,333,333/ month	US/Cdn dollar exchange rate swap	Jan. 08 – Jun. 08	1.1099 Cdn/US	5,865
$10,000,000/ month	US/Cdn dollar collar	Jan. 08 – Dec. 08	1.000 Cdn/US- 1.055 Cdn/US(a)	2,730
				$ 8,595
Total net fair value deficiency of risk management contracts				**$ (149,673)**

(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 the stated ceiling price.

(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 $81.06; if the market price is between $51.67 and the average ceiling of $63.21, the price received is market price; if the market price is over the average ceiling of $63.21, price received is the stated ceiling price.

(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 average ceiling of $58.68, the price received is market price; if the market price is over the average ceiling of $58.68, price received is the stated ceiling price.

(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 average ceiling of $98.73, price received is the stated ceiling price.

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

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

For the year ended December 31, 2007, the total unrealized gain/loss on risk management contracts recognized in the consolidated statement of income and comprehensive income was a loss of $147.8 million (2006 - a gain of $52.2 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.

19. 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.

Results of Continuing Operations	Downstream[1]		Upstream[1]		Total	
	2007	2006	2007	2006	2007	2006
Revenue[2][3]	$ 3,098,556	$ 460,359	$ 1,184,457	$ 1,120,575	$ 4,283,013	$ 1,580,934
Royalties	-	-	(213,413)	(200,109)	(213,413)	(200,109)
Less:						
Purchased products for resale and processing	2,667,714	386,014	-	-	2,667,714	386,014
Operating[4]	229,290	34,063	300,918	242,474	530,208	276,537
Transportation and marketing	34,970	5,060	11,946	12,142	46,916	17,202
General and administrative	1,713	-	34,615	28,372	36,328	28,372
Transaction costs	-	-	-	12,072	-	12,072
Depletion, depreciation, amortization and accretion	72,599	15,482	454,142	413,988	526,741	429,470
	$ 92,270	$ 19,740	$ 169,423	$ 211,418	261,693	231,158
Realized net losses on risk management contracts					(26,291)	(44,808)
Unrealized net (losses) gains on risk management contracts					(147,781)	52,179
Interest and other financing charges on short term debt					(5,584)	(4,864)
Interest and other financing charges on long term debt					(152,201)	(78,828)
Foreign exchange gain (loss)					109,316	(21,100)
Large corporations tax and other tax					974	9
Future income tax					(65,802)	2,300
Net (loss) income					$ (25,676)	$ 136,046
Total Assets[5]	$ 1,482,904	$ 1,727,797	$ 3,952,337	$3,990,004	$ 5,451,683	$ 5,745,558
Capital Expenditures						
Development and other activity	$ 44,111	$ 21,411	$ 300,674	$ 376,881	$ 344,785	$ 398,292
Business acquisitions	-	1,597,793	170,782	2,422,180[6]	170,782	4,019,973
Property acquisitions	-	-	27,943	65,773	27,943	65,773
Property dispositions	-	-	(60,569)	(20,856)	(60,569)	(20,856)
Increase in other non-current assets	-	165	-	-	-	165
Total expenditures	$ 44,111	$ 1,619,369	$ 438,830	$ 2,843,978	$ 482,941	$ 4,463,347
Property, plant and equipment						
Cost	$ 1,164,310	$ 1,320,698	$ 4,247,819	$ 3,801,054	$ 5,412,129	$ 5,121,752
Less: Accumulated depletion, depreciation, amortization and accretion	(72,277)	(14,660)	(1,142,345)	(706,540)	(1,214,622)	(721,200)
Net book value	$ 1,092,033	$ 1,306,038	$ 3,105,474	$ 3,094,514	$ 4,197,507	$ 4,400,552
Goodwill						
Beginning of year	$ 209,930	$ -	$ 656,248	$ 43,832	$ 866,178	$ 43,832
Addition (reduction) to goodwill	(33,946)	209,930	20,546	612,416	(13,400)	822,346
End of year	$ 175,984	$ 290,930	$ 676,794	$ 656,248	$ 852,778	$ 866,178

