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NEWS RELEASE

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Enerplus announces 2008 year end results and reserves information

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CALGARY, Feb. 26 /CNW/ - Enerplus Resources Fund ("Enerplus") is pleased to announce our financial and operating results for the year ended December 31, 2008. Given the global economic down turn that occurred during the course of the year, it proved to be a challenging year on many fronts. We were successful, however, in executing on a number of our key strategic objectives during 2008. This has resulted in Enerplus being in a relatively strong financial position in a depressed market, exiting the year with over a billion dollars of available credit capacity. We believe this affords us a significant advantage to capitalize on potential acquisition opportunities as we move forward in 2009.

As previously announced, we have reduced capital spending plans for 2009 relative to 2008 and have also reduced our distributions to unitholders to preserve our financial strength. Given the current economic environment, we expect cost structures to improve and are working aggressively to reduce costs throughout our organization. We will continue to evaluate our currently planned projects for 2009 relative to both expected reductions in cost structures and direction of commodity prices.

As we move forward in 2009 we will be looking to increase our ownership in the resource plays we have targeted for greater, more profitable growth for 2009 and beyond. We expect that the successful execution of our strategies will be demonstrated over time through improved operational metrics including improved recycle ratios and improved finding and development costs. Ultimately our key objective is to enhance the total return to our unitholders.

STRATEGIC EXECUTION:

- During the first half of 2008, Enerplus successfully completed the acquisition and integration of the assets of Focus Energy Trust, the single largest transaction in our history valued at $1.7 billion.
- We sold our 15% interest in the Joslyn oil sands lease for $502 million. These proceeds were used to reduce our outstanding bank debt.
- We continued to advance on our Kirby oil sands project with the filing of our regulatory application for Phase I in late September. We also increased the contingent resource estimate by 70% to over 400 million barrels of bitumen.
- Crude oil and natural gas prices declined dramatically in the fourth quarter of 2008 as the global economic environment deteriorated. In response, we have reduced our 2009 capital spending plans and

distributions to unitholders. We believe these actions will preserve our balance sheet strength and position us to take advantage of potential acquisition opportunities.

STRATEGIC POSITIONING FOR THE FUTURE:

- We believe that Enerplus currently has one of the strongest balance sheets in the oil and gas sector. With over $1 billion of unused credit capacity we believe this is a tremendous competitive advantage in the current economic environment.
- Enerplus has a proven track record of completing strategic transactions that improve our business. We are focused on acquiring high quality assets in growth areas such as tight gas and tight oil through acquisitions in priority investing development capital in our existing asset base. We are also directing 25% of our 2009 capital program toward growth projects in these areas to provide even greater value growth opportunities in the future.
- We are focused on preserving our financial flexibility. By reducing both our capital spending and distributions relative to our cash flows, we are positioning to minimize any increases in our debt except as may be necessary in our acquisition strategies.
- As we enter 2009, our emphasis is on production optimization and cost reductions to improve capital efficiencies and performance. We have a meaningful inventory of natural gas and oil projects, but in the current commodity price environment, we will look to retain our drilling inventory until such time as prices and cost structures improve.
- We are also undertaking a review of our asset base to identify those conventional properties which do not fit into our longer-term strategic plan of growing our resource play asset base. It is part of our strategy to rationalize these non-core assets at the appropriate time.
- We believe that our asset base is well suited to an income-oriented business model and believe that there will continue to be a growing demand for yield-oriented investments. We continue to evaluate alternatives to our income trust structure with the expectation that we will most likely convert to a dividend paying corporation. With the current forward commodity price and our plans regarding production, costs and capital spending, we do not expect a significant change to our overall tax costs until 2013 even if we were to convert to a corporation during 2010.

FINANCIAL HIGHLIGHTS:

- Cash flow from operating activities totaled $1,263 million in 2008, an increase of 45% over 2007 levels.
- Cash distributions to unitholders totaled $5.06 per trust unit essentially unchanged from the amount paid in 2007, resulting in a payout ratio of 62% versus 74% in 2007.
- Distributions and development capital spending totaled 109% of cash flow, compared to 120% in 2007.
- We maintained a strong balance sheet with a net debt to trailing 12 month cash flow ratio of 0.5x.

OPERATIONAL HIGHLIGHTS:

- Production averaged 95,687 BOE/day in 2008, in-line with our third quarter guidance of 96,000 BOE/day.
- Average December production volumes were 96,400 BOE/day (98,000

BOE/day after adjusting for unexpected downtime at two non-operated facilities, both of which were resolved by year-end). The adjusted exit rate was only slightly behind our exit rate guidance of 98,500 BOE/day.

- Development capital spending was $578 million, 6% higher than our guidance of $545 million principally as a result of accelerating capital spending on certain projects.
- We drilled a record 643 net wells with a 99% success rate.
- General and Administrative ("G&A") expenses were $1.88/BOE, 6% lower than our guidance of $2.00/BOE and 17% lower than $2.26/BOE in 2007.
- Operating costs were $9.50/BOE for 2008, in-line with our guidance but representing an increase of 4% year-over-year.
- We invested $106 million to pursue our resource-play growth strategy including $55 million on exploration drilling, land and seismic, and $51 million on oil sands.
- We continued to focus on the health and safety of our workers and recorded better performance than the Canadian Association of Petroleum Producers' industry average.

RESERVES:

- We replaced 78% of 2008 production through reserve additions from development capital spending and net acquisitions on a proved plus probable basis.
- Proved reserves increased 10% to 319 MMBOE, while probable reserves decreased 24% to 114 MMBOE primarily due to the sale of the Joslyn oil sands interest. Our total proved plus probable reserves decreased by 2% to 432.4 MMBOE.
- Proved plus probable finding, development and acquisition costs ("FD&A") on our conventional oil and gas activities were $29.17/BOE for the year including future development capital.
- Our conventional recycle ratio for 2008 was 1.4x.
- Our Reserve Life Index ("RLI") continues to be one of the longest in the sector at 12.1 years on a proved plus probable basis and 9.4 years on a proved basis.

SELECTED FINANCIAL AND OPERATING HIGHLIGHTS

Readers are referred to "Information Regarding Disclosure in this News Release and Oil and Gas Reserves, Resources and Operational Information", "Notice to U.S. Readers" and "Forward-Looking Information and Statements" at the end of this news release for information regarding the presentation of the financial, reserves, resources and operational information in this news release and information regarding the inclusion of certain forward-looking information and statements in this news release. For information on the use of the term "BOE" see "Information Regarding Disclosure in this News Release and Oil and Gas Reserves, Resources and Operational Information" at the conclusion of this news release.

SELECTED FINANCIAL RESULTS

	Three months ended December 31,		Twelve months ended December 31,	
(in Canadian dollars)	2008	2007	2008	2007
Financial (000's)				
Cash Flow from Operating Activities	$ 258,536	$ 205,084	$ 1,262,782	$ 868,548
Cash Distributions				

to Unitholders(1)	167,017	163,447	786,138	646,835
Cash Withheld for Acquisitions and Capital Expenditures	91,519	41,637	476,644	221,713
Net Income	189,495	98,701	888,892	339,691
Debt Outstanding (net of cash)	657,421	724,975	657,421	724,975
Development Capital Spending	200,254	106,120	577,739	387,165
Acquisitions	1,443	5,095	1,772,826	274,244
Divestments	162	4,003	504,859	9,572
Actual Cash Distributions to Unitholders per Trust Unit	$ 1.23	$ 1.26	$ 5.06	$ 5.04
Financial per Weighted Average Trust Unit(2)				
Cash Flow from Operating Activities	$ 1.56	$ 1.58	$ 7.86	$ 6.80
Cash Withheld for Acquisitions and Capital Expenditures	0.55	0.32	2.97	1.74
Net Income	1.15	0.76	5.54	2.66
Payout Ratio(3)	65%	80%	62%	74%
Selected Financial Results per BOE(4)				
Oil & Gas Sales(5)	$ 46.54	$ 52.33	$ 65.79	$ 50.48
Royalties	(8.61)	(9.83)	(12.27)	(9.49)
Commodity Derivative Instruments	3.54	(0.08)	(2.94)	0.45
Operating Costs	(9.46)	(8.53)	(9.51)	(9.11)
General and Administrative	(1.71)	(1.94)	(1.68)	(1.98)
Interest and Other Income and Foreign Exchange	(2.73)	(1.70)	(1.59)	(1.43)
Taxes	0.92	(1.70)	(0.65)	(0.77)
Asset retirement obligations settled	(0.53)	(0.75)	(0.52)	(0.54)
Cash Flow from Operating Activities before changes in non-cash working capital	$ 27.96	$ 27.80	$ 36.63	$ 27.61
Weighted Average Number of Trust Units Outstanding Including Equivalent				

Exchangeable Limited Partnership Units (thousands)	165,373	129,658	160,589	127,691
Debt/Trailing 12 Month Cash Flow Ratio(6)	0.5x	0.8x	0.5x	0.8x

SELECTED OPERATING RESULTS

	Three months ended December 31, 2008	2007	Twelve months ended December 31, 2008	2007
Average Daily Production				
Natural gas (Mcf/day)	346,439	257,415	338,869	262,254
Crude oil (bbls/day)	35,434	34,221	34,581	34,506
NGLs (bbls/day)	4,529	3,836	4,627	4,104
Total (BOE/day)	97,702	80,959	95,687	82,319
% Natural gas	59%	53%	59%	53%
Average Selling Price(5)				
Natural gas (per Mcf)	$ 6.92	$ 5.91	$ 8.17	$ 6.45
Crude oil (per bbl)	55.16	72.21	91.31	65.11
NGLs (per bbl)	43.55	58.12	68.93	51.35
CDN$/US$ exchange rate	0.82	1.02	0.94	0.93
Net Wells drilled	174	76	643	252
Success Rate(7)	99%	100%	99%	99%

(1) Calculated based on distributions paid or payable.
(2) Based on weighted average trust units outstanding for the period, including the exchangeable limited partnership units assumed through the Focus Energy Trust acquisition during 2008.
(3) Calculated as Cash Distributions to Unitholders divided by Cash Flow from Operating Activities. See "Non-GAAP Measures" in the following Management's Discussion and Analysis.
(4) Non-cash amounts have been excluded.
(5) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(6) Including the trailing 12 month cash flow of Focus Energy Trust for 2008.
(7) Based on wells drilled and cased.

Trust Unit Trading Summary

For the twelve months ended December 31, 2008	TSX - ERF.un (CDN$)	NYSE - ERF (US$)
High	$ 49.85	$ 50.63
Low	$ 21.53	$ 17.07
Close	$ 23.96	$ 19.58

2008 Cash Distributions
Per Trust Unit

Payment Month	CDN$	US$
First Quarter Total	$ 1.26	$ 1.23
Second Quarter Total	$ 1.26	$ 1.25
Third Quarter Total	$ 1.31	$ 1.26
October	$ 0.47	$ 0.39
November	0.38	0.29
December	0.38	0.31
Fourth Quarter Total	$ 1.23	$ 0.99
Total Year-to-Date	$ 5.06	$ 4.73

OPERATIONS

2008 was a very active year for Enerplus as we closed and integrated the single largest acquisition in our history and executed our largest capital development program to date. Our activities essentially delivered our production targets for annual average volumes, exit rate volumes, operating costs and G&A costs. However, we were disappointed with our capital efficiencies and our reserve additions were impacted by negative revisions.

Production

Daily production for 2008 averaged 95,687 BOE/day representing a new record and in-line with our guidance of 96,000 BOE/day. Our average daily volumes were approximately 16% higher than 2007 as a result of the Focus Energy Trust ("Focus") acquisition which closed on February 13, 2008 and added approximately 18,000 BOE/day of annualized production.

We exited 2008 with production volumes of approximately 96,400 BOE/day, roughly 2% lower than our guidance of 98,500 BOE/day due to unexpected downtime at two non-operated facilities. Approximately 1,100 BOE/day was shut in at our Tommy Lakes property during December due to a labour strike at a processing facility and we lost approximately 500 BOE/day due to unplanned downtime at our Bantry facility. Both the strike and the Bantry turnaround were resolved by year-end. After adjusting for these events, our exit rate was approximately 98,000 BOE/day.

Development Activities

Our capital spending program during 2008 totaled $578 million, approximately $33 million above our third quarter guidance of $545 million. We spent an additional $22 million due to accelerated activity associated with good weather conditions and rig availability at Tommy Lakes, Bantry and Shackleton as well as an accelerated seismic program at our Kirby oil sands project. An additional $11 million was incurred due to higher than expected service and drilling costs and higher maintenance costs on various properties. This additional spending is not expected to have a material impact on our 2009 guidance.

Our conventional capital development program in 2008 was equally weighted to both oil and natural gas projects across our portfolio. In total, we drilled 643 net wells with a 99% success rate and brought on approximately 19,500 BOE/day of initial production at an average on-stream cost of $27,000/BOE/day, excluding oil sands spending. Approximately 80% of the capital was spent in our five core resource plays with a majority of the drilling activity targeted to shallow gas (520 wells). We increased our drilling activity in our tight gas resource plays and shifted our U.S. Bakken activity from drilling wells to completing refracs on existing wells. Overall our capital efficiencies decreased from 2007 due to lower performance, continued cost escalation which only began to moderate in the latter half of the year and a higher percentage of infrastructure spending.

We continued to invest in growth projects during 2008 as approximately 18% (or $106 million) of our capital program was invested in these activities including oil sands. This growth spending does not typically add production, reserves or cash flow in the near term as we are investing in land, seismic and exploration activities that help capture new opportunities for the future. We are encouraged by the progress we are making on a number of new growth plays which are in the early stages. We expect this type of spending to grow as a percentage of our capital spending plans going forward.

In 2008 we invested $55 million in exploration drilling and new land and seismic primarily in the Montney regions of Alberta and British Columbia and the Bakken region of southeast Saskatchewan. Spending on our oil sands assets increased from $39 million in 2007 to $51 million in 2008.

2008 Production and Capital

Play Types	Average Daily Production (BOE/day)	Drilling Activity (Net Wells)	Initial Production (BOE/day)	Capital Spending ($MM)	Capital Efficiency ($/BOE/day)
Shallow Gas & Coalbed Methane	23,666	520	5,660	$ 159	$ 28,100
Crude Oil Waterfloods	16,282	40	3,000	84	28,000
Tight Gas	15,070	20	5,100	81	15,900
Bakken/Tight Oil	10,831	11	3,200	99	30,940
Other Conventional Oil & Gas	29,838	52	2,500	104	41,600
Total Conventional	95,687	643	19,460	$ 527	$ 27,100
Oil Sands	0	n/a	n/a	51	n/a
Total Company	95,687	643	19,460	$ 578	$ 29,700

Resource Plays

Shallow Natural Gas and CBM

Shallow natural gas and coal bed methane ("CBM") represented 25% of our average daily production volumes in 2008, an increase of 61% over 2007, reflecting the additional working interests acquired in the Shackleton field from Focus. Given the inventory of higher quality locations from the Focus acquisition and strong natural gas prices for most of the year, we invested $159 million, drilling 520 net shallow gas wells in 2008 with most of our spending at Shackleton in Saskatchewan and Bantry, Verger and Medicine Hat in Alberta.

Our capital efficiency of $28,100/BOE/day was higher than in 2007 due to the early start of our 2009 program to ensure we have our wells tied in before break-up and increased infrastructure costs associated with pipeline repairs and compressor upgrades.

With softening natural gas prices, our projected spending levels for 2009 have been reduced to approximately $75 million. We plan to drill approximately 226 net wells and will continue to focus on infill drilling at Shackleton, Bantry and Verger where our most attractive opportunities exist. We anticipate that over 80% of our total conventional wells in 2009 will be shallow gas wells targeting the Milk River and Medicine Hat formations.

Crude Oil Waterfloods

Crude oil waterfloods represented approximately 17% of our 2008 average daily production from about 12 major properties located across the Western Canadian Sedimentary Basin. We operate over 80% of our waterfloods and invested $84 million in this resource play in 2008. Capital spending was largely focused at Giltedge, Pembina, Virden and Silver Heights where we drilled 40 net wells. Capital efficiency in this resource play was impacted by the ongoing maintenance costs associated with these properties as a percentage of total capital and a higher percentage of investment in infrastructure projects to upgrade facilities which will support longer-term development. Our capital efficiency of $28,000/BOE/day was better than the average efficiency for this resource play in 2006 and 2007.

We expect to decrease our 2009 capital spending significantly in our waterflood assets to approximately $45 million due to the marginal economics of crude oil projects at current price levels. However we plan to continue identifying development prospects in our most attractive plays to be well positioned to restart these programs when oil prices rebound and/or cost structures improve. The current allocated funds will be used for ongoing production optimization projects which have the most attractive economics as well as the completion and tie in of wells that were drilled in the fourth quarter of 2008. Due to the ongoing maintenance requirements and lower level of capital investment, capital efficiencies in this area are not expected to improve in 2009.

Tight Gas

Our tight gas resource play is a growing component of our asset base and almost doubled in size from 2007 mainly due to the acquisition of the Tommy Lakes property in British Columbia. This play now represents 15% of our total corporate production. We more than doubled our capital spending in 2008 to $81 million and increased the number of net wells drilled from 6 to 20 year-over-year. Approximately 40% of our capital was spent at Tommy Lakes to complete and tie-in 17 wells in early 2008. Due to favourable weather conditions, we were able to accelerate our 2009 capital spending in this area with approximately $14 million spent in 2008 for our 2008/09 winter program. The remaining investment in this resource play in 2008 was primarily at our Ansell and Elmworth properties in Alberta.

Our 2008 capital efficiency of $15,900/BOE/day benefited from capital spent by Focus during the 2007/2008 winter drilling program prior to our acquisition in February. Going forward, advances in our use of horizontal and completion technologies and/or deflationary pressures may improve our results.

Our spending levels for 2009 are expected to remain relatively constant compared to 2008 at $78 million. Our plans include ongoing development at Tommy Lakes with a 14 well program including a few step-out wells aimed at expanding the play and the piloting of a horizontal well. We also expect to continue to add to our tight gas land positions in other areas and begin delineating the new lands purchased in 2008.

Bakken/Tight Oil

Our Bakken/tight oil resource play represented roughly 11% of our 2008 average daily production, with virtually all of this production coming from the Sleeping Giant project in Montana. In 2008, we continued to invest in this project, spending approximately $70 million. We also expanded our Bakken interests with the purchase of approximately 30,000 acres of undeveloped land in southeast Saskatchewan. In total we invested $99 million in this resource play in 2008.

We continued our third well per section development drilling program at Sleeping Giant in 2008 and drilled 11 net wells and refrac'd 16 net wells. Capital efficiencies in the U.S. during 2008 were $21,500/BOE/day. When we include the purchase of Bakken lands in Canada, our capital efficiency declined to $30,940/BOE/day. In 2008 we also initiated a full optimization program and tested a variety of techniques to improve production. These efforts added approximately $8 million to our operating costs which also resulted in approximately 600 BOE/day of increased production. We expect to reduce our optimization activities in 2009 and should see an improvement in operating costs as the year progresses.

In 2009, we have allocated $42 million to Bakken/tight oil the majority of which will be invested at Sleeping Giant. We plan on concentrating our spending on refracs (24 planned) and modest drilling subject to commodity price and/or cost improvements. There are approximately 15 third well per section drilling locations, approximately 40 fourth well per section locations and 120 refrac wells remaining in our inventory at Sleeping Giant. We are also participating in a CO2 pilot project on an existing Enerplus producing well with two other industry partners. Injection commenced in January 2009 and we expect to be able to provide an update on these activities later in the year. Outside of Sleeping Giant, we are also pursuing investments in other tight oil resource plays in both the U.S. and Canada.

Other Conventional Oil & Gas

Other conventional oil and gas properties comprised approximately 32% of our average daily production and 18% of capital spending in 2008. This includes a diversified portfolio of both crude oil and natural gas projects across western Canada of which we operate approximately 55% of the production and 70% of the capital spending. Capital investment on these assets was slightly lower year-over-year at $104 million but was reduced from 33% to 20% of our conventional spending as we continued to focus on our core resource plays in 2008.

Our 2008 capital efficiency was negatively impacted by lower than expected performance at Colgate, Shorncliff, Sylvan Lake and a number of non-operated properties as well as higher infrastructure investment. As well, the timing of capital spending late in 2008 has increased capital efficiencies as the associated production will not come on stream until 2009. As a result, capital efficiencies averaged $41,600/BOE/day.

As we continue to concentrate our capital spending in our core resource play areas, coupled with the decrease in commodity prices, we expect that in 2009 our investment in this category will decrease significantly to approximately $35 million, representing a reduction of 66% year-over-year. We will monitor economic conditions throughout the year and will be prepared to adjust our allocation of capital among the various play types as required.

Oil Sands

We invested $51 million in our oil sands portfolio in 2008, $41 million of which was spent on our Kirby SAGD project. Approximately $10 million was spent on the Joslyn project prior to the sale of this asset in July.

Kirby

Kirby is located in the heart of the Athabasca fairway close to other major SAGD projects currently on production and extends over 43,360 gross acres (67 sections of land) in a highly prospective area where we see a number of potential oil sands pay zones. Enerplus holds a 100% working interest in the property. The current plan would see the property developed in phases, with Phase 1 having production capacity of 10,000 bbls/day of bitumen and Phase 2 having an incremental production capacity of 20,000 - 30,000 bbls/day.

In 2008 we completed our first winter delineation drilling program at the Kirby project with great success. A total of 58 delineation wells were drilled including two source water wells and a water disposal well. The results of this program were significant in that our independent reserves engineers reported an increase of 170 million barrels to our contingent resource estimate, an increase of 70% over the 244 million barrels estimated at the time of purchase. We also confirmed that we have an adequate source of saline water (non-potable water) for the Kirby Phase 1 project and that we have a deep reservoir zone capable of handling our disposal water for the life of the project.

Set forth below is the "best estimate" of contingent resources attributable to our Kirby lease as at December 31, 2008 provided by GLJ Petroleum Consultants Ltd., independent petroleum engineers.

Northern Area Wabiskaw D (Project area)	118 million barrels
Northern Area McMurray	191 million barrels
Central and Southern Areas	105 million barrels
Total Kirby Contingent Resource Estimate	414 million barrels

For additional information relating to contingent resource estimates, see "Information Regarding Disclosure in this News Release and Oil and Gas Reserves, Resources and Operational Information" at the conclusion of this news release. As well, for additional information regarding our Kirby Oil Sands project, see our Annual Information Form for the year ended December 31, 2008, a copy of which will be available on or about March 16th, 2009 on our SEDAR profile at www.sedar.com and which will also form part of our Form 40-F for the year ended December 31, 2008 to be filed with the SEC, a copy of which will be available at www.sec.gov.

With our experienced team and a successful winter drilling program, we were able to prepare and submit the development application for Phase 1 to the regulatory authorities in September.

Despite the advancements made at Kirby, our 2009 capital program has been reduced significantly due to the fall in crude oil prices. We will be working with regulators and our stakeholders in an effort to obtain regulatory approval by late 2009. Once we have regulatory approval, our Board of Directors will determine whether to sanction proceeding with the project at that time. Given the downturn in commodity prices, we have elected to defer any additional delineation activity this year, but plan to complete a three dimensional seismic program over 20 sections of our northern lease area. This will position us for future delineation drilling should we move forward with Phase 2 of Kirby. We also plan to complete a more detailed geological review of all potential oil sands zones in our lease which we believe should result in additional contingent resources being identified.

2009 PRODUCTION AND CAPITAL SPENDING PLANS

As previously announced in December 2008, Enerplus is planning a conservative approach to 2009 with reductions in capital spending and distributions in light of current commodity prices and capital market uncertainty. We intend to preserve our financial strength and maintain flexibility so that we are in a position to take advantage of opportunities to add quality assets in what we expect will prove to be an attractive acquisition market.

As a result of reduced capital spending, we anticipate that our annual daily production volumes will average 91,000 BOE/day in 2009, a decline of approximately 5% from 2008. We expect to exit 2009 with production of approximately 88,000 BOE/day.

We currently plan to spend $300 million, a decrease of 48% from our 2008 development capital spending levels. Our plans include $240 million of spending on our Canadian conventional assets, $35 million in the U.S. and $25 million on oil sands. Our program is directed toward high value optimization and development projects, maintaining the integrity of our existing infrastructure and investment in new development areas given our desire to add opportunities in emerging resource plays.

Approximately 56% of our conventional spending will be directed at natural gas resource plays with the remainder on oil. Our natural gas program will be concentrated on shallow gas and tight gas projects which provide an attractive return with natural gas prices at or better than $5.00/Mcf. Our oil program is directed primarily at our U.S. Bakken assets and optimization projects with attractive returns with oil prices at or better than US$40.00/bbl. Included in our plans is approximately $50 million of spending on growth-oriented projects in the Montney gas play in northeastern B.C. and northwestern Alberta, the Bakken oil play in the Williston Basin and a few other select resource plays. We anticipate drilling several pilot wells to test reservoir quality and productivity and accumulate additional prospective lands in key areas. We will also continue to look for acquisition and joint venture opportunities as a way to advance and accelerate our growth in resource plays that target tight gas and tight oil.

This capital spending forecast also includes an estimate of cost savings that we are expecting as a result of the slowdown in industry activity and does not reflect any acquisition or divestment activity that may occur as a normal part of our business. We will review our 2009 capital program and distributions on an on-going basis throughout the year in the context of prevailing economic conditions and make adjustments as deemed necessary. In addition, there is a risk that certain wells could become uneconomic to produce if current market conditions fail to improve thereby impacting our production volumes. We expect that up to one third of our capital spending will occur in the first quarter of 2009 as a result of winter access areas and the continuation of our ongoing program from 2008.

Play Types	2009 Estimated Average Daily Production (BOE/day)	2009 Estimated Drilling Activity (Net Wells)	2009 Estimated Capital Spending ($MM)
Shallow Gas & CBM	22,700	226	$ 75
Crude Oil Waterfloods	16,200	12	45
Tight Gas	14,100	24	78
Bakken/Tight Oil	9,900	4	42

Other Conventional Oil & Gas	28,100	9	35
Total Conventional	91,000	275	$ 275
Oil Sands	0	0	25
Total Company	91,000	275	$ 300

ACQUISITIONS & DIVESTMENTS

In 2008 we leveraged our strategic and execution capabilities to execute two of the most significant transactions in our history. On February 13, 2008 Enerplus acquired Focus Energy Trust for $1.7 billion through an exchange of trust units and the assumption of debt adding approximately 84 MMBOE of proved plus probable conventional oil and natural gas reserves and approximately 20,000 BOE/day of production (18,000 BOE/day annualized from the closing date of February 13, 2008), of which approximately 90% was natural gas. On July 31, 2008, we completed the sale of our 15% working interest in the Joslyn oil sands lease for net cash proceeds of approximately $502 million. We sold 63.5 million barrels of proved plus probable reserves at a cost of $14.36 per barrel including future development capital.

We believe that weak commodity prices and the current downturn in the economy will create acquisition opportunities. Given our financial strength, we believe we are in an excellent position to capitalize on these opportunities to add high quality, growth-oriented assets that will improve our overall portfolio.

