

ener**PLUS**

is energy **PLUS** value.  
In 2012, we focused  
on maintaining  
financial flexibility  
**PLUS** streamlining our  
energy portfolio **PLUS**  
delivering meaningful  
organic growth.

# EN ERPL US

# 2012

ENERPLUS CORPORATION  
FINANCIAL SUMMARY

# PLUS

In a challenging market, Enerplus took prudent steps forward in 2012, by growing our production and reserves, improving the oil and liquids mix in our portfolio and increasing the funds flow our business generates. We also maintained financial flexibility throughout the year in response to weak natural gas prices and are well positioned to meet our operating goals for 2013.

Enerplus is a North American energy producer with a diversified asset base of high-quality, low-decline oil and gas assets, complemented by growth assets in resource plays with superior economics. We are focused on creating value for our investors through the successful development of our properties. We strive to provide investors with a competitive return comprised of both income and organic growth.

## Contents

Selected Financial and Operating Results	1	Supplemental Information	62
2012 Highlights	3	Abbreviations	72
Management's Discussion & Analysis	6	Definitions	73
Financial Statements	29	Board of Directors	75
Five-Year Detailed Statistical Review	60	Officers	76
		Corporate Information	77

# 2012 Summary

## Selected Financial and Operating Results

SELECTED FINANCIAL RESULTS	Three months ended December 31,		Twelve months ended December 31,	
	2012	2011	2012	2011
<b>Financial (000's)</b>				
Funds Flow	\$ 199,678	\$ 156,682	\$ 643,911	\$ 573,609
Cash and Stock Dividends	53,572	97,725	301,560	388,904
Net Income/(Loss)	(158,711)	(299,415)	(155,734)	109,437
Debt Outstanding – net of cash	1,064,365	901,465	1,064,365	901,465
Capital Spending	160,202	344,837	852,843	865,712
Property and Land Acquisitions	121,391	45,263	185,337	255,209
Property Dispositions	220,135	3,082	275,771	641,190
Asset Impairments	331,095	327,309	531,825	359,703
Asset Disposition gain/(loss)	59,440	(29)	131,166	302,053
Debt to Trailing 12 Month Funds Flow	1.7x	1.6X	1.7x	1.6X
<b>Financial per Weighted Average Shares Outstanding</b>				
Funds Flow	\$ 1.01	\$ 0.87	\$ 3.29	\$ 3.19
Net Income	(0.80)	(1.66)	(0.80)	0.61
Weighted Average Number of Shares Outstanding (000's)	198,256	180,845	195,633	179,889
<b>Selected Financial Results per BOE<sup>(1)</sup></b>				
Oil & Gas Sales <sup>(2)</sup>	\$ 45.86	\$ 50.29	\$ 44.56	\$ 48.85
Royalties	(9.54)	(9.62)	(8.95)	(8.92)
Commodity Derivative Instruments	2.04	(1.54)	0.61	(1.21)
Operating Costs	(9.24)	(11.64)	(10.53)	(10.33)
General and Administrative	(2.34)	(2.53)	(2.61)	(2.46)
Equity Based Compensation	(0.03)	(0.52)	(0.18)	(0.53)
Interest and Other Expenses	(1.44)	(1.70)	(1.42)	(1.59)
Taxes	0.08	(0.68)	(0.05)	(2.95)
<b>Funds Flow</b>	<b>\$ 25.39</b>	<b>\$ 22.06</b>	<b>\$ 21.43</b>	<b>\$ 20.86</b>

SELECTED OPERATING RESULTS	Three months ended December 31,		Twelve months ended December 31,	
	2012	2011	2012	2011
<b>Average Daily Production</b>				
Crude oil (bbls/day)	38,597	31,715	36,509	30,181
NGLs (bbls/day)	3,576	3,256	3,627	3,306
Natural gas (Mcf/day)	259,904	253,500	251,773	251,068
Total (BOE/day)	85,490	77,221	82,098	75,332
% Crude Oil & Natural Gas Liquids	49%	45%	49%	44%
<b>Average Selling Price<sup>(2)</sup></b>				
Crude oil (per bbl)	\$ 76.75	\$ 87.56	\$ 78.19	\$ 83.48
NGLs (per bbl)	47.31	68.32	53.01	64.99
Natural gas (per Mcf)	3.01	3.41	2.39	3.72
USD/CDN exchange rate	0.99	1.02	1.00	0.99
Net Wells drilled	11	36	75	107

(1) Non-cash amounts have been excluded.

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

	Three months ended December 31,		Twelve months ended December 31,	
	2012	2011	2012	2011
<b>Average Benchmark Pricing</b>				
WTI crude oil (US\$/bbl)	\$ 88.18	\$ 94.06	\$ 94.21	\$ 95.12
WTI crude oil: CDN\$ equivalent (CDN\$/bbl)	87.30	95.94	94.21	94.18
AECO natural gas – monthly index (CDN\$/Mcf)	3.06	3.47	2.40	3.68
AECO natural gas – daily index (CDN\$/Mcf)	3.22	3.17	2.39	3.62
NYMEX natural gas – monthly NX3 index (US\$/Mcf)	3.36	3.61	2.80	4.07
NYMEX natural gas – monthly NX3 index: CDN\$ equivalent (CDN\$/Mcf)	3.33	3.68	2.80	4.03
USD/CDN exchange rate	0.99	1.02	1.00	0.99

**Share Trading Summary**

For the twelve months ended December 31, 2012

	CDN* – ERF (CDN\$)	U.S.** – ERF (US\$)
High	\$ 26.94	\$ 26.54
Low	\$ 11.53	\$ 11.35
Close	\$ 12.90	\$ 12.96

\* TSX and other Canadian trading data combined.

\*\* NYSE and other U.S. trading data combined.

**2012 Dividends Per Share**

Payment Month

	CDN\$	US\$ <sup>(1)</sup>
First Quarter Total	\$ 0.54	\$ 0.54
Second Quarter Total	\$ 0.54	\$ 0.53
Third Quarter Total	\$ 0.27	\$ 0.27
Fourth Quarter Total	\$ 0.27	\$ 0.27
<b>Total Year-to-Date</b>	<b>\$ 1.62</b>	<b>\$ 1.61</b>

(1) US\$ dividends represent CDN\$ dividends converted at the relevant foreign exchange rate on the payment date.

# 2012 Highlights

## 4TH QUARTER HIGHLIGHTS:

- As a result of our successful capital development program, production volumes in the fourth quarter increased by 5% over the third quarter of 2012 averaging 85,490 BOE per day. When compared to the fourth quarter of 2011, total production volumes grew by 11%.
- Crude oil production in the fourth quarter was 22% higher than in the fourth quarter of 2011.
- Marcellus volumes also increased significantly, up 40% from the third quarter as production volumes previously delayed were brought on-stream.
- As a result of higher production volumes, stronger natural gas prices and lower expenses, funds flow increased by almost 50% from the third quarter of 2012 to approximately \$200 million (\$1.01 per share) for the fourth quarter. As a result of this increase in funds flow, our adjusted payout ratio (capital spending plus dividends net of participation in the Stock Dividend Program (“SDP”) improved significantly to 104%.
- Operating costs improved significantly during the quarter, down 25% to \$9.24 per BOE compared to the third quarter of 2012. General and administrative (“G&A”) costs continued to track under our guidance averaging \$2.34 per BOE.
- We continued to focus our capital spending activities on crude oil assets during the fourth quarter. We invested \$160 million in development capital, 70% of which was weighted to crude oil drilling 10.8 net wells with 16.5 net wells brought on-stream during the quarter.
- We continued to improve the focus and concentration of our portfolio during the quarter through the sale of non-core assets. In December, we sold non-core oil assets in Manitoba including approximately 1,600 BOE per day of production for approximately \$218 million. In addition, in December we consolidated our ownership in Montana through the purchase of an additional 20% working interest in the Sleeping Giant Bakken oil project for \$118 million, essentially replacing the volumes from the Manitoba sale. We realized net proceeds of \$100 million on these transactions.

## 2012 SUMMARY:

### OPERATIONS

- As a result of our successful development program in 2012, Enerplus grew annual average production by 9% to 82,098 BOE per day, in line with our guidance of 82,000 BOE per day. Average crude oil production increased by 21% to 36,509 bbls per day in 2012 and when combined with natural gas liquids, represented 49% of our total corporate volumes during the year. This growth was achieved mainly due to our success in Fort Berthold as well as positive results from our drilling and enhanced oil recovery project (“EOR”) in Medicine Hat, Alberta. U.S. natural gas production primarily from the Marcellus continued to grow throughout 2012, offsetting declines in our Canadian natural gas volumes. On average, our total natural gas production remained virtually unchanged at 252 MMcf per day during 2012.
- We also achieved exit production of approximately 85,800 BOE per day, within our guidance range of 85,000 BOE per day to 88,000 BOE per day. This is an increase of almost 5% over 2011 exit production rates.
- Our total capital spending in 2012 was in line with our guidance at approximately \$853 million. Approximately 72% of our spending was directed to our crude oil plays with the majority invested at Fort Berthold and in our Canadian crude oil assets. Approximately 85% of our capital spending was spent on drilling and completions in 2012 with 75 net wells drilled across all of our assets and 79 net wells brought on-stream.

### RESERVES/RESOURCES

- Total P+P company interest reserves grew by 7.4% to 345.8 MMBOE compared to 321.9 MMBOE at December 31, 2011.
- We added 57.3 MMBOE of P+P reserves as a result of our successful development program, replacing over 190% of production.
- P+P oil and liquids reserves grew by approximately 12% to 206 MMBOE and now represent 60% of our total P+P reserves, up from 57% at year-end 2011. Approximately 66% of the reserve additions were from crude oil and represented a 283% replacement of our 2012 oil production.
- P+P reserves at Fort Berthold increased by 53% from 2011 to 86.1 MMBOE. We replaced almost 800% of our production in 2012 through the addition of 34.2 MMBOE P+P reserves.
- Canadian oil reserves, which are largely comprised of crude oil waterflood properties, decreased by 8% to 91.6 MMbbls mainly due to the sale of 8.3 MMbbls of P+P reserves associated with our Manitoba assets. Through our successful development activities, we replaced 107% of Canadian oil production.

- We replaced 111% of our natural gas production in 2012 and grew our P+P natural gas reserves by approximately 2% to 837 Bcf. The majority of the increase is attributable to our Marcellus shale gas assets where we added 86 Bcf of P+P. Total Marcellus P+P reserves at year-end increased to 225 Bcf and represented 27% of our total P+P natural gas reserves, up from 19% in 2011.
- Our P+P reserve life index increased to 10.9 years at December 31, 2012, up from 9.8 years at December 31, 2011 as a result of the increase in reserves primarily associated with Fort Berthold and the Marcellus.

### Finding and Development Costs

- Our P+P F&D cost including FDC improved to \$24.21 per BOE in 2012 from \$26.26 per BOE in 2011.
- Excluding future development capital, our P+P F&D costs were \$14.88 per BOE.
- 60% of our reserve additions were attributable to Fort Berthold and were added at a cost of \$25.38 per BOE including FDC. The recycle ratio associated with these additions was 2.0 times.
- Our P+P Finding, Development and Acquisition (“FD&A”) cost including FDC was \$22.92 per BOE, reflecting the positive impact of our acquisition and divestment activities.
- Excluding FDC, our P+P FD&A cost was \$13.48 per BOE.

### Contingent Resources

- In addition to booked reserves, an assessment of our portfolio has identified economic best estimate contingent resources of 364 MMBOE, representing over 100% of our booked P+P reserves. Our contingent resources are comprised of:
  - 33.5 MMBOE of contingent resources attributable to both the Bakken and Three Forks at Fort Berthold. We converted 31.2 MMBOE of previously assessed contingent resources to reserves for the year and added 15.6 MMBOE of new contingent resources primarily associated with the Three Forks formation.
  - 60.3 MMBOE of contingent resources attributable to improved oil recovery (“IOR”) and EOR in our Canadian oil assets. We converted 7.1 MMBOE of previously assessed contingent resources to reserves and added 14.3 MMBOE of net new contingent resources associated with our EOR and IOR projects in our waterflood assets.
  - 1.3 Tcf of contingent resources in the Marcellus shale gas. This estimate has decreased from our contingent resource estimate of 2.3 Tcf one year ago due to a number of factors. Approximately 124 Bcf of contingent resources were reclassified as reserves during 2012. However, as a result of a decline in the gas price forecast and lower than expected performance on our operated acreage in Pennsylvania and West Virginia, the contingent resource estimate has been reduced in some areas and eliminated in others where the current economics do not support further development or lease extension of the acreage. We did see an increase in the contingent resource estimates assigned to our non-operated leases in northeast Pennsylvania due to improved performance.
  - 283 Bcf of contingent resources associated with our Wilrich deep gas assets in Canada were identified as a result of our successful drilling activities in 2012.

## FINANCIAL

- Despite the collapse in natural gas prices during 2012, funds flow for the year totaled \$644 million (\$3.29 per share), up 12% from 2011 due to higher oil production, improved netbacks as well as gains from our hedging program.
- We took a number of important steps in 2012 to maintain financial flexibility throughout this period of weak natural gas prices and widening crude oil differentials:
  - we raised \$331 million in proceeds from an equity offering in early 2012;
  - we closed a private placement of long-term notes in May for proceeds of \$405 million;
  - we reduced our monthly dividend from \$0.18 per share to \$0.09 per share in July;
  - we implemented the SDP to allow all of our shareholders the option to receive Enerplus shares instead of cash dividends;
  - we sold the majority of our equity interests, including our shares in Laricina Energy, for proceeds of \$147 million; and

- in aggregate, we generated proceeds of approximately \$200 million on our property divestment activities, net of acquisitions.
- As a result, we ended 2012 in a strong financial position with a debt to trailing 12 month funds flow ratio of 1.7 times, virtually unchanged from 2011. We had approximately \$740 million of unused capacity on our \$1 billion credit facility at December 31, 2012.
- We paid \$1.62 per share in dividends to our shareholders in 2012. Combining our capital spending with our dividends net of participation in the SDP and Dividend Reinvestment Plan (“DRIP”), our adjusted payout ratio improved to 174% for the year versus 212% in 2011. We expect our payout ratio to improve in 2013 as a result of a 20% reduction in our capital spending for the year and an improved outlook for natural gas prices.
- Our operating costs averaged \$10.64 per BOE during 2012 and G&A costs averaged \$2.61 per BOE, both in line with our guidance.
- We realized cash gains on our commodity hedging program of \$18.4 million for the year.
- During 2012, we recorded accounting impairments of \$418 million on our Developed and Producing (D&P) oil and gas assets due to a decline in commodity prices, primarily natural gas prices, and higher future development costs. We also recorded impairments of \$114 million on our Exploration and Evaluation assets during the year due to expiring undeveloped land and unrecoverable costs on discontinued projects. These asset impairments resulted in a net loss of \$156 million (\$0.80 per share) for 2012. The impairments do not impact our funds flow or cash flow. Should natural gas prices improve, we expect the value of our D&P assets to increase, which would positively impact net income in future periods.

# Management's Discussion and Analysis

## Management's Discussion and Analysis ("MD&A")

The following discussion and analysis of financial results is dated February 21, 2013 and is to be read in conjunction with the audited consolidated financial statements (the "Financial Statements") of Enerplus Corporation ("Enerplus" or the "Company"), as at and for the years ended December 31, 2012 and 2011.

All amounts are stated in Canadian dollars unless otherwise specified and all note references relate to the notes included with the Financial Statements. Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE and oil and natural gas liquids ("NGL") have been converted to thousand cubic feet of gas equivalent ("Mcf") based on 0.167 bbl:1 Mcfe. The BOE and Mcfe rates are based on an energy equivalent conversion method primarily applicable at the burner tip and do not represent a value equivalent at the wellhead. Given that the value ratio based on the current price of natural gas as compared to crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value. Use of BOE and Mcfe in isolation may be misleading. All production volumes are presented on a company interest basis, being the Company's working interest share before deduction of any royalties paid to others, plus the Company's royalty interests. Company interest is not a term defined in Canadian National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") and may not be comparable to information produced by other entities.

The following MD&A contains forward-looking information and statements. We refer you to the end of the MD&A under "Forward-Looking Information and Statements" for further information.

### NON-GAAP MEASURES

The Company utilizes the following terms for measurement within the MD&A that do not have a standardized meaning or definition as prescribed by IFRS and therefore may not be comparable with the calculation of similar measures by other entities:

**"Payout ratio"** is used to analyze operating performance, leverage and liquidity. We calculate payout ratio by dividing dividends to shareholders, net of our stock dividends and Dividend Reinvestment Plan ("DRIP") proceeds, by funds flow.

**"Adjusted payout ratio"** is used to analyze operating performance, leverage and liquidity. We calculate our adjusted payout ratio as dividends to shareholders, net of our stock dividends and DRIP proceeds, plus capital spending (including office capital) divided by funds flow.

**"Netback"** is used to evaluate operating performance of our crude oil and natural gas assets. The term netback is calculated as oil and gas sales revenue (net of transportation), less royalties and operating costs.

### 2012 FOURTH QUARTER OVERVIEW

We delivered significant production and funds flow growth in 2012 ending the year with strong fourth quarter results. Our funds flow improved due to higher production and an increased weighting to crude oil. Production was also strong in the fourth quarter as Marcellus wells, which had previously been delayed, were brought on-stream. Our annual average and exit production were within our guidance ranges. Overall our operating results were on track with expectation however net income was negatively impacted by non-cash impairments. We also added more focus to our asset base with the sale of our Manitoba assets for \$218.1 million and the acquisition of an additional interest in our Sleeping Giant property for \$117.6 million. Both assets had similar oil-weighted production. The net proceeds of approximately \$100 million went towards debt reduction. We exited the quarter with a strong balance sheet and a debt-to-funds flow ratio of 1.7 times.

### SUMMARY FOURTH QUARTER INFORMATION

In comparing the fourth quarter of 2012 with the same period in 2011:

- Average daily production was 85,490 BOE/day compared to 77,221 BOE/day in 2011. The increase was primarily due to higher production from our Fort Berthold crude oil properties and from our Marcellus natural gas properties. Our average daily production for the month of December was 85,800 BOE/day, which was within the range of our exit guidance of 85,000 - 88,000 BOE/day.