(1) Accounting policies for segments are the same as those described in the Significant Accounting Policies
(2) Of the total downstream revenue for the year ended December 31, 2007, $2,651.5 million is from one customer (2006 - $427.1 million). No other single customer within either division represents greater than 10% of Harvest's total revenue.
(3) Of the total consolidated revenue for the year ended December 31, 2007, $1,626.3 million is attributable to sales in Canada (2006 - $1,150.5 million), while $2,656.7 million is attributable to sales in the United States (2006 - $430.4 million).
(4) Downstream operating expenses for the period ended December 31, 2007 include $34.5 million of turnaround and catalyst costs related to the planned shutdown of the Isomax and Platformer commencing on September 21, 2007.
(5) Total Assets on a consolidated basis includes $16.4 million (2006 - $27.8 million) relating to the fair value of risk management contracts
(6) Included in this amount is $1,975.3 million relating to the acquisition of Viking, which was acquired through the issuance of Trust Units and is therefore not reflected in the cash flow statement.
(7) There is no intersegment activity.

20. 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 December 31, 2007:

(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 December 31, 2007, North Atlantic had commitments totaling approximately $843.6 million (2006 - $550.2 million) in respect of future crude oil feedstock purchases and related transportation from Vitol Refining S.A.

(b) North Atlantic has an agreement with Newsul Enterprises Inc. ("Newsul") whereby North Atlantic committed to provide Newsul with its inventory and production of sulphur to February 12, 2008. The agreement has been renewed for a further period of ten years.

Newsul has named North Atlantic in a claim in the amount of US$2.7 million and has requested the services of an arbitration board to make a determination on the claim. The claim is for additional costs and lost revenues related to alleged contaminated sulphur delivered by North Atlantic. An accrual of $0.5 million has been established based on North Atlantic's estimate of their liability, but since the eventual outcome of the arbitration hearing is undeterminable, there exists an exposure to loss in excess of the amount accrued.

(c) North Atlantic has an environmental agreement with the Province of Newfoundland and Labrador, Canada, committing to programs that reduce the environmental impact of the refinery over time. Initiatives include a schedule of activities to be undertaken with regard to improvements in areas such as emissions, waste water treatment, terrestrial effects, and other matters. In accordance with the agreement, certain projects have been completed and others have been scheduled. Costs relating to certain activities scheduled to be undertaken over the next two years are estimated to be approximately $3.5 million and are included in the table below; costs cannot yet be estimated for the remaining projects.

(d) North Atlantic has been named a defendant in The State of New Hampshire versus Amerada Hess Corp. et al, one of more than 100 methyl tertiary butyl ether ("MTBE") US product liability litigation cases that have been consolidated for pre-trial purposes in this matter. The plaintiffs seek relief for alleged contamination of ground water from the various defendants' use of the gasoline additive MTBE. Although the plaintiffs have not made a particular monetary demand, they are asserting collective and joint liability against all defendants. All consolidated lawsuits are at a preliminary stage and, accordingly, it is too early in the legal process to reach any conclusion regarding the ability of the State of New Hampshire to properly assert jurisdiction over North Atlantic in the lawsuit or to reach any conclusions regarding the substance of the plaintiffs' claims. Accordingly, the evaluation of the risk of liability to North Atlantic is not determinable at this time and no amounts are accrued in the consolidated financial statements in respect of this matter. Harvest is indemnified by Vitol Group B.V. in respect of this contingent liability.

(e) Petro-Canada, a former owner of the North Atlantic refinery, holds certain contractual rights in relation to production at the refinery, namely:

i. a right to share, subject to a maximum limit, in the profits of the sale of any refined product, refined at the refinery, sold in Canada, exclusive of the province of Newfoundland and Labrador;

ii. a right of first refusal to any refinery and/or terminaling capacity in excess of North Atlantic's requirements;

iii. a right to participate in any venture to produce petrochemicals at the refinery; and

iv. the rights in paragraphs (i) and (ii) above continue for a period of 25 years from December 1, 1986, while the rights in paragraph (iii) continue until amended by the parties.