2008 Acquisition & Divestment Summary

Conventional Oil & Gas	Cost/ Proceeds ($MM)	Proved plus Probable Reserves (MBOE)	Estimated Production (BOE/day)	Cost of Proved plus Probable Reserves ($/BOE)	Cost per Daily Barrel ($/BOE/day)
Acquisitions, net of divestments(*)	$1,770.0	84,237	20,668	$ 21.01	$ 85,640
Oil Sands Divest-ments(xx)	$ 502.0	63,498	-	$ 14.36	-

(*) After adjustment for working capital and excluding future development capital.
(xx) Including future development capital

RESERVES

Enerplus replaced approximately 78% of our produced reserves in 2008, essentially keeping our total proved plus probable reserves consistent year-over-year. Through the Focus acquisition and our development activities, we added over 90 MMBOE of proved plus probable reserves however the sale of

Joslyn and our production more than offset these additions. Our proved reserves as a percent of total reserves increased by 8% (from 66% at December 31, 2007 to 74% in 2008) given the higher percentage of proved reserves attributable to the Focus assets whereas the majority of the reserves associated with the Joslyn lease were in the probable category.

Overall the results from our development program were disappointing as fewer reserves were added than expected and we experienced negative revisions and increased capital costs in some areas. These revisions negatively impacted our finding and development costs ("F&D") as well as our finding, development and acquisition costs ("FD&A"). Our conventional FD&A costs per BOE including future development capital ("FDC") were $29.17 with a recycle ratio of 1.4x driven primarily by the Focus acquisition (see "Recycle Ratio" below for additional information on this metric). Our total finding and development costs on our oil sands assets including FDC were $13.71 per BOE reflecting the impact of the Joslyn sale and the spending on oil sands which added contingent resources but do not at this stage of development qualify as reserves.

The following information highlights some of our key reserve findings

- We added approximately 20 MMBOE of proved plus probable reserves through our conventional development program including:
  - 3.4 MMBOE of proved plus probable reserves added as a result of price forecast revisions by our external independent reserve evaluators as higher long-term prices extended the life and expected reserves in some areas even though the near-term price outlook was lower than in 2007.
  - 6 MMBOE of proved plus probable reserves were added on the Focus assets, primarily at Shackleton and other minor properties.
  - We added 3 MMBOE of proved plus probable reserves at Sleeping Giant. Since acquiring this property in 2005, reserves have increased by 48% through the addition of 17.4 MMBOE of proved plus probable reserves including the replacement of 13.3 MMBOE of produced reserves.
- We experienced negative reserve revisions of 13.6 MMBOE;
  - 5.6 MMBOE of which were due to performance issues associated with our Verger, Hanna Garden and Medicine Hat South shallow gas properties as well as with our Mitsue non-operated oil property.
  - Approximately 5.0 MMBOE of reserves were eliminated from our least attractive shallow gas undeveloped locations, the majority of which were at our Medicine Hat North and Verger shallow gas properties. Lower than expected results combined with a reduced capital budget have resulted in a reduction in future spending plans on these properties. Given the current commodity price environment, we are directing our shallow gas spending to other areas that have higher economic returns.
  - 2.5 million BOE of reserves were eliminated at our Mount Benjamin property as the operator is not planning on drilling in the current commodity price environment.
- Approximately $144 million of future development capital was added to our reserve report to reflect higher costs. Close to half of this amount was associated with increased development costs relating to the Shackleton property. We also experienced an increase in maintenance capital associated with our Mitsue property.
- Given the sale of Joslyn, our Reserve life index and our percentage of reserves tied to resource plays fell to 12.1 years and 74% respectively. We believe that our RLI remains one of the longest in our sector and we expect to continue to increase our percentage of resource oriented reserves through our acquisitions and divestments.

Play Types	Proved Developed Producing Reserves (MMBOE)	Proved Developed Non-Producing Reserves (MMBOE)	Proved Undeveloped Reserves (MMBOE)	Proved Reserves (MMBOE)	Probable Reserves (MMBOE)	Proved Plus Probable Reserves (MMBOE)	Proved plus Probable Reserve Life Index (years)
Crude Oil Waterfloods	67.1	0.0	6.9	74.0	21.7	95.7	16.2
Shallow Gas & CBM	62.4	0.3	23.7	86.4	35.6	122.0	12.6
Tight Gas	35.7	2.0	6.7	44.4	17.0	61.4	10.5
Bakken/ Tight Oil	27.3	1.4	2.1	30.8	9.8	40.6	11.0
Other Conventional Oil & Gas	74.3	0.9	7.7	82.9	29.8	112.7	10.6
Total Company	266.8	4.6	47.1	318.5	113.9	432.4	12.1

Amounts shown in table may not add due to rounding.

Reserve Reporting and Determination Methodologies

All of our reserves, including our U.S. reserves, were evaluated using Canadian National Instrument 51-101 ("NI 51-101") standards. Two external, independent third party engineering firms were used to evaluate and review our reserves this year. Sproule Associates Limited, our historical independent engineering evaluators, evaluated our Canadian conventional reserves. Netherland, Sewell & Associates, Inc. ("NSA") of Dallas, Texas evaluated the reserves attributed to our assets in the United States. Sproule evaluated 93% of the total proved plus probable value (discounted at 10%) of our Canadian conventional year-end reserves and audited the remaining 7% of the reserves which were internally evaluated by Enerplus. NSA evaluated 100% of the reserves in the U.S. and utilized Sproule's forecast price and cost assumptions as of December 31, 2008 in their evaluations to maintain consistency among our reserve reporting. In addition to Sproule and NSA, GLJ Petroleum Consultants Ltd. evaluated the resources on our Kirby oil sands project as described above.

For information regarding the presentation of our oil and gas reserves, please see "Information Regarding Disclosure in this News Release and Oil and Gas Reserves, Resources and Operational Information" and "Notice to U.S. Investors" at the conclusion of this news release.

Reserves Summary

The following table sets out our company interest volumes by production type and reserve category under a forecast price scenario. Under different price scenarios, these reserves could vary as a change in price can affect the economic limit and reserves associated with a property.

2008 Reserve Summary - Company Interest Volumes (Forecast Prices)

OIL AND GAS NATURAL RESERVES

	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)
Proved developed producing							
Canada	64,043	26,979	-	91,022	11,416	813,021	237,942
United States	23,159	-	-	23,159	80	33,928	28,894
Total	87,202	26,979	-	114,181	11,496	846,949	266,836
Proved developed non-producing							
Canada	243	-	-	243	360	15,355	3,162
United States	1,216	-	-	1,216	4	1,532	1,475
Total	1,459	-	-	1,459	364	16,887	4,637
Proved undeveloped							
Canada	4,139	6,160	-	10,299	1,163	197,490	44,377
United States	1,753	-	-	1,753	29	5,208	2,650
Total	5,892	6,160	-	12,052	1,192	202,698	47,027
Total Proved							
Canada	68,425	33,139	-	101,564	12,939	1,025,866	285,481
United States	26,128	-	-	26,128	113	40,668	33,019
Total	94,553	33,139	-	127,692	13,052	1,066,534	318,500
Probable							
Canada	19,274	12,790	-	32,064	4,714	397,651	103,053
United States	6,867	-	-	6,867	51	23,483	10,832
Total	26,141	12,790	-	38,931	4,765	421,134	113,885
Total Proved plus Probable							
Canada	87,699	45,929	-	133,628	17,653	1,423,517	388,534
United States	32,995	-	-	32,995	164	64,151	43,851
Total	120,694	45,929	-	166,623	17,817	1,487,668	432,385

Reserve Reconciliation

The following tables outline the changes in Enerplus' proved, probable and proved plus probable reserves, on a company interest basis, from December 31, 2007 to December 31, 2008.

Proved Reserves

CANADA	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)
Proved Reserves at Dec. 31, 2007	67,386	31,215	8,568	107,169	11,673	829,122	257,029
Acquisitions	3,585	-	-	3,585	2,714	337,623	62,570
Divestments	-	-	(8,568)	(8,568)	-	-	(8,568)
Discoveries	114	-	-	114	6	635	226
Extensions & Improved Recovery	2,922	1,899	-	4,821	331	24,953	9,311
Economic Factors	604	200	-	804	94	7,961	2,225
Technical Revisions	1	2,879	-	2,880	(186)	(55,062)	(6,484)
Production	(6,187)	(3,054)	-	(9,241)	(1,693)	(119,366)	(30,828)
Proved Reserves at Dec. 31, 2008	68,425	33,139	-	101,564	12,939	1,025,866	285,481

UNITED STATES	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)
Proved Reserves at Dec. 31, 2007	26,637	-	-	26,637	112	36,955	32,908
Acquisitions	-	-	-	-	-	-	-
Divestments	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-
Extensions & Improved							

Recovery	2,429	-	-	2,429	16	3,940	3,102
Economic Factors	-	-	-	-	-	-	-
Technical Revisions	465	-	-	465	(2)	4,433	1,202
Production	(3,403)	-	-	(3,403)	(13)	(4,660)	(4,193)
Proved Reserves at Dec. 31, 2008	26,128	-	-	26,128	113	40,668	33,019

TOTAL ENERPLUS	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)
Proved Reserves at Dec. 31, 2007	94,023	31,215	8,568	133,806	11,785	866,077	289,937
Acquisitions	3,585	-	-	3,585	2,714	337,623	62,570
Divestments	-	-	(8,568)	(8,568)	-	-	(8,568)
Discoveries	114	-	-	114	6	635	226
Extensions & Improved Recovery	5,351	1,899	-	7,250	347	28,893	12,413
Economic Factors	604	200	-	804	94	7,961	2,225
Technical Revisions	466	2,879	-	3,345	(188)	(50,629)	(5,282)
Production	(9,590)	(3,054)	-	(12,644)	(1,706)	(124,026)	(35,021)
Proved Reserves at Dec. 31, 2008	94,553	33,139	-	127,692	13,052	1,066,534	318,500

Probable Reserves

CANADA	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total E)(MBO
Probable Reserves at Dec. 31, 2007	17,837	10,948	54,930	83,715	3,797	308,276	138,891

Acquisitions	944	-	-	944	831	119,352	21,667
Divestments	-	-	(54,930)	(54,930)	-	-	(54,930)
Discoveries	37	-	-	37	1	212	73
Extensions & Improved Recovery	1,072	486	-	1,558	168	7,976	3,055
Economic Factors	303	171	-	474	32	4,070	1,184
Technical Revisions	(919)	1,185	-	266	(115)	(42,235)	(6,887)
Production	-	-	-	-	-	-	-
Probable Reserves at Dec. 31, 2008	19,274	12,790	-	32,064	4,714	397,651	103,053

UNITED STATES	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)
Probable Reserves at Dec. 31, 2007	6,719	-	-	6,719	30	27,938	11,406
Acquisitions	-	-	-	-	-	-	-
Divestments	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-
Extensions & Improved Recovery	521	-	-	521	11	1,952	857
Economic Factors	-	-	-	-	-	-	-
Technical Revisions	(373)	-	-	(373)	10	(6,407)	(1,431)
Production	-	-	-	-	-	-	-
Probable Reserves at Dec. 31, 2008	6,867	-	-	6,867	51	23,483	10,832

TOTAL ENERPLUS	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)

Probable Reserves at Dec. 31, 2007	24,556	10,948	54,930	90,434	3,827	336,214	150,297
Acquisitions	944	-	-	944	831	119,352	21,667
Divestments	-	-	(54,930)	(54,930)	-	-	(54,930)
Discoveries	37	-	-	37	1	212	73
Extensions & Improved Recovery	1,593	486	-	2,079	179	9,928	3,912
Economic Factors	303	171	-	474	32	4,070	1,184
Technical Revisions	(1,292)	1,185	-	(107)	(105)	(48,642)	(8,318)
Production	-	-	-	-	-	-	-
Probable Reserves at Dec. 31, 2008	26,141	12,790	-	38,931	4,765	421,134	113,885

Proved Plus Probable Reserves

CANADA	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at Dec. 31, 2007	85,223	42,163	63,498	190,884	15,470	1,137,398	395,920
Acquisitions	4,529	-	-	4,529	3,545	456,975	84,237
Divestments	-	-	(63,498)	(63,498)	-	-	(63,498)
Discoveries	151	-	-	151	7	847	299
Extensions & Improved Recovery	3,994	2,385	-	6,379	499	32,929	12,366
Economic Factors	907	371	-	1,278	126	12,031	3,409
Technical Revisions	(918)	4,064	-	3,146	(301)	(97,297)	(13,371)
Production	(6,187)	(3,054)	-	(9,241)	(1,693)	(119,366)	(30,828)
Proved Plus Probable Reserves at Dec. 31, 2008	87,699	45,929	-	133,628	17,653	1,423,517	388,534

UNITED STATES	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at Dec. 31, 2007	33,356	-	-	33,356	142	64,893	44,314
Acquisitions	-	-	-	-	-	-	-
Divestments	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-
Extensions & Improved Recovery	2,950	-	-	2,950	27	5,892	3,959
Economic Factors	-	-	-	-	-	-	-
Technical Revisions	92	-	-	92	8	(1,974)	(229)
Production	(3,403)	-	-	(3,403)	(13)	(4,660)	(4,193)
Proved Plus Probable Reserves at Dec. 31, 2008	32,995	-	-	32,995	164	64,151	43,851

TOTAL ENERPLUS	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at Dec. 31, 2007	118,579	42,163	63,498	224,240	15,612	1,202,291	440,234
Acquisitions	4,529	-	-	4,529	3,545	456,975	84,237
Divestments	-	-	(63,498)	(63,498)	-	-	(63,498)
Discoveries	151	-	-	151	7	847	299
Extensions & Improved Recovery	6,944	2,385	-	9,329	526	38,821	16,325
Economic Factors	907	371	-	1,278	126	12,031	3,409
Technical Revisions	(826)	4,064	-	3,238	(293)	(99,271)	(13,600)
Production	(9,590)	(3,054)	-	(12,644)	(1,706)	(124,026)	(35,021)

Proved Plus Probable Reserves at Dec. 31, 2008	120,694	45,929	-	166,623	17,817	1,487,668	432,385

NET PRESENT VALUE OF FUTURE PRODUCTION REVENUE

The following tables provide an estimate of the net present value of Enerplus' future production revenue before provision for interest and general and administrative expenses and after deduction of royalties and estimated future capital expenditures, both before and after income taxes. It should not be assumed that the present value of estimated future cash flows shown below is representative of the fair market value of the reserves.

The estimated net present value of all future net revenues at December 31, 2008 was based upon forecast crude oil and natural gas pricing assumptions prepared by Sproule as of December 31, 2008. These prices were applied to the reserves evaluated by Sproule and NSA. The base reference prices and exchange rates used by Sproule are detailed below:

Sproule December 31, 2008 - Forecast Price Assumptions

	WTI crude oil US$/bbl	Light crude(1) Edmonton CDN$/bbl	Hardisty Heavy 12(degrees) API CDN$/bbl	Henry Hub Price US$/ MMbtu	Natural Gas 30 day spot @ AECO CDN$/ MMbtu	Exchange Rate US$/CDN$
2009	53.73	65.35	47.05	6.30	6.82	0.80
2010	63.41	72.78	54.58	7.32	7.56	0.85
2011	69.53	79.95	59.96	7.56	7.84	0.85
2012	79.59	86.57	67.53	8.49	8.38	0.90
2013	92.01	94.97	74.08	9.74	9.20	0.95
Thereafter	(xx)	(xx)	(xx)	(xx)	(xx)	0.95

(1) Edmonton refinery postings for 40 degree API, 0.4% sulphur content crude

(xx) Escalation varies until 2019 and increases at an annual rate of 2% thereafter

Net Present Value of Future Production Revenue - Forecast Prices and Costs (Before Tax) At December 31, 2008

Conventional Reserves ($ Millions, discounted at)	0%	5%	10%	15%
Proved developed producing	$10,366	$6,731	$5,044	$4,069
Proved developed non-producing	173	120	89	70
Proved undeveloped	1,177	704	438	272
Total Proved	$11,716	$7,555	$5,571	$4,411
Probable	5,269	2,362	1,352	890

Total Proved Plus Probable Conventional Reserves	$16,985	$9,917	$6,923	$5,301

Net Present Value of Future Production Revenue - Forecast Prices and Costs (After Tax)
At December 31, 2008

Conventional Reserves ($ Millions, discounted at)	0%	5%	10%	15%
Proved developed producing	$8,573	$5,748	$4,403	$3,610
Proved developed non-producing	127	90	67	53
Proved undeveloped	952	550	332	196
Total Proved	$9,652	$6,388	$4,802	$3,859
Probable	3,896	1,755	1,008	666
Total Proved Plus Probable Conventional Reserves	$13,548	$8,143	$5,810	$4,525

NET ASSET VALUE

Enerplus' estimated net asset value is measured with reference to the estimated net present value of all future net revenue from our reserves, before taxes, as estimated by our independent reserve engineers (Sproule and NSA) plus land values, adjusted for working capital and long-term debt at year-end. This calculation can vary significantly depending on the oil and natural gas price assumptions used by the independent reserve engineers. In addition, this calculation ignores "going concern" value and assumes only the reserves identified in the reserve reports with no further acquisitions or incremental development, despite our 23 year history of replacing production through acquisitions and development.

In addition, we have included in our net asset value calculation provisions for our oil sands portfolio. Given the significant decrease in oil prices and the lack of comparable transactions of oil sands assets, we are showing our costs (acquisition costs and any capital investments made to date) in the net asset value table and have not attempted to determine a current fair market value for our oil sands assets at this time.

Forecast Prices and Costs at December 31, 2008

Conventional Oil and Gas ($ millions except trust unit amounts, discounted at)	0%	5%	10%	15%
Present value of proved plus probable reserves (before tax)				
Total, present value of proved plus probable reserves	$16,985	$9,917	$6,923	$5,301
Undeveloped acreage(1)	85	85	85	85
Asset retirement obligations	(343)	(195)	(74)	(43)
Long-term debt (net of cash)	(657)	(657)	(657)	(657)

Net Working Capital excluding deferred financial asset, distributions to unitholders, deferred credits, and future income tax	(106)	(106)	(106)	(106)
Net Asset Value of Conventional Assets	$15,964	$9,044	$6,17[illegible]	$4,580
Net Asset Value per Trust Unit - Conventional Assets(2)(3)	$96.41	$54.62	$37.27	$27.66

Oil Sands (at cost)				
Kirby Oil Sands Lease(4)	$246	$246	$246	$246
Laricina Equity Investment(5)	25	25	25	25
Undeveloped Oil Sands acreage(6)	11	11	11	11
Net Asset Value of Oil Sands Assets	$282	$282	$282	$282
Net Asset Value per Trust Unit - Oil Sands	$1.70	$1.70	$1.70	$1.70
Total Net Asset Value per Trust Unit(2)	$98.11	$56.32	$38.97	$29.36

(1) Conventional undeveloped acreage valued at $100 per acre except Alberta which was valued at $50 per acre

(2) Asset retirement obligations ("ARO") do not equal the amount on the balance sheet ($207.4 million) as the balance sheet amount uses a 6% discount rate and a portion of the ARO costs are already reflected in the present value of reserves computed by the independent engineers

(3) Based on 165,590,000 trust units outstanding at December 31, 2008

(4) Kirby valuation represents $203.1 million purchase price plus capital spending of $42.9 million since acquisition

(5) Laricina equity investment represents the carrying value of our 4.3 million shares

(6) Undeveloped oil sands acreage valued at cost of land acquisitions and development capital spent on those lands

RESERVE LIFE INDEX ("RLI")

Enerplus continues to maintain one of the longest reserve life indices in the sector. In 2008 our proved plus probable RLI decreased primarily due to the sale of the Joslyn oil sands interest and the removal of proved and probable reserves associated with that lease. At this time, we have only contingent resources and no reserves associated with the Kirby oil sand project and therefore our RLI solely represents our conventional oil and gas assets. Our proved reserve life index declined slightly in 2008 as we did not replace all of the reserves produced during the year.

Conventional Reserves (as at December 31)	2008	2007	2006	2005	2004	2003
Proved	9.4	10.0	9.8	9.6	10.1	10.6
Proved plus Probable	12.1	12.8	12.2	12.0	12.4	13.3

Reserve life index is calculated as year end reserves divided by following year production estimates contained in the independent reserve engineering reports.

FINDING AND DEVELOPMENT COSTS ("F&D") AND FINDING, DEVELOPMENT AND ACQUISITION COSTS ("FD&A")

F&D and FD&A costs have historically been calculated both including and excluding future development capital. F&D and FD&A costs include future development capital as this provides a more representative view of the full cost of reserve additions as it accounts for future costs to bring the reserves to market. Under the historic method, F&D and FD&A costs are understated as reserves are included without taking into account the future capital expenditures required to fully develop the reserve base. We have included both the NI 51-101 method which includes future development capital and the historic method for comparison purposes. 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.

Our F&D and FD&A results were significantly influenced by our acquisition and divestment activity during the year as well as a number of other factors detailed above. When reviewing these numbers in light of these factors, care must be taken before drawing conclusions as to the effectiveness of current spending and the full-cycle economics associated with the recent and ongoing capital investment program.

Our total spending on our conventional asset base delivered a FD&A cost of $29.17/BOE on a proved plus probable basis including future development capital ("FDC"). Our three-year conventional proved plus probable FD&A was $27.13/BOE including changes in future development capital.

Through our conventional capital development program, we added 20.0 million BOE of proved plus probable reserves. We also experienced negative technical revisions of 13.6 million proved plus probable BOE. Therefore on a net basis, our capital development program added only 6.4 million BOE of proved plus probable reserves resulting in F&D costs of $82.34/BOE on our conventional oil and gas assets.

Our oil sands activity consisted of the disposition of the Joslyn oil sands mining lease and capital development at our Kirby SAGD lease. We sold 63.5 million barrels of reserves (87% probable) associated with the Joslyn lease and while the spending on our Kirby oil sands property did not add production or reserves in 2008, it has advanced the Phase I project. As development of the Kirby lease moves forward, we would expect to move contingent resources into the probable reserve category. Key events triggering this move would be regulatory approval of the Phase I project and affirmative sanctioning by our Board of Directors. Our proved plus probable FD&A cost on our oil sands assets was $13.71/BOE including FDC.

F&D and FD&A Costs (Including Future Development Capital) ($ millions except for per BOE amounts)	2008	2007	2006
Proved Reserves			
Conventional Oil & Gas			
Finding & Development Costs			

Capital Expenditures	$526.5	$348.3	$452.1
Net change in Future Development Capital	$(27.9)	$39.3	$22.3
Gross Company Reserve additions (MMBOE)	9.6	17.9	16.1
F&D costs ($/BOE)	$51.94	$21.65	$29.47
Three year average F&D cost ($/BOE)(1)	$31.21	$20.62	$15.54
Finding, Development & Acquisition Costs			
Capital Expenditures and net acquisitions	$2,296.5	$409.8	$502.0
Net change in Future Developments Capital	$252.5	$48.5	$8.0
Gross Company Reserve additions (MMBOE)	72.2	20.4	18.6
FD&A costs ($/BOE)	$35.30	$22.47	$27.42
Three year average FD&A costs ($/BOE)(1)	$31.63	$22.93	$19.80
Oil Sands			
Finding & Development Costs			
Capital Expenditures	$51.2	$38.9	$39.1
Net change in Future Development Capital	$-	$(1.7)	$(10.8)
Gross Company Reserve additions (MMBOE)	0.0	(0.2)	(0.1)
F&D costs ($/BOE)	n/a	$(186.00)	$(283.00)
Three year average F&D cost ($/BOE)(1)	$(389.00)	$15.58	$12.17
Finding, Development & Acquisition Costs			
Capital Expenditures and net acquisitions	$(450.8)	$242.0	$19.4
Net change in Future Development Capital	$(29.3)	$(1.7)	$(13.6)
Gross Company Reserve additions (MMBOE)	(8.6)	(0.2)	(0.7)
FD&A costs ($/BOE)	$55.83	$(1,201.50)	$(8.29)
Three year average FD&A costs ($/BOE)(1)	$24.63	$37.66	$10.44

Proved Plus Probable Reserves ($ millions except for per BOE amounts)	2008	2007	2006
Conventional Oil & Gas			
Finding & Development Costs			
Capital Expenditures	$526.5	$348.3	$452.1
Net change in Future Development Capital	$0.5	$(30.7)	$50.7
Gross Company Reserve additions (MMBOE)	6.4	15.9	18.3
F&D costs ($/BOE)	$82.34	$19.97	$27.48

Three year average F&D cost ($/BOE)(1)	$33.19	$18.85	$20.22
Finding, Development & Acquisition Costs			
Capital Expenditures and net acquisitions	$2,296.5	$409.8	$502.0
Net change in Future Development Capital	$348.8	$(12.0)	$54.4
Gross Company Reserve additions (MMBOE)	90.7	20.1	21.9
FD&A costs ($/BOE)	$29.17	$19.79	$25.41
Three year average FD&A costs ($/BOE)(1)	$27.13	$19.57	$18.10

Oil Sands

Finding & Development Costs			
Capital Expenditures	$51.2	$38.9	$39.1
Net change in Future Development Capital	$-	$105.0	$34.3
Gross Company Reserve additions (MMBOE)	0.0	6.8	6.9
F&D costs ($/BOE)	n/a	$21.16	$10.64
Three year average F&D cost ($/BOE)(1)	$19.60	$14.86	$6.91
Finding, Development & Acquisition Costs			
Capital Expenditures and net acquisitions	$(450.8)	$242.0	$19.4
Net change in Future Development Capital	$(420.1)	$105.0	$15.6
Gross Company Reserve additions (MMBOE)	(63.5)	6.8	3.6
FD&A costs ($/BOE)(1)	$13.71	$51.03	$9.72
Three year average FD&A costs ($/BOE)(1)	$9.21	$28.39	$6.63

(1) Calculated over a three year period.

F&D and FD&A Costs (Excluding Future Development Capital) ($ millions except for per BOE amounts)	2008	2007	2006
Proved Reserves			
Conventional Oil & Gas			
Finding & Development Costs			
Capital Expenditures	$526.5	$348.3	$452.1
Gross Company Reserve additions (MMBOE)	9.6	17.9	16.1
F&D Cost ($/BOE)	$54.84	$19.46	$28.08
Three year average F&D costs ($/BOE)(1)	$30.43	$18.09	$13.17

Finding, Development & Acquisition Costs			
Capital Expenditures and net acquisitions	$2,296.5	$409.8	$502.0
Gross Company Reserve additions (MMBOE)	72.2	20.4	18.6
FD&A costs ($/BOE)	$31.81	$20.09	$26.99
Three year average FD&A costs ($/BOE)(1)	$28.85	$20.33	$17.55

Oil Sands

Finding & Development Costs			
Capital Expenditures	$51.2	$38.9	$39.1
Gross Company Reserve additions (MMBOE)	0.0	(0.2)	(0.1)
F&D Cost ($/BOE)	n/a	$(194.50)	$(391.00)
Three year average F&D costs ($/BOE)(1)	$(430.67)	$12.09	$8.57
Finding, Development & Acquisition Costs			
Capital Expenditures and net acquisitions	$(450.8)	$242.0	$19.4
Gross Company Reserve additions (MMBOE)	(8.6)	(0.2)	(0.7)
FD&A costs ($/BOE)	$52.42	$(1,210.00)	$(27.71)
Three year average FD&A costs ($/BOE)(1)	$19.94	$34.26	$6.92

Proved Plus Probable Reserves ($ millions except for per BOE amounts)	2008	2007	2006

Conventional Oil & Gas

Finding & Development Costs			
Capital Expenditures	$526.5	$348.3	$452.1
Gross Company Reserve additions (MMBOE)	6.4	15.9	18.3
F&D Cost ($/BOE)	$82.27	$21.91	$24.70
Three year average F&D costs ($/BOE)(1)	$32.68	$17.16	$16.66
Finding, Development & Acquisition Costs			
Capital Expenditures and net acquisitions	$2,296.5	$409.8	$502.0
Gross Company Reserve additions (MMBOE)	90.7	20.1	21.9
FD&A costs ($/BOE)	$25.32	$20.39	$22.92
Three year average FD&A costs ($/BOE)(1)	$24.18	$17.36	$15.55

Oil Sands

Finding & Development Costs			
Capital Expenditures	$51.2	$38.9	$39.1

Gross Company Reserve additions (MMBOE)	0.0	6.8	6.9
F&D Cost ($/BOE)	n/a	$5.72	$5.67
Three year average F&D costs ($/BOE)(1)	$9.43	$5.82	$1.34
Finding, Development & Acquisition Costs			
Capital Expenditures and net acquisitions	$(450.8)	$242.0	$19.4
Gross Company Reserve additions (MMBOE)	(63.5)	6.8	3.6
FD&A costs ($/BOE)	$7.10	$35.59	$5.39
Three year average FD&A costs ($/BOE)(1)	$3.57	$18.65	$1.07

(1) Calculated over a three year period.