- Funds flow totaled \$199.7 million compared to \$156.7 million in 2011. Higher production and gains on our commodity derivative contracts helped to increase our funds flow.
- Cash operating expenses decreased to \$9.24/BOE compared to \$11.64/BOE in the prior year. In 2011 we had higher repairs and maintenance and well servicing activity as work had been delayed earlier in the year due to poor weather conditions and access to leases.
- Cash G&A expenses were consistent period over period. Equity based compensation expenses decreased to \$0.03/BOE from \$0.52/BOE in 2011 due to our lower share price in 2012.
- Capital spending decreased to \$160.2 million from \$344.8 million in 2011. Our fourth quarter capital spending was in line with expectations with the majority focused on our core growth areas, investing \$82.4 million on our Fort Berthold properties, \$29.5 million in the Marcellus, \$31.2 million on Canadian crude oil properties and \$16.5 million on Deep Gas properties in Canada.
- Property and land acquisitions were \$121.4 million compared to \$45.3 million in 2011. We purchased additional working interests in our Sleeping Giant crude oil property for \$117.6 million, representing production of approximately 1,550 BOE/day.
- Divestments totaled \$220.1 million compared to \$3.1 million in 2011. In the fourth quarter of 2012 we disposed of our Manitoba assets that were producing 1,600 BOE/day for proceeds of \$218.1 million. In conjunction with the sale we recognized a gain of \$59.7 million.
- We realized a net loss of \$158.7 million compared to a net loss of \$299.4 million in 2011. These losses are primarily due to asset impairments of \$331.1 million in 2012 and \$327.4 million in 2011. Impairments in both years related to our natural gas focused Canadian CGU's and reflect lower forecast natural gas prices along with increased forecasted future development costs in 2012.

## SELECTED QUARTERLY CANADIAN AND U.S. FINANCIAL RESULTS

(CDN\$ millions, except per unit amounts)	Three months ended December 31, 2012			Three months ended December 31, 2011		
	Canada	U.S.	Total	Canada	U.S.	Total
<b>Average Daily Production Volumes</b>						
Crude oil (bbls/day)	20,713	17,884	38,597	19,726	11,989	31,715
Natural gas liquids (bbls/day)	3,177	399	3,576	3,201	55	3,256
Natural gas (Mcf/day)	188,628	71,276	259,904	218,176	35,324	253,500
Total daily sales (BOE/day)	55,328	30,162	85,490	59,290	17,931	77,221
<b>Pricing<sup>(1)</sup></b>						
Crude oil (per bbl)	\$ 72.01	\$ 82.25	\$ 76.75	\$ 86.17	\$ 89.84	\$ 87.56
Natural gas liquids (per bbl)	48.09	41.08	47.31	68.83	38.31	68.32
Natural gas (per Mcf)	2.76	3.67	3.01	3.13	5.11	3.41
<b>Capital Expenditures</b>						
Capital spending	\$ 49.6	\$ 110.6	\$ 160.2	\$ 129.4	\$ 215.4	\$ 344.8
Property and land acquisitions	(0.2)	121.6	121.4	21.5	23.8	45.3
Property dispositions	(220.2)	–	(220.2)	(1.1)	(2.0)	(3.1)
<b>Revenues</b>						
Oil and gas sales <sup>(1)</sup>	\$ 199.8	\$ 160.9	\$ 360.7	\$ 240.9	\$ 116.4	\$ 357.3
Royalties <sup>(2)</sup>	(29.1)	(45.9)	(75.0)	(39.0)	(29.3)	(68.3)
Commodity derivative instruments gain/(loss)	17.7	–	17.7	(119.9)	–	(119.9)
<b>Expenses</b>						
Operating	\$ 58.6	\$ 13.9	\$ 72.5	\$ 72.1	\$ 10.9	\$ 83.0
General and administrative	14.8	3.6	18.4	14.6	3.4	18.0
Equity based compensation	5.2	0.3	5.5	6.0	0.4	6.4
Depletion, depreciation and amortization	76.5	54.8	131.3	89.8	31.1	120.9
Impairments/(reversals)	331.1	–	331.1	337.4	(10.1)	327.3
Current tax expense/(recovery)	(2.2)	1.5	(0.7)	0.6	4.3	4.9

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

(2) U.S. royalties include U.S. state production tax.

## 2012 OVERVIEW

We increased production by over 9% during 2012, averaging 82,098 BOE/day. We exited the year with production of approximately 85,800 BOE/day for the month of December. With our oil weighted capital program we successfully grew our crude oil production by 21%, resulting in a crude oil and liquids weighting of 49% compared to 44% in 2011.

Capital spending and operating costs were in line with expectations totaling \$852.8 million and \$10.64/BOE respectively. General and Administrative (“G&A”) expenses were consistent with our expectations at \$2.61/BOE however equity based compensation was lower than anticipated at \$0.51/BOE as we had reduced charges on our long term incentive plans.

Our funds flow for the year totaled \$643.9 million representing an increase of 12% over 2011. Although we experienced lower realized commodity prices in 2012, increased production and cash gains on our hedging contracts resulted in increased funds flow.

Lower commodity prices resulted in non-cash impairments of \$418.0 million on our developed and producing assets for the year. We also recorded non-cash impairments of approximately \$113.8 million on our exploration and evaluation assets primarily due to land expirations on our less prospective acreage. Although these impairments affect net income they do not impact funds flow or cash flow from operating activities.

We continued to enhance our asset base during 2012 with our acquisition and disposition activities. In the fourth quarter we disposed of oil assets in Manitoba with production of approximately 1,600 BOE/day for proceeds of \$218.1 million. Concurrent with this transaction we purchased additional working interests, representing production of approximately 1,550 BOE/day in our Sleeping Giant, Montana crude oil property for \$117.6 million, increasing our total working interest in this property to 90%.

During 2012 we completed a number of initiatives to preserve our financial flexibility given our capital spending plans and the low natural gas price environment. In the first half of 2012 we completed an equity offering raising net proceeds of \$331 million and also closed a private placement of senior notes for proceeds of approximately \$405 million with maturities extending out 12 years. In July we reduced our monthly dividend to \$0.09/share from \$0.18/share and introduced a new Stock Dividend Program (“SDP”) to provide additional liquidity. We also sold the majority of our equity investment portfolio during the year for cash proceeds of \$146.9 million. Our payout ratio and adjusted payout ratios decreased to 40% and 174% respectively, from 59% and 212% in 2011 after taking into account the stock dividend program but before acquisitions and divestments. At December 31, 2012 we had approximately \$739 million of available credit on our bank credit facility and a conservative trailing twelve month debt to funds flow ratio of 1.7x.

## RESULTS OF OPERATIONS

### Production

Production for 2012 was in-line with our expectations averaging 82,098 BOE/day, representing an increase of 9% from production of 75,332 BOE/day in 2011. Our crude oil production increased by 21% over 2011 mainly due to our capital development program which was targeted to increase production at our Fort Berthold, North Dakota crude oil property. Natural gas volumes were relatively flat year-over-year as increased volumes from our Marcellus assets offset production declines on our conventional natural gas assets in Canada. Our average daily production for the month of December was approximately 85,800 BOE/day, within our anticipated exit range of 85,000 to 88,000 BOE/day.

Our crude oil and liquids production weighting increased to 49% for 2012, up from 44% in 2011. We expect a crude oil and liquids weighting of approximately 50% in 2013. Average daily production volumes for the twelve months ended December 31, 2012 and 2011 are outlined below:

Average Daily Production Volumes	2012	2011	% Change
Crude oil (bbls/day)	36,509	30,181	21%
Natural gas liquids (bbls/day)	3,627	3,306	10%
Natural gas (Mcf/day)	251,773	251,068	–
Total daily sales (BOE/day)	82,098	75,332	9%

In 2013 we have reduced our capital spending plans by approximately 20% from 2012 levels given the continued weakness in natural gas prices. As a result we expect our 2013 production to average between 82,000 BOE/day and 85,000 BOE/day, which at the mid-point of the range would represent a 2% increase over our 2012 average daily production. This guidance does not contemplate future acquisitions or dispositions.

## Pricing

The prices received for our crude oil and natural gas production directly impact our earnings, funds flow and financial condition. The following table compares our average selling prices for 2012 with those of 2011. It also compares the benchmark price indices for the same periods.

Average Selling Price <sup>(1)</sup>	2012	2011	% Change
Crude oil (per bbl)	\$ 78.19	\$ 83.48	(6)%
Natural gas liquids (per bbl)	53.01	64.99	(18)%
Natural gas (per Mcf)	2.39	3.72	(36)%
Per BOE	44.56	48.85	(9)%

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

Average Benchmark Pricing	2012	2011	% Change
WTI crude oil (US\$/bbl)	\$ 94.21	\$ 95.12	(1)%
WTI crude oil CDN\$ equivalent (CDN\$/bbl)	94.21	94.18	–
AECO natural gas – monthly index (CDN\$/Mcf)	2.40	3.68	(35)%
AECO natural gas – daily index (CDN\$/Mcf)	2.39	3.62	(34)%
NYMEX natural gas – monthly NX3 index (US\$/Mcf)	2.80	4.07	(31)%
NYMEX natural gas – monthly NX3 index CDN\$ equivalent (CDN\$/Mcf)	2.80	4.03	(31)%
US/CDN exchange rate	1.00	0.99	1%

Average Differentials (US\$/bbl or US\$/Mcf)	Twelve months ended						
	2012	2011	Q4 2012	Q3 2012	Q2 2012	Q1 2012	Q4 2011
MSW Edmonton – WTI	\$ (7.79)	\$ 1.33	\$ (3.32)	\$ (7.21)	\$ (10.12)	\$ (10.49)	\$ 1.43
WCS Hardisty – WTI	(21.03)	(17.15)	(18.11)	(21.72)	(22.87)	(21.42)	(10.48)
Brent Futures (ICE) – WTI	17.45	15.72	21.81	17.22	15.38	15.40	14.88
AECO monthly – NYMEX	(0.39)	(0.32)	(0.31)	(0.60)	(0.40)	(0.23)	(0.16)

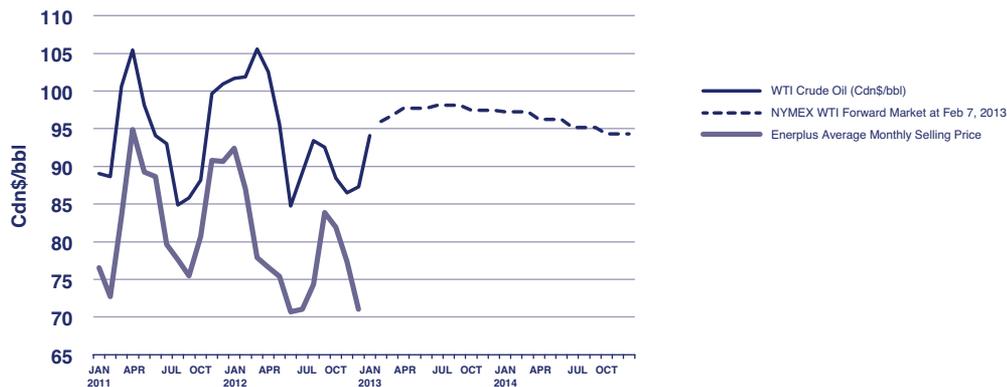
### Crude Oil and Natural Gas Liquids

Crude oil prices started the year at an average price of US\$100.32/bbl in January and finished the year at an average price of US\$88.25/bbl in December. Globally, threats to supply from the continued unrest in the Middle East and low European crude inventories continued to support prices while weak economic conditions negatively impacted prices. The West Texas Intermediate (“WTI”) benchmark price experienced downward pressure relative to Brent prices as the take away capacity at Cushing could not keep pace with rising production and deliveries to the region.

Crude differentials widened in 2012 as supply out of Canada and the U.S. Bakken continued to grow. Year-over-year, light differentials for Mixed Sweet Blend (“MSW”) at Edmonton were US\$9.12/bbl wider, while heavy differentials for Western Canada Select (“WCS”) at Hardisty widened by US\$3.88/bbl. Enerplus’ 2012 weighted average crude oil stream differential to WTI represented a discount of US\$15.11/bbl compared to US\$9.28/bbl in 2011. Downtime at refineries in the spring of 2012 caused differentials to widen significantly, however they did start to recover later in the year with supply cuts from oil sands upgraders and increases in North American rail transportation capacity. Pipeline capacity continues to be a concern with high apportionment levels on a number of lines out of Western Canada. We expect these wide differentials to persist until late 2013 and perhaps longer as we await both new pipeline and heavy refining capacity to come on line.

The average price received for our crude oil (net of transportation costs) was \$78.19/bbl for 2012, a 6% decrease over 2011. In comparison, the WTI benchmark decreased by 1% over the same period. The difference between the change in WTI and the change in our realized prices is due to wider crude oil differentials in 2012.

**Monthly Crude Oil Prices**



**Natural Gas**

The AECO monthly index price entered 2012 at \$3.02/Mcf and the low occurred in May when it settled at \$1.64/Mcf. Natural gas prices fell sharply in early 2012 as supply outpaced demand resulting in rising inventory levels. As the year progressed, gas prices started to recover as significant coal to gas switching occurred in the power sector providing some relief to the high gas inventory levels.

During 2012 we sold our natural gas for an average price of \$2.39/Mcf (net of transportation costs) which represented a 36% decline from 2011. This decrease was slightly larger than the change in the AECO and NYMEX indices as we had losses on some of our short-term physical fixed price gas positions. We entered these fixed price contracts at the beginning of the summer as storage levels appeared to be reaching capacity.

**Monthly Natural Gas Prices**



## Price Risk Management

We have a price risk management program that considers our overall financial position, the economics of our capital program and potential acquisitions. We have continued to add crude oil hedge positions for 2013 as our crude oil production currently accounts for approximately 86% of our corporate netback at current commodity prices. As of February 7, 2013 we have swapped approximately 18,500 bbls/day for 2013 at an average price of US\$100.54/bbl, which represents approximately 61% of our forecasted net oil production after royalties. We have started to add positions for 2014 and have swapped 2,000 bbls/day at \$93.33/bbl.

We have also added a modest level of natural gas price protection however we will continue to look for improvements in prices before adding larger positions. As of February 7, 2013 we have downside protection representing approximately 28% of our forecasted natural gas production after royalties for 2013. This is comprised of 48,500 Mcf/day at AECO \$3.39/Mcf before premiums. Additionally we have swapped 15,000 Mcf/day at NYMEX US\$3.45/Mcf for the first half of 2013. For 2014 we have swapped 10,000 Mcf/day at NYMEX US\$4.03/Mcf. In addition, we continue to hold the physical fixed AECO basis contracts entered into in 2011 that are listed in Note 16.

The following is a summary of our financial contracts in place at February 7, 2013 expressed as a percentage of our anticipated net production volumes:

	Crude Oil (US\$/bbl) <sup>(1)(2)</sup>		AECO Natural Gas <sup>(1)</sup>	NYMEX Natural Gas <sup>(1)</sup>	
	Jan 1, 2013 – Dec 31, 2013	Jan 1, 2014 – Dec 31, 2014	(CDN\$/Mcf) Jan 1, 2013 – Dec 31, 2013	(US\$/Mcf) Jan 1, 2013 – Jun 30, 2013	(US\$/Mcf) Jan 1, 2014 – Dec 31, 2014
Purchased Puts	–	–	\$ 3.17	–	–
%	–	–	11%	–	–
Sold Puts	\$ 63.09	–	–	–	–
%	18%	–	–	–	–
Swaps (fixed price)	\$ 100.54	\$ 93.33	\$ 3.59	\$ 3.45	\$ 4.03
%	61%	7%	13%	8%	5%
Sold Calls	\$ 130.00	–	–	–	–
%	12%	–	–	–	–
Purchased Calls	\$ 104.09	–	–	–	–
%	12%	–	–	–	–

(1) Based on weighted average price (before premiums), assumed average annual production of 83,500 BOE/day for 2013 and 2014, less royalties of 21%.

(2) The majority of our crude oil positions are priced in relation to WTI.

## Accounting for Price Risk Management

During 2012 we realized cash gains of \$18.4 million on our crude oil contracts. In comparison, in 2011 we realized cash losses of \$46.5 million on our crude oil contracts and gains of \$13.3 million on our natural gas contracts. The cash gains in 2012 were due to contracts which provided floor protection above market prices. The cash losses in 2011 were a result of crude oil prices rising above our fixed price swap positions.

As the forward markets for crude oil and natural gas fluctuate and new contracts are executed and existing contracts are realized, changes in fair value are reflected as either a non-cash charge or gain to earnings. At December 31, 2012 the fair value of our crude oil and natural gas contracts represented gains of \$50.7 million and \$3.3 million respectively and are recorded as current

deferred financial assets on our balance sheet. The change in the fair value of our commodity contracts during 2012 represented gains of \$70.3 million and \$3.3 million, respectively. See Note 16 for details.

#### Risk Management Gains/(Losses)

(\$ millions, except per unit amounts)

	2012		2011	
Cash gains/(losses):				
Crude oil	\$ 18.4	\$ 1.38/bbl	\$ (46.5)	\$ (4.22)/bbl
Natural gas	–	\$ –/Mcf	13.3	\$ 0.15/Mcf
Total cash gains/(losses)	\$ 18.4	\$ 0.61/BOE	\$ (33.2)	\$ (1.21)/BOE
Non-cash gains/(losses) on financial contracts:				
Change in fair value – crude oil	\$ 70.3	\$ 5.26/bbl	\$ 18.7	\$ 1.70/bbl
Change in fair value – natural gas	3.3	\$ 0.04/Mcf	(12.6)	\$ (0.14)/Mcf
Total non-cash gains/(losses)	\$ 73.6	\$ 2.45/BOE	\$ 6.1	\$ 0.22/BOE
<b>Total gains/(losses)</b>	<b>\$ 92.0</b>	<b>\$ 3.06/BOE</b>	<b>\$ (27.1)</b>	<b>\$ (0.99)/BOE</b>

#### Revenues

Crude oil and natural gas revenues in 2012 were \$1,339.0 million (\$1,365.5 million, net of \$26.5 million of transportation costs), similar to 2011 revenues of \$1,343.1 million (\$1,363.7 million, net of \$20.6 million of transportation costs). Crude oil revenues in 2012 increased due to higher production levels however were partially offset by lower realized prices. Natural gas and NGL revenues decreased mainly due to lower realized prices.

Analysis of Sales Revenue <sup>(1)</sup> (\$ millions)	Crude Oil	NGLs	Natural Gas	Total
2011 Sales revenue	\$ 919.6	\$ 78.4	\$ 345.1	\$ 1,343.1
Price variance	(70.7)	(15.9)	(123.2)	(209.8)
Volume variance	195.9	7.9	1.9	205.7
<b>2012 Sales revenue</b>	<b>\$ 1,044.8</b>	<b>\$ 70.4</b>	<b>\$ 223.8</b>	<b>\$ 1,339.0</b>

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

#### Royalties

Royalties are paid to various government entities and other land and mineral rights owners. Total royalties increased to \$268.8 million in 2012 from \$245.2 million during 2011 primarily due to an increased proportion of U.S. production where royalty rates are generally higher than those on our Canadian properties. As a percentage of oil and gas sales, net of transportation costs, 2012 royalties were 20% compared to 18% in 2011. We are expecting our average royalty rate in 2013 to increase to 21%.