The following is a summary of Harvest's contractual obligations and commitments as at December 31, 2007:

	Payments Due by Period						
	2008	**2009**	**2010**	**2011**	**2012**	**Thereafter**	**Total**
Debt repayments (1)	-	-	1,279,501	247,825	-	-	**1,527,326**
Capital commitments(2)	15,924	1,300	-	-	-	-	**17,224**
Operating leases(3)	7,572	6,655	5,742	5,292	1,853	248	**27,362**
Pension contributions(4)	1,143	1,583	2,048	2,454	2,847	21,285	**31,360**
Transportation agreements(5)	2,249	1,684	1,269	565	296	47	**6,110**
Feedstock commitments(6)	843,583	-	-	-	-	-	**843,583**
Contractual obligations	**870,471**	**11,222**	**1,288,560**	**256,136**	**4,996**	**21,580**	**2,452,965**

(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 and equipment rental contracts.
(3) Relating to building and automobile leases.
(4) Relating to expected contributions for employee benefit plans [see Note 17].
(5) Relating to oil and natural gas pipeline transportation agreements.
(6) Relating to crude oil feedstock purchases and related transportation costs [see Note 20(a) above].

21. RECONCILIATION OF THE CONSOLIDATED FINANCIAL STATEMENTS TO UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

These consolidated financial statements have been prepared in accordance with Canadian GAAP which, in most respects, conforms to US GAAP. Any differences in accounting principles as they have been applied to the accompanying consolidated financial statements are not material except as described below. Items required for financial disclosure under US GAAP may be different from disclosure standards under Canadian GAAP; any such differences are not reflected here.

The application of US GAAP would have the following effects on net income as reported:

	Year Ended December 31	
	2007	**2006**
Net income (loss) under Canadian GAAP	$ (25,676)	$ 136,046
Adjustments		
Write-down of property, plant and equipment (a)	-	(615,000)
Unrealized loss on risk management contracts (f)	-	(398)
Depletion, depreciation, amortization and accretion (b)	78,180	8,825
Non-cash interest expense on debentures (d)	6,371	454
Non-cash interest expense on Senior Notes (h)	842	-
Amortization of deferred financing charges (d)	(3,471)	65
Foreign exchange gain on Senior Notes (h)	1,720	-
Foreign exchange gain (loss) on unit distribution (i)	10,045	(1,038)
Non-controlling interest (e)	-	(65)
Non-cash general and administrative expenses (c)	(443)	(3,291)
Future income tax recovery (g)	91,626	670
Net income (loss) under US GAAP before cumulative effect of change in accounting policy	159,194	(473,732)
Cumulative effect of change in accounting policy (c)	-	4,891
Net income (loss) under US GAAP after cumulative effect of change in accounting policy	159,194	(468,841)
Net change in cumulative translation adjustment (i)	(253,677)	47,911
Employee future benefits - actuarial loss	(4,339)	-
Comprehensive income (loss)	$ (98,822)	$ (420,930)
BASIC		
Net income (loss) per Trust Unit under US GAAP before cumulative effect of change in accounting policy	$ 1.15	$ (4.66)
Cumulative effect of change in accounting policy	-	0.05
Net income (loss) per Trust Unit under US GAAP after cumulative effect of change in accounting policy	$ 1.15	$ (4.61)

DILUTED				
Net income (loss) per Trust Unit under US GAAP before cumulative effect of change in accounting policy	$	1.14	$	(4.66)
Cumulative effect of change in accounting policy		-		0.05
Net income (loss) per Trust Unit under US GAAP after cumulative effect of change in accounting policy	$	1.14	$	(4.61)
STATEMENT OF ACCUMULATED INCOME (LOSS)				
Balance, beginning of year – US GAAP		33,880		(895,736)
Net income (loss) – US GAAP		159,194		(473,732)
Cumulative effect of change in accounting policy		-		4,891
Change in redemption value of Trust Units		371,316		1,398,457
Balance, end of year – US GAAP		564,390		33,880
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)				
Balance, beginning of year – US GAAP		47,586		-
Other comprehensive income		(258,016)		47,911
Employee future benefits – Adoption of FAS 158 (j)		-		(325)
Balance, end of year – US GAAP		(210,430)		47,586

The application of US GAAP would have the following effect on the consolidated balance sheets as reported:

	December 31, 2007				December 31, 2006			
	Canadian GAAP		US GAAP		Canadian GAAP		US GAAP	
Assets								
Property, plant and equipment (a) (b)	$	4,197,506	$	3,670,688	$	4,393,832	$	3,788,606
Deferred charges (d) (f) (h)	$	-	$	23,390	$	35,657	$	34,199
Non current benefit plan assets (j)	$	-	$	393	$	-	$	373
Future income tax (f) (g)	$	-	$	4,986	$	-	$	-
Liabilities								
Accounts payable and accrued liabilities (c)	$	270,240	$	268,669	$	294,582	$	292,338
Current portion of convertible debentures (d)	$	24,273	$	24,210	$	-	$	-
Current other benefit plan liability (j)	$	-	$	170	$	-	$	162
Deferred credit (f)	$	-	$	-	$	794	$	794
$7^{7/8}$% Senior notes (h)	$	241,148	$	246,710	$	291,350	$	289,952
Convertible debentures – liability (d)	$	627,495	$	671,818	$	601,511	$	627,722
Non current benefit plan liability (j)	$	12,168	$	17,054	$	12,227	$	12,762
Future income tax (f)(g)	$	86,640	$	-	$	-	$	-
Temporary equity (e)	$	-	$	2,997,136	$	-	$	2,680,017
Unitholders' Equity								
Unitholders' capital (e)	$	3,736,080	$	-	$	3,046,876	$	-
Equity component of convertible debentures (d)	$	39,537	$	-	$	36,070	$	-
Additional paid-in capital	$	-	$	9,913	$	-	$	9,913
Accumulated income (i)	$	246,865	$	564,390	$	271,155	$	33,880
Cumulative foreign currency translation adjustment (i)	$	-	$	-	$	46,873	$	-
Accumulated other comprehensive income (j) (i)	$	(196,759)	$	(210,430)	$	-	$	47,586

(a) Under Canadian GAAP, Harvest performs an impairment test that limits the capitalized costs of its petroleum and natural gas assets to the discounted estimated future net revenue from proved and probable petroleum and natural gas reserves plus the cost of unproved properties less impairment, estimated future prices and costs. The discount rate used is equal to Harvest's risk free interest rate. Under US GAAP, entities using the full cost method of accounting for petroleum and natural gas activities perform an impairment test on each cost centre using discounted future net revenue from proved petroleum and natural gas reserves discounted at 10%. The prices used under the US GAAP impairment test are those in effect at year end. There was no impairment under US GAAP at December 31, 2007. As at December 31, 2006, the application of the ceiling test under US GAAP resulted in a write down of $615.0 million of capitalized costs.

(b) Under Canadian GAAP, proved reserves are estimated using estimated future prices and costs. These proved reserves form the basis for the depletion calculation.

Under US GAAP, proved reserves used for the depletion calculation are estimated using constant prices and costs as of the date the estimate of reserves is made. In both the current and comparative year there were differences in proved reserves under US GAAP and Canadian GAAP and as a result the difference is realized in the depletion expense. Additionally, the ceiling test write down required under US GAAP in 2006 reduced the US GAAP depletable asset base which results in a lower depletion expense in 2007 and future years.

(c) Under Canadian GAAP, the Trust determines compensation expense and the resulting obligation related to its Trust Unit Incentive Plan and Unit Award Plan using the intrinsic value method described in Note 2 (j). Under US GAAP, for the year ended December 31, 2006 Harvest adopted SFAS 123(R) "Share Based Payments" using the modified prospective approach. Under FAS 123(R), expenses and obligations for liability-based stock compensation plans are recorded using the fair-value method of accounting and are revalued at each period end. As a result, general and administrative expense is higher under US GAAP by $0.4 million for the year ended December 31, 2007 (2006 - $3.3 million) and accounts payable and accrued liabilities is higher under US GAAP by $0.7 million as at December 31, 2007 (December 31, 2006 – lower by $2.2 million).

To the extent compensation costs relates to employees directly involved in natural gas and crude oil exploration and development activities, such amounts are capitalized to property, plant and equipment. Amounts not capitalized are recognized as administrative expenses.

The Trust adopted SFAS 123(R) under the modified prospective approach, which requires the cumulative impact of a change in an accounting policy to be presented in the current year consolidated statement of income. The cumulative effect of initially adopting SFAS 123(R) on January 1, 2006 was a gain of $4.9 million.