RECYCLE RATIO

Recycle ratio is calculated as operating income (revenues less royalties and operating costs) divided by FD&A including FDC. It is indicative of the value created for each dollar invested and accounts for the quality of reserves, operating costs and attractiveness of acquisitions and internal development capital. We have shown only conventional recycle ratios as most of our oil sands portfolio is in the early stages of development and consequently currently has no operating income or proved plus probable reserves.

Proved Plus Probable Reserves	2008	2007	2006
Conventional Recycle Ratio	1.4x	1.6x	1.2x
Conventional 3-Year Average	1.4x	1.5x	1.4x

Based on 2008 netback of $41.07

MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A")

The following discussion and analysis of financial results is dated February 25, 2009 and is to be read in conjunction with the audited consolidated financial statements as at and for the years ended December 31, 2008 and 2007. All amounts are stated in Canadian dollars unless otherwise specified. All references to GAAP refer to Canadian generally accepted accounting principles. All note references relate to the notes included with the consolidated financial statements. In accordance with Canadian practice revenues are reported on a gross basis, before deduction of Crown and other royalties, unless otherwise stated. In addition to disclosing reserves under the requirements of NI 51-101, we also disclose our reserves on a company interest basis which is not a term defined under NI 51-101. This information may not be comparable to similar measures presented by other issuers. Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE. The BOE rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. Use of BOE in isolation may be misleading.

NON-GAAP MEASURES

Throughout the MD&A we use the term "payout ratio" to analyze operating performance, leverage and liquidity. We calculate payout ratio by dividing cash distributions to unitholders ("cash distributions") by cash flow from operating activities ("cash flow"), both of which are measures prescribed by GAAP which appear on our consolidated statements of cash flows. The term "payout ratio" does not have a standardized meaning or definition as prescribed by GAAP and therefore may not be comparable with the calculation of similar measures by other entities.

Refer to the "Liquidity and Capital Resources" section of the MD&A for further information on cash flow, cash distributions and payout ratio.

2008 OVERVIEW

We began 2008 with the largest acquisition in our 23 year history. Focus Energy Trust ("Focus") was acquired on February 13, 2008 for approximately $1.7 billion and added approximately 18,000 BOE/day of average daily production to our 2008 operating results. Commodity prices started the year off strong and continued to rise throughout the first half of the year, ultimately peaking in July. Higher commodity prices combined with additional production volumes from Focus resulted in our cash flow from operating activities totaling $1,262.8 million, representing a 45% increase from 2007.

On July 31, 2008, as commodity prices began to decline, we reduced our exposure to oil sands and successfully disposed of our interest in the Joslyn oil sands lease ("Joslyn") for net proceeds of $502.0 million. The proceeds were used to pay down debt and, as a result, we believe that we have one of the strongest balance sheets in the sector with a trailing twelve month debt-to-cash flow ratio of 0.5x at December 31, 2008. We believe we are in a strong position given the current market conditions and expect to enhance our asset base with opportunistic acquisitions.

In addition to our successful acquisition and disposition activities, we completed the largest development capital spending program in our history with total spending of approximately $577.7 million, resulting in the drilling of 643 net wells with a 99% success rate.

The sharp decline in commodity prices in the fourth quarter of 2008 has focused our priorities on preserving our balance sheet strength and, as a result, we have decreased our 2009 development capital program along with our monthly distributions. We intend to manage our capital spending and distributions to unitholders at a level which will minimize increases in our debt levels outside of any acquisition activity. We have decided to limit spending on our current properties as we expect the acquisition market will provide the best opportunity to add quality reserves at a reasonable cost in today's credit constrained environment. As a result of our reduced development capital spending, we expect annual production to average 91,000 BOE/day with an exit production rate of 88,000 BOE/day in 2009.

RESULTS OF OPERATIONS

Production

Production during 2008 averaged 95,687 BOE/day, essentially in line with our guidance of 96,000 BOE/day and 16% higher than 82,319 BOE/day in 2007. The increase compared to 2007 was primarily due to the additional production volumes from the Focus assets which were purchased on February 13, 2008. Although our annual average production approximated our guidance we did encounter challenges with production throughout the year. We experienced unplanned downtime at several non-operated facilities along with setbacks executing our capital program due to weather and tie in delays while we assessed alternative well completion techniques.

Average production during the year was weighted 59% to natural gas and 41% to liquids on a BOE basis. Average production volumes for the years ended December 31, 2008 and 2007 are outlined below:

Daily Production Volumes	2008	2007	% Change

Natural gas (Mcf/day)	338,869	262,254	29%
Crude oil (bbls/day)	34,581	34,506	-%
Natural gas liquids (bbls/day)	4,627	4,104	13%
Total daily sales (BOE/day)	95,687	82,319	16%

During the month of December we experienced production interruptions of approximately 1,600 BOE/day on two of our properties. We experienced an interruption of 1,100 BOE/day related to a labour strike at a non-operated facility which processes our Tommy Lakes production and another interruption of 500 BOE/day related to unscheduled downtime at Bantry. As a result, our December average daily production was approximately 96,400 BOE/day. Both of these issues were resolved and production was restored resulting in an adjusted exit rate of approximately 98,000 BOE/day which was 500 BOE/day less than our guidance of 98,500 BOE/day.

Considering our reduced development capital program in 2009, we expect 2009 annual production volumes to average 91,000 BOE/day, weighted 58% to natural gas and 42% to liquids. We expect to exit 2009 with production of approximately 88,000 BOE/day. This guidance does not contemplate any potential acquisitions or dispositions.

Pricing

The prices received for our natural gas and crude oil production directly impact our earnings, cash flow and financial condition. The following table compares our average selling prices for 2008 with those of 2007. It also compares the benchmark price indices for the same periods.

Average Selling Price(1)	2008	2007	% Change
Natural gas (per Mcf)	$ 8.17	$ 6.45	27%
Crude oil (per bbl)	$ 91.31	$ 65.11	40%
Natural gas liquids (per bbl)	$ 68.93	$ 51.35	34%
Per BOE	$ 65.79	$ 50.48	30%

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments

Average Benchmark Pricing	2008	2007	% Change
AECO natural gas - monthly index (CDN$/Mcf)	$ 8.13	$ 6.61	23%
AECO natural gas - daily index (CDN$/Mcf)	$ 8.14	$ 6.45	26%
NYMEX natural gas - monthly NX3 index (US$/Mcf)	$ 8.93	$ 6.92	29%
NYMEX natural gas - monthly NX3 index: CDN$ equivalent (CDN$/Mcf)	$ 9.50	$ 7.44	28%
WTI crude oil (US$/bbl)	$ 99.65	$ 72.34	38%
WTI crude oil: CDN$ equivalent (CDN$/bbl)	$ 106.01	$ 77.78	36%
CDN$/US$ exchange rate	0.94	0.93	1%

Natural Gas

Natural gas prices in Alberta were strong through the first half of 2008, opening at $6.97/Mcf at AECO and rising steadily to a high of $11.82/Mcf by the end of June. The strength in natural gas prices was partly fueled by the crude oil market which hit record levels by mid-year. Also, the key consuming regions of the U.S. experienced cold weather from late January to March 2008 which decreased inventories to the lowest levels since 2004. Early forecasts for an active hurricane season and the expectation for supply disruptions led to further price strength at the start of summer combined with demand in Asia and Europe for liquefied natural gas ("LNG") which diverted the majority of LNG supply away from North America, ultimately helped keep prices high.

By mid-year the market started to adjust to the impact of the increased U.S. shale gas production that had been brought on-stream throughout the year and gas inventories started to rise despite a warmer than average summer. The impact of the global economic crisis began to take its toll on demand as supply additions continued to overwhelm the shrinking demand for gas. Prices declined to a low of $5.79/Mcf at AECO at the end of September and closed the year at $6.34/Mcf.

During 2008 we sold approximately 84% of our natural gas on the AECO index split evenly between the daily and monthly indices and the remaining 16% against the monthly NYMEX index. During 2008 we sold our natural gas for an average price of $8.17/Mcf (net of transportation costs), an increase of 27% from $6.45/Mcf realized in 2007. This increase is comparable to the price increases realized in the AECO daily and monthly indices and the NYMEX monthly index.

Crude Oil

Crude prices were strong through the first two quarters of 2008 reaching a peak of US$147.27/bbl during July. Prices then dropped significantly, approximately 77% through the second half of the year. The global economic crisis and reduced access to credit began to weaken gasoline and distillate demand. Inventories began to grow and the general bearish mood in the market, which was supported by continued weak economic data, pushed prices down reaching a low for the year in mid-December at US$33.87/bbl.

Our crude oil production in 2008 was weighted 76% light/medium and 24% heavy. The average price received for our crude oil (net of transportation costs) was $91.31/bbl during 2008, a 40% increase over 2007. The West Texas Intermediate ("WTI") crude oil benchmark price, after adjusting for the change in the U.S. dollar exchange rate, increased 36% year-over-year. With gasoline demand falling and heavy oil refining capacity increasing, the demand for heavy oil increased. This fundamental change created a narrowing of the heavy differentials which benefited our heavy crude pricing in comparison to the benchmark.

Foreign Exchange

During the first half of the year the Canadian dollar fluctuated around par relative to the U.S. dollar, but by the third quarter it started to weaken along with crude oil prices and by the fourth quarter it dropped dramatically reaching a low CDN$/US$ exchange rate of 0.77. As most of our crude oil and a portion of our natural gas sales are priced in reference to U.S. dollar denominated benchmarks, this movement in the exchange rate during the latter part of the year increased the Canadian dollar prices we realized.

Price Risk Management

We continue to adjust our price risk management program with consideration given to our overall financial position together with the economics of our development capital program and potential acquisitions. Consideration is also given to the upfront and potential costs of our risk management program as we seek to limit our exposure to price downturns. Hedge positions for any given term are transacted across a range of prices and time.

Our existing commodity contracts are designed to protect a portion of our natural gas sales through October 2010 and a portion of our crude oil sales through December 2009. We have also hedged a portion of our electricity consumption through December 2010 to protect against rising electricity costs in the Alberta power market. See Note 12 for a detailed list of our current price risk management positions.

The following is a summary of the financial contracts in place at February 18, 2009 expressed as a percentage of our forecasted net production volumes:

	Natural Gas (CDN$/Mcf)				Crude Oil (US$/bbl)
	January 1, 2009 - March 31, 2009	April 1, 2009 - October 31, 2009	November 1, 2009 - March 31, 2010	April 1, 2010 - October 31, 2010	January 1, 2009 - December 31, 2009
Purchased Puts (floor prices)	$ 9.20	$ 8.30	$ 8.99	$ -	$98.08
%	21%	18%	8%	-	24%
Sold Puts (limiting downside protection)	$ 6.93	$ 7.85	$ -	$ -	$66.17
%	14%	4%	-	-	10%
Swaps (fixed price)	$ 9.35	$ 7.41	$ 7.33	$ 7.33	$100.05
%	3%	11%	9%	9%	2%
Sold Calls (capped price)	$11.60	$ -	$12.13	$ -	$92.98
%	10%	-	2%	-	11%

Based on weighted average price (before premiums), estimated average annual production of 91,000 BOE/day, net of royalties and assuming a 18% royalty rate.

Accounting for Price Risk Management

For the first three quarters of 2008 commodity prices were generally above our swap and sold call positions, resulting in cash losses of $135.0 million on our natural gas and crude oil contracts for the period ending September 30, 2008. In the fourth quarter of 2008 commodity prices declined significantly to levels below our swap and purchased put positions resulting in cash gains of $31.8 million on our natural gas and crude oil contracts. In aggregate we recorded net cash losses of $20.1 million on our natural gas contracts and $83.1 million on our crude oil contracts in 2008. In comparison, during 2007 our commodity price risk management program resulted in cash gains of $23.6 million on our natural gas contracts and cash losses of $10.0 million on our crude oil contracts.

At December 31, 2008 the fair value of our natural gas and crude oil derivative instruments, net of premiums, represented a gain of $24.3 million and $96.6 million respectively. These gains are recorded as current deferred financial assets on our balance sheet. In comparison, at December 31, 2007 the fair value of our natural gas derivative instruments, net of premiums, represented a gain of $9.7 million which was recorded on our balance sheet as a deferred financial asset and the fair value of our crude oil derivative instruments, net of premiums, represented a loss of $52.5 million which was recorded on our balance sheet as a deferred financial credit. The change in the fair value of our financial contracts during the year, after adjusting for the Focus derivative instruments, resulted in unrealized gains of $16.2 million for natural gas and $153.4 million for crude oil. As the forward markets for natural gas and crude oil fluctuate, new contracts are executed and existing contracts are realized, the changes in fair value will be reflected as a non-cash charge or non-cash gain in earnings. See Note 12 for details.

The following table summarizes the effects of our financial contracts on income for the years ended December 31, 2008 and 2007.

Risk Management Costs ($ millions, except per unit amounts)	2008		2007	
Cash (losses)/gains:				
Natural gas	$ (20.1)	$(0.16)/Mcf	$ 23.6	$ 0.25/Mcf
Crude oil	(83.1)	$(6.57)/bbl	(10.0)	$(0.79)/bbl
Total cash (losses)/gains	$ (103.2)	$(2.94)/BOE	$ 13.6	$ 0.45/BOE
Non-cash gains/(losses) on financial contracts:				
Change in fair value - natural gas	$ 16.2	$ 0.13/Mcf	$ (3.0)	$(0.03)/Mcf
Change in fair value - crude oil	153.4	$ 12.12/bbl	(63.4)	$(5.03)/bbl
Total non-cash gains/(losses)	$ 169.6	$ 4.84/BOE	$ (66.4)	$(2.21)/BOE
Total gains/(losses)	$ 66.4	$ 1.90/BOE	$ (52.8)	$(1.76)/BOE

Cash Flow Sensitivity

The sensitivities below reflect all commodity contracts as listed in Note 12 and are based on forward markets as at February 18, 2009. To the extent the market price of crude oil and natural gas change significantly from current levels, the sensitivities will no longer be relevant as the effect of our commodity contracts will change.

Sensitivity Table	Effect on 2009 Cash Flow per Trust Unit(1)
Change of $0.50 per Mcf in the price of AECO natural gas	$0.20
Change of US$5.00 per barrel in the price of WTI crude oil	$0.32
Change of 1,000 BOE/day in production	$0.06
Change of $0.01 in the US$/CDN$ exchange rate	$0.08
Change of 1% in interest rate	$0.04

(1) Assumes constant working capital and 165,590,000 units outstanding. The impact of a change in one factor may be compounded or offset by changes in other factors. This table does not consider the impact of any inter-relationship among the factors.

Revenues

Crude oil and natural gas revenues in 2008 were $2,304.2 million ($2,331.9 million, net of $27.7 million of transportation costs), an increase of 52% or $787.1 million compared to $1,517.1 million ($1,539.2 million, net of $22.1 million of transportation costs) during 2007. Higher commodity prices and production resulting primarily from our Focus acquisition helped to increase revenues significantly over 2007 levels.

Analysis of Sales Revenue(1) ($ millions)	Crude oil	NGLs	Natural Gas	Total
2007 Sales Revenue	$ 820.1	$ 76.9	$ 620.1	$ 1,517.1
Price variance(1)	331.6	29.7	221.2	582.5
Volume variance	4.0	10.1	190.5	204.6
2008 Sales Revenue	$ 1,155.7	$ 116.7	$ 1,031.8	$ 2,304.2

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

Other Income

Other income during 2008 was $8.5 million compared to $15.0 million in 2007. During 2008 we realized a gain of $8.3 million on the sale of marketable securities and business interruption insurance proceeds of $8.9 million related to the Giltedge fire. In addition we recorded a write down of $10.0 million related to one of our equity investments in a private company. In 2007 we had a gain of $14.1 million on the sale of marketable securities.

Royalties

Royalties are paid to various government entities and other land and mineral rights owners. Total royalties paid during 2008 increased to $429.9 million compared to $285.1 million in 2007 due to increased commodity prices and production volumes. As a percentage of oil and gas sales, net of transportation costs, royalties remained at approximately 19%.

On January 1, 2009 a new royalty regime came into effect in the province of Alberta where approximately 60% of our production is located. This new regime has provisions for escalating royalty rates depending on production and product price levels. The fundamental design of this regime (which increases royalty rates as commodity prices increase) has removed some of the price upside producers had previously factored into their risk assessments for capital investment. The Alberta government further modified the new regime with programs to encourage the drilling of medium and deeper wells but with our reduced development capital spending plans we expect no material impact in 2009 from these modifications. Assuming current forward commodity prices and our production profile, we expect our average royalty rate to decrease slightly in 2009. The following is a summary of our estimated corporate average royalty rates under various commodity price scenarios.

2009 Royalty Rate

Light Crude Oil (Cdn $/bbl)(1)	$40.00	$50.00	$60.00	$70.00	$80.00	$100.00	$120.00
AECO Natural Gas ($/Mcf)	$ 4.00	$ 5.00	$ 6.00	$ 7.00	$ 8.00	$ 10.00	$ 12.00
Corporate royalty rate	15.6%	17.2%	18.7%	20.2%	21.5%	24.0%	25.9%
Incremental Annual							

Royalties(2) ($ Millions)	$(28.6)	$(18.0)	$(0.1)	+$25.0	+$53.3	+$ 123.8	+$ 203.1

(1) Canadian dollar denominated prices before quality differentials and transportation
(2) Compared to 2008 corporate average rate of 19%

Operating Expenses

Operating expenses during 2008 were $9.50/BOE or $332.6 million which was in-line with our guidance and 4% higher than 2007 operating costs of $9.12/BOE or $274.2 million. Although we expected the acquisition of Focus to decrease operating costs on a BOE basis, rising costs due to high industry activity for most of 2008 resulted in higher than expected charges for repairs and maintenance, chemicals, labour and supplies. In addition we increased our service rig activity related to our U.S. optimization program.

For 2009 we expect operating costs to average $10.65/BOE, representing an increase of 12% per BOE compared to 2008. Approximately half of this increase is due to lower production while the remainder is due to increased power and regulatory costs as well as optimization efforts on our Canadian properties.

General and Administrative Expenses ("G&A")

G&A expenses were $1.88/BOE or $65.7 million during 2008, approximately 6% lower than our guidance of $2.00/BOE and 17% lower than $2.26/BOE in 2007. G&A expenses were lower than our guidance primarily due to lower than anticipated compensation charges. All our compensation plans impact cash G&A with the exception of our trust unit rights incentive plan which is non-cash.

Our 2008 G&A expenses included non-cash charges for our trust unit rights incentive plan of $7.0 million or $0.20/BOE compared to $8.4 million or $0.28/BOE for 2007. These amounts relate solely to our trust unit rights incentive plan and are based on the fair value which is determined on the grant date using a binomial lattice option-pricing model. These values may not represent the amount realized by employees. See Note 10 for further details.

The following table summarizes the cash and non-cash expenses recorded in G&A:

General and Administrative Costs ($ millions)	2008	2007
Cash	$58.7	$59.5
Trust unit rights incentive plan (non-cash)	7.0	8.4
Total G&A	$65.7	$67.9

(Per BOE)	2008	2007
Cash	$1.68	$1.98
Trust unit rights incentive plan (non-cash)	0.20	0.28
Total G&A	$1.88	$2.26

Our 2008 cash G&A costs were significantly impacted by the drop in our trust unit price during the year. Our compensation plans are directly tied to the movement in our trust unit price. During 2008 our trust unit price decreased 40% from $39.87 to $23.96 which significantly reduced the projected payouts on our plans and our 2008 G&A per BOE measure. In 2009 we expect cash G&A costs to be $2.25/BOE which is more consistent with 2007 levels adjusted for increased technical staff added and additional office space acquired during 2008. We expect total G&A costs in 2009 to be $2.45/BOE including non-cash G&A costs of approximately $0.20/BOE.

Interest Expense

Interest expense includes interest on long-term debt, the premium amortization on our US$175 million senior unsecured notes, unrealized gains and losses resulting from the change in fair value of our interest rate swaps as well as the interest component on our cross currency interest rate swap ("CCIRS"). See Note 8 for further details.

Interest on long-term debt during 2008 totaled $42.6 million, a $0.7 million increase from $41.9 million in 2007. This increase is due to higher average indebtedness offset by lower interest rates year-over-year. As a result of the Focus acquisition in February 2008, $330.9 million of additional debt was assumed when average interest rate was approximately 4.5%. In July 2008 we used the proceeds of $502.0 million from the disposition of Joslyn to reduce debt outstanding. The Bank of Canada interest rates declined through 2008 from 4.25% to 1.50% at the end of the year. During 2008 our weighted average interest rate was 3.8% compared to 4.8% in 2007.

For the year ended December 31, 2008 we recorded unrealized gains of $18.4 million compared to $8.3 million in 2007. The changes in the fair value of our interest rate swaps and CCIRS that result from movements in forward market interest rates cause non-cash interest to fluctuate between periods.

The following table summarizes the cash and non-cash interest expense:

Interest Expense ($ millions)	2008	2007
Interest on long-term debt	$42.6	$41.9
Unrealized gain	(18.4)	(8.3)
Total Interest Expense	$24.2	$33.6

At December 31, 2008 approximately 28% of our debt was based on fixed interest rates while 72% had floating interest rates. In comparison, at December 31, 2007 approximately 18% of our debt was based on fixed interest rates and 82% was floating.

Capital Expenditures

During 2008 we spent $577.7 million on development capital, which was $190.5 million or 49% greater than 2007. The increased capital spending in 2008 was due to our expanded asset base resulting from the Focus acquisition as well as increased spending on shallow gas, deep gas and Bakken oil projects given higher commodity prices for the majority of the year. Included in our development capital spending was $54.8 million of exploratory drilling seismic and undeveloped land acquisitions mainly within the Montney and Bakken plays which we expect to provide future development opportunities. We achieved a 99% success rate drilling 643 net wells during 2008.

Our 2008 development capital was approximately $33.0 million above our guidance of $545.0 million, mainly due to $22.0 million of accelerated activity in the Tommy Lakes, Bantry and Shackleton areas. The remaining $11.0 million related to cost overages on various properties including pipeline maintenance at Golden and drilling costs at Pembina and Virden. We expect the impact on production and overall capital spending for 2009 to be minimal.

Corporate acquisitions for 2008 totaled approximately $1.7 billion and relate to the Focus acquisition which closed February 13, 2008 (refer to Note 5 for further details). Property dispositions were $504.8 million during 2008 compared to $9.6 million in 2007. Our 2008 divestments relate mainly to the Joslyn disposition which closed in July 2008 for net proceeds of $502.0 million. Our 2007 divestments included $5.6 million of property interests in the Thorhild area and the sale of undeveloped land in North Dakota for approximately $3.6 million.

Property acquisitions were $15.3 million during 2008 compared to $274.2 million in 2007. The majority of our 2007 acquisitions related to the purchase of our Kirby Oil Sands Project ("Kirby") for total consideration of $203.1 million and the purchase of gross-overriding royalty interests in the Jonah area for approximately $61.0 million.

Capital Expenditures ($ millions)	2008	2007
Development expenditures	$ 442.4	$ 321.3
Plant and facilities	135.3	65.9
Development Capital	577.7	387.2
Office	10.6	6.5
Sub-total	588.3	393.7
Property acquisitions(1)	15.3	274.2
Corporate acquisitions	1,757.5	-
Capital Expenditures	2,361.1	667.9
Property dispositions(1)	(504.8)	(9.6)
Total Net Capital Expenditures	$ 1,856.3	$ 658.3
Total Capital Expenditures financed with cash flow	$ 476.7	$ 221.7
Total Capital Expenditures financed with debt and equity	1,379.6	443.2
Total non-cash consideration for property dispositions	-	(6.6)
Total Net Capital Expenditures	$ 1,856.3	$ 658.3

(1) Net of post-closing adjustments.

The following is a summary by play type of our development capital expenditures during 2008 and 2007, as well as our current expectations for 2009.

Play type ($ millions)	2009 Estimate	2008	2007
Shallow Gas and CBM	$ 74.3	$159.1	$ 39.3
Crude Oil Waterfloods	45.4	84.0	54.2
Tight Gas	78.4	81.0	34.7
Bakken/Tight Oil	41.8	99.0	106.2
Other Conventional Oil and Gas	35.1	103.4	113.9
Oil Sands	25.0	51.2	38.9

Total	$300.0	$577.7	$387.2

We expect development capital expenditures in 2009 to be approximately $300 million including oil sands development capital of approximately $25 million and $50 million on initial resource investments (land and seismic) neither of which are expected to impact 2009 production.

Oil Sands

Our current oil sands portfolio includes the 100% owned and operated Kirby steam assisted gravity drainage ("SAGD") project and a 12% minority equity ownership interest in Laricina Energy Ltd., a private oil sands company focused on SAGD development in the Athabasca oil sands.

Our Kirby project has not commenced commercial production. As a result, all associated costs inclusive of acquisition expenditures are capitalized and excluded from our depletion calculation. During 2008 we capitalized costs of $40.6 million associated with the Kirby project including costs of our regulatory application, which we filed on September 26, 2008. At December 31, 2008 capitalized costs life-to-date for our oil sands development were $257.6 million compared to $321.8 million at December 31, 2007. Included in the 2007 amount was our Joslyn interest which we sold on July 31, 2008.

As a result of current low crude oil prices we have reduced our 2009 capital spending on the Kirby project to $25.0 million consisting primarily of engineering and regulatory costs associated with advancing Phase I and seismic costs aimed at expanding the overall resource base associated with this lease. Kirby has a reserve life of over 25 years and we believe over the longer term oil prices will recover to justify proceeding with development. Our regulatory application is currently under review and we expect to receive regulatory approval by the end of 2009. Our board of directors will re-evaluate whether to continue to proceed with or delay the Kirby project at that time.

Depletion, Depreciation, Amortization and Accretion ("DDA&A")

DDA&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. For 2008 DDA&A was $640.4 million or $18.29/BOE compared to $463.7 million or $15.43/BOE in 2007. The increase is a result of higher PP&E and production from the Focus acquisition.

No impairment of the Fund's PP&E values existed at December 31, 2008 using year-end reserves and management's estimates of future prices. Our future price estimates are more fully discussed in Note 3.

Goodwill

The goodwill balance of $634.0 million arose as a result of previous corporate acquisitions and represents the excess of the total purchase price over the fair value of the net identifiable assets and liabilities acquired.

Accounting standards require the goodwill balance be assessed for impairment at least annually or more frequently if events or changes in circumstances indicate the balance might be impaired. If such impairment exists, it would be charged to income in the period in which the impairment occurs. No goodwill impairment exists as of December 31, 2008.