#### Operating Expenses

Our 2012 operating expenses were \$10.64/BOE which was in line with our guidance of \$10.70/BOE. Our operating expenses totaled \$319.6 million (\$10.64/BOE) compared to \$281.2 million (\$10.23/BOE) in 2011, representing a 4% increase on a BOE basis.

In 2012 we had higher well servicing and repairs and maintenance costs as poor weather in 2011 delayed some planned maintenance activity into 2012. In Fort Berthold we started collecting the natural gas and NGL production associated with our oil production and sending it through a third party processing facility which generated additional facility charges during 2012. We also recorded non-cash mark-to-market losses on our electricity contracts during 2012 compared to gains in the prior year which contributed \$0.20/BOE to the year-over-year variance.

2013 operating expenses are expected to be consistent with 2012 at approximately \$10.70/BOE.

## Netbacks

The following tables outline our crude oil and natural gas netbacks for 2012 and 2011. The crude oil and natural gas classifications below contain properties according to their dominant production category. These properties may include associated crude oil, natural gas or natural gas liquids volumes which have been converted to the equivalent BOE/day or Mcfe/day and as such, the revenue per BOE or per Mcfe may not correspond with the average selling price under the “Pricing” section of this MD&A.

Netbacks by Property Type	Year ended December 31, 2012		
	Crude Oil	Natural Gas	Total
Average Daily Production	40,136 BOE/day	251,773 Mcfe/day	82,098 BOE/day
Netback <sup>(1)</sup> \$ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Revenue <sup>(2)</sup>	\$ 72.05	\$ 3.04	\$ 44.56
Royalties	(16.06)	(0.36)	(8.95)
Cash operating costs	(11.98)	(1.53)	(10.53)
Netback before hedging	\$ 44.01	\$ 1.15	\$ 25.08
Cash gains/(losses)	1.25	–	0.61
Netback after hedging	\$ 45.26	\$ 1.15	\$ 25.69
<b>Netback before hedging (\$ millions)</b>	<b>\$ 646.7</b>	<b>\$ 107.0</b>	<b>\$ 753.7</b>
<b>Netback after hedging (\$ millions)</b>	<b>\$ 665.1</b>	<b>\$ 107.0</b>	<b>\$ 772.1</b>

Netbacks by Property Type	Year ended December 31, 2011		
	Crude Oil	Natural Gas	Total
Average Daily Production	33,185 BOE/day	252,883 Mcfe/day	75,332 BOE/day
Netback <sup>(1)</sup> \$ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Revenue <sup>(2)</sup>	\$ 77.17	\$ 4.42	\$ 48.85
Royalties	(16.27)	(0.52)	(8.92)
Cash operating costs	(11.77)	(1.53)	(10.33)
Netback before hedging	\$ 49.13	\$ 2.37	\$ 29.60
Cash gains/(losses)	(3.84)	0.14	(1.21)
Netback after hedging	\$ 45.29	\$ 2.51	\$ 28.39
<b>Netback before hedging (\$ millions)</b>	<b>\$ 595.3</b>	<b>\$ 218.6</b>	<b>\$ 813.9</b>
<b>Netback after hedging (\$ millions)</b>	<b>\$ 548.8</b>	<b>\$ 231.9</b>	<b>\$ 780.7</b>

(1) See “Non-GAAP Measures” in this MD&A.

(2) Net of oil and gas transportation costs.

Our crude oil properties accounted for 86% of our corporate netback before hedging for 2012 compared to 73% for the same period in 2011. Crude oil netbacks per BOE during 2012 were similar to 2011 as lower realized crude oil prices were offset by cash hedging gains. Natural gas netbacks per Mcfe decreased in 2012 due to lower realized natural gas prices.

## General and Administrative Expenses

G&A expenses during 2012 were \$78.3 million or \$2.61/BOE compared to \$67.6 million or \$2.46/BOE in 2011. The increase compared to the prior year was primarily due to expanding our U.S. operations as well as higher professional and legal fees in 2012. We expect G&A expenses to increase modestly to approximately \$2.70/BOE during 2013.

## Equity Based Compensation Expenses

Equity based compensation expenses decreased to \$15.5 million in 2012 from \$26.8 million in 2011. These expenses include charges related to our long-term incentive plans (“LTI plans”) and our stock option plan (see Note 15 for further details). The costs of our LTI plans are dependent on our share price and can fluctuate from period to period. Our LTI costs were significantly lower in 2012 as a result of the decrease in our share price during the year.

We also recorded gains of \$0.4 million during 2012 related to equity swaps on our LTI plans that we entered into during the year. Utilizing the equity swaps we effectively fixed the future settlement cost related to our LTI plans at a weighted average price of \$12.49 per share on 1,030,000 shares, representing approximately 65% of the notional shares outstanding under these plans.

Equity Based Compensation Expenses (\$ millions)	2012	2011
LTI plans expense – cash	\$ 5.6	\$ 14.5
LTI plans equity swap loss/(gain) – non-cash	(0.4)	–
Stock option plan – non-cash	10.3	12.3
<b>Total equity based compensation expenses</b>	<b>\$ 15.5</b>	<b>\$ 26.8</b>

Equity Based Compensation Expenses (Per BOE)	2012	2011
LTI plans expense – cash	\$ 0.18	\$ 0.53
LTI plans equity swap loss/(gain) – non-cash	(0.01)	–
Stock option plan – non-cash	0.34	0.45
<b>Total equity based compensation expenses</b>	<b>\$ 0.51</b>	<b>\$ 0.98</b>

Based on our current share price we would expect cash equity based compensation expenses of approximately \$0.45/BOE in 2013.

### Finance Expense

Interest on our senior notes and bank credit facility in 2012 totaled \$53.1 million compared to \$47.0 million in 2011. The increase is due to higher average debt levels in 2012 and an increased weighting of senior notes with higher interest rates after our \$405 million private placement of senior notes in May 2012. Non-cash amounts recorded in finance expense include accretion of decommissioning liabilities, amortization of financing fees and premiums, and unrealized gains and losses resulting from the change in fair value of our interest rate swaps and the interest component on our cross currency interest rate swap (“CCIRS”). See Note 11 for further details.

Finance Expense (\$ millions)	2012	2011
Interest on senior notes and bank facility	\$ 53.1	\$ 47.0
Non-cash finance expense	17.0	13.4
<b>Total finance expense</b>	<b>\$ 70.1</b>	<b>\$ 60.4</b>

At December 31, 2012, after including our underlying derivatives, approximately 71% of our debt was based on fixed interest rates while 29% had floating interest rates. In comparison, at December 31, 2011 approximately 46% of our debt was based on fixed interest rates and 54% was floating.

## Foreign Exchange

We recorded net foreign exchange gains of \$17.2 million in 2012 compared to losses of \$4.2 million in 2011. We realized foreign exchange gains during 2012 on our day-to-day US dollar cash transactions in Canada and on our short-term US dollar advances under our credit facility. Our 2012 foreign exchange also includes both the \$18.0 million loss realized upon settlement of our second quarter US\$175 million senior note CCIRS settlement and the \$18.0 million unrealized gain to remove the mark-to-market position previously recorded on the swap. See Note 12 for details.

Foreign Exchange (\$ millions)	2012	2011
Realized loss/(gain)	\$ 6.5	\$ 18.4
Unrealized loss/(gain)	(23.7)	(14.2)
<b>Total foreign exchange loss/(gain)</b>	<b>\$ (17.2)</b>	<b>\$ 4.2</b>

## Capital Investment

Our 2012 capital spending totaled \$852.8 million, in-line with our guidance of \$850 million and slightly down from \$865.7 million in 2011. We directed approximately 80% of our capital spending towards oil and liquids rich natural gas properties. This included investing \$441.6 million on our Fort Berthold crude oil property, \$168.5 million on our Canadian crude oil properties and \$69.5 million on our liquids rich deep gas properties in Canada. We also spent \$153.6 million on our Marcellus assets primarily focused on non-operated drilling for lease retention in core areas. Through our capital program we added 57.3 MBOE of proved plus probable reserves, replacing approximately 190% of our 2012 production.

Property and land acquisitions during 2012 totaled \$185.3 million. The majority of our 2012 spending related to our December 17, 2012 acquisition where we spent \$117.6 million (US\$119.5 million) for an additional 20% working interest in our operated leases on our Sleeping Giant Bakken oil property in Montana, increasing our total working interest to approximately 90%. During the year we continued to invest in undeveloped land to fill in key acreage positions in our core areas with spending of \$13.6 million in Canada and \$14.0 million in the Marcellus and Fort Berthold areas within the U.S. We also spent \$37.0 million on our Marcellus carry obligation for the year which fully satisfied our carry commitment.

During 2011 we spent \$112.5 million on undeveloped land in Canada and in the U.S. we spent approximately \$33.1 million on additional undeveloped land in the Marcellus surrounding around our existing holdings along with US\$111.0 million on our Marcellus carry obligation.

We plan to spend \$685 million on capital projects in 2013 with over 85% of our spending focused on oil and liquids rich natural gas projects. We expect to invest approximately \$340 million on light crude oil development at Fort Berthold, \$185 million on our Canadian crude oil properties and \$79 million on liquids rich natural gas drilling in the Canadian Deep Basin region. Our natural gas spending will be focused primarily in the Marcellus where we expect to spend approximately \$80 million on non-operated drilling to retain core acreage. By the end of 2013 we expect to have the majority of our core Marcellus acreage held by production.

## Dispositions

Property dispositions in 2012 totaled \$275.8 million compared to \$641.2 million in 2011. During the year we sold assets in Manitoba for proceeds of \$218.1 million. We also disposed of non-core assets in the U.S. for proceeds of \$21.9 million. In aggregate we recognized gains of \$83.8 million during the year on these dispositions.

During 2011 we disposed of approximately 91,000 net acres of our Marcellus interests for proceeds of \$567.9 million (US\$580 million), and in Canada we disposed of non-core assets for total proceeds of approximately \$61.8 million. We recognized gains of \$302.1 million on these disposition activities.

Our total capital investment activity for 2012 and 2011 is outlined below:

Capital Investment (\$ millions)	2012	2011
Capital spending	\$ 852.8	\$ 865.7
Office capital	11.9	11.3
Sub-total	\$ 864.7	\$ 877.0
Property and land acquisitions	\$ 185.3	\$ 255.2
Property dispositions	(275.8)	(641.2)
Sub-total	\$ (90.5)	\$ (386.0)
<b>Total net capital investment</b>	<b>\$ 774.2</b>	<b>\$ 491.0</b>

### Depletion, Depreciation and Amortization (“DD&A”)

DD&A of property, plant and equipment (“PP&E”) is recognized using the unit-of-production method based on proved plus probable reserves. For 2012 DD&A was \$510.8 million or \$17.00/BOE compared to \$433.4 million or \$15.76/BOE in 2011. The increase in our DD&A in 2012 is primarily due to higher production and well costs with respect to our U.S. operations resulting in higher depletion per BOE.

### Impairments

In 2012 we recorded total D&P impairments of \$418.0 million, compared to \$334.3 million in 2011. The impairments in 2012 related to lower forecast commodity prices along with increased forecast future development costs with respect to our Canadian CGUs. The impairments recognized in 2011 were also due to lower commodity price forecasts in our Canadian CGUs. Although these impairments affect net income they do not impact funds flow or cash flow from operating activities. Further fluctuations in forecast prices could cause additional impairments or impairment reversals going forward.

Exploration and Evaluation (“E&E”) assets are also tested for impairment when there are indicators that suggest their carrying values may exceed their recoverable amount. In 2012 we recorded E&E impairments totaling \$113.8 million of which \$65.9 million related to expiring Marcellus leases in West Virginia and Maryland and \$47.9 million related to our Saskatchewan Bakken and Deep Gas E&E assets in Canada. In 2011 we recorded E&E impairments of \$35.5 million related to expiring acreage in Canada.

Impairment Expense (\$ millions)	2012	2011
D&P impairments	\$ 418.0	\$ 334.3
E&E impairments	113.8	35.5
E&E impairment reversals	–	(10.1)
<b>Total impairment expense</b>	<b>\$ 531.8</b>	<b>\$ 359.7</b>

### Other Assets

Other assets consist of our portfolio of equity investments in other oil and gas companies. These investments are carried at their estimated fair value with changes in fair value recorded in other comprehensive income. During the year we sold the majority of our portfolio, consisting primarily of our shares in Laricina Energy Ltd., for net cash proceeds of \$146.9 million resulting in a gain of \$47.4 million.

### Decommissioning Liabilities

In connection with our operations we incur abandonment and reclamation costs related to assets such as surface leases, wells, facilities and pipelines. Total decommissioning liabilities included on our balance sheet are estimated by management based on our net ownership interest, estimated costs to abandon and reclaim and the estimated timing of the costs to be incurred in future periods.

We have estimated the net present value of our decommissioning liability to be \$599.7 million at December 31, 2012 compared to \$563.8 million at December 31, 2011. Our overall liability increased year over year as decreases in the liability resulting from our Manitoba non-core asset disposition were more than offset by increases in liability estimates for some of our non-operated facilities

along with increases in the liability resulting from changes in the risk-free rate used to calculate the present value of the liability, which decreased to 2.36% at December 31, 2012 from 2.49% at December 31, 2011. See Note 10 for further information.

We take an active approach to managing our abandonment, reclamation and remediation obligations. During 2012 we spent \$19.9 million (2011 – \$21.7 million) on our decommissioning liabilities and we expect to spend approximately \$25.8 million in 2013. Our decommissioning expenditures are expected to be incurred over the next 66 years with the majority between 2022 and 2052. We do not reserve cash or assets for the purpose of funding our future decommissioning liabilities. Any reclamation or abandonment costs are anticipated to be funded out of cash flow.

## Environment

We strive to carry out our activities and operations in compliance with all applicable regulations and good industry practices. Our operations are subject to laws and regulations concerning pollution, protection of the environment and the handling of hazardous materials and waste. We set corporate targets and mandates to improve environmental performance and execute environmental initiatives to become more energy efficient and to reduce, reuse and recycle water and minimize waste.

Our Board of Directors’ Safety and Social Responsibility (“S&SR”) Committee has oversight and responsibility for the review of our S&SR management system to ensure that our activities are planned and executed in a safe and responsible manner and to ensure we have adequate systems to support ongoing compliance. We may be subject to environmental and other costs resulting from unknown and unforeseeable environmental impacts arising from our operations. There are inherent risks of spills and pipeline leaks at our operating sites and clean-up costs may be significant. However, we have active site inspection, corrosion risk management and asset integrity management programs to help minimize this risk. In addition, we carry environmental insurance to help mitigate the cost of spills should they occur.

The ongoing uncertainty surrounding the direction from government on regulations affects our ability to proactively manage potential risks and opportunities associated with greenhouse gas emissions. We intend to continue to improve energy efficiencies and proactively manage our emissions.

We use the hydraulic fracturing process in our operations. Government and regulatory agencies continue to frame regulations related to this process. We believe we are in compliance with all current government regulations in the U.S. and Canada. We would expect to adjust our operations going forward, if necessary, to meet any new or revised regulations when established.

## Taxes

We recorded a tax recovery of \$61.2 million in 2012 compared to an expense of \$32.6 million in 2011. The change in tax expense relates primarily to the decrease in net income in 2012.

Our current tax expense was \$1.6 million in 2012 compared to \$81.2 million in 2011. Current taxes were significantly higher in 2011 due to higher income resulting from the gain on our Marcellus property disposition. Our current tax expense is comprised mainly of Alternative Minimum Tax (“AMT”) payable with respect to our U.S. subsidiary. We expect to recover AMT in future years as an offset to regular U.S. income taxes otherwise payable.

Income Tax (\$ millions)	2012	2011
Current tax expense/(recovery)	\$ 1.6	\$ 81.2
Deferred tax expense/(recovery)	(62.8)	(48.6)
<b>Total tax expense/(recovery)</b>	<b>\$ (61.2)</b>	<b>\$ 32.6</b>

We expect to pay U.S. cash taxes of approximately 3% of U.S. cash flow until 2016. We currently do not expect to pay material cash taxes in Canada until after 2016. These estimates may vary depending on numerous factors including commodity prices, capital spending, tax regulations and acquisition and disposition activity.

## Tax Pools

Our estimated tax pools at December 31, 2012 are as follows:

Pool Type (\$ millions)	2012	2011
Canadian		
COGPE	\$ 315	\$ 542
CDE	316	245
UCC	375	440
CEE	216	208
Non-capital losses	488	533
	\$ 1,710	\$ 1,968
U.S.		
AMT	\$ 84	\$ 83
Tax losses	462	66
Other (including depletable and depreciable assets)	1,048	1,050
	\$ 1,594	\$ 1,199
<b>Total tax pools</b>	<b>\$ 3,304</b>	<b>\$ 3,167</b>
<b>Available capital losses</b>	<b>\$ 1,212</b>	<b>\$ 1,367</b>

At December 31, 2012, we had unused capital losses of \$1.2 billion (2011 – \$1.4 billion). The available capital losses reflect the balance of unused capital losses available for carry-forward in Canada. These capital losses have an indefinite carry-forward period however can only be used to offset capital gains.

## Net Income/(Loss)

For the year ended 2012 we recorded a net loss of \$155.7 million compared to net income of \$109.4 million in 2011. The decrease in net income was primarily due to higher impairments as a result of lower forecast commodity prices, lower gains on asset dispositions, as well as increased depletion and operating costs. The overall decrease was partially offset by gains on our commodity derivative instruments and lower current tax expense.

## Reconciliation of Funds Flow to Net Income per BOE

Per BOE of production <sup>(2)</sup>	Year ended December 31, 2012			Year ended December 31, 2011		
	Funds Flow	Non-Cash Items	Net Income	Funds Flow	Non-Cash Items	Net Income
Weighted average sales price <sup>(1)</sup>	\$ 44.56	\$ –	\$ 44.56	\$ 48.85	\$ –	\$ 48.85
Royalties	(8.95)	–	(8.95)	(8.92)	–	(8.92)
Commodity derivative instruments	0.61	2.45	3.06	(1.21)	0.22	(0.99)
Asset disposition gain/(loss)	–	4.37	4.37	–	10.98	10.98
Operating costs	(10.53)	(0.11)	(10.64)	(10.33)	0.10	(10.23)
General and administrative	(2.61)	–	(2.61)	(2.46)	–	(2.46)
Equity based compensation	(0.18)	(0.33)	(0.51)	(0.53)	(0.45)	(0.98)
Interest, foreign exchange and other expenses	(1.42)	(0.39)	(1.81)	(1.59)	(0.67)	(2.26)
Current tax	(0.05)	–	(0.05)	(2.95)	–	(2.95)
Depletion, depreciation and amortization	–	(17.00)	(17.00)	–	(15.76)	(15.76)
Impairments	–	(17.70)	(17.70)	–	(13.08)	(13.08)
Deferred tax (expense)/recovery	–	2.10	2.10	–	1.78	1.78
<b>Total net income/(loss) per BOE</b>	<b>\$ 21.43</b>	<b>\$ (26.61)</b>	<b>\$ (5.18)</b>	<b>\$ 20.86</b>	<b>\$ (16.88)</b>	<b>\$ 3.98</b>

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

(2) Based on 82,098 BOE/day of production in 2012 and 75,332 BOE/day of production in 2011.