(d) Under Canadian GAAP, Harvest's convertible debentures are classified as debt with a portion, representing the value associated with the conversion feature, being allocated to equity under Canadian GAAP. Issue costs related to the debentures are netted against each respective debt and equity component. In addition, under Canadian GAAP a non-cash interest expense representing the effective yield of the debt component and the amortization of the issue costs is recorded in the consolidated statements of income with a corresponding credit to the convertible debenture liability balance to accrete that balance to the full principal due on maturity.

Under US GAAP, the convertible debentures are classified as debt in their entirety, and issue costs are recorded as deferred charges. To the extent that a portion of the issue costs are netted against the respective debt and equity components of the convertible debentures under Canadian GAAP there is a difference in the capitalization and amortization of the related deferred charges under US GAAP. The non-cash interest expense recorded under Canadian GAAP would not be recorded under US GAAP.

In addition, convertible debentures that are assumed in a business combination are recorded at their fair value at the date of the acquisition as part of the cost of the acquired enterprise. Under US GAAP, if the conversion feature is in-the-money at the acquisition date (a beneficial conversion feature), the feature should be recognized and measured by allocating a portion of the proceeds equal to the intrinsic value of that feature to additional paid-in capital. Where the debenture has a stated redemption date, the corresponding value is recognized as a discount on the convertible debenture balance and accreted from the date of acquisition to the redemption date.

(e) Under Harvest's Trust Indenture, Trust Units are redeemable at any time on demand by the Unitholder for cash. Under US GAAP, the amount included on the consolidated balance sheet for Unitholders' Equity would be reduced by an amount equal to the redemption value of the Trust Units as at the balance sheet date. The redemption value of the Trust Units is determined with respect to the trading value of the Trust Units as at each balance sheet date, and the amount of the redemption value is classified as temporary equity. Changes, if any, in the redemption value during a period results in a charge to permanent equity.

(f) Under US GAAP, SFAS 133 "Accounting for Derivative Instruments and Hedging Activities" requires that all derivative instruments be recorded on the consolidated balance sheet as either an asset or liability measured at fair value, and requires that changes in fair value be recognized currently in income unless specific hedge accounting criteria are met. US GAAP requires that a company formally document, designate, and assess the effectiveness of derivative instruments before hedge accounting may be applied. Harvest had not formally documented and designated any hedging relationships as at December 31, 2007 or December 31, 2006 and as such, its risk management contracts were not eligible for hedge accounting treatment under US GAAP.

Harvest implemented fair value accounting effective January 1, 2004 under Canadian GAAP and had designated a portion of its risk management contracts as hedges. During the year ended December 31, 2004, the Trust discontinued hedge accounting for all risk management contracts under Canadian GAAP. Upon discontinuing hedge accounting, a deferred charge or gain is recorded representing the fair value of the contract at that time. This difference is amortized over the term of the contract. Under US GAAP there were no contracts designated as hedges. To the extent deferred charges and credits were recorded and amortized when hedge accounting was discontinued, there is a difference between Canadian and US GAAP. The deferred charges and gains were to be amortized under Canadian GAAP for the year ended December 31, 2006, and created a difference from US GAAP. There was no such impact for the year ended December 31, 2007.

(g) The Canadian GAAP liability method of accounting for income taxes is similar to the US GAAP SFAS 109, "Accounting for Income Taxes", which requires the recognition of tax assets and liabilities for the expected future tax consequences of events that have been recognized in Harvest's consolidated financial statements. Pursuant to US GAAP, enacted tax rates are used to calculate future income tax, whereas Canadian GAAP uses substantively enacted rates. There are no differences for the years ended December 31, 2007 and December 31, 2006 relating to tax rate differences.

Under Canadian GAAP as at December 31, 2007, Harvest's carrying value of its net assets exceed its tax basis and accordingly results in recording a future income tax liability. Adjustments under US GAAP result in a large future income tax recovery and corresponding future income tax asset balance being booked, as the ceiling test write down from 2006 significantly lowered Harvest's property, plant, and equipment carrying value under US GAAP and thus increased the corresponding temporary differences for future tax purposes.