Asset Retirement Obligations

We have estimated our future asset retirement obligations based on our net ownership interest in wells and facilities, along with the estimated cost and timing to abandon and reclaim wells and facilities in the future. Our asset retirement obligation was $207.4 million at December 31, 2008 compared to $165.7 million at December 31, 2007. The majority of the $41.7 million increase was due to the addition of abandonment obligations associated with the Focus acquisition. The remainder of the increase was due to additional costs from development capital activity and accretion expense offset by retirement costs incurred. See Note 4 for further details.

The following chart shows the amortization of the asset retirement cost and accretion of the asset retirement obligation compared to asset retirement obligations settled.

($ millions)	2008	2007
Amortization of the asset retirement cost	$20.0	$11.4
Accretion of the asset retirement obligation	11.9	6.7
Total Amortization and Accretion	$31.9	$18.1
Asset Retirement Obligations Settled	$18.3	$16.3

Actual asset retirement costs are incurred at different times compared to the recording of amortization and accretion charges. Actual asset retirement costs will be incurred over the next 66 years with the majority between 2039 and 2048. For accounting purposes, the asset retirement cost is amortized using a unit-of-production method based on proved reserves before royalties, while the asset retirement obligation accretes until the time the obligation is settled.

Taxes

Canadian Government's tax changes

In 2008, the Canadian Federal government introduced draft tax legislation that allowed for the conversion of a specified investment flow-through ("SIFT") entity into corporate form on a tax deferred basis, defined the provincial tax component of the SIFT tax, and accelerated the recognition of the "Safe Harbour" limit. None of the above were enacted prior to the prorogation of Parliament in December 2008. Therefore, all bills containing the draft legislation have lapsed.

Subsequent to the year end, the Federal government has introduced draft tax legislation which includes the above mentioned measures as part of Canada's Economic Action Plan. When or if this draft tax legislation becomes substantially enacted, Enerplus will be able to recognize the tax benefit associated with the lower provincial tax component of the SIFT tax.

Future Income Taxes

Future income taxes arise from differences between the accounting and tax basis of assets and liabilities. A portion of the future income tax liability recorded on the balance sheet will be recovered through earnings before 2011. The balance will be realized when future income tax assets and liabilities are realized or settled.

The future income tax recovery for 2008 was $51.2 million compared to $1.0 million in 2007. The change was due to the following:

- The enactment of the SIFT tax which resulted in a future income tax expense of $78.1 million in 2007;
- The enactment of corporate income tax rate reductions which resulted in a future income tax recovery of $22.6 million in 2007 as compared to $2.7 million in 2008;

- The sale of Joslyn in 2008 resulted in a future income tax recovery of $58.9 million relating to the non-taxable portion of the realized gain, along with the recognition of tax losses previously unrecognized; and
- The incremental future tax expense of $51.8 million in 2008 related to the increase in the net income attributed to the fund.

After consideration of the above items the future tax provisions were comparable between periods.

Current Income Taxes

In our current structure payments are made between the operating entities and the Fund, which ultimately transfers both income and future income tax liability to our unitholders. As a result minimal cash income taxes are generally paid by our Canadian operating entities. However, effective January 1, 2011 we will be subject to the SIFT tax should we remain a trust.

A Canadian income tax liability of $24.3 million was triggered on the acquisition of Focus in 2008. This liability was included in Focus' assumed working capital at the time of acquisition. We have accrued for the recovery of these taxes in 2008 which constitutes the majority of the Canadian income tax recovery.

During 2008 our U.S. operations incurred current taxes in the amount of $47.8 million compared to $23.0 million in 2007. The increase is due to higher net income combined with a modest decrease in drilling and completion expenditures for the year.

The amount of current taxes recorded throughout the year on our U.S. operations is dependent upon the timing of both capital expenditures and repatriation of funds to Canada. Our U.S. taxes as a percentage of cash flow, assuming constant working capital, were 18% in 2008 compared to our guidance of 20% as a result of lower commodity prices in the fourth quarter. We expect current income and withholding taxes to average approximately 15% of cash flow from U.S. operations in 2009 based on our current development capital program and assuming all funds are repatriated to Canada.

Tax Pools

We estimate our tax pools at December 31, 2008 to be as follows:

Pool Type ($ millions)	Trust	Operating entities	Total
COGPE	$ 470	$ 165	$ 635
CDE	-	670	670
UCC	-	680	680
CEE	-	125	125
Tax losses and other	15	380	395
Foreign tax pools	-	210	210
Total	$ 485	$2,230	$2,715

Net Income

Net income in 2008 was $888.9 million or $5.54 per trust unit compared to $339.7 million or $2.66 per trust unit in 2007. The $549.2 million increase in net income was primarily due to a $787.0 million increase in oil and gas sales (net of transportation costs), $119.3 million increase in commodity derivative instrument gains and a $48.3 million increase in future tax recovery, partially offset by increased DDA&A charges of $176.7 million, increased royalty expense of $144.8 million and increased operating costs of $58.4 million.

Cash Flow from Operating Activities

Cash flow from operating activities in 2008 was $1,262.8 million or $7.86 per trust unit compared to $868.5 million or $6.80 per trust unit in 2007. The increase is primarily due to increased commodity prices in the first three quarters of 2008 and higher production volumes.

Selected Financial Results

Per BOE of production (6:1)	Year ended December 31, 2008 Operating Cash Flow(1)	Non-Cash & Other Items	Total	Year ended December 31, 2007 Operating Cash Flow(1)	Non-Cash & Other Items	Total
Production per day			95,687			82,319
Weighted average sales price (2)	$ 65.79	$ -	$ 65.79	$ 50.48	$ -	$ 50.48
Royalties	(12.27)	-	(12.27)	(9.49)	-	(9.49)
Commodity derivative instruments	(2.94)	4.84	1.90	0.45	(2.21)	(1.76)
Operating costs	(9.51)	0.01	(9.50)	(9.11)	(0.01)	(9.12)
General and administrative	(1.68)	(0.20)	(1.88)	(1.98)	(0.28)	(2.26)
Interest expense, net of interest income	(0.91)	0.51	(0.40)	(1.37)	0.28	(1.09)
Foreign exchange gain / (loss)	(0.68)	(0.05)	(0.73)	(0.06)	0.30	0.24
Current income tax	(0.65)	-	(0.65)	(0.77)	-	(0.77)
Restoration and abandonment cash costs	(0.52)	0.52	-	(0.54)	0.54	-
Depletion, depreciation, amortization and accretion	-	(18.29)	(18.29)	-	(15.43)	(15.43)
Future income tax (expense) / recovery	-	1.46	1.46	-	0.04	0.04
Other Income	-	(0.05)	(0.05)	-	0.47	0.47
Total per BOE	$36.63	$(11.25)	$ 25.38	$ 27.61	$(16.30)	$ 11.31

(1) Cash Flow from Operating Activities before changes in non-cash operating working capital.
(2) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

Selected Annual Canadian and U.S. Financial Results

The following table provides a geographical analysis of key operating and financial results for 2008 and 2007.

(CDN$ millions, except per unit amounts)	Year ended December 31, 2008 Canada	U.S.	Total	Year ended December 31, 2007 Canada	U.S.	Total
Average Daily Production Volumes						
Natural gas (Mcf/day)	326,138	12,731	338,869	251,561	10,693	262,254
Crude oil (bbls/day)	25,248	9,333	34,581	24,590	9,916	34,506
Natural gas liquids (bbls/day)	4,627	-	4,627	4,104	-	4,104
Total daily sales (BOE/day)	84,232	11,455	95,687	70,621	11,698	82,319
Pricing (1)						
Natural gas (per Mcf)	$ 8.14	$ 8.93	$ 8.17	$ 6.45	$ 6.55	$ 6.45
Crude oil (per bbl)	$ 90.28	$ 94.09	$ 91.31	$ 62.27	$ 72.17	$ 65.11
Natural gas liquids (per bbl)	$ 68.93	$ -	$ 68.93	$ 51.35	$ -	$ 51.35
Capital Expenditures						
Development capital and office	$ 518.2	$ 70.1	$ 588.3	$ 287.3	$ 106.4	$ 393.7
Acquisitions of oil and gas properties	$ 15.2	$ 0.1	$ 15.3	$ 213.3	$ 60.9	$ 274.2
Corporate Acquisitions	$1,757.5	$ -	$1,757.5			
Dispositions of oil and gas properties	$ (504.9)	$ 0.1	$ (504.8)	$ (6.0)	$ (3.6)	$ (9.6)
Revenues						
Oil and gas sales (1)	$1,941.2	$ 363.0	$2,304.2	$1,230.4	$ 286.7	$1,517.1
Royalties	$ (351.9)	$(78.0)(2)	$(429.9)	$ (226.4)	$(58.7)(2)	$(285.1)
Commodity derivative instruments gain/(loss)	$ 66.4	$ -	$ 66.4	$ (52.8)	$ -	$ (52.8)

Expenses						
Operating	$ 314.5	$ 18.1	$ 332.6	$ 264.4	$ 9.8	$ 274.2
General and administrative	$ 58.6	$ 7.1	$ 65.7	$ 62.6	$ 5.3	$ 67.9
Depletion, depreciation, amortization and accretion	$ 550.0	$ 90.4	$ 640.4	$ 359.8	$ 103.9	$ 463.7
Current income taxes (recovery)/ expense	$ (25.1)	$ 47.8	$ 22.7	$ -	$ 23.0	$ 23.0

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(2) Royalties include U.S. state production tax.

Three Year Summary of Key Measures

Overall, increased production volumes from our Focus acquisition and increased commodity prices have resulted in higher oil and gas sales, net income and cash flow from operating activities during 2008 compared to 2007. The rise in crude oil prices during 2006, 2007 and the first three quarters of 2008 contributed to higher overall sales, however gas sales moderated in 2007 as a result of lower natural gas prices. The following table provides a summary of net income, cash flow and other key measures.

($ millions, except per unit amounts)	2008	2007	2006
Oil and gas sales(1)	$2,304.2	$1,517.1	$1,572.7
Net income	888.9	339.7	544.8
Per unit (Basic)(2)	5.54	2.66	4.48
Per unit (Diluted)	5.53	2.66	4.47
Cash flow from operating activities	1,262.8	868.5	863.7
Per unit (Basic) (2)	7.86	6.80	7.10
Cash distributions	786.1	646.8	614.3
Per unit (Basic) (2)	4.90	5.07	5.05
Payout ratio	62%	74%	71%
Total assets	6,230.1	4,303.1	4,203.8
Long-term debt, net of cash	657.4	725.0	679.7

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(2) Based on weighted average trust units outstanding. Cash distributions to unitholders per unit will not correspond to actual distributions as a result of using the annual weighted average trust units outstanding.

Liquidity and Capital Resources

Capital Markets and Enerplus' Credit Exposure

The recent turmoil in the financial markets has impacted the availability of credit and equity in the marketplace. The current market conditions indicate that it may be difficult to issue additional equity or increase credit capacity without significant costs at this time. In addition, there has been a dramatic reduction in crude oil and natural gas prices since the summer of 2008. As a result there has been a greater emphasis on evaluating credit capacity, credit counterparties and liquidity. We have discussed these risks as they relate to our credit facility, oil and gas sales counterparties, financial derivative counterparties and joint venture partners below.

Credit Facility

Enerplus' bank credit facility is an unsecured, covenant-based credit agreement with a syndicate of thirteen financial institutions, a summary of which was filed on March 18, 2008 as a "Material document" on the Fund's SEDAR profile atwww.sedar.com Of the thirteen syndicate members in Enerplus' facility, seven are major Canadian banks which represent approximately $1.025 billion or 73% of the commitments under the $1.4 billion facility. The facility is extendable each year and is currently set to expire in November 2010. Rates under the facility range between 55.0 and 110.0 basis points over bankers' acceptance rates and are significantly lower than rates currently being negotiated in the marketplace. At December 31, 2008 we have drawn $380.9 million or approximately 27% of our $1.4 billion facility and have a trailing debt-to-cash flow ratio of 0.5x. Our borrowing cost is currently 55.0 basis points over bankers' acceptance rates.

At December 31, 2008 Enerplus was in compliance with all covenants under the credit facility. Our exposure to our lenders relates to their potential inability to fund. Should a lender be unable or choose not to fund, other lenders have the right, but not the obligation, to increase their commitment levels to cover the shortfall. Failure to fund would be considered a breach of contract and could result in potential damages in favour of Enerplus, however the likelihood of substantiating and receiving damages is unknown. We have not experienced any funding issues under the facility to date.

Oil and Gas Sales Counterparties

The Fund's oil and gas receivables are with customers in the petroleum and natural gas business and are subject to normal credit risks. Concentration of credit risk is mitigated by marketing production to numerous purchasers under normal industry sale and payment terms. A credit review process is in place to assess and monitor our counterparties' credit worthiness on a regular basis. This process involves reviewing and ratifying our corporate credit guidelines, assessing the credit ratings of our counterparties and setting exposure limits. When warranted we obtain financial assurances such as letters of credit, parental guarantees, or third party insurance to mitigate our credit risk. This process is completed for both our oil and gas sales counterparties as well as our financial derivative counterparties. For the year ended December 31, 2008 we have made a $1.5 million bad debt provision, the majority of which relates to our exposure to a Canadian subsidiary of SemGroup L.P., which is currently subject to insolvency proceedings in the U.S.

Financial Derivative Counterparties

The Fund is exposed to credit risk in the event of non-performance by our financial counterparties regarding our derivative contracts. The Fund mitigates this risk by entering into transactions with major financial institutions, the majority of which are members of our bank syndicate. We have no exposure to Lehman Brothers, which is currently in insolvency proceedings. We have International Swaps and Derivatives Association ("ISDA") agreements in place with the majority of our financial counterparties. These agreements provide some credit protection in that they generally allow parties to aggregate amounts owing to each other under all outstanding transactions and settle with a single net amount in the case of a credit event. Absent an ISDA we rely on long form confirmations which provide Enerplus with similar credit protection in terms of aggregating transactions and netting for settlement in the case of a credit event. At December 31, 2008 we had $128.1 million in mark-to-market assets offset by $26.4 million of mark-to-market liabilities consisting of net asset positions of $77.2 million with major Canadian institutions and $24.5 million with U.S. institutions.

We will continue to monitor developments in the financial markets that could impact the credit worthiness of our financial counterparties, however it has recently been very difficult to foresee counterparty solvency issues. To date we have not experienced any losses due to non-performance by our derivative counterparties.

Joint Venture Partners

We attempt to mitigate the credit risk associated with our joint interest receivables by reviewing and actively following up on older accounts. In addition, we are specifically monitoring our receivables against a watch list of publicly traded companies that have high debt-to-cash flow ratios or fully drawn bank facilities. We do not anticipate any significant issues in the collection of our joint interest receivables at this time. However, if the current low commodity prices and tight capital markets prevail, there is a risk of increased bad debts related to our industry partners, and as a result we have increased our bad debt provision by $1.0 million.

Distribution Policy

The amount of cash distributions is proposed by management and approved by the Board of Directors. We continually assess distribution levels with respect to anticipated cash flows, debt levels, capital spending plans and capital market conditions. The level of cash withheld has historically varied between approximately 10% and 40% of annual cash flow from operating activities and is dependent upon numerous factors, the most significant of which are the prevailing commodity price environment, our current levels of production, debt obligations, funding requirements for our development capital program and our access to equity markets.

The sharp decrease in crude oil and natural gas prices has resulted in a decrease in our overall cash flows. This commodity price downturn, combined with the ongoing uncertainty and reduced access to the debt and equity markets, has reinforced our belief in the importance of maintaining strong financial flexibility. To that end, we have reduced our monthly cash distributions three times during the last five months to the current level of $0.18 per unit effective February 20, 2009. We intend to manage our distribution levels and capital spending in order to minimize increases in our debt levels and preserve our balance sheet strength for future acquisitions.

Although we intend to continue to make cash distributions to our unitholders, these distributions are not guaranteed. To the extent there is taxable income at the trust level, determined in accordance with the Canadian Income Tax Act, the distribution of that taxable income is non-discretionary.

Sustainability of our Distributions and Asset Base

As an oil and gas producer we have a declining asset base and therefore rely on ongoing development activities and acquisitions to replace production and add additional reserves. Our future oil and natural gas production is highly dependent on our success in exploiting our asset base and acquiring or developing additional reserves. To the extent we are unsuccessful in these activities our cash distributions could be reduced.

Development activities and acquisitions may be funded internally by withholding a portion of cash flow or through external sources of capital such as debt or the issuance of equity. To the extent that we withhold cash flow to finance these activities, the amount of cash distributions to our unitholders may be reduced. Should external sources of capital become limited or unavailable, our ability to make the necessary development expenditures and acquisitions to maintain or expand our asset base may be impaired and ultimately reduce the amount of cash distributions.

Our 2009 development capital spending is expected to be $300 million which represents a 48% decrease from 2008 spending of $577.7 million. In 2009 we expect to spend $50 million on initial resource investments such as land acquisitions and seismic to position us for development opportunities in the future, which is not expected to add production in 2009. As a result we expect our production to decrease to an annual average of 91,000 BOE/day and an exit rate of 88,000 BOE/day in 2009. At this level of capital spending it will be difficult to replace our production without reliance on acquisitions to supplement our reserves.

Enerplus currently has approximately $9.5 billion of safe harbour growth capacity within the context of the Canadian Government's "normal growth" guidelines for SIFT's. This amount is calculated in reference to the combined market capitalizations of Enerplus and Focus on October 31, 2006 and also includes equity that may be issued to replace existing debt of both entities at that time.

Cash Flow from Operating Activities, Cash Distributions and Payout Ratio

Cash flow from operating activities and cash distributions are reported on the Consolidated Statements of Cash Flows. During 2008 cash distributions of $786.1 million were funded entirely through cash flow of $1,262.8 million. Our payout ratio, which is calculated as cash distributions divided by cash flow, was 62% for 2008 compared to 74% in 2007. See "Non-GAAP Measures" in this MD&A.

In aggregate, our 2008 cash distributions of $786.1 million and our development capital and office expenditures of $588.3 million totaled $1,374.4 million, or approximately 109% of our cash flow of $1,262.8 million. We expect to support our distributions and capital expenditures with our cash flow, however we will continue to fund acquisitions and growth through additional debt and equity when required. We anticipate that our reduced capital spending plans for 2009 along with our reductions in monthly cash distributions will help minimize any increases in debt levels and preserve our balance sheet. There will be years when we are investing capital in opportunities that do not immediately generate cash flow (such as our Kirby oil sands project) where we may also use debt and equity to support the investment. Despite our 2008 cash flow being less than the aggregate of our cash distributions and development capital, we continue to have conservative debt levels with a trailing twelve month debt-to-cash flow ratio of 0.5x at December 31, 2008 and an annualized fourth quarter 2008 debt-to-cash flow ratio of 0.7x.

For the year ended December 31, 2008 our net income exceeded our cash distributions by $102.8 million whereas in 2007 our cash distributions exceeded our net income by $307.1 million. Non-cash items, such as changes in the fair value of our derivative instruments and future income taxes, cause net income to fluctuate between periods but do not impact cash flow from operations. In addition, other non-cash charges such as DDA&A are not a good proxy for the cost of maintaining our productive capacity as they are based on the historical costs of our PP&E and not the fair market value of replacing those assets within the context of the current environment.

It is not possible to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities in the oil and gas sector due to the nature of reserve reporting, natural reservoir declines and the risks involved with capital investment. As a result we do not distinguish maintenance capital separately from development capital spending. The level of investment in a given period may not be sufficient to replace productive capacity given the natural declines associated with oil and natural gas assets. In these instances a portion of the cash distributions paid to unitholders may represent a return of the unitholders' capital.

The following table compares cash distributions to cash flow and net income.

($ millions, except per unit amounts)	2008	2007	2006
Cash flow from operating activities	$1,262.8	$ 868.5	$ 863.7
Cash Distributions	786.1	646.8	614.3
Excess of cash flow over cash distributions	$ 476.7	$ 221.7	$ 249.4
Net income	$ 888.9	$ 339.7	$ 544.8
Excess/(shortfall) of net income over cash distributions	$ 102.8	$ (307.1)	$ (69.5)
Cash distributions per weighted average trust unit	$ 4.90	$ 5.07	$ 5.05
Payout ratio (1)	62%	74%	71%

(1) Based on cash distributions divided by cash flow from operating activities.

Asset Retirement Costs

Actual asset retirement costs incurred in the period are deducted for the purposes of calculating cash flow. Differences between actual asset retirement costs incurred and the amortization and accretion of the asset retirement obligation are discussed in the Asset Retirement Obligations section of this MD&A and Note 4.

Long-Term Debt

Long-term debt at December 31, 2008 was $664.3 million, a decrease of $62.4 million from $726.7 million at December 31, 2007. Long-term debt at December 31, 2008 was comprised of $380.9 million of bank indebtedness and $283.4 million of senior unsecured notes. Our bank indebtedness decreased by $116.5 million year-over-year mainly due to proceeds received from the Joslyn disposition of $502.0 million which was partially offset by additional debt of $330.9 million acquired in the Focus acquisition. Our senior unsecured notes are comprised of our US$175 million senior notes and our US$54 million senior notes. The change in period end foreign exchange rate resulted in an increase in the carrying value of our senior notes to $283.4 million compared to $229.3 million at December 31, 2007.

Our working capital, excluding cash, at December 31, 2008 increased $147.2 million compared to December 31, 2007 primarily due to an increase in our deferred financial assets relating to our financial derivative contracts. Excluding deferred financial assets and credits, our working capital decreased by $16.4 million compared to the prior year. This is primarily due to an increase in future income taxes payable offset slightly by a decrease in distributions payable and an increase in accounts receivable.

We continue to maintain a conservative balance sheet as demonstrated below with over $1.0 billion in unused credit capacity under our current facility:

Financial Leverage and Coverage	Year ended Dec. 31, 2008	Year ended Dec. 31, 2007
Long-term debt to trailing 12 month cash flow	0.5 x	0.8 x
Long-term debt to annualized fourth quarter cash flow	0.7 x	0.9 x
Cash flow to interest expense (12 month trailing)	46.5 x	25.8 x
Long-term debt to long-term debt plus equity	13%	22%

Long-term debt is measured net of cash.

At December 31, 2008 Enerplus had a $1.4 billion unsecured covenant based term bank facility maturing November 2010, through its wholly-owned subsidiary EnerMark Inc. We have the ability to extend the facility each year or repay the entire balance at the end of the term. Due to the volatility in the credit markets we chose not to extend the term of the credit facility this year. The facility carries floating interest rates that we expect to range between 55.0 and 110.0 basis points over bankers' acceptance rates, depending on Enerplus' ratio of senior debt to earnings before interest, taxes and non-cash items.

Payments with respect to the bank facilities, senior unsecured notes and other third party debt have priority over claims of, and future distributions to, the unitholders. Unitholders have no direct liability should cash flow be insufficient to repay this indebtedness. The agreements governing these bank facilities and senior unsecured notes stipulate that if we default or fail to comply with certain covenants, the ability of the Fund's operating subsidiaries to make payments to the Fund and consequently the Fund's ability to make distributions to the unitholders may be restricted. At December 31, 2008 we were in compliance with our debt covenants, the most restrictive of which limits our long-term debt to three times trailing cash flow including acquisition cash flows. Refer to "Debt of Enerplus" in our Annual Information Form for the year ended December 31, 2008 for a detailed description of these covenants.

Principal payments on Enerplus' senior unsecured notes are required commencing in 2010 and are more fully discussed below under "Commitments" and Note 13.

We continue to have adequate liquidity to fund planned development capital spending for 2009 through a combination of cash flow retained by the business and debt, if needed.

Commitments

We have contracted to transport 143 MMcf/day of natural gas on the TransCanada system in Alberta, 70 MMcf/day on TransGas in Saskatchewan, 48 MMcf/day in B.C.via Spectra, as well as 9 MMcf/day on the Alliance pipeline to the U.S. Midwest.

Our gas supply dedicated to aggregator sales contracts will decline in 2009 to approximately 6% of gas production (22.0 MMcf/day), down from more than 20% in 2008. The early truncation of the ProGas and Cargill aggregator pools leaves Pan-Alberta as the only remaining aggregator. Under these arrangements, we receive a price based on the average netback price of the pool, net of transportation costs incurred by the aggregator, for the life of the reserves.

In addition, we also have a contract to transport a minimum of 2,480 bbls/day of crude oil from field locations to suitable marketing sales points within western Canada.

Our Canadian and U.S. office leases expire in 2014 and 2011 respectively. Annual costs of these lease commitments include rent and operating fees. The Fund's commitments, contingencies and guarantees are more fully described in Note 13.

As at December 31, 2008 Enerplus has the following minimum annual commitments including long-term debt:

	Minimum Annual Commitment Each Year						Total Committ-ed after
($ millions)	Total	2009	2010	2011	2012	2013	2013
Bank credit facility(1)	$380.9	$ -	$380.9	$ -	$ -	$ -	$ -
Senior unsecured notes(1)(2)	323.2	-	53.7	64.6	64.6	64.6	75.7
Pipeline commitments	62.7	18.8	11.8	9.1	6.7	5.4	10.9
Processing commitments	25.6	7.6	7.7	7.3	3.0	-	-
Office leases	69.6	8.7	11.7	12.5	12.6	12.6	11.5
Total commitments(3)	$862.0	$ 35.1	$465.8	$ 93.5	$ 86.9	$ 82.6	$ 98.1

(1) Interest payments have not been included since future debt levels and interest rates are not known at this time.
(2) Includes the economic impact of derivative instruments directly related to the senior unsecured notes (CCIRS and foreign exchange swap - see Note 12).
(3) Crown and surface royalties, lease rentals, mineral taxes, and abandonment and reclamation costs (hydrocarbon production rights) have not been included as amounts paid depend on future ownership, production, prices and the legislative environment.

Accumulated Deficit

We have historically paid cash distributions in excess of accumulated earnings as cash distributions are based on the actual cash flow generated in the period, whereas accumulated earnings are based on net income which includes non-cash items such as DDA&A charges, derivative instrument mark-to-market gains and losses, unit based compensation charges and future income tax provisions.

Trust Unit Information

We had 165,590,000 trust units outstanding at December 31, 2008 compared to 129,813,000 trust units outstanding at December 31, 2007.

Included in the December 31, 2008 outstanding units were 30,150,000 units issued on February 13, 2008 to acquire Focus. In addition 9,087,000 exchangeable partnership units were assumed on the Focus acquisition which became exchangeable into Enerplus trust units at the ratio of 0.425 of a trust unit for each partnership unit. During 2008 1,849,000 partnership units were converted into 786,000 trust units, leaving 7,238,000 partnership units outstanding at December 31, 2008 representing the equivalent of 3,076,000 trust units.

In addition 1,881,000 trust units (2007 - 1,307,000) were issued pursuant to the Trust Unit Monthly Distribution Reinvestment and Unit Purchase Plan ("DRIP") and the trust unit rights incentive plan, net of redemptions. This resulted in $70.5 million (2007 - $56.8 million) of additional equity to the Fund. For further details see Note 10.

The weighted average basic number of trust units outstanding during 2008 was 160,589,000 compared to 127,691,000 trust units during 2007. At February 20, 2009 we had 165,707,000 trust units outstanding including the equivalent limited partnership units.

Income Taxes

The following is a general discussion of the Canadian and U.S. tax consequences of holding Enerplus trust units as capital property. The summary is not exhaustive in nature and is not intended to provide legal or tax advice. Investors or potential unitholders should consult their own legal or tax advisors as to their particular tax consequences.