## SELECTED ANNUAL CANADIAN AND U.S. FINANCIAL RESULTS

The following table provides a geographical analysis of key operating and financial results for 2012 and 2011.

(CDN\$ millions, except per unit amounts)	Year ended December 31, 2012			Year ended December 31, 2011		
	Canada	U.S.	Total	Canada	U.S.	Total
<b>Average Daily Production Volumes</b>						
Crude oil (bbls/day)	20,647	15,862	36,509	19,125	11,056	30,181
Natural gas liquids (bbls/day)	3,244	383	3,627	3,177	129	3,306
Natural gas (Mcf/day)	198,356	53,417	251,773	219,129	31,939	251,068
Total average daily production (BOE/day)	56,950	25,148	82,098	58,824	16,508	75,332
<b>Pricing<sup>(1)</sup></b>						
Crude oil (per bbl)	\$ 75.21	\$ 82.08	\$ 78.19	\$ 82.02	\$ 86.01	\$ 83.48
Natural gas liquids (per bbl)	54.86	37.35	53.01	65.63	49.40	64.99
Natural gas (per Mcf)	2.17	3.21	2.39	3.54	4.98	3.72
<b>Capital Expenditures</b>						
Capital spending	\$ 254.8	\$ 598.0	\$ 852.8	\$ 325.9	\$ 539.8	\$ 865.7
Property and land acquisitions	13.6	171.7	185.3	112.5	142.7	255.2
Property dispositions	(253.9)	(21.9)	(275.8)	(61.8)	(579.4)	(641.2)
<b>Revenues</b>						
Oil and gas sales <sup>(1)</sup>	\$ 794.1	\$ 544.9	\$ 1,339.0	\$ 935.1	\$ 408.0	\$ 1,343.1
Royalties <sup>(2)</sup>	(121.5)	(147.3)	(268.8)	(143.0)	(102.2)	(245.2)
Commodity derivative instruments gain/(loss)	92.0	—	92.0	(27.1)	—	(27.1)
<b>Expenses</b>						
Operating	\$ 266.8	\$ 52.8	\$ 319.6	\$ 245.2	\$ 36.0	\$ 281.2
General and administrative	63.5	14.8	78.3	57.2	10.4	67.6
Equity based compensation	15.4	0.1	15.5	25.2	1.6	26.8
Depletion, depreciation and amortization	315.6	195.2	510.8	335.9	97.5	433.4
Impairments/(reversals)	465.9	65.9	531.8	369.8	(10.1)	359.7
Current income tax expense/(recovery)	(2.1)	3.7	1.6	0.6	80.6	81.2

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

(2) U.S. royalties include state production tax.

### THREE YEAR SUMMARY OF KEY MEASURES AND QUARTERLY FINANCIAL INFORMATION

Oil and gas sales were relatively flat in 2012 as higher production volumes offset the impact of lower realized commodity prices. During 2011 and 2010 higher crude oil prices were generally offset by declining natural gas prices and lower production levels due to our disposition activity, resulting in flat oil and gas sales during those periods.

Net income has been affected by fluctuating risk management costs, impairments related to the decrease in natural gas prices, gains on asset dispositions along with changes in tax provisions.

Cash and stock dividends were lower in 2012 due to the reduction in our monthly dividend from \$0.18 per month to \$0.09 per month, effective in July 2012.

Our long-term debt has increased and our spending has exceeded our cash flows as we continue to invest in our asset base.

(\$ millions, except per share amounts)	2012	2011	2010
Oil and gas sales <sup>(1)</sup>	\$ 1,339.0	\$ 1,343.1	\$ 1,300.2
Net income/(loss)	(155.7)	109.4	(179.3)
Per share (Basic) <sup>(2)</sup>	(0.80)	0.61	(1.02)
Per share (Diluted) <sup>(2)</sup>	(0.80)	0.61	(1.02)
Funds flow	643.9	573.6	729.0
Per share (Basic) <sup>(2)</sup>	3.29	3.19	4.15
Cash and Stock Dividends <sup>(3)</sup>	301.6	388.9	384.1
Per share (Basic) <sup>(2)(3)</sup>	1.54	2.16	2.19
Total assets	5,412.2	5,723.3	5,489.2
Long-term debt, net of cash <sup>(4)</sup>	1,064.4	901.5	724.0

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

(2) Based on weighted average shares outstanding.

(3) Calculated based on shares paid or payable. Cash and Stock Dividends to shareholders per share may not correspond to actual dividends as a result of using the annual weighted average shares outstanding.

(4) Including current portion of long-term debt.

(CDN\$ millions, except per share amounts)	Oil and Gas Sales <sup>(1)</sup>	Net Income/(Loss)	Net Income/(Loss) Per Share	
			Basic	Diluted
<b>2012</b>				
Fourth Quarter	\$ 360.7	\$ (158.7)	\$ (0.80)	\$ (0.80)
Third Quarter	324.9	(63.5)	(0.32)	(0.32)
Second Quarter	314.4	100.3	0.51	0.51
First Quarter	339.0	(33.8)	(0.18)	(0.18)
<b>Total</b>	<b>\$ 1,339.0</b>	<b>\$ (155.7)</b>	<b>\$ (0.80)</b>	<b>\$ (0.80)</b>
<b>2011</b>				
Fourth Quarter	\$ 357.3	\$ (299.4)	\$ (1.66)	\$ (1.65)
Third Quarter	312.9	111.3	0.62	0.62
Second Quarter	354.2	268.0	1.50	1.49
First Quarter	318.7	29.5	0.17	0.16
<b>Total</b>	<b>\$ 1,343.1</b>	<b>\$ 109.4</b>	<b>\$ 0.61</b>	<b>\$ 0.61</b>

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

### LIQUIDITY AND CAPITAL RESOURCES

During 2012 we completed a number of initiatives to preserve our financial flexibility given our capital spending plans and lower funds flow resulting from depressed natural gas prices. In the first half of 2012 we completed an equity offering raising net proceeds of \$331 million and also closed a private placement of senior notes for proceeds of approximately \$405 million with maturities extending out 12 years.

In July we reduced our monthly dividend from \$0.18 per share to \$0.09 per share and also replaced our Dividend Reinvestment Program with a Stock Dividend Program that is available to all shareholders. The current participation rate is approximately 18% and we expect this rate to increase over time due to the favorable tax attributes of this program.

During 2012 we completed several dispositions which also enhanced our liquidity. We raised net cash proceeds of approximately \$146.9 million through the sale of the majority of our equity investment portfolio, the largest of which was the disposition of all of our shares in Laricina Energy Ltd. In December, we sold our interests in our Manitoba assets for proceeds of \$218.1 million and purchased additional working interests in Sleeping Giant for \$117.6 million.

We are continuing to pursue other measures to support our 2013 capital spending activities including the partial sale or joint venture of our interests in the Duvernay and Montney and the sale of other non-core producing properties.

Total debt at December 31, 2012, including the current portion, was \$1,069.6 million compared to \$907.1 million at December 31, 2011. Total debt at December 31, 2012 was comprised of \$260.9 million of bank indebtedness and \$808.6 million of senior notes. We have \$739.1 million of available credit on our bank credit facility at December 31, 2012 and a conservative trailing twelve month debt to funds flow ratio of 1.7x.

Our working capital deficiency, excluding cash and current deferred financial assets and credits, was \$172.4 million at December 31, 2012, decreasing by \$190.2 million from \$362.6 million at December 31, 2011. The decrease in our working capital deficit resulted from decreased accounts payable balances due to lower capital spending compared to the fourth quarter of 2011 as well as lower dividends payable following the reduction of our monthly dividend. We expect to finance our working capital deficit through funds flow and our bank credit facility.

Our payout ratio, which is calculated as dividends, net of our stock dividends and DRIP proceeds, divided by funds flow, was 40% for 2012 compared to 59% in 2011. Our adjusted payout ratio, which is calculated as dividends, net of our stock dividends and DRIP proceeds, plus capital spending and office capital divided by funds flow, was 174% for 2012 compared to 212% in 2011. The decrease in our payout ratio was a result of increased funds flow over the prior year along with the reduction in our monthly dividend.

Our key leverage ratios are detailed below:

<b>Financial Leverage and Coverage</b>	<b>December 31, 2012</b>	<b>December 31, 2011</b>
Long-term debt to funds flow (12 month trailing) <sup>(1)</sup>	1.7 x	1.6 x
Funds flow to interest expense (12 month trailing) <sup>(2)</sup>	12.1 x	12.2 x
Long-term debt to long-term debt plus equity <sup>(1)</sup>	26%	22%

(1) Long-term debt is measured net of cash and includes the current portion of the senior notes.

(2) Interest expense is finance expense excluding non-cash items.

On October 31, 2012, our \$1.0 billion bank credit facility was extended for a three year term, maturing October 31, 2015 with the same commercial terms and pricing. At December 31, 2012 we were in compliance with all covenants under our bank credit facility and outstanding senior notes. Our bank credit facility and senior note purchase agreements have been filed as material documents on our SEDAR profile at [www.sedar.com](http://www.sedar.com).

## Counterparty Credit

### Oil and Gas Sales Counterparties

Our oil and gas receivables are with customers in the oil and 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' creditworthiness 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 some of our credit risk. This process is utilized for both our oil and gas sales counterparties as well as our financial derivative counterparties.

### Financial Derivative Counterparties

We are exposed to credit risk in the event of non-performance by our financial counterparties regarding our derivative contracts. We mitigate this risk by entering into transactions with major financial institutions, the majority of which are members of our bank syndicate. We have International Swaps and Derivatives Association ("ISDA") agreements in place with the majority of our financial counterparties. These agreements provide some credit protection by generally allowing 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. To date we have not experienced any losses due to non-performance by our derivative counterparties. At December 31, 2012 we had \$62.1 million in mark-to-market assets offset by \$35.6 million of mark-to-market liabilities resulting in a net asset position of \$26.5 million.

### Dividends

We reported a total of \$301.6 million (\$1.53/share) in dividends to our shareholders in 2012, of which \$23.6 million was non-cash and related to our SDP. We reduced our monthly dividend from \$0.18 per share to \$0.09 per share, effective for our July 20, 2012 dividend payment and we will continue to assess our dividend levels with respect to anticipated funds flow, debt levels, capital spending plans and capital market conditions.

Participation in the SDP is optional allowing our shareholders to continue to receive cash dividends unless they elect to receive stock dividends. Currently we have a participation rate of approximately 18% or approximately \$3.2 million per month. As with our previous DRIP, the SDP will serve as a source of capital by allowing us to retain cash that would otherwise be paid out as dividends and extends this option to all of our shareholders.

### Commitments

For our Bakken crude oil in the U.S. we have aggregate transportation capacity of approximately 12,500 bbl/day for 2013, 8,500 bbl/day from 2014 to 2016 and 7,500 bbl/day for 2017. This consists of contracted pipeline capacity for 8,500 bbl/day until May 2016 with 7,500 bbl/day of that continuing through December 2017 as well as a firm commitment for rail capacity to the U.S. Gulf Coast for 6,000 bbl/day during January 2013 and 4,000 bbl/day from February 2013 through January 2014.

In Canada we have contracted up to 239 MMcf/day of natural gas pipeline capacity, some of it in series, with contract terms that range anywhere from one month to five years.

Our Canadian and U.S. office leases expire in 2019. Annual costs of these lease commitments include rent and operating fees. Our commitments, contingencies and guarantees are more fully described in Note 17.

As at December 31, 2012 we had the following minimum annual commitments including long-term debt:

(\$ millions) <sup>(1)</sup>	Total	Minimum Annual Commitment Each Year					Total Committed after 2017
		2013	2014	2015	2016	2017	
Bank credit facility	\$ 261.0	\$ -	\$ -	\$ 261.0	\$ -	\$ -	\$ -
Senior unsecured notes <sup>(2)</sup>	808.6	45.6	45.6	90.5	-	115.4	511.5
Transportation commitments	126.5	49.5	24.1	18.4	11.2	10.0	13.3
Processing commitments	1.2	0.4	0.3	0.3	0.2	-	-
Drilling and completions commitment	25.5	20.1	5.4	-	-	-	-
Decommissioning liability <sup>(3)</sup>	659.7	25.8	26.0	26.0	26.0	26.0	529.9
Office leases	81.8	13.3	12.9	10.9	11.4	11.4	21.9
<b>Total commitments<sup>(4)</sup></b>	<b>\$ 1,964.3</b>	<b>\$ 154.7</b>	<b>\$ 114.3</b>	<b>\$ 407.1</b>	<b>\$ 48.8</b>	<b>\$ 162.8</b>	<b>\$ 1,076.6</b>

(1) US\$ commitments have been converted to CDN\$ using the December 31, 2012 foreign exchange rate of 0.9949.

(2) Interest payments have not been included.

(3) Based upon current spending estimates.

(4) Crown and surface royalties, lease rentals, and mineral taxes (hydrocarbon production rights) have not been included as amounts paid depend on future ownership, production, prices and the legislative environment.

## Shareholders' Capital

On February 8, 2012 we completed a bought deal equity financing of 14,708,500 common shares at a price of \$23.45 per share for gross proceeds of \$344.9 million (\$330.6 million net of issuance costs). During 2012 a total of 2,816,000 shares (2011 – 2,510,000) and \$43.9 million of additional equity (2011 – \$64.0 million) was issued pursuant to the Stock Dividend Program, our former DRIP and the stock option plan. For further details see Note 15.

We had 198,684,000 shares outstanding at December 31, 2012 compared to 181,159,000 shares outstanding at December 31, 2011. The weighted average basic number of shares outstanding during 2012 was 195,633,000 shares compared to 179,889,000 shares during 2011. At February 20, 2013 we had 199,217,000 shares outstanding.

## CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with IFRS 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 decommissioning liabilities and the application of impairment tests. Revisions or changes in reserve estimates can have either a positive or a negative impact on net income.

### 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 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.

### Decommissioning Liability

Management calculates the decommissioning liability 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. There are uncertainties related to decommissioning liabilities and the impact on the financial statements could be material as the eventual timing and costs for the obligations could differ from our estimates. Factors that could cause our estimates to differ include any changes to laws or regulations, reserve estimates, costs and technology.

### 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 National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities and (b) future prices of oil and gas.

### 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 underlying estimate of future commodity prices, foreign currency exchange rates, interest rates and counterparty credit risk.

## RECENT IFRS ACCOUNTING AND RELATED PRONOUNCEMENTS

Refer to Note 3 in our Financial Statements for a detailed listing of Standards and Interpretations that were issued but not yet effective at December 31, 2012.

## RISK FACTORS AND RISK MANAGEMENT

### Commodity Price Risk

Our operating results and financial condition are dependent on the prices we receive for our crude oil, NGLs, 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 and crude oil, political stability, transportation facilities, availability of processing, fractionation and refining 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 unhedged. 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. Refer to the "Price Risk Management" section for further details on our price risk management program.*

### Oil and Gas Reserves and Resources Risk

The value of our company is based on, among other things, the underlying value of our 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 along with lower development capital spending associated with certain projects may increase the risk of write-downs for our oil and gas property investments. Changes in reporting methodology as well as regulatory practices can result in reserve or resource write-downs.

*Each year, independent reserves engineers evaluate the majority of our proved and probable reserves as well as the resources attributable to a significant portion of our undeveloped land. All reserves information, including our U.S. reserves, has been prepared in accordance with Canadian National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") standards. Independent reserve evaluations have been conducted on approximately 88% of the total proved plus probable value (discounted at 10%) of our reserves at December 31, 2012. McDaniel & Associates Consultants Ltd. ("McDaniel") evaluated the majority of our Canadian reserves as well as substantially all of the reserves associated with our western U.S. assets and reviewed the internal evaluation completed by Enerplus on the remaining portion. Haas Petroleum Engineering Services, Inc. ("Haas") evaluated 100% of our Marcellus shale gas assets in the U.S. and provided the estimate of contingent resources.*

*The evaluation of contingent resources associated with our leases at Fort Berthold and our Wilrich Deep Gas assets in Canada was conducted by Enerplus and audited by McDaniel. The contingent resource assessments associated with a portion of our waterflood properties were completed internally by Enerplus qualified reserve evaluators.*

*The Reserves Committee of the Board of Directors has reviewed and approved the reserve and resource reports of the independent evaluators.*

### Access to Capital Markets

Our access to capital has allowed us to fund a portion of our acquisitions and development capital program through equity and debt. Continued access to capital is dependent on our ability to optimize our existing assets 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 provide continuous disclosure and maintain complete public filings. Nonetheless, our continued access to capital markets is dependent on corporate performance and investor perception of future performance (both corporate and for the oil and gas sector in general).*

### Access to Transportation and Processing Capacity

Market access for crude oil, NGLs and natural gas production in Canada and the United States is dependent on our ability to obtain transportation capacity on third party pipelines, rail and access to processing facilities. Newer resource plays, such as the North Dakota Bakken and the Marcellus shale gas, generally experience a sharp production increase in the area which could exceed the

existing capacity of the gathering, pipeline, processing or rail infrastructure. While third party pipelines, processors and independent rail operators generally expand capacity to meet market needs, there can be differences in timing between the growth of production and the growth of capacity. There are occasionally operational reasons for curtailing transportation and processing capacity. Accordingly, there can be periods where transportation and processing 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 and review with the third party pipelines and other market participants. Where available and commercially appropriate, given the production profile and commodity, we attempt to mitigate this risk by contracting for firm pipeline or processing capacity or using other means of transportation, including rail and truck.*

### **Access to Field Services**

Our ability to drill, complete and tie-in wells in a timely manner may be impacted by our access to service providers and supplies. Activity levels in a given area may limit our access to these resources, restricting our ability to execute our capital plans in a timely manner. In addition, field service costs are influenced by market conditions and therefore can become cost prohibitive.

*Although we have entered into service contracts for a portion of field services that will secure some of our drilling and fracturing services into 2014, access to field services and supplies in other areas of our business will continue to be subject to market availability.*

### **Title Defects or Litigation**

Unforeseen title defects or litigation may result in a loss of entitlement to production, reserves and resources.

*Although we conduct title reviews prior to the purchase of assets these reviews do not guarantee that an unforeseen defect in the chain of title will not arise. We maintain good working relationships with our industry partners, however disputes may arise from time to time with respect to ownership of rights of certain properties or resources.*

### **Regulatory Risk & Greenhouse Gas Emissions**

Government royalties, environmental laws and regulatory requirements can have a significant financial and operational impact on us. As an oil and gas producer, we are subject to a broad range of regulatory requirements that continue to increase both within Canada and the United States.