(h) With the adoption of Financial Instruments under Canadian GAAP effective January 1, 2007, issue costs are applied against the $7^{7/8}$% Senior Notes balance and accreted into income using the effective interest method. Under US GAAP, these amounts are capitalized as a deferred charge and expensed into income using the effective interest method.

(i) With the adoption of the new accounting standards for financial instruments under Canadian GAAP effective January 1, 2007, the cumulative translation adjustment generated upon translating the financial statements of Harvest's downstream operations denominated in a foreign currency previously recognized as a separate component of equity is now recognized in comprehensive income consistent with the treatment under US GAAP. Additionally, under US GAAP, partnership distributions are required to be translated at the historic foreign exchange rate in place at the time of initial paid-in capital and any translation gains or losses are recorded in other comprehensive income. Under Canadian GAAP, it is permissible to translate foreign currency denominated partnership distributions at the historic exchange rate that has been proportionately adjusted for the subsequent periods when income has been earned. The effects of the translation is reflected in net income.

(j) At December 31, 2006 the Trust adopted US GAAP SFAS 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R). Under SFAS 158, the over-funded or under-funded status of our defined benefit postretirement plan are recognized on the balance sheet as an asset or liability and changes in the funded status are recognized through comprehensive income. As a result, for the year ended December 31, 2007 employee future benefits are higher by $4.3 million (2006 – $0.3 million) and $4.3 million was included in other comprehensive income (2006 – $0.3 million included in accumulated other comprehensive income on adoption of SFAS 158). Canadian GAAP currently does not require the Trust to recognize the funding status of the plan on its balance sheet.

(k) In its December 31, 2007 financial statements, Harvest adopted the FASB Interpretation No. 48 "Accounting for Uncertainty for Income Taxes" (FIN 48). FIN 48 is an interpretation of FASB Statement 109 "Accounting for Income Taxes" and outlines the recognition and related disclosure requirements of uncertain tax positions determined to be more likely than not, defined as greater than 50%, to be sustained on audit. This adoption did not result in a US GAAP difference.

The following are standards and interpretations that have been issued by the Financial Accounting Standards Board ("FASB") which are not yet in effect for the periods presented but would become US GAAP when implemented:

In September 2006, FASB issued Statement 157, "Fair Value Measurements". SFAS 157 defines fair value, establishes a framework for measuring fair value under US GAAP and expands disclosures about fair value measurements. This statement is effective for fiscal years beginning after November 15, 2007. We do not expect the adoption of this statement will have a material impact on our results of operations or financial position.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities - Including an Amendment of FASB Statement No. 115." This pronouncement permits entities to use the fair value method to measure certain financial assets and liabilities by electing an irrevocable option to use the fair value method at specified election dates. After election of the option, subsequent changes in fair value would result in the recognition of unrealized gains or losses as period costs during the period the change occurred. SFAS No. 159 becomes effective as of the beginning of the first fiscal year that begins after November 15, 2007, with early adoption permitted. However, entities may not retroactively apply the provisions of SFAS No. 159 to fiscal years preceding the date of adoption. We are currently evaluating the impact that SFAS No. 159 may have on our financial position, results of operations and cash flows.

Additional disclosures required under US GAAP:

(thousands of Canadian dollars)	December 31, 2007	December 31, 2006
Components of accounts receivable		
Trade	$ 115,112	$ 135,578
Accruals	100,691	118,573
	$ 215,803	$ 254,151
Components of prepaid expenses and deposits		
Prepaid expenses	$ 14,004	$ 11,877
Funds on deposit	1,140	836
	$ 15,144	$ 12,713

22. SUBSEQUENT EVENTS

Subsequent to December 31, 2007, Harvest declared a distribution of $0.30 per unit for Unitholders of record on January 24, 2008, February 22, 2008, March 25, 2008 and April 22, 2008.

Between January 1, 2008 and March 12, 2008, an additional $577.0 million was committed to the purchase of feedstock inventory under the Supply and Offtake Agreement held with Vitol Refining S.A. [see table in Note 20].

On January 31, 2008 the 10.5% debentures matured and the obligation was settled through the issuance of 1,116,593 Trust Units. See Note 12 for further details.