Canadian Unitholders

We qualify as a mutual fund trust under the Income Tax Act (Canada) and accordingly, trust units of Enerplus are qualified investments for RRSPs, RRIFs, RESPs, DPSPs and TFSAs. Each year we have historically transferred all of our taxable income to the unitholders by way of distributions.

In computing income, unitholders are required to include the taxable portion of distributions received in that year. An investor's adjusted cost base ("ACB") in a trust unit equals the purchase price of the trust unit less any non-taxable cash distributions received from the date of acquisition. To the extent a unitholder's ACB is reduced below zero, such amount will be deemed to be a capital gain to the unitholder and the unitholder's ACB will be brought to $nil.

We paid $4.89 per trust unit in cash distributions to unitholders on record during 2008. For Canadian tax purposes, approximately 2% of these distributions, or $0.08 per trust unit was a tax deferred return of capital, approximately 98% or $4.81 per trust unit was taxable to unitholders as other income, and there was no eligible dividend income.

For 2009, we estimate that 95% of cash distributions will be taxable and 5% will be a tax deferred return of capital. Actual taxable amounts may vary depending on actual distributions which are dependent upon, among other things, production, commodity prices and cash flow experienced throughout the year.

U.S. Unitholders

U.S. unitholders who received cash distributions were subject to at least a 15% Canadian withholding tax. The withholding tax is applied to both the taxable portion of the distribution as computed under Canadian tax law and the non-taxable portion of the distribution. U.S. taxpayers may be eligible for a foreign tax credit with respect to Canadian withholding taxes paid.

For U.S. taxpayers the taxable portion of cash distributions are considered to be a dividend for U.S. tax purposes. For most U.S. taxpayers this should be a "Qualified Dividend" eligible for the reduced tax rate. The 15% preferred rate of tax on "Qualified Dividends" is currently scheduled to expire in 2010. We are unable to determine whether or to what extent the preferred rate of tax on "Qualified Dividends" may be extended.

We paid US$4.77 per trust unit to U.S. residents during the 2008 calendar year of which 8% or US$0.38 per trust unit was a tax deferred return of capital and 92% or US$4.39 per unit was a taxable qualified dividend.

For 2009, we estimate that 90% of cash distributions will be taxable to most U.S. investors and 10% will be a tax deferred return of capital. Actual taxable amounts may vary depending on actual distributions which are dependent upon production, commodity prices and cash flow experienced throughout the year.

Quarterly Financial Information

In general, crude oil and natural gas sales increased from 2007 to mid 2008 due to increased production and increased commodity prices. Oil and gas sales decreased during the second half of 2008 as a result of the sharp decline in commodity prices.

Net income has been affected by fluctuating commodity prices and risk management costs, the fluctuating Canadian dollar, higher operating costs and changes in future tax provisions due to the SIFT tax and corporate rate reductions. Furthermore, changes in the fair value of our commodity derivative instruments and other financial instruments cause net income to continually fluctuate between quarters.

Quarterly Financial Information (CDN$ millions, except per trust unit amounts)	Oil and Gas Sales(1)	Net Income	Net Income Per Trust Unit Basic	Net Income Per Trust Unit Diluted
2008				
Fourth Quarter	$ 418.3	$ 189.5	$ 1.15	$ 1.15
Third Quarter	647.8	465.8	2.82	2.82
Second Quarter	734.4	112.2	0.68	0.68
First Quarter	503.7	121.4	0.82	0.82
Total	$ 2,304.2	$ 888.9	$ 5.54	$ 5.53
2007				
Fourth Quarter	$ 389.8	$ 98.7	$ 0.76	$ 0.76
Third Quarter	364.8	93.0	0.72	0.72
Second Quarter	382.5	40.1	0.31	0.31
First Quarter	380.0	107.9	0.88	0.87
Total	$ 1,517.1	$ 339.7	$ 2.66	$ 2.66

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments

Summary Fourth Quarter Information

In comparing the fourth quarter of 2008 with the same period in 2007:

- Average daily production increased 21% to 97,702 BOE/day primarily due to the acquisition of Focus.
- The average selling price per BOE decreased 11% to $46.54 due to a significant drop in crude oil prices in the fourth quarter of 2008.
- Cash flow increased to $258.5 million in 2008 compared to $205.1 million in 2007 due to increased production offset by lower crude oil prices.
- Net income increased 92% from the fourth quarter of 2007 to $189.5 million due to increased commodity derivative instrument gains and increased production.
- The payout ratio decreased 19% compared to the fourth quarter of 2007 as a result of higher cash flow during the fourth quarter of 2008.
- Cash distributions per unit were reduced during the fourth quarter

of 2008 which resulted in a 20% decrease from the fourth quarter of 2007.

- Operating expenses, including non-cash amounts, increased by 10% to $9.44/BOE from $8.57/BOE during the fourth quarter of 2007 due to increased service rig activity and repairs and maintenance.
- G&A expenses, including non-cash amounts, decreased 14% on a BOE basis to $1.89/BOE from $2.21/BOE in the fourth quarter of 2007 due to lower compensation costs.
- Development capital spending increased 89% compared to the fourth quarter of 2007 due to a larger capital development program that included the Focus properties, along with accelerated capital spending at several locations.

The following tables provide an analysis of key financial and operating results for the three months ended December 31, 2008 and 2007.

(CDN$ millions, except per unit amounts)	Three Months Ended December 31, 2008	Three Months Ended December 31, 2007
Financial (000's)		
Net Income	$ 189.5	$ 98.7
Cash Flow from Operating Activities	$ 258.5	$ 205.1
Cash Distributions to Unitholders(1)	$ 167.0	$ 163.4
Financial per Unit(2)		
Net Income	$ 1.15	$ 0.76
Cash Flow from Operating Activities	$ 1.56	$ 1.58
Cash Distributions to Unitholders(1)	$ 1.01	$ 1.26
Payout Ratio(3)	65%	80%
Average Daily Production	97,702	80,959
Selected Financial Results per BOE(4)		
Oil and Gas Sales(5)	$ 46.54	$ 52.33
Royalties	(8.61)	(9.83)
Commodity Derivative Instruments	3.54	(0.08)
Operating Costs	(9.46)	(8.53)
General and Administrative	(1.71)	(1.94)
Interest and Foreign Exchange	(2.73)	(1.70)
Taxes	0.92	(1.70)
Restoration and Abandonment	(0.53)	(0.75)
Cash Flow from Operating Activities before changes in non-cash working capital	$ 27.96	$ 27.80
Weighted Average Number of Units Outstanding (thousands)	165,373	129,658
Development Capital	200.3	106.1
Net Wells Drilled	174	76
Success Rate	99%	100%
Average Benchmark Pricing		
AECO natural gas - monthly index (CDN$/Mcf)	$ 6.79	$ 6.00
AECO natural gas - daily index (CDN$/Mcf)	$ 6.68	$ 6.14

NYMEX natural gas - monthly NX3 index (US$/Mcf)	$ 6.77	$ 7.03
NYMEX natural gas - monthly NX3 index: CDN$ equivalent (CDN$/Mcf)	$ 8.26	$ 6.89
WTI crude oil (US$/bbl)	$ 58.73	$ 90.68
WTI crude oil: CDN$ equivalent (CDN$/bbl)	$ 71.62	$ 88.90
CDN$/US$ exchange rate	0.82	1.02

(1) Calculated based on distributions paid or payable. Cash distributions to unitholders per unit may not correspond to actual distributions of $1.01 per trust unit as a result of using the annual weighted average trust units outstanding.
(2) Based on weightedaverage trust units outstanding.
(3) Based on cash distributions divided by cash flow from operating activities.
(4) Non-cash amounts have been excluded.
(5) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

Selected Quarterly Canadian and U.S. Financial Results

(CDN$ millions, except per unit amounts)	Three months ended December 31, 2008 Canada	U.S.	Total	Three months ended December 31, 2007 Canada	U.S.	Total
Average Daily Production Volumes						
Natural gas (Mcf/day)	333,046	13,393	346,439	245,219	12,196	257,415
Crude oil (bbls/day)	26,122	9,312	35,434	24,248	9,973	34,221
Natural gas liquids (bbls/day)	4,529	-	4,529	3,836	-	3,836
Total daily sales (BOE/day)	86,158	11,544	97,702	68,953	12,006	80,959
Pricing(1)						
Natural gas (per Mcf)	$ 7.01	$ 4.81	$ 6.92	$ 5.91	$ 5.98	$ 5.91
Crude oil (per bbl)	$ 54.85	$ 56.02	$ 55.16	$ 68.94	$ 80.16	$ 72.21
Natural gas liquids (per bbl)	$ 43.55	$ -	$ 43.55	$ 58.12	$ -	$ 58.12
Capital Expenditures						
Development capital and office	$ 186.7	$ 18.1	$ 204.8	$ 94.3	$ 13.7	$ 108.0
Acquisitions of oil and gas properties	$ 1.3	$ 0.1	$ 1.4	$ 5.0	$ 0.1	$ 5.1
Dispositions						

of oil and gas properties	$ (0.2)	$ -	$ (0.2)	$ (0.4)	$ (3.6)	$ (4.0)
Revenues						
Oil and gas sales(1)	$ 364.4	$ 53.9	$ 418.3	$ 309.5	$ 80.3	$ 389.8
Royalties	$ (65.8)	$(11.6)(2)	$ (77.4)	$ (56.1)	$(17.1)(2)	$ (73.2)
Commodity derivative instru- ments gain/ (loss)	$ 161.2	$ -	$ 161.2	$ (48.8)	$ -	$ (48.8)
Expenses						
Operating	$ 80.0	$ 4.8	$ 84.8	$ 61.0	$ 2.8	$ 63.8
General and adminis- trative	$ 13.9	$ 3.1	$ 17.0	$ 16.5	$ (0.1)	$ 16.4
Depletion, depreciation, amortization and accretion	$ 142.9	$ 24.1	$ 167.0	$ 89.9	$ 21.8	$ 111.7
Current income taxes	$ (8.2)	$ (0.1)	$ (8.3)	$ -	$ 12.6	$ 12.6

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(2) Royalties include U.S. state production tax.

Critical Accounting Policies

The financial statements have been prepared in accordance with GAAP. A summary of significant accounting policies is presented in Note 1. A reconciliation of differences between Canadian and United States GAAP is presented in Note 15. Most accounting policies are mandated under GAAP however, in accounting for oil and gas activities, we have a choice between the full cost and the successful efforts methods of accounting.

We apply the full cost method of accounting for oil and natural gas activities. Under the full cost method of accounting, all costs of acquiring, exploring and developing oil and natural gas properties are capitalized, including unsuccessful drilling costs and administrative costs associated with acquisitions and development. Under the successful efforts method of accounting, all exploration costs, except costs associated with drilling successful exploration wells, are expensed in the period in which they are incurred. The difference between these two methodologies is not expected to be significant to the Fund's net income or net income per unit as the majority of the Fund's drilling activity is not exploratory in nature and is more focused on low risk development drilling that has traditionally achieved high success rates.

Under the full cost method of accounting, an impairment test is applied to the overall carrying value of property, plant and equipment, on a country by country cost centre basis with the reserves valued using estimated future commodity prices at period end. Under the successful efforts method of accounting, the costs are aggregated on a property-by-property basis. The carrying value of each property is subject to an impairment test. Each method of accounting may generate a different carrying value of property, plant and equipment and a different net income depending on the circumstances at period end. Net costs related to operating and administrative activities during the development of large capital projects are capitalized until commercial production has commenced and are tested for impairment separately under full cost accounting.

Critical Accounting Estimates

The preparation of financial statements in accordance with GAAP requires management to make certain judgments and estimates. Due to the timing of when activities occur compared to the reporting of those activities, management must estimate and accrue operating results and capital spending. Changes in these judgments and estimates could have a material impact on our financial results and financial condition.

Reserves

The process of estimating reserves is critical to several accounting estimates. It requires significant judgments based on available geological, geophysical, engineering and economic data. These estimates may change substantially as data from ongoing development and production activities becomes available, and as economic conditions impacting oil and gas prices, operating costs and royalty burdens change. 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 and the asset retirement obligation.

Asset Retirement Obligation

Management calculates the asset retirement obligation based on estimated costs to abandon and reclaim its net ownership interest in all wells and facilities and the estimated timing of the costs to be incurred in future periods. The fair value estimate is capitalized to PP&E as part of the cost of the related asset and amortized over its useful life.

Business Combinations

Management makes various assumptions in determining the fair values of any acquired company's assets and liabilities in a business combination. The most significant assumptions and judgments made relate to the estimation of the fair value of the oil and gas properties. To determine the fair value of these properties, we estimate (a) oil and gas reserves in accordance with NI 51-101 reserve standards, and (b) future prices of oil and gas.

Commodity Prices

Management's estimates of future crude oil and natural gas prices are critical as these prices are used to determine the carrying amount of PP&E, assess impairment in our cost centers, and determine the change in fair value of financial contracts. Management's estimates of prices are based on the price forecast from our reserve engineers and the current forward market.

Trust Unit Rights

Management calculates the fair value of rights granted under our trust unit rights incentive plan using a binomial lattice option-pricing model. This process involves the use of significant estimates and assumptions which may change over time. The values calculated under the option-pricing model may not reflect the actual value realized by trust unit rights holders, especially in times of decreasing commodity prices and trust unit values.

Derivative Financial Instruments

We utilize derivative financial instruments to manage our exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Fair values of derivative contracts fluctuate depending on the underlyingestimate of future commodity prices, foreign currency exchange rates, interest rates and counterparty credit risk.

RECENT CANADIAN ACCOUNTING AND RELATED PRONOUNCEMENTS

Current Year Accounting Changes

Effective January 1, 2008, the Fund adopted three new accounting standards that were issued by the Canadian Institute of Chartered Accountants ("CICA"): Handbook Section 1535, Capital Disclosures, Section 3862, Financial Instruments - Disclosures and Section 3863, Financial Instruments - Presentation.

Capital Disclosures

Section 1535 establishes standards for disclosing information regarding an entity's capital and how it is managed.

Financial Instruments - Disclosures, Financial Instruments - Presentation

Sections 3862 and 3863 establish standards for enhancing financial statements users' understanding of the significance of financial instruments to an entity's financial position, performance and cash flows. They require that entities provide disclosures regarding the nature and extent of risks arising from financial instruments to which they are exposed both during the reporting period and at the balance sheet date, as well as how the entities manage those risks.

These standards were adopted prospectively.

Future Accounting Changes

Goodwill and Intangible Assets

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 3064 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. The Trust is currently evaluating the impact of the adoption of this new Section, however does not expect a material impact on its Consolidated Financial Statements.

Convergence of Canadian GAAP with International Financial Reporting Standards ("IFRS")

In 2006, Canada's Accounting Standards Board (AcSB) ratified a strategic plan that will result in Canadian GAAP being converged with IFRS by 2011 for public reporting entities. On February 13, 2008 the AcSB confirmed that IFRS will be required for public companies beginning January 1, 2011.

In order to meet our reporting requirements and transition to IFRS we have established a project team comprised of individuals from Finance, Information Systems and Business Solutions, Tax, Investor Relations and Management. Our transition plan consists of four main phases:

- An IFRS diagnostic phase which involves an assessment of the differences between Canadian GAAP and IFRS,
- An assessment and selection phase whereby we will determine accounting policies for transition and our continuing IFRS accounting policies,
- An evaluation of our information systems, business processes, procedures and controls to support the new reporting standards, and
- Training and development.

To date we have completed our IFRS diagnostic assessment and have started to analyze and identify accounting policy choices, which include assessing the impact on information systems and business processes. We have also provided training to certain business groups which are impacted. We intend to generate financial information in accordance with IFRS during 2010 to provide comparative information for the 2011 financial statements.

The transition from current Canadian GAAP to IFRS is a significant undertaking that may materially affect our reported financial position and results of operations. As we have not yet determined our accounting policies, we are unable to quantify the impact of adopting IFRS on our financial statements. In addition, due to anticipated changes to IFRS and International Accounting Standards prior to our adoption of IFRS, our plan is subject to change based on new facts and circumstances that arise after the date of this MD&A.

RISK FACTORS AND RISK MANAGEMENT

Commodity Price Risk

Enerplus' operating results and financial condition are dependent on the prices we receive for our crude oil and natural gas production. These prices have fluctuated widely in response to a variety of factors including global and domestic demand, weather conditions, the supply and price of imported oil and liquefied natural gas, the production and storage levels of North American natural gas, political stability, transportation facilities, the price and availability of alternative fuels and government regulations.

We may use financial derivative instruments and other hedging mechanisms to help limit the adverse effects of natural gas and crude oil price volatility. However, we do not hedge all of our production and expect there will always be a portion that remains un-hedged. Furthermore, we may use financial derivative instruments that offer only limited protection within selected price ranges. To the extent price exposure is hedged, we may forego the benefits that would otherwise be experienced if commodity prices increase, and may be exposed to risk of default by the counterparties. Refer to the "Price Risk Management" section.

Credit Facility Risk and Credit Exposure

Recent economic conditions have negatively affected the availability of credit and increased the risk that certain counterparties for our oil and gas sales, financial derivatives, and our operating partners may fail to pay.

Enerplus has drawn only approximately 27% of its $1.4 billion bank credit facility at December 31, 2008. Also approximately 70% of the commitments under this facility are represented by major Canadian banks which are considered to be among the most sound credit providers. When the time comes to renew our banking facility we expect to pay higher rates and there is no guarantee that all our banks will renew at their current commitment levels.

There are normal credit risks with receivables associated with our product sales, derivative contracts, insurers and joint venture partners. We mitigate these risks through diversification and review processes that assess and monitor our counterparties' credit worthiness on a regular basis. If the current low commodity prices and uncertain credit markets prevail there is a risk of increasing bad debts.

See the "Liquidity and Capital Resources" section for further information related to our credit facility and credit exposure.

Access to Capital Markets

Historically access to capital has allowed us to fund a portion of our acquisitions and development capital program through equity and debt and as a result, distribute the majority of our cash flow to our unitholders. Recently, with global capital markets in turmoil and the sharp decline in commodity prices, we have chosen to reduce our reliance on the capital markets by balancing the level of capital spending and distributions more closely to our cash flow. Nonetheless, it will be difficult to pursue material acquisitions and value creation opportunities without accessing the capital markets in the future. We expect the debt markets will recover but the cost of debt financing will increase and credit capacity may be tight for the next few years. The equity capital markets are showing some signs of recovery however, equity issues are generally at higher discounts and smaller sizes than previously experienced. Equity market receptivity depends in large part upon the market's expectation for oil and natural gas prices. Continued access to capital is also dependent on our ability to maintain our track record of performance and to demonstrate the advantages of the acquisition or development program that we are financing at the time.

We are listed on the Toronto and New York stock exchanges and maintain an active investor relations program.

We maintain a prudent capital structure by retaining a portion of cash flow forcapital spending and utilizing the equity markets when deemed appropriate.

Oil and Gas Reserves and Resources Risk

The value of our trust units are based on, among other things, the underlying value of the oil and gas reserves and resources. Geological and operational risks along with product price forecasts can affect the quantity and quality of reserves and resources and the cost of ultimately recovering those reserves and resources. Lower crude oil and natural gas prices may increase the risk of write-downs for our oil and gas property investments. Regulatory changes to reporting practices can also result in reserve or resource write-downs.

We strive to acquire low risk, properties with a high proportion of proved reserves, positive operating metrics, long reserve lives and predictable production. Similarly, we generally participate in lower-risk development projects. If we do engage in exploration it is usually in areas where there is potential for larger scale resource development if successful.

Each year, independent engineers evaluate a significant portion of our proved and probable reserves as well as the resources attributable to our oil sands properties.

Sproule Associates Limited ("Sproule") evaluated 93% of the total proved plus probable value (discounted at 10%) of our Canadian conventional year-end reserves, in accordance with NI 51-101 and has reviewed the remainder of the reserves which Enerplus evaluated internally. Netherland, Sewell & Associates Inc. ("NSA") of Dallas, Texas, evaluated 100% of the reserves attributed to our assets in the United States and utilized Sproule's forecast and constant price and cost assumptions as of December 31, 2008 to maintain consistency. GLJ Petroleum Consultants Ltd. ("GLJ") evaluated the resources attributable to all our oil sands areas. The Reserves Committee of the Board of Directors has reviewed and approved the reserve and resource reports of the independent evaluators.

Strategy Post 2010

We continue to evaluate alternatives to our income trust structure beyond 2010 in response to the Canadian Federal Government's plan to tax income trusts effective January 1, 2011.

We are currently hesitant to make structural changes for the next two years unless opportunities arise, as we believe this exemption period has value for our unitholders. Unless circumstances change within the current capital markets or the regulatory, tax or political environment, we will most likely convert into a dividend paying corporation however, we are keeping our options open at this time.

We do not expect the conversion to a corporation to have a major impact on our underlying operating strategy or business affairs. We expect such a conversion can be achieved without creating a taxable event for most unitholders. However, going forward, the tax treatment of our distributions or dividends may be different for our unitholders/shareholders depending on their jurisdiction and whether they are holding their investment in a taxable account or tax-deferred account.

After 2010, the applicable Canadian income tax rate at the entity level will be similar whether we remain a trust or convert to a corporation. The most important variables that will determine the level of cash taxes incurred in a given year will be the price of crude oil and natural gas, capital spending and the amount of tax pools at the time of conversion.

With the current forward market for commodity prices and our current plans with respect to production, costs and capital spending, we would not expect a significant change to our overall tax costs until 2013 even if we were to convert to a corporation during 2010. Even after 2013 we expect our capital spending will help shelter taxes and would expect cash taxes to average around 15% of cash flow, which is not dissimilar to other oil and gas production companies.

If crude oil and natural gas prices were to strengthen beyond the levels anticipated by the current forward market, our tax pools would be utilized more quickly and we may experience higher than expected cash taxes.

We must emphasize it is difficult to give guidance on future taxability as we operate within an industry that constantly changes given acquisitions, divestments, capital spending, distributions and overall commodity prices.

Regulatory Risk

Government royalties, income tax laws, environmental laws and regulatory requirements can have a significant financial and operational impact on us. In the province of Alberta a new royalty regime came into effect on January 1, 2009. The Canadian Federal Government enacted a new tax on publicly traded income trusts and limited partnerships, the SIFT tax, effective January 1, 2011. In early 2008 the Canadian government presented a long term plan to reduce greenhouse gas emissions, with the intent of issuing draft regulations in the fall of 2008. The draft regulations have been delayed as the federal government considers aligning its approach in this area with that of the new administration in the U.S. Accordingly the cost impact to our business remains uncertain.

Our operations expose us to possible regulatory changes and greater emphasis on regulatory requirements by both the Canadian and U.S. governments. As an oil and gas producer, we are subject to a broad range of regulatory requirements. Similarly, as a mutual fund trust, we have a unique structure that is vulnerable to changes in legislation or income tax law.

Although we have no control over these regulatory risks, we continuously monitor changes in these areas by participating in industry organizations, conferences, exchanging information with third party experts and employing qualified individuals to assess the impact of such changes on our financial and operating results. In 2008 we also initiated an extensive review of the regulatory compliance obligations across our full business in all jurisdictions. We intend to complete this review in 2009.

Production Replacement Risk

Oil and natural gas reserves naturally deplete as they are produced over time. Our ability to replace production depends on our success in acquiring new reserves and resources and developing existing reserves and resources. We have reduced our capital spending plans dramatically for 2009 and this will make it difficult to replace our production without relying on acquisitions. Acquisitions of oil and gas assets depend on our assessment of value at the time of acquisition. Incorrect assessments of value may adversely affect distributions to unitholders and the value of our trust units.

Acquisitions and our development capital program are subject to investment guidelines, due diligence and review. Major acquisitions are approved by the Board of Directors and where appropriate, independent reserve engineer evaluations are obtained.

Access to Transportation Capacity

Market access for crude oil and natural gas production in Canada and the United States is dependent on our ability to access sufficient transportation capacity on third party pipelines to transport all production volumes. While the third party pipelines generally expand capacity to meet market needs, there can be differences in timing between the growth of production and the growth of pipeline capacity. There are also occasionally operational reasons for curtailing transportation capacity. Accordingly, there can be periods where transportation capacity is insufficient to accommodate all of the production from a given region, causing added expense and/or volume curtailments for all shippers.

We continuously monitor this risk for both the short and longer term through dialogue with the third party pipelines and other market participants, as well as by review of supply and demand studies prepared by third party experts. Where available and commercially appropriate given the production profile and commodity, we attempt to mitigate this risk by contracting for firm transportation capacity or using other means of transportation.

Health, Safety and Environmental Risk ("HSE")

Health, safety and environmental risks influence the workforce, operating costs and the establishment of regulatory standards.

We have established a HSE Management System designed to:

- provide staff with the training and resources needed to complete work safely and effectively;
- incorporate hazard assessment and risk management as an integral part of everyday business;
- monitor performance to ensure that our operations comply with legal obligations and the standards we set for ourselves; and
- identify and manage environmental liabilities associated with our existing asset base and potential acquisitions.

We have a site inspections program and a corrosion risk management program designed to ensure compliance with environmental laws and regulations. We carry insurance to cover a portion of our property losses, liability and business interruption. HSE risks are reviewed regularly by the HSE committee comprised of members of the Board of Directors.

Foreign Currency Exposure

We have exposure to fluctuations in foreign currency as our senior unsecured notes are denominated in U.S. dollars. Our U.S. operations are directly exposed to fluctuations in the U.S. dollar when translated to our Canadian dollar denominated financial statements.

We also have indirect exposure to fluctuations in foreign currency as our crude oil sales and a portion of our natural gas sales are based on U.S. dollar indices. Our oil and gas revenues are positively impacted as the Canadian dollar weakens relative to the U.S. dollar.

We have hedged our foreign currency exposure on both our US$175 million and US$54 million senior unsecured notes using financial swaps that convert the U.S. denominated debt to Canadian dollar debt. In addition we have hedged our interest obligation on our US$175 million notes.

We have not entered into any other foreign currency derivatives with respect to oil and gas sales or our U.S. operations.

Interest Rate Exposure

We have exposure to movements in interest rates and credit markets as changing interest rates affect our borrowing costs and the trust unit price of yield-based investments such as our trust units.

We monitor the interest rate forward market and have fixed the interest rate on approximately 28% of our debt through our senior unsecured notes and interest rate swaps.

Non-Resident Ownership and Mutual Fund Trust Status

Based on information received from our transfer agent and financial intermediaries in February 2009, an estimated 65% of our outstanding trust units were held by non-residents. This estimate may not be accurate as it is based on certain assumptions and data from the securities industry that does not have a well-defined methodology to determine the residency of beneficial holders of securities.

We currently meet the requirements of a mutual fund trust as defined in the Income Tax Act (Canada). Our trust indenture does not have a specific limit on the percentage of trust units that may be owned by non-residents. At this time, we do not anticipate any legislative changes that would affect our status as a mutual fund trust.

SUMMARY 2009 OUTLOOK

Enerplus offers investors the benefits of owning a large, diversified portfolio of producing crude oil and natural gas properties within Canada and the United States. As such, our business prospects are closely linked to the opportunities and challenges associated with oil and natural gas production. In particular, we are strongly influenced by the price of crude oil and natural gas, both of which have been volatile in recent years. Our comments with respect to our 2009 outlook should be taken within the context of the current commodity price environment.

The following summarizes our 2009 guidance as provided throughout this MD&A. We do not attempt to forecast commodity prices and, as a result, we do not forecast future cash flow or cash distributions. Readers are encouraged to apply their own price expectations to the following factors to arrive at an expected cash distribution.