*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.*

*Specifically with respect to regulations for the reduction of greenhouse gas emissions, the Canadian federal government continues to seek alignment for the regulations to be issued in Canada with those of the United States. Accordingly, while we continue to prepare to meet the potential requirements, the actual cost impact and its materiality to our business remains uncertain.*

### **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 land, reserves and/or resources and developing existing reserves and resources. Acquisitions of oil and gas assets will depend on our assessment of value at the time of acquisition and ability to secure the acquisitions generally through a competitive bid process.

*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.*

### **Health, Safety and Environmental Risk (“HSE”)**

Health, safety and environmental risks impact our workforce, operating costs and the establishment of regulatory standards. Certain government and regulatory agencies in Canada and the United States have begun investigating the potential risks associated with hydraulic fracturing. We expect regulatory frameworks will be amended or continue to emerge in this regard and regulations may be amended. The impact of such changes on our business could increase our cost of compliance and the risk of litigation and environmental liability.

*Enerplus has established a Safety and Social Responsibility (“S&SR”) team that develops standards and systems to manage health safety and environmental risks, regulatory compliance and stakeholder engagement for the organization. The actions of the S&SR team are driven in part by a steering committee which is comprised of executives and senior management. All S&SR risks are reviewed regularly by the S&SR committee which is comprised of members of the Board of Directors. We also carry insurance to cover a portion of our property losses, liability and potential losses from business interruption.*

### Counterparty and Joint Venture Credit Exposure

The low natural gas price environment increases the risk of bad debts related to our joint venture and industry partners. A failure of our counterparties to perform their financial or operational obligations may adversely affect our operations and financial position.

*A credit review process is in place to assess and monitor our counterparties' credit worthiness on a regular basis. This includes reviewing and ratifying our corporate credit guidelines, assessing the credit ratings of our counterparties and setting exposure limits. When warranted we attempt to obtain financial assurances such as letters of credit, parental guarantees, or third party insurance to mitigate our counterparty risk. In addition, we monitor our receivables against a watch list of publicly traded companies that have high debt-to-cash flow ratios or fully drawn bank facilities. In certain instances we may be able to aggregate all amounts owing to each other and settle with a single net amount.*

*See the "Liquidity and Capital Resources" section for further information.*

### Foreign Currency Exposure

We have exposure to fluctuations in foreign currency as most of our senior 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 when the Canadian dollar weakens relative to the U.S. dollar.

*We have hedged our foreign currency exposure on our US\$175 million, US\$54 million and a portion of our US\$225 million senior notes using financial swaps that convert the U.S. denominated debt to Canadian dollar debt. In addition, we have hedged the U.S. dollar interest obligation on our US\$175 million notes. We have not entered into any other foreign currency derivatives with respect to our 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 value of investments such as our shares as well as other equity investments.

*We monitor the interest rate forward market and have fixed the interest rate on approximately 71% of our debt through our senior notes and interest rate swaps.*

### Changes in Income Tax and Other Laws

Income tax, other laws or government incentive programs relating to the oil and gas industry may be changed in a manner that adversely affects us or our security holders. Tax authorities may interpret applicable tax laws, tax treaties or administrative positions differently than we do or may disagree with how we calculate our income for tax purposes in a manner which is detrimental to us and our security holders.

*We monitor developments with respect to pending legal changes and work with the industry and professional groups to ensure that our concerns with any changes are made known to various government agencies. We obtain confirmation from independent legal counsel and advisors with respect to the interpretation and reporting of material transactions.*

## Cash Flow Sensitivity

The sensitivities below reflect all commodity contracts listed in Note 16 and are based on forward markets as at February 7, 2013. To the extent crude oil and natural gas prices change significantly from current levels, the sensitivities will no longer be relevant.

Sensitivity Table <sup>(2)</sup>	Estimated Effect on 2013 Funds Flow per Share <sup>(1)</sup>
Change of \$0.50 per Mcf in the price of AECO natural gas	\$ 0.16
Change of US\$5.00 per barrel in the price of WTI crude oil	\$ 0.13
Change of 1,000 BOE/day in production	\$ 0.06
Change of \$0.01 in the US\$/CDN\$ exchange rate	\$ 0.05
Change of 1% in interest rate	\$ 0.02

(1) Assumes 200,740,000 weighted average shares outstanding.

(2) 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.

## 2013 GUIDANCE

A summary of our 2013 guidance is below. This guidance does not include any potential acquisitions or divestments.

Summary of 2013 Expectations	Target
Average annual production	82,000 - 85,000 BOE/day
Exit rate production	84,000 - 88,000 BOE/day
Capital spending	\$685 million
Production mix (volumes)	50% crude oil and liquids, 50% natural gas
Average royalty rate (% of gross sales, net of transportation)	21%
Operating costs	\$10.70/BOE
G&A expenses – cash	\$2.70/BOE
Equity based compensation expenses – cash	\$0.45/BOE
Cash taxes (% of U.S. funds flow)	~3%
Average interest and financing costs	5%

## INTERNAL CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures and internal control over financial reporting as defined in Rule 13a-15 under the U.S. Securities Exchange Act of 1934 and as defined in Canada under National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of Enerplus Corporation have concluded that, as at December 31, 2012, our disclosure controls and procedures and internal control over financial reporting were effective. There were no changes in our internal control over financial reporting during the period beginning on October 1, 2012 and ended December 31, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

## ADDITIONAL INFORMATION

Additional information relating to Enerplus, including our current Annual Information Form, is available under our profile on the SEDAR website at [www.sedar.com](http://www.sedar.com), on the EDGAR website at [www.sec.gov](http://www.sec.gov) and at [www.enerplus.com](http://www.enerplus.com).

## FORWARD-LOOKING INFORMATION AND STATEMENTS

*This MD&A contains certain forward-looking information and forward-looking statements within the meaning of applicable securities laws (“forward-looking information”). 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. In particular, but without limiting the foregoing, this MD&A contains forward-looking information pertaining to the following: expected 2013 average production volumes and the anticipated production mix; the results from our drilling program and the timing of related production; future oil and natural gas prices and our commodity risk management programs; future royalty rates on our production; anticipated cash and non-cash G&A and financing expenses; operating costs; capital spending levels in 2013 and its impact on our production level and land holdings; potential future asset impairments and reversals; the amount of our future abandonment and reclamation costs and decommissioning liabilities; future environmental expenses; our future U.S. cash taxes; deferred income taxes, our tax pools and the time at which we may pay Canadian cash taxes; future debt and working capital levels and debt-to-funds-flow ratio and adjusted payout ratio, financial capacity, liquidity and capital resources to fund capital spending and working capital requirements; the amount and timing of future cash dividends that we may pay to our shareholders; the amount and timing of future debt and equity issuances and expected use of proceeds therefrom; and the amount and timing, and use of proceeds from, future asset dispositions.*

*The forward-looking information contained in this MD&A reflects several material factors, expectations and assumptions including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and resource volumes; commodity price and cost assumptions; the continued availability of adequate debt and/or equity financing and funds flow to fund our capital and operating requirements and dividend payments as needed; the availability of third party services; and the extent of our liabilities. We believe the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.*

*The forward-looking information included in this MD&A is not a guarantee of future performance and should not be unduly relied upon. Such information involves 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 including, without limitation: changes in commodity prices; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties, increased debt levels or debt service requirements; inaccurate estimation of our 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; the impact of competitors; reliance on industry partners and third party service providers; a failure to complete planned asset dispositions on the terms anticipated or at all; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks and contingencies described under “Risk Factors and Risk Management” in this MD&A and in our other public filings.*

*The forward-looking information contained in this MD&A speaks only as of the date of this MD&A, and we do not assume any obligation to publicly update or revise such forward-looking information to reflect new events or circumstances, except as may be required pursuant to applicable laws.*

# Reports

## Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Under the supervision of our Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, we have concluded that as of December 31, 2012, our internal control over financial reporting is effective.

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

The effectiveness of the Company's internal control over financial reporting as of December 31, 2012, has been audited by Deloitte LLP, the Company's Independent Registered Chartered Accountants, who also audited the Company's Consolidated Financial Statements for the year ended December 31, 2012.



**Gordon J. Kerr**  
President and  
Chief Executive Officer

Calgary, Alberta  
February 21, 2013



**Robert J. Waters**  
Senior Vice President and  
Chief Financial Officer

## Report of Independent Registered Chartered Accountants

To the Board of Directors and Shareholders of Enerplus Corporation

We have audited the internal control over financial reporting of Enerplus Corporation and subsidiaries (the “Company”) as of December 31, 2012, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying management’s report on internal control over financial reporting. Our responsibility is to express an opinion on the Company’s internal control over financial reporting based on our audit.

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

A company’s internal control over financial reporting is a process designed by, or under the supervision of, the company’s principal executive and principal financial officers, or persons performing similar functions, and effected by the company’s board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with International Financial Reporting Standards. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with International Financial Reporting Standards, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as at and for the year ended December 31, 2012 of the Company and our report dated February 21, 2013 expressed an unqualified opinion on those financial statements.

*Deloitte LLP*

Independent Registered Chartered Accountants

February 21, 2013  
Calgary, Canada

## Management's Responsibility for Financial Statements

In management's opinion, the accompanying consolidated financial statements of Enerplus Corporation have been prepared within reasonable limits of materiality and in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board. Since a precise determination of many assets and liabilities is dependent on future events, the preparation of financial statements necessarily involves the use of estimates and approximations. These have been made using careful judgment and with all information available up to February 21, 2013. Management is responsible for all information in the annual report and for the consistency, therewith, of all other financial and operating data presented in this report.

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

The consolidated financial statements have been examined by Deloitte LLP, Independent Registered Chartered Accountants. Their responsibility is to express a professional opinion on the fair presentation of the consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board. The Independent Registered Chartered Accountants Report outlines the scope of their examination and sets forth their opinion.

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



**Gordon J. Kerr**  
President and  
Chief Executive Officer

Calgary, Alberta  
February 21, 2013



**Robert J. Waters**  
Senior Vice President and  
Chief Financial Officer

## Report of Independent Registered Chartered Accountants

To the Board of Directors and Shareholders of Enerplus Corporation

We have audited the accompanying consolidated financial statements of Enerplus Corporation and subsidiaries (the “Company”), which comprise the consolidated balance sheets as at December 31, 2012 and 2011, and the consolidated statements of income (loss) and comprehensive income (loss), changes in shareholders’ equity and cash flows for the years ended December 31, 2012 and 2011, and notes to the consolidated financial statements.

### Management’s Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

### Auditor’s Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor’s judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity’s preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

### Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enerplus Corporation and subsidiaries as at December 31, 2012 and 2011, and their financial performance and cash flows for the years ended December 31, 2012 and 2011 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

### Other Matter

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Enerplus Corporation’s internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 21, 2013 expressed an unqualified opinion on the Company’s internal control over financial reporting.

*Deloitte LLP*

Independent Registered Chartered Accountants

February 21, 2013  
Calgary, Canada

# Statements

## Consolidated Balance Sheets

(CDN\$ thousands)	Note	December 31, 2012	December 31, 2011
<b>Assets</b>			
Current assets			
Cash		\$ 5,200	\$ 5,629
Accounts receivable		150,372	124,806
Deferred financial assets	16	54,165	2,312
Other current		15,068	14,655
		\$ 224,805	\$ 147,402
Exploration and evaluation assets	4	773,820	874,799
Property, plant and equipment	5	4,242,447	4,332,011
Goodwill		151,390	154,691
Deferred financial assets	16	8,013	6,585
Other assets	8	11,687	207,824
<b>Total Assets</b>		<b>\$ 5,412,162</b>	<b>\$ 5,723,312</b>
<b>Liabilities</b>			
Current liabilities			
Accounts payable		\$ 274,387	\$ 422,666
Dividends payable		17,882	32,609
Current portion of long-term debt	9	45,566	46,808
Deferred financial credits	16	18,522	35,711
		\$ 356,357	\$ 537,794
Long-term debt	9	\$ 1,023,999	\$ 860,286
Deferred financial credits	16	17,127	31,820
Deferred tax liability	13	365,473	452,670
Decommissioning liability	10	599,652	563,763
		\$ 2,006,251	\$ 1,908,539
<b>Total Liabilities</b>		<b>\$ 2,362,608</b>	<b>\$ 2,446,333</b>
<b>Equity</b>			
Shareholders' capital	15	\$ 3,818,043	\$ 3,442,364
Contributed surplus	15	36,088	26,910
Accumulated deficit		(736,761)	(279,467)
Accumulated other comprehensive income/(loss)		(67,816)	87,172
		\$ 3,049,554	\$ 3,276,979
<b>Total Liabilities &amp; Equity</b>		<b>\$ 5,412,162</b>	<b>\$ 5,723,312</b>

See accompanying notes to the Consolidated Financial Statements

Approved on behalf of the Board of Directors:



**Douglas R. Martin**  
Director



**Robert B. Hodgins**  
Director

## Consolidated Statements of Income (loss) and Comprehensive Income (loss)

For the year ended December 31 (CDN\$ thousands)	Note	2012	2011
<b>Revenues</b>			
Oil and gas sales		\$ 1,365,542	\$ 1,363,726
Royalties		(268,831)	(245,230)
Commodity derivative instruments gain/(loss)	16	91,995	(27,092)
		<u>\$ 1,188,706</u>	<u>\$ 1,091,404</u>
<b>Expenses</b>			
Operating		\$ 319,644	\$ 281,217
General and administrative		78,341	67,660
Equity based compensation	15	15,503	26,773
Transportation		26,569	20,647
Depletion, depreciation and amortization	5	510,758	433,366
Impairments	6	531,825	359,703
Foreign exchange (gain)/loss	12	(17,204)	4,216
Finance expense	11	70,127	60,439
Asset disposition (gain)	7	(131,166)	(302,053)
Other expense/(income)		1,276	(2,576)
		<u>\$ 1,405,673</u>	<u>\$ 949,402</u>
<b>Income/(loss) before taxes</b>			
Current tax expense/(recovery)	13	1,647	81,195
Deferred tax expense/(recovery)	13	(62,880)	(48,630)
		<u>\$ (155,734)</u>	<u>\$ 109,437</u>
<b>Net Income/(loss)</b>			
<b>Other Comprehensive Income</b>			
Change due to marketable securities (net of tax)	8		
Unrealized gains/(losses)		\$ (69,728)	\$ 50,658
Realized gains reclassified to net income/(loss)		(39,491)	-
Change in cumulative translation adjustment		(45,769)	36,536
		<u>\$ (154,988)</u>	<u>\$ 87,194</u>
<b>Other Comprehensive Income/(loss), net of tax</b>			
		<u>\$ (154,988)</u>	<u>\$ 87,194</u>
<b>Total Comprehensive Income/(loss)</b>			
		<u>\$ (310,722)</u>	<u>\$ 196,631</u>
Net income/(loss) per share			
Basic		\$ (0.80)	\$ 0.61
Diluted		\$ (0.80)	\$ 0.61
Weighted average number of shares outstanding (thousands)			
Basic	15	195,633	179,889
Diluted		195,633	180,345

See accompanying notes to the Consolidated Financial Statements

## Consolidated Statements of Changes in Shareholders' Equity

For the year ended December 31 (CDN\$ thousands)	2012	2011
<b>Shareholders' Capital</b>		
Balance, beginning of year	\$ 3,442,364	\$ 5,639,380
Reclassification of EELP units	–	44,387
Reclassification of accumulated deficit	–	(2,314,775)
Public offering	330,618	–
Stock Option Plan – cash	1,180	11,626
Stock Option Plan – non cash	1,119	9,371
Dividend Reinvestment Plan	19,150	52,375
Stock Dividend Program	23,612	–
Balance, end of year	\$ 3,818,043	\$ 3,442,364
<b>Contributed Surplus</b>		
Balance, beginning of year	\$ 26,910	\$ 3,795
Reclassification of trust unit rights liability	–	20,156
Stock Option Plan – exercised	(1,119)	(9,371)
Stock Option Plan – expensed	10,297	12,330
Balance, end of year	\$ 36,088	\$ 26,910
<b>Accumulated Deficit</b>		
Balance, beginning of year	\$ (279,467)	\$ (2,314,775)
Reclassification to Shareholders' Capital	–	2,314,775
Net income/(loss)	(155,734)	109,437
Dividends to shareholders	(301,560)	(388,904)
Balance, end of year	\$ (736,761)	\$ (279,467)
<b>Accumulated other comprehensive income</b>		
Balance, beginning of year	\$ 87,172	\$ (22)
Changes due to marketable securities (net of tax)		
Unrealized gains/(losses)	(69,728)	50,658
Realized gains reclassified to net income	(39,491)	–
Change in cumulative translation adjustment	(45,769)	36,536
Balance, end of year	\$ (67,816)	\$ 87,172
<b>Total Equity</b>	<b>\$ 3,049,554</b>	<b>\$ 3,276,979</b>

See accompanying notes to the Consolidated Financial Statements

## Consolidated Statements of Cash Flows

For the year ended December 31 (CDN\$ thousands)	2012	2011
<b>Operating Activities</b>		
Net income/(loss)	\$ (155,734)	\$ 109,437
Non-cash items add/(deduct):		
Depletion, depreciation and amortization	510,758	433,366
Impairments	531,825	359,703
Change in fair value of derivative instruments	(85,163)	(31,920)
Deferred tax expense/(recovery)	(62,880)	(48,630)
Foreign exchange loss/(gain) on U.S. dollar debt	(7,647)	7,185
Accretion expense	13,522	13,803
Equity based compensation – Stock Option Plan	10,297	12,330
Amortization of debt transaction costs	1,693	1,269
Derivative settlement on senior notes principal repayment	18,406	19,119
Asset disposition gain	(131,166)	(302,053)
Funds Flow	\$ 643,911	\$ 573,609
Decommissioning expenditures	(19,905)	(21,656)
Changes in non-cash operating working capital	(88,929)	71,487
Cash flow from operating activities	\$ 535,077	\$ 623,440
<b>Financing Activities</b>		
Issuance of shares	\$ 350,948	\$ 64,001
Cash dividends	(277,948)	(388,904)
Change in bank debt	(189,251)	212,732
Repayment on senior notes	(46,236)	(45,523)
Proceeds from senior note issue	406,088	–
Derivative settlement on senior notes principal repayment	(18,406)	(19,119)
Changes in non-cash financing working capital	(14,727)	451
Cash flow from financing activities	\$ 210,468	\$ (176,362)
<b>Investing Activities</b>		
Capital expenditures	\$ (864,684)	\$ (876,975)
Property and land acquisitions	(185,337)	(255,209)
Property dispositions	245,771	641,190
Sale of equity investments	146,898	1,544
Changes in non-cash investing working capital	(90,252)	38,592
Cash flow from investing activities	\$ (747,604)	\$ (450,858)
Effect of exchange rate changes on cash	\$ 1,630	\$ 1,035
Change in cash	\$ (429)	\$ (2,745)
Cash, beginning of year	5,629	8,374
<b>Cash, end of year</b>	<b>\$ 5,200</b>	<b>\$ 5,629</b>
<b>Supplementary Cash Flow Information</b>		
Cash income taxes paid	\$ 17,946	\$ 49,592
Cash interest paid	\$ 49,826	\$ 47,756

See accompanying notes to the Consolidated Financial Statements

# Notes

## Notes to Consolidated Financial Statements

### 1. REPORTING ENTITY

These annual audited consolidated financial statements (“Consolidated Financial Statements”) and notes present the results of Enerplus Corporation including its Canadian and U.S. subsidiaries. Enerplus is a North American crude oil and natural gas exploration and development company. Enerplus is publicly traded on the Toronto and New York stock exchanges under the ticker symbol ERF. Enerplus’ head office is located in Calgary, Alberta, Canada. The Consolidated Financial Statements were authorized for issue by the Board of Directors on February 21, 2013.