23. RELATED PARTY TRANSACTIONS

During the year ended December 31, 2007, in the normal course of operations, Vitol Refining S.A. purchased $354.8 million of Iraqi 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 December 31, 2007, no amount related to these transactions is included in accounts payable and accrued liabilities and $68.0 million is included in feedstock commitments for the purchase of Iraqi crude oil [See Note 20]. None of the US $577.0 million committed to the purchase of feedstock inventory under the Supply and Offtake Agreement held with Vitol Refining S.A. between January 1, 2008 and March 12, 2008 [see Note 22] was purchased from this private corporation. During the year ended December 31, 2006, there were no related party transactions.

24. COMPARATIVES

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

FORWARD-LOOKING INFORMATION

In the interest of providing our unitholders and potential investors with information regarding Harvest, including our assessment of our future plans and operations, this annual report 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 refinery 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 tax, royalty and environment laws and regulation; 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 annual report include, but are not limited to, production volumes, refinery throughput volumes, royalty rates, operating costs, commodity prices, administrative costs, commodity price risk management activity, acquisitions and dispositions, capital spending, reserve estimates, distributions, access to credit facilities, capital taxes, income taxes, Cash Flow 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 or estimates or opinions change except as required by law. Forward-looking statements contained in this annual report are expressly qualified by this cautionary statement.

All estimates of original oil in place (OOIP) in this Annual Report are classified as Discovered Petroleum Initially-In-Place which is defined as that quantity of Petroleum that is estimated as at September 30, 2007, to be contained in known accumulations prior to production. There is no certainty that it will be commercially viable to produce any portion of these resources.

Corporate *INFORMATION*

DIRECTORS

M. Bruce Chernoff, Chairman [3]
Kevin Bennett [2]
Dale Blue [1]
David Boone [2]
John Brussa [3]
William Friley [3]
Verne Johnson [1] [2]
Hector McFadyen [1]

[1] Member of the Audit Committee.
[2] Member of the Reserves, Safety and Environment Committee.
[3] Member of the Corporate Governance/Compensation Committee.

OFFICERS & SENIOR MANAGEMENT

John Zahary, P.Eng.
President & Chief Executive Officer

Robert Fotheringham, C.A.
Chief Financial Officer

Rob Morgan, P.Eng.
Chief Operating Officer, Upstream

Brad Aldrich
Chief Operating Officer, Downstream

Jacob Roorda, P.Eng.
Vice President, Corporate

Gary Boukall, P. Geol
Vice President, Geosciences

Les Hogan
Vice President, Land

Phil Reist, C.A.
Vice President, Controller

Jim Sheasby, P.Eng
Vice President, Engineering

Neil Sinclair
Vice President, Operations

Dean Beacon
Treasurer

David Rain, C.A.
Corporate Secretary

F. Steven Saunders, C.A.
Director of Taxation and Assistant Corporate Secretary

TRUST UNIT LISTING

Toronto Stock Exchange: HTE.UN
New York Stock Exchange: HTE

Convertible Debenture Listings:

TSX Ticker	Coupon	Conversion Price	Maturity
HTE.DB	9%	$13.85	May 31, 2009
HTE.DB.A	8%	$16.07	September 30, 2009
HTE.DB.B	6.5%	$31.00	December 31, 2010
HTE.DB.D	6.40%	$46.00	October 31, 2012
HTE.DB.E	7.25%	$32.20	September 30, 2013
HTE.DB.F	7.25%	$27.25	February 28, 2014

REGISTRAR AND TRANSFER AGENT

Valiant Trust Company
310, 606-4th Street S.W.
Calgary, Alberta , Canada T2P 1T1
Telephone: (403) 233-2801

AUDITOR

KPMG LLP

LEGAL COUNSEL

Canada: Burnet, Duckworth & Palmer
U.S: Paul, Weiss, Rifkind, Wharton & Garrison

RESERVES EVALUATORS

McDaniel & Associates Ltd.
GLJ Petroleum Consultants Ltd.

INVESTOR RELATIONS

Toll Free: 866-666-1178
Email: information@harvestenergy.ca

Please contact us if you would like to receive an investor package or be added to Harvest's mailing lists.

Designed by Bryan Mills Iradesso

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