Summary of 2009 Expectations	Target	Comments
Average annual production	91,000 BOE/day	Does not include any further potential acquisitions/divestments
Exit rate 2009 production	88,000 BOE/day	Assumes $300 million development capital spending
2009 production mix	58% gas, 42% liquids	
Average royalty rate	18%	Percentage of gross sales
Operating costs	$10.65/BOE	
G&A costs	$2.45/BOE	Includes non-cash charges of $0.20/BOE (unit rights incentive plan)
U.S. income and withholding tax - cash costs	15%	Applied to net cash flow generated by U.S. operations and assumes repatriation of the funds to Canada after U.S. development capital spending
Average interest cost	3%	Based on current fixed rate contracts and forward market
Payout ratio	50% - 75%	We intend to manage our distributions and capital spending in order to minimize increases in debt outside of acquisitions
Development capital spending	$300 million	We intend to monitor commodity prices and cost

structures and will adjust capital spending in order to minimize increases in debt outside of acquisitions

We believe it is important to maintain a conservative balance sheet as a defense against commodity price changes and to be positioned to capture acquisition opportunities. As a result, we have reduced our 2009 development capital spending to $300 million, which is 48% lower than our 2008 spending. We have also reduced our monthly distributions to unitholders to $0.18 per trust unit and based on current commodity prices we do not expect to materially increase our debt levels in 2009 outside of acquisition activities.

We will continue to focus on low-risk development opportunities and review our risk management strategies in response to changing prices, the current economic environment and the economics of our acquisition and development projects.

For 2009, we estimate that 95% of cash distributions will be taxable and 5% will be a tax-deferred return of capital for our Canadian unitholders. For our U.S. unitholders, we estimate that 90% of cash distribution will be taxable and 10% will be a tax-deferred return of capital.

CONSOLIDATED BALANCE SHEETS

As at December 31 (CDN$ thousands)	2008	2007
Assets		
Current assets		
Cash	$ 6,922	$ 1,702
Accounts receivable	163,152	145,602
Deferred financial assets (Note 12)	121,281	10,157
Future income taxes (Note 11)	-	10,807
Other current	3,783	6,373
	295,138	174,641
Property, plant and equipment (Note 3)	5,246,998	3,872,818
Goodwill (Note 1(f))	634,023	195,112
Deferred financial assets (Note 12)	6,857	-
Other assets	47,116	60,559
	$ 6,230,132	$ 4,303,130
Liabilities		
Current liabilities		
Accounts payable	$ 272,818	$ 269,375
Distributions payable to unitholders	41,397	54,522
Future income taxes (Note 11)	30,198	-
Deferred financial credits (Note 12)	-	52,488
	344,413	376,385
Long-term debt (Note 7)	664,343	726,677
Deferred financial credits (Note 12)	26,392	90,090
Future income taxes (Note 11)	648,821	304,259
Asset retirement obligations (Note 4)	207,420	165,719
	1,546,976	1,286,745

Equity			
Unitholders' capital (Note 10)			
Trust Units and Trust Units Equivalent			
Authorized:	Unlimited		
Issued and Outstanding:	2008 - 165,590,240		
	2007 - 129,813,445	5,471,336	4,032,680
Accumulated deficit		(1,181,199)	(1,283,953)
Accumulated other comprehensive income (Notes 1(i) and (j))		48,606	(108,727)
		(1,132,593)	(1,392,680)
		4,338,743	2,640,000
		$ 6,230,132	$ 4,303,130

CONSOLIDATED STATEMENTS OF ACCUMULATED DEFICIT

For the year ended December 31 (CDN$ thousands)	2008	2007
Accumulated income, beginning of year	$ 2,286,927	$ 1,952,960
Adjustment for adoption of financial instruments standards	-	(5,724)
Revised Accumulated income, beginning of year	2,286,927	1,947,236
Net income	888,892	339,691
Accumulated income, end of year	3,175,819	2,286,927
Accumulated cash distributions, beginning of year	(3,570,880)	(2,924,045)
Cash distributions	(786,138)	(646,835)
Accumulated cash distributions, end of year	(4,357,018)	(3,570,880)
Accumulated deficit, end of year	$(1,181,199)	$(1,283,953)

CONSOLIDATED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

For the year ended December 31 (CDN$ thousands)	2008	2007
Balance, beginning of year	$ (108,727)	$ (8,979)
Transition adjustments:		
Cash flow hedges	-	660
Available for sale marketable securities	-	14,252
Other comprehensive (loss)/income	157,333	(114,660)
Balance, end of year	$ 48,606	$ (108,727)

CONSOLIDATED STATEMENTS OF INCOME

For the year ended December 31 (CDN$ thousands except per trust unit amounts)	2008	2007
Revenues		
Oil and gas sales	$ 2,331,884	$ 1,539,153
Royalties	(429,943)	(285,148)
Commodity derivative instruments (Note 12)	66,434	(52,841)
Other income (Note 12)	8,464	14,991
	1,976,839	1,216,155
Expenses		
Operating	332,622	274,150
General and administrative	65,667	67,921
Transportation	27,650	22,098
Interest (Note 8)	24,224	33,627
Foreign exchange (Note 9)	25,852	(7,071)
Depletion, depreciation, amortization and accretion	640,440	463,718
	1,116,455	854,443
Income before taxes	860,384	361,712
Current taxes	22,722	23,011
Future income tax recovery (Note 11)	(51,230)	(990)
Net Income	$ 888,892	$ 339,691
Net income per trust unit		
Basic	$ 5.54	$ 2.66
Diluted	$ 5.53	$ 2.66
Weighted average number of trust units outstanding (thousands)		
Basic	160,589	127,691
Diluted	160,640	127,752

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the year ended December 31 (CDN$ thousands)	2008	2007
Net income	$ 888,892	$ 339,691
Other comprehensive (loss)/income, net of tax:		
Unrealized gain on marketable securities	2,578	629
Realized gains on marketable securities included in net income (Note 12 (b))	(6,158)	(11,302)

Gains and losses on derivatives designated as hedges in prior periods included in net income	74	(733)
Change in cumulative translation adjustment	160,839	(103,254)
Other comprehensive (loss)/income	157,333	(114,660)
Comprehensive income	$ 1,046,225	$ 225,031

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the year ended December 31 (CDN$ thousands)	2008	2007
Operating Activities		
Net income	$ 888,892	$ 339,691
Non-cash items add/(deduct):		
Depletion, depreciation, amortization and accretion	640,440	463,718
Change in fair value of derivative instruments (Note 12)	(240,085)	91,852
Unit based compensation (Note 10 (d))	6,996	8,435
Foreign exchange on translation of senior notes (Note 9)	54,792	(41,182)
Future income tax (Note 11)	(51,230)	(990)
Impairment of marketable securities	10,000	-
Amortization of senior notes premium	(668)	(631)
Reclassification adjustments from AOCI to net income and other	92	(865)
Gain on sale of marketable securities (Note 12)	(8,263)	(14,055)
Asset retirement obligations settled (Note 4)	(18,308)	(16,280)
	1,282,658	829,693
Decrease/(Increase) in non-cash operating working capital	(19,876)	38,855
Cash flow from operating activities	1,262,782	868,548
Financing Activities		
Issue of trust units, net of issue costs (Note 10)	70,516	256,369
Cash distributions to unitholders	(786,138)	(646,835)
(Decrease)/Increase in bank credit facilities (Note 7)	(447,371)	148,827
Decrease in non-cash financing working capital	(13,125)	2,799
Cash flow from financing activities	(1,176,118)	(238,840)
Investing Activities		
Capital expenditures	(588,337)	(393,655)
Property acquisitions (Note 6)	(15,306)	(226,480)
Property dispositions (Note 6)	504,859	2,947
Proceeds on sale of marketable securities	18,320	16,467
Purchase of investments	(7,150)	(2,927)

Increase in non-cash investing working capital	(1,618)	(21,046)
Cash flow from investing activities	(89,232)	(624,694)
Effect of exchange rate changes on cash	7,788	(3,436)
Change in cash	5,220	1,578
Cash, beginning of year	1,702	124
Cash, end of year	$ 6,922	$ 1,702

Supplementary Cash Flow Information		
Cash income taxes paid	$ 73,914	$ 17,431
Cash interest paid	$ 42,695	$ 42,861

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The management of Enerplus Resources Fund ("Enerplus" or the "Fund") prepares the consolidated financial statements in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). A reconciliation between Canadian GAAP and United States of America GAAP ("U.S. GAAP") is disclosed in Note 15. 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 reporting period. Actual results could differ from those estimated. In particular, the amounts recorded for depletion and depreciation of the petroleum and natural gas properties and for asset retirement obligations are based on estimates of reserves and future costs. By their nature, these estimates, and those related to future cash flows used to assess impairment, are subject to measurement uncertainty and the impact on the financial statements of future periods could be material.

The following significant accounting policies are presented to assist the reader in evaluating these consolidated financial statements and, together with the following notes, should be considered an integral part of the consolidated financial statements.

(a) Organization and Basis of Accounting

The Fund is an open-end investment trust created under the laws of the Province of Alberta operating pursuant to the Amended and Restated Trust Indenture between EnerMark Inc. (the Fund's wholly-owned subsidiary), Enerplus Resources Corporation ("ERC") and Computershare Trust Company of Canada. The beneficiaries of the Fund (the "unitholders") are holders of the trust units issued by the Fund. As a trust under the Income Tax Act (Canada), Enerplus is limited to holding and administering permitted investments and making distributions to the unitholders.

The Fund's financial statements include the accounts of the Fund and its subsidiaries on a consolidated basis. All inter-entity transactions have been eliminated. Many of the Fund's production activities are conducted through joint ventures and the financial statements reflect only the Fund's proportionate interest in such activities.

(b) Revenue Recognition

Revenueassociated with the sale of crude oil, natural gas and natural gas liquids is recognized when title passes from the Fund to its customers based on price, volumes delivered and contractual delivery points. A portion of the properties acquired through the March 5, 2003 acquisition of PCC Energy Inc. and PCC Energy Corp. are subject to a royalty arrangement, with a private company, that is structured as a net profits interest. The results from operations included in the Fund's consolidated financial statements for these properties are reduced for this net profits interest.

(c) Property, Plant and Equipment ("PP&E")

The Fund follows the full cost method of accounting for petroleum and natural gas properties under which all acquisition and development costs are capitalized on a country by country cost centre basis. Such costs include land acquisition, geological, geophysical, drilling costs for productive and non-productive wells, facilities and directly related overhead charges. Repairs, maintenance and operational costs that do not extend or enhance the recoverable reserves are charged to earnings. Proceeds from the sale of petroleum and natural gas properties are applied against the capitalized costs. Gains and losses are not recognized upon disposition of oil and natural gas properties unless such a disposition would alter the rate of depletion by 20% or more. Net costs related to operating and administrative activities during the development of large capital projects are capitalized until commercial production has commenced.

(d) Impairment Test

A limit is placed on the aggregate carrying value of PP&E (the "impairment test"). The Fund performs an impairment test on a country by country basis. An impairment loss exists when the carrying amount of the country's PP&E exceeds the estimated undiscounted future net cash flows associated with the country's proved reserves. If an impairment loss is determined to exist, the costs carried on the balance sheet in excess of the discounted future net cash flows associated with the country's proved and probable reserves are charged to income. Net costs related to projects in the pre-commercial phase of development are excluded from the country by country impairment test and are tested for impairment separately.

(e) Depletion and Depreciation

The provision for depletion and depreciation of oil and natural gas assets is calculated on a country by country basis using the unit-of-production method, based on the country's share of estimated proved reserves before royalties. Reserves and production are converted to equivalent units on the basis of 6 Mcf = 1 bbl, reflecting the approximate relative energy content.

(f) Goodwill

The Fund, when appropriate, recognizes goodwill relating to corporate acquisitions when the total purchase price exceeds the fair value of the net identifiable assets and liabilities of the acquired companies. The goodwill balance is assessed for impairment annually at year-end or as events occur that could result in an impairment. To assess impairment, the fair values of the Canadian and U.S. reporting units are compared to their respective book values. If the fair value is less than the book value, a second test is performed to determine the amount of impairment. The amount of impairment is measured by allocating the fair value of the reporting unit to its identifiable assets and liabilities as if they had been acquired in a business combination for a purchase price equal to their fair value. If goodwill determined in this manner is less than the carrying value of goodwill, an impairment is recognized in the period in which it occurs. Goodwill is stated at cost less impairment and is not amortized. Goodwill is not deductible for income tax purposes.

(g) Asset Retirement Obligations

The Fund recognizes as a liability the estimated fair value of the future retirement obligations associated with PP&E. The fair value is capitalized and amortized over the same period as the underlying asset. The Fund estimates the liability based on the estimated costs to abandon and reclaim its net ownership interest in all wells and facilities and the estimated timing of the costs to be incurred in future periods. This estimate is evaluated on a periodic basis and any adjustment to the estimate is prospectively applied. As time passes, the change in net present value of the future retirement obligation is expensed through accretion. Retirement obligations settled during the period reduce the future retirement liability. No gains or losses on retirement activities were realized due to settlements approximating the estimates.

(h) Income Taxes

The Fund is a taxable entity under the Income Tax Act (Canada) and is taxable only on Canadian income that is not distributed or distributable to the Fund's unitholders. In the Trust structure, payments made between the Canadian operating entities and the Fund ultimately transfers both income and future income tax liability to the unitholders. The future income tax liability associated with Canadian assets recorded on the balance sheet is recovered over time through these payments. As the Canadian operating entities transfer all of their Canadian taxable income to the Fund, no provision for current Canadian income tax has been made by any Canadian operating entity.

Effective January 1, 2011, the Fund will be subject to a 29.5% SIFT (specified investment flow-through) tax on Canadian income that has not been subject to a Canadian corporate income tax in the Canadian operating entities. Therefore, the future tax liability associated with Canadian assets recorded on the balance sheet as at that date will be realized over time as the temporary differences between the carrying value of assets in the consolidated financial statements and their respective tax bases are realized. Current Canadian income taxes will be accrued for at that time to the extent that there is taxable income in the Trust or its underlying operating entities.

The U.S. operating entity is subject to U.S. income taxes on its taxable income determined under U.S. income tax rules and regulations. Repatriation of funds from U.S. operations will also be subject to applicable withholding taxes as required under U.S. tax law.

The Fund 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 the temporary differences between the carrying value of the assets and liabilities on the consolidated financial statements and their respective tax bases, using substantively enacted income tax rates. The effect of a change in these income tax rates on future income tax liabilities and assets is recognized in income during the period that the change occurs.

(i) Financial Instruments

The Fund is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments are used by the Fund to reduce its exposure to these risks. The Fund records its derivative instruments on the Consolidated Balance Sheet at fair value and recognizes any change in fair value through net income during the period. The fair values of these derivative instruments are generally based on an estimate of the amounts that would be received or paid to settle these instruments at the balance sheet date.

The Fund has certain minor equity investments in entities involved in the oil and gas industry. Investments that have a quoted price in an active market are measured at fair value with changes in fair value recognized in other comprehensive income. When the investment is ultimately sold any gains or losses are recognized in net income and any unrealized gains or losses previously recognized in other comprehensive income are reversed. Investments that do not have a quoted price in an active market are measured at cost unless there has been an other than temporary impairment, in which case a charge is recognized in net income to record the loss in value.

(j) Foreign Currency Translation

The Fund's U.S. operations are self-sustaining. Assets and liabilities of these operations are translated into Canadian dollars at period end exchange rates, while revenues and expenses are converted using average rates for the period. Gains and losses from the translation into Canadian dollars are deferred and included in the cumulative translation adjustment ("CTA") which is part of accumulated other comprehensive income ("AOCI").

Other monetary assets and liabilities, not related to the Fund's U.S. operations, are translated into Canadian dollars at rates of exchange in effect at the balance sheet date. The other assets and related depreciation, depletion and amortization, other liabilities, revenue and other expenses are translated into Canadian dollars at rates of exchange in effect at the respective transaction dates. The resulting exchange gains or losses are included in earnings.

(k) Unit Based Compensation

The Fund uses the fair value method of accounting for the trust unit rights incentive plan. Under this method, the fair value of the rights is determined on the date in which fair value can reasonably be determined, generally being the grant date. This amount is charged to earnings over the vesting period of the rights, with a corresponding increase in contributed surplus. When rights are exercised, the proceeds, together with the amount recorded in contributed surplus, are recorded to unitholders' capital.

2. CHANGES IN ACCOUNTING POLICIES

Current Year Accounting Changes

Effective January 1, 2008, the Fund adopted three new accounting standards that were issued by the Canadian Institute of Chartered Accountants ("CICA"): Handbook Section 1535, Capital Disclosures, Section 3862, Financial Instruments - Disclosures and Section 3863, Financial Instruments - Presentation.

(a) Capital Disclosures

Section 1535 establishes standards for disclosing information regarding an entity's capital and how it is managed.

(b) Financial Instruments - Disclosures, Financial Instruments - Presentation

Sections 3862 and 3863 establish standards for enhancing financial statements users' understanding of the significance of financial instruments to an entity's financial position, performance and cash flows. They require that entities provide disclosures regarding the nature and extent of risks arising from financial instruments to which they are exposed both during the reporting period and at the balance sheet date, as well as how the entities manage those risks.

These standards were adopted prospectively.

Future Accounting Changes

(a) Goodwill and Intangible Assets

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 3064 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. The Fund is currently evaluating the impact of the adoption of this new Section, however does not expect a material impact on its Consolidated Financial Statements.

(b) Convergence of Canadian GAAP with International Financial Reporting Standards ("IFRS")

In 2006, Canada's Accounting Standards Board (AcSB) ratified a strategic plan that will result in Canadian GAAP being converged with International Financial Reporting Standards (IFRS) by 2011 for public reporting entities. On February 13, 2008 the AcSB confirmed that IFRS will be required for public companies beginning January 1, 2011.

3. PROPERTY, PLANT AND EQUIPMENT

($ thousands)	2008	2007
Property, plant and equipment	$8,497,206	$6,429,241
Accumulated depletion, depreciation and accretion	(3,250,208)	(2,556,423)
Net property, plant and equipment	$5,246,998	$3,872,818

Capitalized general and administrative ("G&A") expenses for 2008 of $21,766,000 (2007 - $17,185,000) are included in PP&E. The depletion and depreciation calculation includes future capital costs of $773,371,000 (2007 - $521,650,000) as indicated in our reserve reports. Excluded from PP&E for the depletion and depreciation calculation is $257,608,000 (2007 - $321,801,000) related to the Kirby oil sands project ("Kirby") which has not yet commenced commercial production. The 2007 amount included costs related to the Joslyn oil sands project which was sold in July, 2008.

An impairment test calculation was performed on a country by country basis on the PP&E values at December 31, 2008 in which the estimated undiscounted future net cash flows associated with the proved reserves exceeded the carrying amount of the Fund's PP&E.

The following table outlines estimated benchmark prices and the exchange rate used in the impairment tests for both Canadian and U.S. cost centers at December 31, 2008:

Year	WTI Crude Oil(1) US$/bbl	Exchange Rate CDN$/US$	Edm Light Crude(1) CDN$/bbl	Natural Gas 30 day spot @ AECO(1) CDN$/Mcf
2009	$53.73	$0.80	$65.35	$6.82
2010	63.41	0.85	72.78	7.56
2011	69.53	0.85	79.95	7.84
2012	79.59	0.90	86.57	8.38
2013	92.01	0.95	94.97	9.20
Thereafter(*)	+2% yr	0.95	+2% yr	+2% yr

(1) Prices used in the impairment test were adjusted for commodity price differentials specific to the Fund

(*) Escalation varies after 2013.

4. ASSET RETIREMENT OBLIGATIONS

Total future asset retirement obligations were estimated by management based on the Fund's net ownership interest in wells and facilities, estimated costs to abandon and reclaim the wells and facilities, and the estimated timing of the costs to be incurred in future periods. The Fund has estimated the net present value of its total asset retirement obligations to be $207,420,000 at December 31, 2008 compared to $165,719,000 at December 31, 2007 based on a total undiscounted liability of $644,423,000 and $542,781,000 respectively. These payments are expected to be made over the next 66 years with the majority of costs incurred between 2039 and 2048. To calculate the present value of the asset retirement obligations for 2008 the Fund used a weighted credit-adjusted rate of approximately 6.1% and an inflation rate of 2.0%, (2007 - 6.1% and 2.0%). Settlements during 2008 and 2007 approximated our estimates and as a result no gains or losses were recognized.

Following is a reconciliation of the asset retirement obligations:

($ thousands)	2008	2007
Asset retirement obligations, beginning of year	$165,719	$123,619
Corporate acquisition	36,784	-

Changes in estimates	4,087	46,000
Acquisition and development activity	7,394	6,441
Dispositions	(110)	(756)
Asset retirement obligations settled	(18,308)	(16,280)
Accretion expense	11,854	6,695
Asset retirement obligations, end of year	$207,420	$165,719

5. CORPORATE ACQUISITIONS

Focus Energy Trust

On February 13, 2008 Enerplus closed the acquisition of Focus Energy Trust ("Focus"). Under the plan of arrangement, Focus unitholders received 0.425 of an Enerplus trust unit for each Focus trust unit and Focus Exchangeable Limited Partnership Units became exchangeable into Enerplus trust units at the option of the holder on the basis of 0.425 of an Enerplus trust unit for each Focus Exchangeable Limited Partnership Unit. Total consideration was $1,366,494,000 consisting of 30,150,000 trust units issued, 9,087,000 exchangeable limited partnership units assumed (convertible into 3,861,833 trust units) and transaction costs of $5,350,000. The Fund also assumed bank debt plus an estimated working capital deficit including certain transaction costs paid by Focus of $357,305,000.

The acquisition has been accounted for using the purchase method of accounting and results from the operations of Focus from February 13, 2008 onward have been included in the Fund's consolidated financial statements. The allocation of the consideration paid to the fair value of the assets acquired and liabilities assumed plus future income tax cost is summarized below:

Net Assets Acquired ($ thousands)	
Property, plant and equipment	$1,757,520
Other assets	4,566
Goodwill	403,588
Working capital deficit	(26,393)
Deferred financial credits	(5,919)
Long-term debt	(330,912)
Asset retirement obligations	(36,784)
Future income taxes	(399,172)
Total net assets acquired	$1,366,494

Consideration paid ($ thousands)	
Trust units issued(1)	$1,206,593
Exchangeable limited partnership units assumed(1)	154,551
Transaction costs	5,350
Total consideration paid	$1,366,494

(1) Recorded based on a fair value of $40.02 per trust unit

6. PROPERTY ACQUISITIONS AND DISPOSITIONS

Joslyn Oil Sands Interest

On July 31, 2008 the Fund disposed of its interest in the Joslyn oil sands project for net cash proceeds of $502,000,000.

Kirby Oil Sands Project

On April 10, 2007 the Fund acquired a 90% interest in Kirby for total consideration of $182,800,000, consisting of $128,050,000 in cash and the issuance of 1,104,945 trust units at a price of $49.55 per unit ($54,750,000 of equity). On June 22, 2007 the Fund acquired the remaining 10% interest in Kirby for cash consideration of $20,276,000. The acquisition of Kirby has been accounted for as an asset acquisition pursuant to the guidance in the Emerging Issues Committee Abstract 124.

7. LONG-TERM DEBT

($ thousands)	2008	2007
Bank credit facilities (a)	$380,888	$497,347
Senior notes (b)		
US$175 million (issued June 19, 2002)	217,327	175,973
US$54 million (issued October 1, 2003)	66,128	53,357
Total long-term debt	$664,343	$726,677

(a) Unsecured Bank Credit Facility

Enerplus has a $1.4 billion unsecured covenant based facility ($1.0 billion at December 31, 2007) that matures November 18, 2010. The facility is extendible each year with a bullet payment required at maturity. At December 31, 2008 Enerplus had available credit of $1,019,112,000. Various borrowing options are available under the facility including prime based advances and bankers' acceptances. This facility carries floating interest rates that are expected to range between 55 and 110 basis points over bankers' acceptance rates, depending on Enerplus' ratio of senior debt to earnings before interest, taxes and non-cash items. The weighted average effective interest rate on the facility for the year ended December 31, 2008 was 3.8% (2007 - 5.1%).

(b) Senior Unsecured Notes

On June 19, 2002 Enerplus issued US$175,000,000 senior unsecured notes that mature June 19, 2014. The notes have a coupon rate of 6.62% priced at par, with interest paid semi-annually on June 19 and December 19 of each year. Principal payments are required in five equal installments beginning June 19, 2010 and ending June 19, 2014. Concurrent with the issuance of the notes on June 19, 2002, the Fund entered into a cross currency interest rate swap ("CCIRS") with a syndicate of financial institutions. Under the terms of the swap, the amount of the notes was fixed for purposes of interest and principal repayments at a notional amount of CDN$268,328,000. Interest payments are made on a floating rate basis, set at the rate for three-month Canadian bankers' acceptances, plus 1.18%.

On October 1, 2003, when the CDN/US dollar exchange rate was 0.74, Enerplus issued US$54,000,000 senior unsecured notes that mature October 1, 2015. The notes have a coupon rate of 5.46% priced at par with interest paid semi-annually on April 1 and October 1 of each year. Principal payments are required in five equal installments beginning October 1, 2011 and ending October 1, 2015. The notes are translated into Canadian dollars using the period end foreign exchange rate. In September 2007 Enerplus entered into foreign exchange swaps that effectively fix the five principal payments on the US$54,000,000 senior unsecured notes at a CDN/USexchange rate of 0.98 or CDN$55,080,000.

On January 1, 2007 in conjunction with the adoption of CICA Sections 3855 and 3865, the Fund elected to stop designating the CCIRS as a fair value hedge on the US$175,000,000 senior notes. As a result, the Fund recorded the senior notes at their fair value of US$178,681,000. The premium amount of US$3,681,000, representing the difference between the January 1, 2007 fair value and the face amount of the senior notes, will be amortized to net income over the remaining term of the notes using the effective interest method. The effective interest rate over the remaining term of the senior notes is 6.16%. The senior notes are carried at amortized cost and are translated into Canadian dollars using the period end foreign exchange rate. At December 31, 2008 the amortized cost of the US$175,000,000 senior notes was US$177,467,000.

The bank credit facility and the senior notes (the "Combined Facilities") are the legal obligation of EnerMark Inc. and are guaranteed by its subsidiaries. Payments with respect to the Combined Facilities have priority over payments to the Fund and over claims of and future distributions to the unitholders however, unitholders have no direct liability beyond their equity investment should cash flow be insufficient to repay the Combined Facilities.

8. INTEREST EXPENSE

($ thousands)	2008	2007
Realized		
Interest on long-term debt	$42,626	$41,934
Unrealized		
Gain on cross currency interest rate swap	(27,559)	(7,340)
Loss/(gain) on interest rate swaps	9,825	(447)
Amortization of the premium on senior unsecured notes	(668)	(631)
Other	-	111
Interest Expense	$ 24,224	$ 33,627

9. FOREIGN EXCHANGE

($ thousands)	2008	2007
Realized		
Foreign exchange loss	$ 23,881	$ 1,909
Unrealized		
Foreign exchange loss/(gain) on translation of U.S. dollar denominated senior notes	54,792	(41,182)
Foreign exchange (gain)/loss on cross currency interest rate swap	(45,539)	31,777

Foreign exchange (gain)/loss on foreign exchange swaps	(7,282)	425
Foreign exchange loss/(gain)	$ 25,852	$ (7,071)

The US$54,000,000 and US$175,000,000 senior unsecured notes are exposed to foreign currency fluctuations and are translated into Canadian dollars at the exchange rate in effect at the balance sheet date. Foreign exchange gains and losses are included in the determination of net income for the period.