### 2. BASIS OF PREPARATION

Enerplus’ Consolidated Financial Statements for the years ended December 31, 2012 and 2011 are prepared in accordance with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board (“IASB”). These Consolidated Financial Statements present Enerplus’ results of operations and financial position under IFRS as at and for the year ended December 31, 2012, and the 2011 comparative periods.

#### (a) Basis of Measurement

The Consolidated Financial Statements have been prepared on the historical cost basis except for the following items which are measured at fair value:

- cash;
- derivative financial instruments;
- available for sale financial instruments; and
- share-based payment transactions.

#### (b) Functional and Presentation Currency

These Consolidated Financial Statements are presented in Canadian dollars, which is Enerplus’ functional currency. All financial information presented in Canadian dollars has been rounded to the nearest thousand unless otherwise indicated.

#### (c) Use of Estimates and Judgment

The preparation of financial statements requires management to use judgment, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results could differ from those estimated.

The amounts recorded for depletion and depreciation of the oil and gas assets 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. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future periods affected.

The provision for decommissioning liability is based on current legal and constructive requirements, technology, estimated costs and expected timing for remediation. Actual costs can differ from estimated costs because of changes in laws and regulations, market conditions, discovery and analysis of site conditions and changes in technology.

IFRS requires that the Company’s oil and gas assets be aggregated into cash-generating units, based on their ability to generate largely independent cash flows, which are used to assess the assets for impairment. The determination of the Company’s cash-generating units is subject to management’s judgment.

The decision to transfer assets from exploration and evaluation to property, plant and equipment is based on management’s assessment of technical feasibility and commercial viability and this is subject to management’s judgment.

The estimated fair value of derivative instruments, by their very nature, are subject to measurement uncertainty.

Compensation costs recorded for the stock option plan are subject to estimation as they are calculated using the Black Scholes option pricing model which is based on significant assumptions such as volatility, dividend yield, expected term and forfeiture rate. Other compensation plans are performance based and are also subject to management's judgment as to whether or not certain performance criteria will be met.

The determination of the income tax provision and other tax issues can be complex and require management judgment. As such, income taxes are subject to measurement uncertainty. Income tax filings are subject to audits and re-assessments and changes in facts, circumstances and interpretations may result in an increase or decrease in the Company's provision for income taxes.

Additional details concerning estimates and judgment have been provided in Note 3.

### 3. SIGNIFICANT ACCOUNTING POLICIES

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) Basis of Consolidation

These Consolidated Financial Statements include the accounts of Enerplus and its subsidiaries. Intercompany balances and transactions are eliminated on consolidation. Interests in jointly controlled assets are accounted for using the proportionate consolidation method, whereby Enerplus' proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

The acquisition method of accounting is used to account for acquisitions of companies and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets transferred, equity instruments issued and liabilities incurred or assumed at the acquisition date. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date.

#### (b) Revenue

Revenue associated with the sale of crude oil and natural gas is recognized when title passes from the Company to its customers and is measured at the fair value of the consideration received or receivable based on price, volumes delivered and contractual delivery points. Realized gains and losses from commodity price risk management activities are recognized in revenue when the contract is settled and unrealized gains and losses on commodity price risk management activities are recognized in revenue based on the changes in fair value of the contracts at the end of the respective reporting period.

#### (c) Exploration and Evaluation Assets ("E&E") and Property, Plant and Equipment ("PP&E")

##### (i) E&E Assets

Costs incurred prior to acquiring the legal right to explore an area are charged directly to net income.

Costs incurred after the legal right to explore is obtained but before technical feasibility and commercial viability of the area has been established are capitalized as E&E assets. These assets include both tangible and intangible costs such as unproved property acquisition costs, geological and geophysical costs, sampling and appraisals, related drilling and completion costs and directly attributable internal costs.

Once an area is determined to be technically feasible and commercially viable the accumulated costs are tested for impairment. The carrying value, net of any impairment, is then reclassified to PP&E as a Developed and Producing ("D&P") asset. If an area is determined not to be technically feasible and commercially viable, or the Company discontinues its exploration and evaluation activity, any unrecoverable costs are charged to net income.

##### (ii) PP&E

All costs directly associated with the development of crude oil and natural gas reserves are capitalized on an area-by-area basis if they extend or enhance the recoverable reserves of the underlying assets. These expenditures are referred to as D&P assets and include assets where technical feasibility and commercial viability has been determined. Costs in this category include property acquisitions, drilling and completion costs, gathering and infrastructure, capitalized decommissioning costs, directly attributable internal costs and transfers of exploration and evaluation assets. Repairs and maintenance and operational costs that do not extend or enhance the recoverable reserves are charged to net income in the period.

D&P assets are aggregated into cash generating units (“CGUs”) for the purposes of impairment testing and depletion calculations. CGUs are groups of assets that generate independent cash inflows and are generally defined based on geographic areas, with consideration given to how the assets are managed.

Gains and losses on disposals of properties are determined by comparing the proceeds to the net carrying value of the property and are recognized in net income.

#### **(d) Depletion and Depreciation**

The net carrying value of D&P assets is depleted using the unit of production method, calculated as the ratio of production in the year compared to the related proved plus probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Natural gas reserves and production are converted to equivalent units on the basis of 6 mcf = 1 bbl, reflecting the approximate energy content. Proved plus probable reserves are generally estimated using independent reserve engineers and represent the estimated quantities of crude oil and natural gas which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be economically recoverable in future years.

E&E assets are not depleted.

#### **(e) Impairment**

##### **(i) E&E**

E&E assets are tested for impairment when indicators of impairment exist or when technical feasibility and commercial viability are established and the assets are reclassified to PP&E. The impairment test compares the E&E assets’ carrying value to their recoverable amount plus any excess recoverable amounts on D&P assets on a country by country basis. E&E assets that are determined not to be technically feasible and commercially viable are charged to net income.

##### **(ii) PP&E and Goodwill**

D&P assets included in PP&E are reviewed for impairment at a CGU level when indicators of impairment exist. When indicators of impairment exist, the carrying value of each CGU, including goodwill, is compared to its recoverable amount which is defined as the higher of its fair value less cost to sell (“FVLCTS”) or its value in use (“VIU”). FVLCTS is determined to be the amount for which the asset could be sold in an arm’s length transaction. VIU is based upon the estimated before tax net present value of the Company’s proved plus probable reserves, as prepared by independent reserve evaluators. These estimates of future net revenues are based on forecast prices and costs, and are stated prior to the provision of financing and general and administrative expenses and after the deduction of royalties and estimated future capital expenditures. Forecast prices reflect heating values, quality differentials and transportation costs specific to the Company’s assets. Estimated future net revenues are discounted using the Company’s weighted average cost of capital.

Where the carrying value exceeds the recoverable amount an impairment loss exists and is charged to net income. Impairment losses are first recorded against goodwill within a CGU and the remainder is recorded against the D&P assets.

Reversals of impairments are recognized when events or circumstances that triggered the original impairment have changed. Impairments can only be reversed in future periods up to the carrying amount that would have been determined, net of depletion and depreciation, had no impairment losses been previously recognized. Goodwill impairments are not reversible.

#### **(f) Foreign Currency**

##### **(i) Foreign currency transactions**

Transactions in foreign currencies are generally translated to Canadian dollars at the average exchange rate for the period. Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars at the period end exchange rate. Foreign currency differences arising on translation are recognized in net income in the period in which they arise.

**(ii) Foreign operations**

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

**(g) Financial Instruments**

Financial instruments are classified into one of five categories: fair value through profit or loss, held to maturity investments, loans and receivables, available for sale financial assets or other liabilities.

**(i) Non-derivative financial instruments**

Non-derivative financial instruments comprise cash, accounts receivable, accounts payable, dividends payable to shareholders and debt. Cash is classified as "fair value through profit or loss" and is carried at fair value. Accounts receivable are classified as "loans and receivables" and are carried at amortized cost less any allowance for impairment. Accounts payable, dividends payable to shareholders and debt are classified as "other financial liabilities" and are carried at amortized cost using the effective interest method.

Enerplus has certain equity investments in entities involved in the oil and gas industry which are included in other assets on the Consolidated Balance Sheets. These investments are classified as "available-for-sale" and are carried at fair value with changes in fair value recorded in other comprehensive income. The fair value of investments that are publicly traded are determined by reference to quoted market bid prices at the close of business on the balance sheet date. For investments where there is no public market, fair value is determined using valuation techniques including using recent arm's length market transactions. When investments are 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.

Enerplus capitalizes transaction costs and premiums on long-term debt. These costs are amortized using the effective interest method.

**(ii) Derivative financial instruments**

Enerplus enters into financial derivative contracts in order to manage its exposure to market risks from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. Enerplus has not designated its financial derivative contracts as effective accounting hedges, and thus has not applied hedge accounting, even though it considers most of these contracts to be economic hedges. As a result, all financial derivative contracts are classified as "fair value through profit or loss" and are recorded at fair value on the Consolidated Balance Sheets with changes in fair value recorded in net income. The fair values of these derivative instruments are generally based on an estimate of the amounts that would be paid or received to settle these instruments at the balance sheet date.

Enerplus accounts for its physical delivery purchase and sales contracts as executory contracts as they were entered into and continue to be held for the purpose of receipt or delivery of products in accordance with its expected purchase, sale or usage requirements. As such, these contracts are not considered to be derivative financial instruments. Settlements on these physical contracts are recognized in net income over the term of the contracts as they occur.

**(h) Goodwill**

Enerplus 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 portion of goodwill that relates to its U.S. operations fluctuates due to changes in foreign exchange rates. For the purposes of impairment testing, goodwill is allocated to the CGUs that benefited from the synergies of the respective business combinations and is tested for impairment in conjunction with the CGU on an annual basis. Goodwill is stated at cost less impairment and is not amortized. Goodwill is not deductible for income tax purposes.

**(i) Assets Held for Sale**

Non-current assets, or disposal groups consisting of assets and liabilities, are classified as held for sale if management intends to sell the assets, the sale is highly probable and the assets are available for immediate sale in their present condition.

Assets classified as held for sale are measured at the lower of the carrying amount and fair value less costs to sell. Any impairments are recognized in net income in the period measured. Non-current assets and disposal groups held for sale are

presented in current assets and liabilities within the Consolidated Balance Sheets. Assets held for sale are not depreciated, depleted or amortized.

#### **(j) Share Based Payments**

Enerplus uses the Black Scholes option pricing model to calculate the grant date fair value of stock options granted under the Company's stock option plan. This amount is charged to earnings as equity based compensation over the vesting period of the options, with a corresponding increase in contributed surplus. When options are exercised, the proceeds, together with the amount recorded in contributed surplus, are recorded to shareholders' capital.

Enerplus recognizes a liability in respect of its cash settled Performance Share, Restricted Share and Director Share incentive plans, based on their estimated fair value. The liability is re-measured at each reporting date and at settlement date with any changes in the fair value recorded as equity based compensation in net income.

#### **(k) Provisions**

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by recognizing the present value of the estimated future cash flows, discounted using a risk-free rate.

#### **(l) Decommissioning Liabilities**

Enerplus' oil and gas operating activities give rise to dismantling, decommissioning and site remediation activities. Enerplus recognizes a liability for the estimated present value of the future decommissioning liabilities at each balance sheet date. The associated decommissioning cost is capitalized and amortized over the same period as the underlying asset. Changes in the estimated liability resulting from revisions to estimated timing, amount of cash flows, or changes in the discount rate are recognized as a change in the decommissioning liability and related capitalized decommissioning cost.

Amortization of capitalized decommissioning costs is included in depreciation, depletion and amortization in net income. Increases in decommissioning liabilities resulting from the passage of time are recorded as accretion which is included with finance expense in net income. Actual expenditures incurred are charged against the decommissioning liability.

#### **(m) Income Tax**

Income tax expense is comprised of current and deferred tax.

Current tax is the expected tax payable on taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, along with any adjustment to tax payable in respect of previous years.

Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax is recognized in net income except to the extent that it relates to items recognized directly in equity. Deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

#### **(n) Net Income Per Share**

Basic net income per common share is computed by dividing net income by the weighted average number of common shares outstanding during the period.

For the diluted net income per common share calculation, the weighted average number of shares outstanding is adjusted for the potential number of shares which may have a dilutive effect on net income. The weighted average number of diluted shares is calculated in accordance with the treasury stock method which assumes that the proceeds received from the exercise of all stock options would be used to repurchase common shares at the average market price.

**(o) Recent Pronouncements Issued**

The following Standards and Interpretations which have not been applied in these financial statements have been released but not yet effective at December 31, 2012.

- IFRS 7 *Financial Instruments Disclosures* – Amendments to this standard are required to be adopted for annual periods beginning January 1, 2013. The adoption of this standard is not expected to have any impact on Enerplus' financial statements.
- IFRS 9 *Financial Instruments* – The standard is required to be adopted for periods beginning January 1, 2015. Portions of the standard remain in development and the full impact of the standard will not be known until the project is complete.
- IFRS 10 *Consolidated Financial Statements* – The standard is required to be adopted for periods beginning January 1, 2013. The adoption of this standard is not expected to have any impact on Enerplus' financial statements.
- IFRS 11 *Joint Arrangements* – The standard is required to be adopted for periods beginning January 1, 2013. The adoption of this standard is not expected to have any impact on Enerplus' financial statements.
- IFRS 12 *Disclosure of Interests in Other Entities* – The standard is required to be adopted for periods beginning January 1, 2013. The adoption of this standard is not expected to have any impact on Enerplus' financial statements.
- IFRS 13 *Fair Value Measurement* – The standard is required to be adopted for periods beginning January 1, 2013. The adoption of this standard is not expected to have any impact on Enerplus' financial statements.
- IAS 27 *Consolidation and Separate Financial Statements* – The standard is required to be adopted for periods beginning January 1, 2013. The adoption of this standard is not expected to have any impact on Enerplus' financial statements.
- IAS 28 *Investments in Joint Ventures* – The standard is required to be adopted for periods beginning January 1, 2013. The adoption of this standard is not expected to have any impact on Enerplus' financial statements.
- IAS 32 *Financial Instruments Presentation* – Amendments to this standard are required to be adopted for annual periods beginning January 1, 2014. The adoption of this standard is not expected to have any impact on Enerplus' financial statements.

**4. E&E ASSETS**

Carrying value (\$ thousands)	E&E assets
At December 31, 2010	\$ 1,545,378
Capital spending and acquisitions	620,172
Dispositions	(300,629)
Transfers to Property, Plant and Equipment	(969,036)
Impairment expense, net	(25,401)
Foreign currency translation adjustment	4,315
At December 31, 2011	\$ 874,799
Capital spending and acquisitions	265,893
Dispositions	(23,794)
Transfers to Property, Plant and Equipment	(214,761)
Impairment expense	(113,824)
Foreign currency translation adjustment	(14,493)
<b>As at December 31, 2012</b>	<b>\$ 773,820</b>

As at December 31, 2012 the E&E asset balance of \$773,820,000 (December 31, 2011 – \$874,799,000) consists of undeveloped lands and assets that management has not fully evaluated for technical feasibility and commercial viability.

## 5. PP&E

Carrying value before accumulated depletion and depreciation (\$ thousands)	D&P assets	Office and other	Total
As at December 31, 2010	\$ 4,253,439	\$ 59,542	\$ 4,312,981
Capital spending and acquisitions	500,748	11,264	512,012
Transfers from Exploration and Evaluation	969,036	–	969,036
Change in decommissioning costs (Note 10)	179,635	–	179,635
Dispositions	(39,305)	–	(39,305)
Foreign currency translation adjustment	41,306	210	41,516
As at December 31, 2011	\$ 5,904,859	\$ 71,016	\$ 5,975,875
Capital spending and acquisitions	772,350	11,778	784,128
Transfers from Exploration and Evaluation	214,761	–	214,761
Change in decommissioning costs (Note 10)	75,381	–	75,381
Dispositions	(244,907)	–	(244,907)
Foreign currency translation adjustment	(38,290)	(206)	(38,496)
<b>As at December 31, 2012</b>	<b>\$ 6,684,154</b>	<b>\$ 82,588</b>	<b>\$ 6,766,742</b>

Accumulated Depletion and Depreciation	D&P assets	Office and other	Total
As at December 31, 2010	\$ 827,331	\$ 45,082	\$ 872,413
Depletion, Depreciation and Amortization	425,806	7,560	433,366
Impairment expense	334,302	–	334,302
Foreign currency translation adjustment	3,760	23	3,783
As at December 31, 2011	\$ 1,591,199	\$ 52,665	\$ 1,643,864
Depletion, Depreciation and Amortization	502,991	7,767	510,758
Impairment expense	418,001	–	418,001
Dispositions	(44,075)	–	(44,075)
Foreign currency translation adjustment	(4,213)	(40)	(4,253)
<b>As at December 31, 2012</b>	<b>\$ 2,463,903</b>	<b>\$ 60,392</b>	<b>\$ 2,524,295</b>

Net Carrying Value	D&P assets	Office and other	Total
As at December 31, 2010	\$ 3,426,108	\$ 14,460	\$ 3,440,568
As at December 31, 2011	\$ 4,313,660	\$ 18,351	\$ 4,332,011
<b>As at December 31, 2012</b>	<b>\$ 4,220,251</b>	<b>\$ 22,196</b>	<b>\$ 4,242,447</b>

## 6. IMPAIRMENT

(\$ thousands)	2012	2011
D&P assets	\$ 418,001	\$ 334,302
E&E assets	113,824	35,548
E&E impairment reversal	–	(10,147)
<b>Impairment expense</b>	<b>\$ 531,825</b>	<b>\$ 359,703</b>

The estimated recoverable amounts used for impairment testing were based on the respective assets value in use, calculated using proved plus probable reserves discounted at 10%. D&P asset impairments recorded for the years ended December 31, 2012 and 2011 relate to the impact of lower forecast commodity prices on Enerplus' natural gas focused CGUs. E&E asset impairments of \$113,824,000 for the year ended December 31, 2012 (December 31, 2011 – \$35,548,000) relate to expiring undeveloped land and unrecoverable costs on other projects where activity is being discontinued. There were no E&E asset impairment reversals for the

year ended December 31, 2012. E&E asset impairment reversals of \$10,147,000 for the year ended December 31, 2011 relate to an increase in the estimated recoverable amount for certain E&E assets.

The following table outlines forecasted commodity prices and exchange rates used in Enerplus' CGU impairment tests at December 31, 2012. The forecast commodity prices are consistent with those used by Enerplus' external reserve evaluators.

Year	WTI Crude Oil <sup>(1)</sup> US\$/bbl	Exchange Rate US\$/CDN\$	Edm Light Crude <sup>(1)</sup> CDN\$/bbl	U.S. Henry Hub Gas price <sup>(1)</sup> US\$/Mcf	Natural Gas 30 day spot @ AECO <sup>(1)</sup> CDN\$/Mcf
2013	\$ 92.50	\$ 1.00	\$ 87.50	\$ 3.75	\$ 3.35
2014	92.50	1.00	90.50	4.30	3.85
2015	93.60	1.00	92.60	4.85	4.35
2016	95.50	1.00	94.50	5.25	4.70
2017	97.40	1.00	96.40	5.70	5.10
Thereafter <sup>(2)</sup>	+2% yr	1.00	+2% yr	+2% yr	+2% yr

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

(2) Escalation varies after 2017.

## 7. ASSET DISPOSITION GAIN

During the year ended December 31, 2012 Enerplus recorded a gain of \$131,166,000 (December 31, 2011 – \$302,053,000) related to the sale of certain properties and marketable securities.

(\$ thousands)	2012	2011
Gain on property dispositions	\$ 83,800	\$ 301,950
Gain on sale of marketable securities	47,366	103
<b>Total asset disposition gain</b>	<b>\$ 131,166</b>	<b>\$ 302,053</b>

## 8. OTHER ASSETS

Other assets of \$11,687,000 (December 31, 2011 – \$207,824,000) represent Enerplus' marketable securities portfolio. During the year ended December 31, 2012 Enerplus sold certain marketable securities for proceeds of \$146,898,000 (net of transaction costs of \$1,785,000) recognizing a gain of \$47,366,000. In connection with these sales, realized gains of \$39,491,000 net of tax (\$46,770,000 before tax) were reclassified from accumulated other comprehensive income to net income.

For the year ended December 31, 2012 the change in fair value of these investments represented unrealized losses of \$69,728,000 net of tax (\$79,835,000 before tax). For the year ended December 31, 2011 the change in fair value of these investments represented unrealized gains of \$50,658,000 (\$58,555,000 before tax).

## 9. DEBT

(\$ thousands)	December 31, 2012	December 31, 2011
Current:		
Current portion of long-term debt	\$ 45,566	\$ 46,808
	\$ 45,566	\$ 46,808
Long-term:		
Bank credit facility	\$ 260,950	\$ 446,182
Senior notes		
CDN\$30 million (Matures May 15, 2019)	30,000	–
US\$20 million (Matures May 15, 2022)	19,898	–
US\$355 million (Matures May 15, 2024)	353,190	–
CDN\$40 million (Matures June 18, 2015)	40,000	40,000
US\$40 million (Matures June 18, 2015)	39,796	40,680
US\$225 million (Matures June 18, 2021)	223,853	228,825
US\$54 million (Matures October 1, 2015) <sup>(1)</sup>	21,490	32,951
US\$175 million (Matures June 19, 2014) <sup>(2)</sup>	34,822	71,648
	\$ 1,023,999	\$ 860,286
<b>Total debt</b>	<b>\$ 1,069,565</b>	<b>\$ 907,094</b>

(1) The outstanding U.S principal as at December 31, 2012 was US\$32,400, a portion of which is classified as current.

(2) The outstanding U.S principal as at December 31, 2012 was US\$70,000, a portion of which is classified as current.

### Bank Credit Facility

Enerplus has an unsecured, covenant-based, \$1 billion bank credit facility that matures on October 31, 2015. Drawn fees range between 160 and 325 basis points over bankers' acceptance rates, with current drawn fees of 180 basis points. Standby fees on the undrawn portion of the facility are based on 20% of the drawn pricing. The Company has the ability to request an extension of the facility each year or repay the entire balance at the end of the term. At December 31, 2012 Enerplus had \$260,950,000 drawn and was in compliance with all financial covenants under the facility. During 2012 a fee of \$700,000 was paid to extend the facility. The weighted average interest rate on the facility for the year ended December 31, 2012 was 2.4% (December 31, 2011 – 2.7%).

### Senior Notes

On May 15, 2012 Enerplus closed a private offering of senior unsecured notes raising gross proceeds of approximately \$405,000,000. The notes rank equally with the bank credit facility and other outstanding senior notes.

On June 19, 2012 Enerplus made its third principal repayment on the US\$175 million senior notes and associated cross currency interest rate swap principal settlement for a total of \$53,666,000. On October 1, 2012 Enerplus made its second principal repayment and associated foreign exchange swap settlement on the US\$54 million senior notes for a total of \$10,976,000.

The terms and rates of the Company's outstanding senior notes are detailed below:

Issue Date	Original Principal (\$ thousands)	Remaining Principal (\$ thousands)	Coupon Rate	Interest Payment Dates	Repayment
May 15, 2012	CDN\$30,000	CDN\$30,000	4.34%	May 15 and Nov 15	Bullet payment on May 15, 2019
May 15, 2012	US\$20,000	US\$20,000	4.40%	May 15 and Nov 15	Bullet payment on May 15, 2022
May 15, 2012	US\$355,000	US\$355,000	4.40%	May 15 and Nov 15	5 equal annual installments beginning May 15, 2020
June 18, 2009	CDN\$40,000	CDN\$40,000	6.37%	June 18 and Dec 18	Bullet payment on June 18, 2015
June 18, 2009	US\$40,000	US\$40,000	6.82%	June 18 and Dec 18	Bullet payment on June 18, 2015
June 18, 2009	US\$225,000	US\$225,000	7.97%	June 18 and Dec 18	5 equal annual installments beginning June 18, 2017
Oct 1, 2003	US\$54,000	US\$32,400	5.46%	April 1 and Oct 1	5 equal annual installments beginning Oct 1, 2011
June 19, 2002	US\$175,000	US\$70,000	6.62%	June 19 and Dec 19	5 equal annual installments beginning June 19, 2010

## 10. DECOMMISSIONING LIABILITY

Enerplus has estimated the net present value of its decommissioning liability to be \$599,652,000 at December 31, 2012 compared to \$563,763,000 at December 31, 2011, based on a total undiscounted liability of \$659,714,000 and \$644,922,000 respectively. The decommissioning liability was calculated using a risk free rate of 2.36% at December 31, 2012 (December 31, 2011 – 2.49%). Enerplus' decommissioning expenditures are expected to be incurred over the next 66 years with the majority between 2022 and 2052. The change in capitalized decommissioning costs for the year ended December 31, 2012 was \$75,381,000 (December 31, 2011 – \$179,635,000).

(\$ thousands)	December 31, 2012	December 31, 2011
Decommissioning liability, beginning of year	\$ 563,763	\$ 392,709
Change in estimates	69,822	174,807
Property acquisition and development activity	5,559	4,828
	\$ 75,381	\$ 179,635
Dispositions	(33,584)	(692)
Decommissioning expenditures	(19,905)	(21,656)
Accretion	13,522	13,803
Foreign currency translation adjustment	475	(36)
<b>Decommissioning liability, end of year</b>	<b>\$ 599,652</b>	<b>\$ 563,763</b>

## 11. FINANCE EXPENSE

(\$ thousands)	2012	2011
Realized:		
Interest on bank debt and senior notes	\$ 53,074	\$ 47,049
Unrealized:		
Cross currency interest rate swap (gain)/loss	2,963	355
Interest rate swap (gain)/loss	(1,125)	(2,037)
Debt transaction cost amortization	1,693	1,269
Accretion of decommissioning liability	13,522	13,803
<b>Finance expense</b>	<b>\$ 70,127</b>	<b>\$ 60,439</b>

## 12. FOREIGN EXCHANGE

(\$ thousands)	2012	2011
Realized:		
Foreign exchange (gain)/loss	\$ 6,508	\$ 18,421
Unrealized:		
Translation of U.S. dollar debt (gain)/loss	(7,647)	7,185
Cross currency interest rate swap (gain)/loss	(15,118)	(15,133)
Foreign exchange swaps (gain)/loss	(947)	(6,257)
<b>Foreign exchange (gain)/loss</b>	<b>\$ (17,204)</b>	<b>\$ 4,216</b>

### 13. INCOME TAXES

The deferred tax liability arises as a result of the following temporary differences:

(\$ thousands)	Deferred Tax Liability/(Asset)	
	December 31, 2012	December 31, 2011
PP&E and E&E assets	\$ 894,601	\$ 929,494
Tax loss carry-forwards and other credits	(388,816)	(354,513)
Decommissioning liability	(156,048)	(144,937)
Long-Term debt	10,825	12,807
Investments in other entities	(2,193)	27,156
Deferred financial assets and credits	10,320	(9,209)
Other assets and liabilities	(3,216)	(8,128)
<b>Deferred tax liability/(asset)</b>	<b>\$ 365,473</b>	<b>\$ 452,670</b>

Deferred tax assets have not been recognized for realized capital losses in Canada for approximately \$1.2 billion at December 31, 2012 (December 31, 2011 – \$1.1 billion) as it is not probable that future taxable capital gains will be available against which the company can utilize the losses. These losses have an indefinite carry-forward period.

The Company has income tax filings that are subject to audit and potential reassessment whereby the audit findings may impact the Company's tax liability. The Company does not anticipate adjustments arising from these audits that would materially affect its financial position and believes that it has adequately provided for current and deferred income taxes.

The following provides a reconciliation of effective tax expense:

(\$ thousands)	2012	2011
Income/(loss) before taxes	\$ (216,967)	\$ 142,002
Income tax (recovery)/expense at the applicable Canadian rate of 25.32% (26.82% for 2011) <sup>(1)</sup>	\$ (54,936)	\$ 38,085
Recovery due to change in tax rate on undistributed profits	–	(34,118)
Effect of tax rates in foreign jurisdictions	(6,142)	34,312
Effect of differences in applicable tax rates	(4,200)	2,163
Reversal/(Recognition) of realized capital losses	8,840	(11,688)
Non-taxable portion of gains	(7,178)	(364)
Equity based compensation	2,574	3,307
Other	(191)	868
<b>Tax (recovery)/expense</b>	<b>\$ (61,233)</b>	<b>\$ 32,565</b>

(1) The applicable rate consists of the combined Federal and Provincial statutory corporate tax rates in Canada for the years ended December 31, 2012 and December 31, 2011. The combined Federal and Provincial corporate tax rate lowered to 25.32% in 2012 from 26.82% in 2011 due to a decrease in the Federal rate of 1.5% (16.5% in 2011 to 15% in 2012).

The detail of the Company's tax expense is as follows:

For the year ended December 31, 2012 (\$ thousands)	Canadian	U.S.	Total
<b>Current tax expense/(recovery)</b>	\$ (2,074)	\$ 3,721	\$ 1,647
<b>Deferred tax expense/(recovery)</b>			
Changes in temporary differences	\$ (77,393)	\$ 5,673	\$ (71,720)
Reversal of previously recognized tax losses	8,840	–	8,840
	\$ (68,553)	\$ 5,673	\$ (62,880)
<b>Total tax expense/(recovery)</b>	<b>\$ (70,627)</b>	<b>\$ 9,394</b>	<b>\$ (61,233)</b>
For the year ended December 31, 2011 (\$ thousands)	Canadian	U.S.	Total
<b>Current tax expense/(recovery)</b>	\$ 569	\$ 80,626	\$ 81,195
<b>Deferred tax expense/(recovery)</b>			
Changes in temporary differences	\$ (110,239)	\$ 99,237	\$ (11,002)
Recognition of previously unrecognized tax losses	(11,688)	(25,940)	(37,628)
	\$ (121,927)	\$ 73,297	\$ (48,630)
<b>Total tax expense/(recovery)</b>	<b>\$ (121,358)</b>	<b>\$ 153,923</b>	<b>\$ 32,565</b>

Deferred income tax recovery recognized in Other Comprehensive Income totaled \$17,386,000 for 2012 (\$7,647,000 expense for 2011) related to marketable securities.

#### 14. KEY MANAGEMENT PERSONNEL EXPENSE

Key management personnel are comprised of all officers and directors of the Company.

(\$ thousands)	2012	2011
Salaries, benefits and other	\$ 9,265	\$ 9,601
Equity based compensation <sup>(1)</sup>	6,114	12,384
<b>Total key management personnel expenses</b>	<b>\$ 15,379</b>	<b>\$ 21,985</b>

(1) Includes costs related to the stock option and long term incentive plans.

#### 15. SHAREHOLDERS' CAPITAL

##### (a) Share Capital

Authorized unlimited number of common shares Issued: (thousands)	2012		2011	
	Shares	Amount	Shares	Amount
Balance, beginning of year	181,159	\$ 3,442,364	176,946	\$ 5,639,380
Corporate Conversion:				
Reclassification of EELP units (non-cash)	–	–	1,703	44,387
Reclassification of Accumulated Deficit (non-cash)	–	–	–	(2,314,775)
Issued for cash:				
Public offerings	14,709	330,618	–	–
Dividend reinvestment plan	955	19,150	1,928	52,375
Stock option plan	68	1,180	582	11,626
Non-cash:				
Stock dividend program	1,793	23,612	–	–
Stock option plan	–	1,119	–	9,371
<b>Balance, end of year</b>	<b>198,684</b>	<b>\$ 3,818,043</b>	<b>181,159</b>	<b>\$ 3,442,364</b>

Effective January 1, 2011, Enerplus Resources Fund (the “Fund”) converted from an income trust into a corporate entity under a Plan of Arrangement pursuant to the *Business Corporations Act (Alberta)* (the “Plan of Arrangement”) and continued as Enerplus Corporation. Under the Plan of Arrangement, former unitholders of the Fund received one common share in Enerplus Corporation in exchange for each trust unit held and 0.425 of a common share in Enerplus Corporation for each exchangeable partnership unit of Enerplus Exchangeable Limited Partnership (“EELP”) held. On January 1, 2011, all outstanding securities of the Fund and EELP were cancelled.

Under IFRS, EELP units and trust unit rights were considered liabilities and were recorded on the Consolidated Balance Sheets at their amortized fair value. Upon conversion to a corporation these liabilities were converted into equity and the EELP liability of \$44,387,000 was recorded to share capital and the trust unit rights liability of \$20,156,000 was recorded to contributed surplus. Pursuant to the Plan of Arrangement, Shareholders’ Capital was reduced by the amount of the accumulated deficit of the Fund on December 31, 2010 of \$2,314,775,000.

On February 8, 2012 Enerplus issued 14,709,000 common shares for gross proceeds of \$344,914,000 (\$330,618,000 net of issuance costs).

### (b) Dividends

(\$ thousands)	2012	2011
Cash dividends	\$ 277,948	\$ 388,904
Stock dividends	23,612	–
<b>Dividends to shareholders</b>	<b>\$ 301,560</b>	<b>\$ 388,904</b>

On January 25, 2013 Enerplus declared a dividend of \$0.09 per share payable on February 20, 2013.

### (c) Equity Based Compensation

The following table summarizes Enerplus’ equity based compensation expense:

(\$ thousands)	2012	2011
Cash:		
Long term incentive plans expense	\$ 5,618	\$ 14,443
Non-Cash:		
Stock option plan expense	10,297	12,330
Equity total return swap gain	(412)	–
<b>Equity based compensation expense</b>	<b>\$ 15,503</b>	<b>\$ 26,773</b>

The following assumptions were used to arrive at the estimates of fair value during each of the respective reporting periods:

Weighted average for the period	December 31, 2012	December 31, 2011
Dividend yield <sup>(1)</sup>	8.2%	7.14%
Volatility <sup>(1)</sup>	28.35%	35.00%
Risk-free interest rate	1.35%	2.34%
Forfeiture rate	10.0%	9.4%
Expected life	4.5 years	4.5 years

(1) Reflects the expected dividend yield and volatility of Enerplus shares over the life of the option.

The weighted average grant date fair value of options granted in 2012 was \$2.22 (December 31, 2011 – \$4.77). At December 31, 2012, 2,558,000 options were exercisable at a weighted average reduced exercise price of \$27.20 with a weighted average remaining contractual term of 3.49 years, giving an aggregate intrinsic value of nil (December 31, 2011 – \$4,446,000).

For the year ended December 31, 2012, 68,000 options were exercised at a weighted average price of \$17.35. The weighted average share price during the year was \$16.98.

For the year ended December 31, 2012 Enerplus expensed a total of \$10,297,000 (December 31, 2011 – \$12,330,000) related to its Stock Option Plan. The remaining unamortized grant date fair value of outstanding options of \$7,084,000

(December 31, 2011 – \$6,854,000) will be recognized in net income over the remaining vesting period. Activity for the periods is as follows:

	Year ended December 31, 2012		Year ended December 31, 2011	
	Number of Options (000's)	Weighted Average Exercise Price <sup>(1)</sup>	Number of Options (000's)	Weighted Average Exercise Price <sup>(1)</sup>
Options outstanding				
Beginning of year	5,098	\$ 29.41	5,457	\$ 32.11
Granted	7,313	19.00	2,154	30.27
Exercised	(68)	17.35	(582)	19.97
Forfeited	(1,056)	24.92	(845)	33.22
Expired	(519)	44.67	(1,086)	47.05
<b>End of year</b>	<b>10,768</b>	<b>\$ 22.11</b>	<b>5,098</b>	<b>\$ 29.41</b>
<b>Options exercisable at the end of year</b>	<b>2,558</b>	<b>\$ 27.20</b>	<b>1,932</b>	<b>\$ 33.86</b>

(1) Exercise price reflects grant prices less any reduction in strike price for outstanding rights under the rights incentive plan.