10. UNITHOLDERS' CAPITAL

Unitholders' capital as presented on the Consolidated Balance Sheets consists of trust unit capital, exchangeable partnership unit capital and contributed surplus.

Unitholders' capital ($ thousands)	2008	2007
Trust units	$ 5,328,629	$ 4,020,228
Exchangeable limited partnership units	123,107	-
Contributed surplus	19,600	12,452
Balance, end of year	$ 5,471,336	$ 4,032,680

(a) Trust Units

Authorized: Unlimited number of trust units

(thousands)	2008		2007	
Issued:	Units	Amount	Units	Amount
Balance before Contributed Surplus, beginning of year	129,813	$4,020,228	123,151	$3,706,821
Issued for cash:				
Pursuant to public offerings	-	-	4,250	199,558
Pursuant to rights incentive plan	210	6,755	205	6,758
Cancelled trust units	(116)	(3,794)	-	-
Exchangeable limited partnership units exchanged	786	31,444	-	-
Trust unit rights incentive plan (non-cash) - exercised	-	3,642	-	2,288
DRIP(*), net of redemptions	1,671	63,761	1,102	50,053
Issued for acquisition of corporate and property interests (non-cash)	30,150	1,206,593	1,105	54,750
	162,514	5,328,629	129,813	4,020,228
Equivalent exchangeable partnership units	3,076	123,107	-	-
Balance, end of year	165,590	$5,451,736	129,813	$4,020,228

(*) Distribution Reinvestment and Unit Purchase Plan

On February 13, 2008 the Fund issued 30,150,000 trust units pursuant to the Focus acquisition valued at $40.02 per trust unit, being the weighted average trading price of the Fund's units on the Toronto Stock Exchange during the five day trading period surrounding the announcement date of December 3, 2007, for a recorded value of $1,206,593,000.

On April 10, 2007 the Fund closed an equity offering of 4,250,000 trust units at a price of $49.55 per unit for gross proceeds of $210,588,000 ($199,558,000 net of issuance costs).

In conjunction with the acquisition of Kirby on April 10, 2007, the Fund issued 1,105,000 trust units at a price of $49.55 per unit for gross proceeds of $54,750,000.

Pursuant to the monthly Distribution Reinvestment and Unit Purchase Plan ("DRIP"), Canadian unitholders are entitled to reinvest cash distributions in additional trust units of the Fund. Trust units are issued at 95% of the weighted average market price on the Toronto Stock Exchange for the 20 trading days preceding a distribution payment date without service charges or brokerage fees. Eligible unitholders are also entitled to make optional cash payments to acquire additional trust units; however, the 5% discount does not apply.

Trust units are redeemable by unitholders at approximately 85% of the current market price. Redemptions are limited to $500,000 during any rolling two calendar months. Redemption requests in excess of $500,000 can be paid using investments of the Fund or a non-interest bearing instrument.

(b) Exchangeable Limited Partnership Units

In conjunction with the Focus acquisition 9,087,000 Exchangeable Limited PartnershipUnits issued by Focus Limited Partnership (since renamed Enerplus Exchangeable Limited Partnership) became exchangeable into Enerplus trust units at a ratio of 0.425 of an Enerplus trust unit for each limited partnership unit (3,862,000 trust units). The exchangeable limited partnership units are convertible at any time into trust units at the option of the holder and receive cash distributions and have voting rights in accordance with the 0.425 exchange ratio. The Board of Directors may redeem the exchangeable limited partnership units after January 8, 2017, unless certain conditions are met to permit an earlier redemption date. The exchangeable limited partnership units are not listed on any stock exchange and are not transferable. The exchangeable limited partnership units were recorded at fair value, based on Enerplus' five day weighted average trust unit trading price surrounding the December 3, 2007 announcement date of $40.02 multiplied by the 0.425 exchange ratio.

During the period February 13, 2008 to December 31, 2008, 1,849,000 exchangeable limited partnership units were converted into 786,000 trust units. As at December 31, 2008, the 7,238,000 outstanding exchangeable limited partnership units represent the equivalent of 3,076,000 trust units.

(thousands)	2008		2007	
Issued:	Units	Amount	Units	Amount
Assumed on February 13, 2008	9,087	$154,551	-	$ -

Exchanged for trust units	(1,849)	(31,444)	-	-
Balance, end of period	7,238	$123,107	-	$ -

(c) Contributed Surplus

Contributed surplus ($ thousands)	2008	2007
Balance, beginning of year	$ 12,452	$ 6,305
Trust unit rights incentive plan (non-cash) - exercised	(3,642)	(2,288)
Trust unit rights incentive plan (non-cash) - expensed	6,996	8,435
Cancelled trust units	3,794	-
Balance, end of year	$ 19,600	$ 12,452

(d) Trust Unit Rights Incentive Plan

As at December 31, 2008 a total of 4,001,000 rights issued pursuant to the Trust Unit Rights Incentive Plan ("Rights Incentive Plan") were outstanding at an average exercise price of $45.05. This represents 2.4% of the total trust units outstanding, of which 2,024,000 rights, with an average exercise price of $46.44, were exercisable. Under the Rights Incentive Plan, distributions per trust unit to Enerplus unitholders in a calendar quarter which represent a return of more than 2.5% of the net PP&E of Enerplus at the end of such calendar quarter may result in a reduction in the exercise price of the rights. Results for the year ended December 31, 2008 reduced the exercise price of the outstanding rights by $1.65 per trust unit of which a $0.59 reduction is effective January 2009 and a $0.22 reduction is effective April 2009. Plan members have the choice to exercise rights using the original exercise price or a reduced strike price. In certain circumstances, it may be more advantageous to use the original exercise price as it could effectively result in higher after tax proceeds for the plan member.

The Fund uses a binomial lattice option-pricing model to calculate the estimated fair value of rights granted under the plan. The following assumptions were used to arrive at the estimate of fair value:

	2008	2007
Dividend yield	12.09%	10.37%
Volatility	27.12%	26.35%
Risk-free interest rate	2.90%	4.41%
Forfeiture rate	7.30%	6.20%
Right's exercise price reduction	$1.91	$1.75

The fair value of the rights granted under the plan during 2008 and 2007 ranged between 9% and 12% of the underlying market price of a trust unit on the grant date.

During the year the Fund expensed $6,996,000 or $0.04 per unit (2007 - $8,435,000 or $0.07 per unit) of unit based compensation expense using the fair value method. The remaining future fair value of the rights of

$4,678,000 at December 31, 2008 (2007 - $6,195,000) will be recognized in earnings over the vesting period of the rights. Activity for the rights issued pursuant to the Rights Incentive Plan is as follows:

	2008		2007	
	Number of Rights (000's)	Weighted Average Exercise Price(1)	Number of Rights (000's)	Weighted Average Exercise Price(1)
Trust unit rights outstanding				
Beginning of year	3,404	$47.59	3,079	$48.53
Granted	1,403	42.00	816	48.71
Exercised	(210)	32.22	(205)	32.90
Forfeited and expired	(596)	44.94	(286)	50.74
End of year	4,001	$45.05	3,404	$47.59
Rights exercisable at the end of the year	2,024	$46.44	1,635	$44.84

(1) Exercise price reflects grant prices less reduction in strike price discussed above.

The following table summarizes information with respect to outstanding rights as at December 31, 2008. Rights vest between one and three years and expire between four and six years.

Rights Outstanding at December 31, 2008 (000's)	Original Exercise Price	Exercise Price after Price Reductions	Expiry Date December 31	Rights Exercisable at December 31, 2008 (000's)
4	33.00	23.85	2009	4
2	36.00	27.23	2009	2
57	37.62	29.24	2009	57
3	40.70	32.71	2009 - 2010	3
17	37.25	29.63	2009 - 2010	17
21	38.83	31.61	2009 - 2010	21
231	40.80	33.93	2009 - 2010	231
37	45.55	39.00	2009 - 2011	37
62	44.86	38.66	2009 - 2011	62
74	49.75	43.95	2009 - 2011	74
499	56.93	51.54	2009 - 2011	499
98	56.55	51.64	2010 - 2012	74
352	54.21	49.80	2010 - 2012	254
211	56.00	52.10	2010 - 2012	166
400	52.90	49.51	2010 - 2012	283
133	48.86	45.97	2011 - 2013	55
394	50.25	47.87	2011 - 2013	138
124	45.14	43.27	2011 - 2013	43
13	38.70	37.35	2011 - 2013	4
1,142	42.05	41.21	2012 - 2014	-
73	47.19	46.78	2012 - 2014	-
35	38.76	38.76	2012 - 2014	-
19	23.58	23.58	2012 - 2014	-

4,001	$ 48.28	$ 45.05	2,024

(e) Basic and Diluted per Trust Unit Calculations

Basic per-unit calculations are calculated using the weighted average number of trust units and exchangeable limited partnership units (converted at the 0.425 exchange ratio) outstanding during the period. Diluted per-unit calculations include additional trust units for the dilutive impact of rights outstanding pursuant to the Rights Incentive Plan.

Net income per trust unit has been determined based on the following:

(thousands)	2008	2007
Weighted average units	160,589	127,691
Dilutive impact of rights	51	61
Diluted trust units	160,640	127,752

In 2008 we excluded 837,961 rights because their exercise price was greater than the annual average unit market price of $38.49. In 2007 we excluded 222,347 rights because their exercise price was greater than the annual average unit market price of $47.11.

(f) Performance Trust Unit Plan

In 2007 the Board of Directors, upon recommendation of the Compensation Committee, approved new Performance Trust Unit ("PTU") plans for executives and employees. These plans will result in employees and officers receiving cash compensation in relation to the value of a specified number of underlying notional trust units. The number of notional trust units awarded is variable to individuals and they vest at the end of three years.

Upon vesting, the plan participant receives a cash payment based on the fair value of the underlying trust units plus notional accrued distributions. The value determined upon vesting of the PTU Plans is dependent upon the performance of the Fund compared to its peers over the three year period. The level of performance within the peer group then determines a performance multiplier.

For the year ended December 31, 2008 the Fund recorded compensation costs of $8,448,000 (2007 - $1,934,000) under the plan which are included in general and administrative expenses.

During 2008 282,000 PTU's were granted and at December 31, 2008 there were 410,000 performance trust units outstanding.

11. INCOME TAXES

The Fund is an inter-vivos trust for income tax purposes. As such, the Fund's income that is not allocated to the Fund's unitholders is taxable. The Fund intends to allocate all income to unitholders.

For 2008, the Fund had taxable income of $763,000,000 (2007 - $632,000,000) or $4.81 per trust unit (2007 - $4.92 per trust unit). Taxable income of the Fund is comprised of dividend, royalty, interest and partnership income, less deductions for Canadian oil and gas property expense ("COGPE") and trust unit issue costs.

There were no dividend income and COGPE deductions for 2008. The amounts of COGPE and issue costs in the fund remaining as at December 31, 2008 are $466,700,000 and $17,185,000 respectively.

Canadian Government's tax on income trusts

In 2007, the Canadian Federal government enacted tax legislation which imposed a tax at a rate equivalent to the corporate tax rate on publicly traded trusts in Canada effective January 1, 2011.

In 2008, the Canadian Federal government introduced draft tax legislation that would have allowed for the conversion of a SIFT into a corporation on a Canadian tax deferred basis; defined the provincial tax component of the SIFT tax; and accelerated the recognition of the "Safe Harbour" limit. None of the above draft legislations were enacted prior to the prorogation of Parliament in December 2008. Therefore, all bills containing the draft legislation lapsed in 2008.

Subsequent to the year end, the Canadian Federal government has introduced draft tax legislation which includes the above mentioned measures as part of Canada's Economic Action Plan.

We continue to evaluate alternatives to our income trust structure beyond 2010. We are currently hesitant to make structural changes as we believe that the exemption period until 2011 has value for our unitholders. While we are keeping our options open, we will most likely convert into a dividend paying corporation prior to the end of 2010.

The future income tax liability on the balance sheet arises as a result of the following temporary differences:

($ thousands)	Canadian	Foreign	2008 Total
Excess of net book value of property, plant and equipment over the underlying tax bases	$ 479,753	$ 200,837	$ 680,590
Asset retirement obligations	(53,057)	-	(53,057)
Deferred financial assets and other	51,218	268	51,486
Future income taxes	$ 477,914	$ 201,105	$ 679,019
Current future income tax liability	$ 30,198	$ -	$ 30,198
Long-term future income tax liability	$ 447,716	$ 201,105	$ 648,821

($ thousands)	Canadian	Foreign	2007 Total
Excess of net book value of property, plant and equipment over the underlying tax bases	$ 176,962	$ 194,393	$ 371,355

Asset retirement obligations	(41,669)	-	(41,669)
Other	(2,825)	(33,409)	(36,234)
Future income taxes	$ 132,468	$ 160,984	$ 293,452
Current future income tax asset	$ (10,807)	$ -	$ (10,807)
Long-term future income tax liability	$ 143,275	$ 160,984	$ 304,259

The provision for income taxes varies from the amounts that would be computed by applying the combined Canadian federal and provincial income tax rates for the following reasons:

($ thousands)	2008	2007
Income before taxes	$ 860,384	$ 361,712
Computed income tax expense at the enacted rate of 29.94% (32.41% for 2007)	$ 257,599	$ 117,231
Increase/(decrease) resulting from:		
Net income attributed to the Fund	(213,871)	(162,016)
Recognition of previously unrecognized pools	(13,405)	-
Non-taxable portion of (gains)/losses	(45,495)	-
Amended returns and pool balances	(7,464)	5,150
Change in tax rate	(2,700)	(22,640)
SIFT Tax	-	78,110
Other	(3,172)	6,186
	$ (28,508)	$ 22,021
Future income tax recovery	$ (51,230)	$ (990)
Current tax	$ 22,722	$ 23,011

The breakdown of our current and future income tax balances between our Canadian and Foreign operations is as follows:

For the year ended December 31, 2008 ($ thousands)	Canadian	Foreign	Total
Future income tax (recovery)/expense	$ (52,706)	$ 1,476	$ (51,230)
Current income tax (recovery)/expense	(25,069)	47,791	22,722

For the year ended December 31, 2007 ($ thousands)	Canadian	Foreign	Total
Future income tax (recovery)/expense	$ (8,183)	$ 7,193	$ (990)
Current income tax	-	23,011	23,011

12. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

(a) Fair Value of Financial Instruments

As a result of the adoption of the new financial instrument and hedging accounting standards on January 1, 2007, certain financial instruments are now measured and reported on the balance sheet at fair value which were previously reported at amortized cost.

The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's-length transaction between knowledgeable, willing parties who are under no compulsion to act. Fair values are determined by reference to quoted bid or ask prices, as appropriate, in the most advantageous active market for that instrument to which we have immediate access. Where bid and ask prices are unavailable, we would use the closing price of the most recent transaction for that instrument. In the absence of an active market, we determine fair values based on prevailing market rates for instruments with similar characteristics, considering credit risk. Fair values may also be determined based on internal and external valuation models, such as option pricing models and discounted cash flow analysis, that use observable market based inputs and assumptions.

(b) Carrying Value and Fair Value of Non-Derivative Financial Instruments

i. Cash

Cash is classified as held-for-trading and is reported at fair value.

ii. Accounts Receivable

Accounts receivable are classified as loans and receivables which are reported at amortized cost. At December 31, 2008 the carrying value of accounts receivable approximated their fair value.

iii. Marketable Securities

Marketable securities with a quoted market price in an active market are classified as available-for-sale and are reported at fair value, with changes in fair value recorded in other comprehensive income. During the first quarter of 2008 the Fund recorded an unrealized gain on certain publicly traded marketable securities of $3,645,000 ($2,578,000 net of tax) which was recorded in accumulated other comprehensive income. These marketable securities were then sold, which resulted in a gain of $8,263,000 ($6,158,000 net of tax) being reclassified from accumulated other comprehensive income to other income on the Consolidated Statement of Income. During the first quarter of 2007 the Fund disposed of certain marketable securities which resulted in a gain of $14,055,000 ($11,302,000 net of tax) which was also reclassified from accumulated other comprehensive income to other income on the Consolidated Statement of Income.

As at December 31, 2008 the Fund did not hold any investments in publicly traded marketable securities. As at December 31, 2007 the Fund reported investments in publicly traded marketable securities at a fair value of $14,676,000.

Marketable securities without a quoted market price in an active market are reported at cost unless an other than temporary impairment exists. In the fourth quarter of 2008 the Fund reduced the carrying value of an investment in a private company to nil resulting in a charge of $10,000,000 to the income statement. As at December 31, 2008 the Fund reported investments in marketable securities of private companies at a cost of $47,116,000 (December 31, 2007 - $45,400,000) in other assets on the Consolidated Balance Sheet. Realized gains and losses on marketable securities are included in other income.

iv. Accounts Payable & Distributions Payable to Unitholders

Accounts payable as well as distributions payable to unitholders are classified as other liabilities and are reported at amortized cost. At December 31, 2008 the carrying value of these accounts approximated their fair value.

v. Long-term Debt

Bank Credit Facilities

The bank credit facilities are classified as other liabilities and are reported at cost. At December 31, 2008 the carrying value of the bank credit facility approximated its fair value.

US$175 million senior notes

The US$175,000,000 senior notes, which are classified as other liabilities, are reported at amortized cost of US$177,467,000 and are translated to Canadian dollars at the period end exchange rate. At December 31, 2008 the Canadian dollar amortized cost of the senior notes was approximately $217,327,000 and the fair value of these notes was $205,942,000.

US$54 million senior notes

The US$54,000,000 senior notes, which are classified as other liabilities, are reported at their amortized cost of US$54,000,000 and are translated into Canadian dollars at the period end exchange rate. At December 31, 2008 the Canadian dollar amortized cost of the senior notes was approximately $66,128,000 and the fair value of these notes was $60,485,000.

c) Fair Value of Derivative Financial Instruments

The Fund's derivative financial instruments are classified as held for trading and are reported at fair value with changes in fair value recorded through earnings. The deferred financial assets and credits on the Consolidated Balance Sheets result from recording derivative financial instruments at fair value. At December 31, 2008 a current deferred financial asset of $121,281,000, a non-current deferred financial asset of $6,857,000 and a non-current deferred financial credit of $26,392,000 are recorded on the consolidated balance sheet.

The deferred financial asset relating to crude oil instruments of $96,641,000 at December 31, 2008 represents a gain position of $117,428,000 less the related deferred premiums of $20,787,000. The deferred financial asset relating to natural gas instruments of $24,292,000 at December 31, 2008 represents a gain position of $41,953,000 less the related deferred premiums of $17,661,000.

The following table summarizes the fair value as at December 31, 2008 and change in fair value for the period ended December 31, 2008. The fair values indicated below are determined using observable market data including price quotations in active markets.

($ thousands)	Interest Rate Swaps	Currency Interest Rate Swaps	Foreign Exchange Swaps	Electricity Swaps
Deferred financial (credits)/assets, at the beginning of period	$ (226)	$ (89,439)	$ (425)	$ 451
Change in fair value (credits)/asset	(9,825)(3)	73,098(4)	7,282(5)	(103)(6)
Deferred financial (credits)/assets, end of period	$ (10,051)	$ (16,341)	$ 6,857	$ 348
Balance sheet classification:				
Current (liability)/asset	$ -	$ -	$ -	$ 348
Non-current (liability)/asset	$ (10,051)	$ (16,341)	$ 6,857	$ -

($ thousands)	Commodity Derivative Instruments Oil	Gas	Total
Deferred financial (credits)/assets, at the beginning of period	$(56,783)(1)	$ 8,083(2)	$ (138,339)
Change in fair value (credits)/asset	153,424(7)	16,209(7)	240,085
Deferred financial (credits)/assets, end of period	$ 96,641	$ 24,292	$ 101,746
Balance sheet classification:			
Current (liability)/asset	$ 96,641	$ 24,292	$ 121,281
Non-current (liability)/asset	$ -	$ -	$ (19,535)

(1) Includes the Focus opening credit balance at February 13, 2008 of

$4,295.
(2) Includes the Focus opening credit balance at February 13, 2008 of $1,624.
(3) Recorded in interest expense.
(4) Recorded in foreign exchange expense (gain of $45,539) and interest expense (gain of $27,559).
(5) Recorded in foreign exchange expense.
(6) Recorded in operating expense.
(7) Recorded in commodity derivative instruments (see below).

The following table summarizes the income statement effects of commodity derivative instruments:

($ thousands)	2008	2007
Gain/(loss) due to change in fair value	$ 169,631	$ (66,393)
Net realized cash (losses)/gain	(103,197)	13,552
Commodity derivative instruments gain/(loss)	$ 66,434	$ (52,841)

(d) Risk Management

The Fund is exposed to a number of financial risks including market, counterparty credit and liquidity risk. Risk management policies have been established by the Fund's Board of Directors to assist in managing a portion of these risks, with the goal of protecting earnings, cash flow and unitholder value.

i. Market Risk

Market risk is comprised of commodity price risk, currency risk and interest rate risk.

Commodity Price Risk

The Fund is exposed to commodity price fluctuations as part of its normal business operations, particularly in relation to its crude oil and natural gas sales. The Fund manages a portion of these risks through a combination of financial derivative and physical delivery sales contracts. The Fund's policy is to enter into commodity contracts considered appropriate to a maximum of 80% of forecasted production volumes net of royalties. The Fund's outstanding commodity derivative contracts as at February 18, 2009 are summarized below:

Crude Oil Instruments:

Enerplus has entered into the following financial option contracts to reduce the impact of a downward movement in crude oil prices. These contracts are classified as held-for-trading and are reported at fair value. At December 31, 2008 the fair value of these contracts represented an asset of $96,641,000 and the change in fair value of these contracts during 2008 represented an unrealized gain of $153,424,000.

The following table summarizes the Fund's crude oil risk management positions at February 18, 2009:

WTI US$/bbl

	Daily Volumes bbls/day	Sold Call	Purchased Put	Sold Put	Fixed Price and Swaps
Term January 1, 2009 - December 31, 2009					
Put	1,400	-	$122.00	-	-
Put	1,000	-	$120.00	-	-
Put	500	-	$116.00	-	-
Collar	850	$100.00	$ 85.00	-	-
Collar	1,000	-	$ 92.00	$ 79.00	-
3-Way option	1,000	$ 85.00	$ 70.00	$ 57.50	-
3-Way option	1,000	$ 95.00	$ 79.00	$ 62.00	-
Swap	500	-	-	-	$100.05

Natural Gas Instruments:

Enerplus has certain financial contracts outstanding as at February 18, 2009 on its natural gas production that are detailed below.

These contracts are classified as held-for-trading and are reported at fair value. At December 31, 2008 the fair value of these contracts represented an asset of $24,292,000 and the change in fair value of these contracts during 2008 represented an unrealized gain of $16,000.

The following table summarizes the Fund's natural gas risk management positions at February 18, 2009:

				AECO CDN$/Mcf		
	Daily Volumes MMcf/day	Purchased Call	Sold Call	Purchased Put	Sold Put	Fixed Price and Swaps
Term January 1, 2009 - March 31, 2009						
Put	4.7	-	-	$11.34	-	-
Put	4.7	-	-	$11.61	-	-
Put	4.7	-	-	$ 9.50	-	-
Call	5.7	$ 9.50	-	-	-	-
Collar	3.8	-	$ 9.50	$ 8.44	-	-
Collar	1.9	-	$ 9.50	$ 8.44	-	-
Collar	4.7	-	-	$ 8.97	$ 7.39	-
Collar	4.7	-	-	$ 8.97	$ 7.39	-
3-Way option	5.7	-	$10.71	$ 7.91	$ 5.80	-
3-Way option	1.9	-	$10.55	$ 8.44	$ 6.33	-
3-Way option	5.7	-	$10.71	$ 8.44	$ 6.33	-
3-Way option	14.2	-	$12.45	$ 8.97	$ 7.39	-
Swap	2.8	-	-	-	-	$ 9.42
Swap	2.8	-	-	-	-	$ 9.28

Swap	2.8	-	-	-	-	$ 9.34
April 1, 2009 - October 31, 2009						
Put	9.5	-	-	$ 8.44	-	-
Put(1)	14.2	-	-	$ 7.70	-	-
Put(1)	2.8	-	-	$ 7.78	-	-
Put(1)	4.7	-	-	$ 7.87	-	-
Put(1)	4.7	-	-	$ 7.72	-	-
Collar	2.8	-	-	$ 9.23	$ 7.65	-
Collar	2.8	-	-	$ 9.50	$ 7.91	-
Collar	5.7	-	-	$ 9.60	$ 7.91	-
Swap	3.8	-	-	-	-	$ 7.86
April 1, 2009 - October 31, 2010						
Swap(1)	23.7	-	-	-	-	$ 7.33
November 1, 2009 - March 31, 2010						
Put(1)	9.5	-	-	$ 8.97	-	-
Put(1)	2.8	-	-	$ 9.07	-	-
Put(1)	9.5	-	-	$ 9.06	-	-
Call(1)	4.7	-	$ 12.13	-	-	-
2009 - 2010						
Physical	2.0	-	-	-	-	$ 2.67

(1) Financial contracts entered into during the fourth quarter of 2008.

The following sensitivities show the impact to after-tax net income of the respective changes in forward crude oil and natural gas prices as at December 31, 2008 on the Fund's outstanding commodity derivative contracts at that time with all other variables held constant:

	Increase / (decrease) to after-tax net income	
($ thousands)	25% decrease in forward prices	25% increase in forward prices
Crude oil derivative contracts	$ 19,157	$ (19,839)
Natural gas derivative contracts	$ 29,565	$ (27,481)

Electricity Instruments:

The Fund has entered into electricity swaps that fix the price of electricity. These contracts are classified as held-for-trading and are reported at fair value. At December 31, 2008 the fair value of these contracts represented an asset of $348,000 and the change in fair value of these contracts during 2008 represented an unrealized loss of $103,000.

Unrealized gains or losses resulting from changes in fair value along with realized gains or losses on settlement of the electricity contracts are recognized as operating costs.

The following table summarizes the Fund's electricity management positions at February 18, 2009.

Term	Volumes MWh	Price CDN$/MWh
January 1, 2009 - December 31, 2009	4.0	$74.50
January 1, 2009 - December 31, 2010	4.0	77.50

Currency Risk

The Fund is exposed to currency risk in relation to its U.S. dollar cash balances and U.S. dollar denominated senior unsecured notes. The Fund generally maintains a minimal amount of U.S. dollar cash and manages the currency risk relating to the senior unsecured notes through the currency derivative instruments that are detailed below.

Cross Currency Interest Rate Swap ("CCIRS")

Concurrent with the issuance of the US$175,000,000 senior notes on June 19, 2002, the Fund entered into a CCIRS with a syndicate of financial institutions. Under the terms of the swap, the amount of the notes was fixed for purposes of interest and principal payments at a notional amount of CDN$268,328,000. Interest payments are made on a floating rate basis, set at the rate for three-month Canadian bankers' acceptances, plus 1.18%.

Foreign Exchange Swaps

In September 2007 the Fund entered into foreign exchange swaps on US$54,000,000 of notional debt at an average CDN/US foreign exchange rate of 0.98. These foreign exchange swaps mature between October 2011 and October 2015 in conjunction with the principal repayments on the US$54,000,000 senior notes.

The following sensitivities show the impact to after-tax net income of the respective changes in the period end and applicable forward foreign exchange rates as at December 31, 2008, with all other variables held constant:

	Increase/(decrease) to after-tax net income	
($ thousands)	25% decrease in $CDN relative to $US	25% increase in $CDN relative to $US
Translation of US$54 million senior notes	$ (11,582)	$ 11,582
Translation of US$175 million senior notes	(38,099)	38,099
Total	$ (49,681)	$ 49,681

	Increase/(decrease) to after-tax net income	
	25% decrease in $CDN relative	25% increase in $CDN relative

($ thousands)	to $US	to $US
Foreign exchange swaps	$ 9,513	$ (9,840)
Cross currency interest rate swap(1)	34,183	(34,186)
Total	$ 43,696	$ (44,026)

(1) Represents change due to foreign exchange rates only

Interest Rate Risk

The Fund's cash flows are impacted by fluctuations in interest rates as its outstanding bank debt carries floating interest rates and payments made under the CCIRS are based on floating interest rates. To manage a portion of interest rate risk relating to the bank debt, the Fund has entered into interest rate swaps on $120,000,000 of notional debt at rates varying from 3.70% to 4.61% that mature between June 2011 and July 2013.

If interest rates change by 1%, either lower or higher, on our variable rate debt outstanding at December 31, 2008 with all other variables held constant, the Fund's after-tax net income for a quarter would change by $927,000.

The following sensitivities show the impact to after-tax net income of the respective changes in the applicable forward interest rates as at December 31, 2008, with all other variables held constant:

	Increase/(decrease) to after-tax net income	
($ thousands)	25% decrease in forward interest rates	25% increase in forward interest rates
Interest rate swaps	$ (990)	$ 990
Cross currency interest rate swap(1)	3,451	(3,451)
Total	$ 2,461	$ (2,461)

(1) Represents change due to interest rates only

ii. Credit Risk

Credit risk represents the financial loss the Fund would experience due to the potential non-performance of counterparties to our financial instruments. The Fund is exposed to credit risk mainly through its joint venture, marketing and financial counterparty receivables.

The Fund mitigates credit risk through credit management techniques, including conducting financial assessments to establish and monitor a counterparty's credit worthiness, setting exposure limits, monitoring exposures against these limits and obtaining financial assurances such as letters of credit, parental guarantees, or third party credit insurance where warranted. The Fund monitors and manages its concentration of counterparty credit risk on an ongoing basis.

The Fund's maximum credit exposure at the balance sheet date consists of the carrying amount of its non-derivative financial assets as well as the fair value of its derivative financial assets. At December 31, 2008 approximately 95% of our marketing receivables were with companies considered investment grade or just below investment grade. This level of credit concentration is typical of oil and gas companies of our size producing in similar regions.

At December 31, 2008 approximately $7,453,000 or 5% of our total accounts receivable are aged over 120 days and considered past due. The majority of these accounts are due from various joint venture partners. The Fund actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production or net paying when the accounts are with joint venture partners. Should the Fund determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If the Fund subsequently determines an account is uncollectible the account is written off with a corresponding charge to the allowance account. The Fund's allowance for doubtful accounts balance at December 31, 2008 is $5,352,000 which includes a $2,500,000 provision made during during the year. There were no accounts written off during the year.

iii. Liquidity Risk & Capital Management

Liquidity risk represents the risk that the Fund will be unable to meet its financial obligations as they become due. The Fund mitigates liquidity risk through actively managing its capital, which it defines as long-term debt (net of cash) and unitholders' capital. Enerplus' objective is to provide adequate short and longer term liquidity while maintaining a flexible capital structure to sustain the future development of the business. The Fund strives to balance the portion of debt and equity in its capital structure given its current oil and gas assets and planned investment opportunities.

Management monitors a number of key variables with respect to its capital structure, including debt levels, capital spending plans, distributions to unitholders, access to capital markets, as well as acquisition and divestment activity.

Debt Levels

The Fund commonly measures its debt levels relative to its "debt-to-cash flow ratio" which is defined as long-term debt (net of cash) divided by the trailing twelve month cash flow from operating activities. The debt to-cash flow ratio represents the time period, expressed in years, it would take to pay off the debt if no further capital investments were made or distributions paid and if cash flow from operating activities remained constant.

At December 31, 2008 the debt to cash flow ratio was 0.5x (December 31, 2007 - 0.8x). Enerplus' bank credit facilities and senior debenture covenants carry a maximum debt-to-cash flow ratio of 3.0x including cash flow from acquisitions on a pro-forma basis. Traditionally Enerplus has managed its debt levels such that the debt-to-cash flow ratio has been below 1.5x, which has provided flexibility in pursuing acquisitions and capital projects. Enerplus' five-year history of debt to cash flow is illustrated below:

	2008	2007	2006	2005	2004
Debt-to-Cash Flow Ratio	0.5x	0.8x	0.8x	0.8x	1.1x

At December 31, 2008 Enerplus had additional borrowing capacity of $1,019,112,000 under its $1,400,000,000 bank credit facility. Enerplus does not have any subordinated or convertible debt outstanding at this time.

Capital Spending Plans

In 2009 Enerplus expects to spend approximately $300,000,000 on development capital activities. A portion of this capital spending is considered discretionary. There are limitations to changing the capital spending plans during a year as long project lead times, economies of scale, logistical considerations and partner commitments reduce the ability to adjust or down-size the capital program. Alternatively, the ability to rapidly increase spending may be limited by staff capacity, availability of services and equipment, access to sites, and regulatory approvals.

Distributions to Unitholders

Enerplus distributes a portion of its cash flow to its unitholders every month. These distributions are not guaranteed and the board of directors can change the amount at any time. During periods of sustained commodity price declines, distributions have been reduced. Similarly, in periods of sustained higher commodity prices, distributions have increased. To the extent that cash flow exceeds distributions additional funds are available to reduce debt, invest in capital development programs or finance acquisitions. The less cash required to finance these activities typically means more cash available for distributions and vice versa.

By paying distributions, we effectively earn a tax deduction against the corporate taxes in our underlying subsidiaries and pass along the Canadian tax liability to our unitholders. If distributions are lowered and too much cash flow is retained within the structure there is a risk that tax obligations in the operating entities may be created thereby eroding the flow-through advantage of the trust structure.

Access to Capital Markets

Enerplus relies on both the debt and equity markets to manage its cost of capital and fund future opportunities. There are times when the cost and access to these markets will vary. For example, the ability to issue new equity at a reasonable cost is strongly influenced by the equity market's perceptions of energy prices, macroeconomic factors, and Enerplus' future prospects. Similarly, the ability to increase bank credit or issue debentures is dependent on the overall state of the credit markets, as well as creditors' perceptions of the energy sector and Enerplus' credit quality. We intend to manage our distribution levels and capital spending in order to minimize increases in our debt levels and preserve our balance sheet strength for future acquisitions.

Enerplus currently has an NAIC2 rating on the senior unsecured notes in the U.S. private debt markets.

Acquisition & Divestment Activity

In periods of market uncertainty and volatility, it is important to have a conservative balance sheet and access to capital markets to take advantage of acquisition opportunities as they arise. The Fund attempts to manage its capital in a manner that reflects the likelihood and magnitude of potential acquisitions and/or opportunities to dispose of non-core assets.

Enerplus was successful in disposing of its Joslyn interest during the third quarter of 2008. The net proceeds of $502.0 million were used to repay debt, reinforcing Enerplus' borrowing capacity and enhancing the ability to fund future capital spending and acquisition activity.

Liability Maturity Analysis

It is Enerplus' intention to renew the bank credit facility before or as it comes due. Similarly, Enerplus expects that the senior unsecured notes will be replaced with new notes or bank debt as they become due. Enerplus cannot currently predict with any certainty the terms or rates at which senior unsecured notes or bank debt will be obtained but we expect such terms and rates may be less favourable than current terms. Over the long-term, Enerplus expects to balance short-term credit requirements with bank debt and to look to the term debt markets for longer-term credit support.

13. COMMITMENTS AND CONTINGENCIES

(a) Pipeline Transportation

Enerplus has contracted to transport 143 MMcf/day of natural gas on the TransCanada system in Alberta, 70 MMcf/day on TransGas in Saskatchewan, 48 MMcf/day in B.C.via Spectra, as well as 9 MMcf/day on the Alliance pipeline to the U.S. midwest.

In addition, Enerplus has a contract to transport a minimum of 2,480 bbls/day of crude oil from field locations to suitable marketing sales points within western Canada.

(b) Office Lease

Enerplus has office lease commitments for both its Canadian and U.S. operations that expire in 2014 and 2011 respectively. Annual costs of these lease commitments include rent and operating fees.

(c) Guarantees

(i) Corporate indemnities have been provided by the Fund to all directors and certain officers of its subsidiaries and affiliates for various items including, but not limited to, all costs to settle suits or actions due to their association with the Fund and its subsidiaries and/or affiliates, subject to certain restrictions. The Fund has purchased directors' and officers' liability insurance to mitigate the cost of any potential future suits or actions. Each indemnity, subject to certain exceptions, applies for so long as the indemnified person is a director or officer of one of the Fund's subsidiaries and/or affiliates. The maximum amount of any potential future payment cannot be reasonably estimated.

(ii) The Fund may provide indemnifications in the normal course of business that are often standard contractual terms to counterparties in certain transactions such as purchase and sale agreements. The terms of these indemnifications will vary based upon the contract, the nature of which prevents the Fund from making a reasonable estimate of the maximum potential amounts that may be required to be paid. Management believes the resolution of these matters would not have a material adverse impact on the Fund's liquidity, consolidated financial position or results of operations.

Enerplus has the following minimum annual commitments including the Fund's principal maturity analysis for the Fund's non-derivative financial liabilities at December 31, 2008:

($ thousands)	Total	Minimum Annual Commitment Each Year 2009	2010	2011
Accounts Payable(1)	$ 272,818	$272,818	$ -	$ -
Distributions payable to unit-holders(2)	41,397	41,397	-	-
Bank credit facility	380,888	-	380,888	-
Senior unsecured notes(3)	323,210	-	53,666	64,642
Pipeline commitments	62,747	18,850	11,782	9,091
Processing commitments	25,568	7,578	7,677	7,307
Office leases	69,586	8,730	11,736	12,478
Total commitments	$1,176,214	$349,373	$465,749	$93,518

($ thousands)	Minimum Annual Commitment Each Year 2012	2013	Total Committed after 2013
Accounts Payable(1)	$ -	$ -	$ -
Distributions payable to unit-holders(2)	-	-	-
Bank credit facility	-	-	-
Senior unsecured notes(3)	64,642	64,642	75,618
Pipeline commitments	6,751	5,369	10,904
Processing commitments	3,006	-	-
Office leases	12,563	12,563	11,516
Total			

commitments	$ 86,962	$82,574	$98,038

(1) Accounts payable are generally settled between 30 and 90 days from the balance sheet date.
(2) Distributions payable to unitholders are paid on the 20th day of the month following the balance sheet date.
(3) Includes the economic impact of derivative instruments directly related to the senior unsecured notes (CCIRS and foreign exchange swap - see Note 12).

In addition, the Fund is involved in claims and litigation arising in the normal course of business. The resolution of these claims is uncertain and there can be no assurance they will be resolved in favour of the Fund; however, management believes the resolution of these matters would not have a material adverse impact on the Fund's liquidity, consolidated financial position or results of operations.

14. GEOGRAPHICAL INFORMATION

As at December 31, 2008

($ thousands)	Canada	U.S.	Total
Oil and gas revenue	$ 1,968,865	$ 363,019	$ 2,331,884
Capital assets	4,552,482	694,515	5,246,998
Goodwill	451,120	182,903	634,023

As at December 31, 2007

($ thousands)	Canada	U.S.	Total
Oil and gas revenue	$ 1,252,413	$ 286,740	$ 1,539,153
Capital assets	3,293,413	579,405	3,872,818
Goodwill	47,532	147,580	195,112

5 YEAR DETAILED STATISTICAL REVIEW

($ thousands, except per unit amounts)	2008	2007	2006	2005	2004
Financial					
Oil and gas sales(1)	$2,370,668	$1,464,214	$1,569,487	$1,413,734	$ 989,266
Cash flow from operating activities	1,262,782	868,548	863,696	774,633	555,060
Cash distributions to unitholders	786,138	646,835	614,340	498,205	423,311
Per unit	4.89	5.04	5.04	4.47	4.20
Cash withheld for acquisitions and Capital Expenditures	476,644	221,713	249,356	276,428	113,248
Development					

capital spending	577,739	387,165	491,226	368,689	206,874
Acquisitions	1,772,826	274,244	51,313	704,028	636,326
Divestments	504,859	9,572	21,127	66,511	31,742
Total net capital expenditures	1,856,305	658,327	526,387	1,010,549	813,636
Total assets	6,230,132	4,303,130	4,203,804	4,130,623	3,180,748
Long-term debt, net of cash	657,421	724,975	679,650	649,825	584,991
Payout ratio(2)	62%	74%	71%	64%	76%
Net debt/cash flow ratio	0.5x	0.8x	0.8x	0.8x	1.1x

Trust Unit Trading Information					
Toronto Stock Exchange trading summary					
Close	$23.96	$39.87	$50.68	$55.86	$43.60
Volume	127.679	96,898	82,120	62,278	52,821
New York Stock Exchange trading summary					
Close	$19.58	$40.05	$43.61	$47.98	$36.31
Volume	97.164	54.192	81,677	70,454	67,570
Weighted average number of units outstanding (basic)	160,589	127,691	121,588	109,083	99,273
Number of units outstanding at December 31	165,590	129,813	123,151	117,539	104,124

Average Benchmark Pricing					
AECO natural gas (per Mcf)	$8.13	$6.61	$6.99	$8.48	$6.79
NYMEX natural gas (US$ per Mcf)	8.93	6.92	7.26	8.55	6.09
WTI crude oil (US$ per bbl)	99.65	72.34	66.22	56.56	41.40
CDN$/US$ exchange rate	0.94	0.93	0.88	0.83	0.77

($ per BOE except percentage data)

Oil and Gas Economics					
Net royalty rate	19%	19%	19%	19%	21%
Weighted average price(3)	$65.79	$50.48	$50.23	$52.36	$40.90
Hedging(4)	(2.94)	0.45	(1.10)	(4.90)	(3.50)

Weighted average price(1)	62.85	50.93	49.13	47.46	37.40
Net royalty expense	12.27	9.49	9.36	10.21	8.40
Operating expense (4)	9.51	9.11	8.02	7.45	7.14
Operating netback	41.07	32.33	31.75	29.80	21.86
General and administrative expense(4)	1.68	1.98	1.71	1.28	1.06
Management fee	-	-	-	-	-
Interest expense, net of interest and other income (4)	0.91	1.37	0.95	0.51	0.68
Foreign exchange(4)	0.68	0.06	(0.02)	0.13	(0.01)
Taxes	0.65	0.77	0.70	0.31	0.24
Restoration and abandonment cash costs	0.52	0.54	0.37	0.27	0.25
Cash flow before changes in non-cash working capital	$36.63	$27.61	$28.04	$27.30	$19.64

(1) Net of commodity derivative instruments and transportation
(2) Calculated as cash distributions to unitholders divided by cash flow from operating activities
(3) Net of transportation and before the effects of commodity derivative instruments
(4) Does not include non-cash portion of expense

OPERATIONAL STATISTICS

The following information outlines Enerplus' gross average daily production volumes for the years indicated and our Company interest reserves based upon forecast prices and costs at December 31 each year.

	2008(1)	2007(1)	2006(1)	2005(1)	2004(1)
Daily Production					
Oil Sands	n/a	n/a	n/a	n/a	n/a
Crude Oil (bbls/day)	35,434	34,506	36,134	29,315	25,550
NGLs (bbls/day)	4,529	4,104	4,483	4,689	4,398
Natural Gas (Mcf/day)	346,439	262,254	270,972	274,336	271,091
BOE per day	97,702	82,319	85,779	79,727	75,130
Drilling Activity (net wells)	643	252	361	393	367
Success Rate	99%	99%	99%	99%	99%

Production Replacement	78%	90%	82%	247%	384%
Proved Reserves(2)					
Oil Sands	-	8,568	8,730	9,453	n/a
Crude Oil (Mbls)	127,692	125,238	125,048	129,745	104,408
NGLs (Mbbls)	13,052	11,785	12,690	13,084	12,776
Natural Gas (MMcf)	1,066,534	866,077	920,061	965,776	971,598
MBOE	318,500	289,937	299,812	313,245	279,117
Probable Reserves(2)					
Oil Sands	-	54,930	47,998	43,700	47,747
Crude Oil (Mbls)	38,931	35,504	34,421	31,567	26,783
NGLs (Mbbls)	4,765	3,827	3,777	3,539	3,292
Natural Gas (MMcf)	421,134	336,214	344,025	342,518	295,698
MBOE	113,885	150,297	143,533	135,892	127,105
Proved Plus Probable Reserves(2)					
Oil Sands	-	63,498	56,728	53,153	47,747
Crude Oil (Mbls)	166,623	160,742	159,469	161,312	131,191
NGLs (Mbbls)	17,817	15,612	16,467	16,623	16,068
Natural Gas (MMcf)	1,487,668	1,202,291	1,264,086	1,308,294	1,267,296
MBOE	432,385	440,234	443,345	449,137	406,222
Reserve Life Index(3)					
Without Oil Sands:					
Proved (years)	9.4	10.0	9.8	9.6	10.1
Proved Plus Probable (years)	12.1	12.8	12.2	12.0	12.4
With Oil Sands:					
Proved (years)	9.4	10.3	10.1	9.9	10.1
Proved Plus Probable (years)	12.1	14.8	14.0	13.5	14.0

(1) Reserve information reflects NI 51-101 reporting methodology.
(2) Company interest reserves consist of gross revenues (as defined in National Instrument 51-101) plus Enerplus' royalty interests. Company interest reserves are not a term defined in National Instrument 51-101 and may not be comparable to reserves disclosed by other issuers.
(3) The Reserve Life Indices (RLI) are based upon year-end proved plus

probable reserves divided by the following year's proved and proved plus probable production volumes as determined in the independent reserve engineering reports.

PRODUCTION AND RESERVES PER TRUST UNIT

Production and reserves per unit are one measure of sustainability however they do not differentiate between the various commodity types and the quality of the reserves. When adjusted for debt and distributions it also provides an ability to compare results between our distributing model with other more traditional oil and gas entities that generally reinvest the majority of their cash flow into exploration and development activities. Our 2008 metrics have been impacted by the acquisition of Focus Energy Trust, the divestment of our Joslyn oil sands lease and negative reserve revisions.

Production per debt-adjusted trust unit is measured in respect of the average daily production for the year, and the weighted average number of trust units outstanding during the year. The measurements are then debt-adjusted by assuming additional trust units are issued at quarter-end unit prices to replace long-term debt outstanding at each quarter-end. The average number of trust units created over the four quarters is then added to the weighted average number of trust units to obtain the debt-adjusted number of trust units for the year. To distribution-adjust the metric, we utilized the amount of cash distributions paid each month and retired units using the quarter-end trust unit price thereby lowering the total number of units outstanding.

In 2008, our production per debt and distribution-adjusted unit declined by 6% due to the units issued as compared to the production added as a result of the Focus acquisition.

Production per Debt and Distribution-Adjusted Trust Unit	2008	2007	2006
Average daily production	95,687	82,319	85,779
Debt-adjusted weighted average trust units (000's)	182,401	142,666	132,208
Production per debt-adjusted trust unit (BOE/unit)	0.192	0.211	0.237
Production per debt and distribution adjusted trust unit (BOE/unit)	0.368	0.392	0.390

Reserves per debt-adjusted trust unit are measured in respect of year-end proved plus probable reserves and the number of units outstanding at year-end. To eliminate the temporary timing effects of financing decisions, we have debt-adjusted these measurements by assuming we issue additional trust units at year-end prices to replace year-end long-term debt. To distribution-adjust the metric, we utilized the amount of cash distributions paid to unitholders throughout the year and retired units using the year-end trust unit price thereby lowering the total number of units outstanding.

During 2008 our reserves per debt and distribution-adjusted unit declined 25% compared to the prior year. This was a significant change compared to historic performance. Approximately 10% of the decline was directly attributable to the methodology associated with using a lower unit price at year end to convert debt to units. As a result, additional notional trust units were required to replace long term debt, which negatively affects the debt and distribution-adjusted calculation. A further 7% of the decrease was a result of fewer net reserve additions associated with our capital development program. Our Focus acquisition and Joslyn disposition also reduced our debt and distribution-adjusted reserves per unit by 5% and 3% respectively. Focus was a strategic acquisition with significant development opportunity. Although Joslyn decreased our reserves per debt and distribution-adjusted unit, these reserves were lower quality bitumen which would have required significant future capital. Furthermore, the Joslyn disposition increased our net asset value and balance sheet strength.

Reserves per Debt and Distribution-Adjusted Trust Unit	2008	2007	2006
Year-end proved plus probable reserves	432,385	440,234	443,345
Debt-adjusted trust units outstanding at year end (000's)	193,029	147,997	136,562
Reserves per debt-adjusted trust unit (BOE/unit)	2.24	2.97	3.25
Reserves per debt and distribution adjusted trust unit (BOE/unit)	4.09	5.43	5.32

INFORMATION REGARDING DISCLOSURE IN THIS NEWS RELEASE AND OIL AND GAS RESERVES, RESOURCES AND OPERATIONAL INFORMATION

All amounts in this news release are stated in Canadian dollars unless otherwise specified.

Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE. The BOE rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. Use of BOE in isolation may be misleading. In accordance with Canadian practice, production volumes and revenues are reported on a gross basis, before deduction of Crown and other royalties, unless otherwise stated. Unless otherwise specified, all reserves volumes in this news release (and all information derived therefrom) are based on "company interest reserves" using forecast prices and costs. "Company interest reserves" consist of "gross reserves" (as defined in National Instrument 51-101 adopted by the Canadian securities regulators ("NI 51-101") plus Enerplus' royalty interests in reserves. "Company interest reserves" are not a measure defined in NI 51-101 and does not have a standardized meaning under NI 51-101. Accordingly, our company interest reserves may not be comparable to reserves presented or disclosed by other issuers. Our oil and gas reserves statement for the year ended December 31, 2008, which will include complete disclosure of our oil and gas reserves and other oil and gas information in accordance with NI 51-101, will be contained within our Annual Information Form which will be available on our about March 16, 2009 on our website at www.enerplus.com and on our SEDAR profile at www.sedar.com. Additionally, the Annual Information Form will form part of our Form 40-F that will be filed with the SEC and available on www.sec.gov. Readers are also urged to review the Management's Discussion & Analysis and financial statements included in this news release for more complete disclosure on our operations.

This news release contains estimates of "contingent resources". "Contingent resources" are not, and should not be confused with, oil and gas reserves. "Contingent resources" are defined in the Canadian Oil and Gas

Evaluation Handbook (the "COGE Handbook") as "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage."

There is no certainty that Enerplus will produce any portion of the volumes currently classified as "contingent resources". The primary contingencies which currently prevent the classification of Enerplus' disclosed contingent resources associated with the Kirby oil sands project as reserves consist of current uncertainties around the specific scope and timing of the project development, proposed reliance on technologies that have not yet been demonstrated to be commercially applicable in oil sands applications, the prevailing commodity price environment, the uncertainty regarding marketing plans for production from the subject areas and improved estimation of project costs. Based on current information and market conditions, Enerplus believes that development of the Kirby project will proceed as described in this news release, although readers should consider the described uncertainties regarding SAGD expansion as described herein. However, there are a number of inherent risks and contingencies associated with the development of the Kirby project, including commodity price fluctuations, project costs, receipt of regulatory approvals and those other risks and contingencies described above and under "Risk Factors and Risk Management" in the Management's Discussion and Analysis section of this news release and under "Risk Factors" in the Fund's Annual Information Form (and corresponding Form 40-F) dated March 13, 2008, as well as the risk factors to be contained in the Fund's Annual Information Form (and corresponding Form 40-F) to be filed in mid-March 2009.

NOTICE TO U.S. READERS

The oil and natural gas reserves contained in this Annual Information Form has generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects of United States or other foreign disclosure standards. For example, the United States Securities and Exchange Commission (the "SEC") currently generally permits oil and gas issuers, in their filings with the SEC, to disclose only proved reserves (as defined in SEC rules). Canadian securities laws require oil and gas issuers, in their filings with Canadian securities regulators, to disclose not only proved reserves (which are defined differently from the SEC rules) but also probable reserves, each as defined in NI 51-101. Accordingly, proved reserves disclosed in this news release may not be comparable to U.S. standards, and in this news release, Enerplus has disclosed reserves designated as "probable reserves" and "proved plus probable reserves". Probable reserves are higher risk and are generally believed to be less likely to be accurately estimated or recovered than proved reserves. The SEC's guidelines currently strictly prohibit reserves in these categories from being included in filings with the SEC that are required to be prepared in accordance with U.S. disclosure requirements. In addition, under Canadian disclosure requirements and industry practice, reserves and production are reported using gross (or, as noted above, "company interest") volumes, which are volumes prior to deduction of royalty and similar payments. The practice in the United States is to report reserves and production using net volumes, after deduction of applicable royalties and similar payments. Additionally, the SEC prohibits disclosure of oil and gas resources, whereas Canadian issuers may disclose resource volumes. Resources are different than, and should not construed as reserves. For a description of the definition of, and the risks and uncertainties surrounding the disclosure of, contingent resources, see above.

FORWARD-LOOKING INFORMATION AND STATEMENTS

This news release contains certain forward-looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends", "budget", "strategy" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this news release contains forward-looking information and statements pertaining to the following: the volumes and estimated value of the Fund's oil and gas reserves; the life of the Fund's reserves; the volume and product mix of the Fund's oil and gas production; future oil and natural gas prices and the Fund's commodity risk management programs; the amount of future asset retirement obligations; future liquidity and financial capacity and capital resources; future results from operations and operating metrics; future costs, expenses and royalty rates; future interest costs; future development, exploration, acquisition and development activities (including drilling plans) and related capital expenditures, including with respect to both our conventional and oil sands activities and in particular the development of the Kirby lease; future acquisitions and dispositions; asset retirement obligations, the making and timing of future regulatory filings and applications; the value of the Fund's equity investments; future tax treatment of income trusts and future taxes payable by the Fund; the Fund's tax pools; the future trust or corporate structure of the Fund and its subsidiaries; the amount, timing and tax treatment of cash distributions to unitholders; and future payout ratios.

The forward-looking information and statements contained in this news release reflect several material factors and expectations and assumptions of the Fund including, without limitation: that the Fund will continue to conduct its operations in a manner consistent with past operations; the general continuance of current or, where applicable, assumed industry conditions; the continuance of existing (and in certain circumstances, the implementation of proposed) tax, royalty and regulatory regimes; the accuracy of the estimates of the Fund's reserve and resource volumes; certain commodity price and other cost assumptions; the continued availability of adequate debt and/or equity financing and cash flow to fund its capital and operating requirements as needed; and the extent of its liabilities. The Fund believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information and statements included in this news release are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information or statements including, without limitation: changes in commodity prices; changes in the demand for or supply of the Fund's products; unanticipated operating results or production declines; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in development plans the Fund or by third party operators of the Fund's properties, increased debt levels or debt service requirements; inaccurate estimation of the Fund's oil and gas reserve and resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; declines in the value of the Fund's equity investments; the impact of competitors; reliance on industry partners; and certain other risks detailed from time to time in the Fund's public disclosure documents (including, without limitation, those risks identified in this news release and in the Fund's Annual Information Form and Form 40-F described above).

The forward-looking information and statements contained in this news release speak only as of the date of this news release, and none of the Fund or its subsidiaries assumes any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable laws.

Gordon J. Kerr
President & Chief Executive Officer
Enerplus Resources Fund

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