The following tables summarize the Contributed Surplus activity for the year ended December 31, 2012 and the ending balances as at December 31, 2012:

(\$ thousands)	2012	2011
Balance, beginning of year	\$ 26,910	\$ 3,795
Reclassification of trust unit rights liability	–	20,156
Stock Option Plan – exercised	(1,119)	(9,371)
Stock Option Plan – expensed	10,297	12,330
<b>Balance, end of year</b>	<b>\$ 36,088</b>	<b>\$ 26,910</b>

(\$ thousands)	2012	2011
Cancelled shares	\$ 3,893	\$ 3,795
Stock Option Plan	32,195	23,115
<b>Balance, end of year</b>	<b>\$ 36,088</b>	<b>\$ 26,910</b>

The following table summarizes information with respect to outstanding options as at December 31, 2012:

Options Outstanding at December 31, 2012 (000's)	Original Exercise Price	Exercise Price after <sup>(1)</sup> Price Reductions	Expiry Date	Options Exercisable at December 31, 2012 (000's)
18	\$ 48.86	\$ 45.16	2013	18
84	50.25	47.06	2013	84
16	45.14	42.46	2013	16
2	38.70	36.54	2013	2
411	42.05	40.40	2013 - 2014	411
17	47.19	45.97	2013 - 2014	17
7	38.76	37.95	2013 - 2014	7
4	23.58	23.36	2013 - 2014	4
706	17.11	17.11	2013 - 2015	706
-	19.30	19.30	2013 - 2015	-
11	25.97	25.97	2013 - 2015	11
5	22.76	22.76	2013 - 2015	5
1	23.65	23.65	2013 - 2015	1
1,085	23.58	23.58	2014 - 2016	704
19	23.05	23.05	2014 - 2016	12
10	24.30	24.30	2014 - 2016	7
5	30.32	30.32	2014 - 2016	3
1,489	30.40	30.40	2018	507
17	30.64	30.64	2018	6
47	30.26	30.26	2018	16
20	27.43	27.43	2018	7
40	25.70	25.70	2018	14
3,842	23.00	23.00	2019	-
169	14.14	14.14	2019	-
2,690	13.23	13.23	2019	-
31	15.61	15.61	2019	-
22	12.88	12.88	2019	-
<b>10,768</b>	<b>\$ 22.21</b>	<b>\$ 22.11</b>		<b>2,558</b>

(1) Exercise price reductions are only applicable to the predecessor trust unit rights plan.

#### (d) Basic and Diluted Earnings per Share

Net income/(loss) per share has been determined based on the following:

(thousands of units)	2012	2011
Weighted average shares	195,633	179,889
Dilutive impact of options <sup>(1)</sup>	-	456
<b>Diluted shares</b>	<b>195,633</b>	<b>180,345</b>

(1) For the year ended December 31, 2012 options are anti-dilutive as their conversion to shares would not increase the loss per share.

#### (e) Long-Term Incentive Plans

Enerplus' long-term incentive plans include its Performance Share Unit ("PSU"), Restricted Share Unit ("RSU") and Director Share Unit ("DSU") plans.

Under Enerplus' RSU plan employees receive cash compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded varies by individual and vests one-third each year for three years. Upon vesting, the plan participants receive a cash payment based on the value of the underlying notional shares plus notional accrued dividends over the vesting period.

Under Enerplus' PSU plan executives and management receive cash compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded varies by individual and they vest at the end of three years. Upon vesting, the plan participants receive a cash payment based on the value of the underlying shares plus notional accrued

dividends. The payment is subject to a multiplier that ranges from 0.5 to 2.0 depending on the performance of Enerplus compared to a group of peers over the vesting period.

Under Enerplus' DSU plan directors receive cash compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded is based on the annual non-cash retainer value and they vest upon the director leaving the Board. Upon vesting, the plan participants receive a cash payment based on the value of the underlying notional shares plus notional accrued dividends over the vesting period.

For the year ended December 31, 2012 the Company recorded cash compensation costs of \$5,618,000 (December 31, 2011 – \$14,443,000) for these plans which was included in equity based compensation. At December 31, 2012 the long term incentive plans had a liability balance of \$13,316,000 (December 31, 2011 – \$21,785,000) which is included in accounts payable on the Consolidated Balance Sheets.

The following table summarizes the PSU, RSU and DSU activity for the year ended December 31, 2012:

(thousands of units)	Number of PSUs	Number of RSUs	Number of DSUs
Balance, beginning of year	170	895	14
Granted	488	694	29
Vested	–	(497)	(9)
Forfeited	(53)	(129)	–
<b>Balance, end of year</b>	<b>605</b>	<b>963</b>	<b>34</b>

## 16. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

Enerplus' non-derivative financial instruments include cash, accounts receivable, accounts payable, marketable securities, dividends payable, bank indebtedness and long-term debt. Refer to Note 3 for details relating to Enerplus' significant accounting policies for recognition and measurement of financial instruments.

#### (i) Cash, Accounts Receivable, Accounts Payable, Dividends Payable, Bank Credit Facilities and Senior Notes

As at December 31, 2012 the carrying value of cash, accounts receivable, accounts payable, dividends payable and bank credit facilities approximated their fair value. Cash is classified as held for trading and is reported at fair value based on a level 1 designation.

#### (ii) Marketable Securities

Enerplus has assessed the relative inputs used in the determination of the fair value of its marketable securities. Enerplus' publicly traded marketable securities are classified as level 1 and Enerplus' marketable securities in private companies are classified as level 3. The inputs used in determining the fair value of private company securities are based on recent market transactions.

As at December 31, 2012 the fair value of Enerplus' marketable securities was \$11,687,000 (December 31, 2011 – \$207,824,000), including marketable securities in private companies of \$3,909,000 (December 31, 2011 – \$202,882,000) and marketable securities in public companies of \$7,778,000 (December 31, 2011 – \$4,942,000).

(iii) Debt

Senior Notes

The following table details carrying values and fair values of Enerplus' senior notes:

Original Principal (\$ thousands)	Remaining Principal	Reported CDN\$ Carrying Value	CDN\$ Fair Value
CDN\$30,000	CDN\$30,000	\$ 30,000	\$ 30,401
US\$20,000	US\$20,000	19,898	20,581
US\$355,000	US\$355,000	353,190	377,571
CDN\$40,000	CDN\$40,000	40,000	43,097
US\$40,000	US\$40,000	39,796	43,961
US\$225,000	US\$225,000	223,853	274,013
US\$54,000	US\$32,400	32,235	34,489
US\$175,000	US\$70,000	69,643	72,758
		<b>\$ 808,615</b>	<b>\$ 896,871</b>

**(b) Fair Value of Derivative Financial Instruments**

Enerplus has assessed the relative inputs used in the determination of the fair value of all derivative financial instruments and has determined that a fair value classification of level 2 is appropriate for each of the instruments. A level 2 assignment is appropriate where observable inputs other than quoted prices are used in the fair value determination.

The deferred financial assets and credits on the Consolidated Balance Sheets result from recording derivative financial instruments at fair value. At December 31, 2012 a current deferred financial asset of \$54,165,000, a current deferred financial credit of \$18,522,000, a non-current deferred financial asset of \$8,013,000 and a non-current deferred financial credit of \$17,127,000 are recorded on the Consolidated Balance Sheets.

The following table summarizes the fair value as at December 31, 2012 and change in fair value for the year ended December 31, 2012.

(\$ thousands)	Interest Rate Swaps	Cross Currency Interest Rate Swap	Foreign Exchange Swaps	Electricity Swaps	Equity Swaps	Commodity Derivative Instruments		Total
						Oil	Gas	
Deferred financial assets/(liabilities), beginning of period	\$ (1,603)	\$ (46,317)	\$ 6,642	\$ 2,255	\$ -	\$ (19,611)	\$ -	\$ (58,634)
Change in fair value gain/(loss)	1,125 <sup>(1)</sup>	12,155 <sup>(2)</sup>	947 <sup>(3)</sup>	(3,108) <sup>(4)</sup>	412 <sup>(5)</sup>	70,283 <sup>(6)</sup>	3,349 <sup>(6)</sup>	85,163
<b>Deferred financial assets/(liabilities), end of period</b>	<b>\$ (478)</b>	<b>\$ (34,162)</b>	<b>\$ 7,589</b>	<b>\$ (853)</b>	<b>\$ 412</b>	<b>\$ 50,672</b>	<b>\$ 3,349</b>	<b>\$ 26,529</b>

(1) Recorded in finance expense.

(2) Recorded in foreign exchange expense (gain of \$15,118) and finance expense (loss of \$2,963).

(3) Recorded in foreign exchange expense.

(4) Recorded in operating expense.

(5) Recorded in equity based compensation.

(6) Recorded in commodity derivative instruments (see below).

Balance Sheet Classification:	Interest Rate Swaps	Cross Currency Interest Rate Swap	Foreign Exchange Swaps	Electricity Swap	Equity Swap	Commodity Derivative Instruments		Total
						Oil	Gas	
Current assets	\$ –	\$ –	\$ –	\$ –	\$ 144	\$ 50,672	\$ 3,349	\$ 54,165
Current liabilities	(478)	(17,035)	(156)	(853)	–	–	–	(18,522)
Non-current assets	–	–	7,745	–	268	–	–	8,013
Non-current liabilities	–	(17,127)	–	–	–	–	–	(17,127)
<b>Total</b>	<b>\$ (478)</b>	<b>\$ (34,162)</b>	<b>\$ 7,589</b>	<b>\$ (853)</b>	<b>\$ 412</b>	<b>\$ 50,672</b>	<b>\$ 3,349</b>	<b>\$ 26,529</b>

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

(\$ thousands)	2012	2011
Change in fair value of commodity derivative instruments gain/(loss)	\$ 73,632	\$ 6,092
Net realized cash gain/(loss)	18,363	(33,184)
<b>Commodity derivative instruments gain/(loss)</b>	<b>\$ 91,995</b>	<b>\$ (27,092)</b>

### (c) Risk Management

#### (i) Market Risk

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

##### Commodity Price Risk

Enerplus manages a portion of commodity price risk through a combination of financial derivative and physical delivery sales contracts. Enerplus' policy is to enter into commodity contracts considered appropriate subject to a maximum of 80% of forecasted production volumes net of royalties.

##### Crude Oil Instruments:

At December 31, 2012 the fair value of Enerplus' crude oil derivative contracts represented an asset of \$50,672,000 and the change in fair value of these contracts during 2012 represented an unrealized gain of \$70,283,000. The following table summarizes Enerplus' crude oil risk management positions at February 7, 2013:

Instrument Type	bbls/day	US\$/bbl <sup>(1)</sup>
<b>Jan 1, 2013 – Jan 31, 2013</b>		
WTI Swap	17,000	100.84
WTI Purchased Call	3,500	104.09
WTI Sold Put	5,500	63.09
WTI Sold Call	3,500	130.00
<b>Feb 1, 2013 – Dec 31, 2013</b>		
WTI Swap	18,500	100.52
WTI Purchased Call	3,500	104.09
WTI Sold Put	5,500	63.09
WTI Sold Call	3,500	130.00
<b>Jan 1, 2014 – Dec 31, 2014</b>		
WTI Swap	2,000	93.33

(1) Transactions with a common term have been aggregated and presented as the weighted average price/bbl.

The following sensitivities show the impact to after-tax net income of the respective changes in forward crude oil prices as at December 31, 2012 on Enerplus' outstanding crude oil contracts at that time with all other variables held constant:

(\$ thousands)	Increase/(decrease) to after-tax net income	
	25% decrease in forward prices	25% increase in forward prices
Crude oil derivative contracts	\$ 100,315	\$ (96,932)

Natural Gas Instruments:

At December 31, 2012 the fair value of Enerplus' natural gas derivative contracts represented an asset of \$3,349,000 and the change in fair value of these contracts during 2012 represented an unrealized gain of \$3,349,000. The following table summarizes Enerplus' natural gas financial contracts at February 7, 2013:

Instrument Type	MMcf/day	CDN\$/Mcf	US\$/Mcf
<b>Jan 1, 2013 – Jan 31, 2013</b>			
AECO Swap	23.7	3.63	
AECO Purchased Put	22.7	3.17	
<b>Feb 1, 2013 – Jun 30, 2013</b>			
AECO Swap	28.4	3.54	
AECO Purchased Put	22.7	3.17	
<b>Jul 1, 2013 – Dec 31, 2013</b>			
AECO Swap	23.7	3.63	
AECO Purchased Put	22.7	3.17	
<b>Jan 1, 2013 – Jun 30, 2013</b>			
NYMEX Swap	15.0		3.45
<b>Jan 1, 2014 – Dec 31, 2014</b>			
NYMEX Swap	10.0		4.03

The following sensitivities show the impact to after-tax net income of the respective changes in forward natural gas prices as at December 31, 2012 on Enerplus' outstanding natural gas contracts at that time with all other variables held constant:

(\$ thousands)	Increase/(decrease) to after-tax net income	
	25% decrease in forward prices	25% increase in forward prices
Natural gas derivative contracts	\$ 9,052	\$ (7,285)

Enerplus also has the following physical gas contracts in place at February 7, 2013:

Instrument Type	MMcf/day	CDN\$/Mcf
<b>Mar 1, 2013 – Dec 31, 2013</b>		
AECO-NYMEX Basis	42.0	0.70
<b>Jan 1, 2014 – Oct 31, 2014</b>		
AECO-NYMEX Basis	53.5	0.69

Electricity:

Enerplus is subject to electricity price fluctuations and manages this risk by entering into forward fixed rated electricity derivative contracts on a portion of its electricity requirements. At December 31, 2012 the fair value of Enerplus' electricity contracts

represented a liability of \$853,000 and the change in fair value of these contracts during 2012 represented an unrealized loss of \$3,108,000. The Company's outstanding electricity derivative contracts at February 7, 2013 are summarized below:

Instrument Type	MWh	CDN\$/Mwh
<b>Jan 1, 2013 – Dec 31, 2013</b>		
AESO Power Swap <sup>(1)</sup>	12.0	63.81
<b>Jan 1, 2014 – Dec 31, 2014</b>		
AESO Power Swap <sup>(1)</sup>	12.0	53.69
<b>Jan 1, 2015 – Dec 31, 2015</b>		
AESO Power Swap <sup>(1)</sup>	6.0	50.38

(1) Alberta Electrical System Operator ("AESO") fixed pricing.

#### Currency Risk

Enerplus is exposed to currency risk in relation to its U.S. dollar denominated senior notes and U.S. dollar denominated working capital held in Canada. Enerplus manages the currency risk relating to its senior notes through the derivative instruments detailed below.

Cross Currency Interest Rate Swap ("CCIRS"):

Concurrent with the issuance of the US\$175,000,000 senior notes on June 19, 2002, Enerplus 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%. At December 31, 2012 the remaining USD principal is fixed at a notional amount of CDN\$107,331,000. The CCIRS matures between June 2013 and June 2014 in conjunction with the remaining principal repayments on the notes.

Foreign Exchange Swaps:

In September 2007 Enerplus entered into foreign exchange swaps on US\$54,000,000 of notional debt at an average US\$/CDN\$ foreign exchange rate of 1.02. At December 31, 2012, following the second settlement, Enerplus had USD\$32,400,000 of remaining notional debt swapped. These foreign exchange swaps mature between October 2013 and October 2015 in conjunction with the remaining principal repayments on the US\$54,000,000 senior notes.

During 2011 Enerplus entered into foreign exchange swaps on US\$175,000,000 of notional debt at approximately par. These foreign exchange swaps mature between June 2017 and June 2021 in conjunction with the principal repayments on the US\$225,000,000 senior notes.

The following sensitivities show the impact to after-tax net income of the changes in the period end and applicable forward foreign exchange rates, respectively, as at December 31, 2012, with all other variables held constant:

(\$ thousands)	Increase/(decrease) to after-tax net income	
	10% weakening of CDN\$ relative to US\$	10% strengthening of CDN\$ relative to US\$
Translation of U.S. dollar denominated debt	\$ (71,607)	\$ 71,607
Translation of U.S. dollar denominated working capital	30,691	(30,691)
<b>Total</b>	<b>\$ (40,916)</b>	<b>\$ 40,916</b>

(\$ thousands)	Increase/(decrease) to after-tax net income	
	10% weakening of CDN\$ relative to US\$	10% strengthening of CDN\$ relative to US\$
Foreign exchange swaps	\$ 14,468	\$ (14,029)
Cross currency interest rate swap <sup>(1)</sup>	5,097	(10,195)
<b>Total</b>	<b>\$ 19,565</b>	<b>\$ (24,224)</b>

(1) Represents change due to foreign exchange rates only.

### Interest Rate Risk

Enerplus' cash flows are impacted by fluctuations in interest rates as advances under the bank facility and payments made under the CCIRS are based on floating interest rates. To manage a portion of this interest rate risk, Enerplus entered into interest rate swaps on \$45,000,000 of notional debt at rates varying from 3.70% to 3.75% that mature between April and July 2013.

If interest rates change by 1%, either lower or higher, on Enerplus' effective outstanding variable rate debt at December 31, 2012 with all other variables held constant, Enerplus' after-tax net income for a year would change by \$2,414,000.

### (ii) Credit Risk

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

Enerplus 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. Enerplus monitors and manages its concentration of counterparty credit risk on an ongoing basis.

Enerplus' 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, 2012 approximately 70% of Enerplus' marketing receivables were with companies considered investment grade.

At December 31, 2012 approximately \$4,666,000 or 3% of Enerplus' total accounts receivable were aged over 120 days and considered past due. The majority of these accounts are due from various joint venture partners. Enerplus actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production, netting amounts off future payments or seeking other remedies including legal action. Should Enerplus 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 Enerplus subsequently determines an account is uncollectible the account is written off with a corresponding charge to the allowance account. Enerplus' allowance for doubtful accounts balance at December 31, 2012 was \$2,803,000 (December 31, 2011 – \$2,895,000).

### (iii) Liquidity Risk & Capital Management

Liquidity risk represents the risk that Enerplus will be unable to meet its financial obligations as they become due. Enerplus mitigates liquidity risk through actively managing its capital, which it defines as debt (net of cash) and shareholders' capital. Enerplus' objective is to provide adequate short and longer term liquidity while maintaining a flexible capital structure to sustain the future development of its business. Enerplus 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, dividends to shareholders, access to capital markets, as well as acquisition and divestment activity. Enerplus commonly measures its debt levels relative to its "debt-to-funds flow ratio" which is defined as long-term debt (net of cash) divided by the trailing twelve-month funds flow. Enerplus defines funds flow as cash flow from operating activities before changes in non-cash operating working capital and decommissioning expenditures. The debt-to-funds flow ratio represents the time period, expressed in years, it would take to pay off the debt if funds flow remained constant and no further capital investments were made or dividends paid.

Enerplus' five-year history of debt-to-funds flow is illustrated below:

	2012	2011	2010	2009	2008
Debt-to-Funds Flow Ratio	1.7x	1.6x	1.0x	0.6x	0.5x

## 17. COMMITMENTS AND CONTINGENCIES

Enerplus has the following minimum annual commitments at December 31, 2012:

(\$ thousands) <sup>(1)</sup>	Total	Minimum Annual Commitment Each Year					Total Committed after 2017
		2013	2014	2015	2016	2017	
Accounts payable <sup>(2)</sup>	\$ 274,387	\$ 274,387	\$ –	\$ –	\$ –	\$ –	\$ –
Dividends payable <sup>(3)</sup>	17,882	17,882	–	–	–	–	–
Bank credit facility <sup>(4)</sup>	260,950	–	–	260,950	–	–	–
Senior notes <sup>(4)</sup>	808,614	45,566	45,566	90,541	–	115,408	511,533
Transportation commitments	126,533	49,454	24,110	18,426	11,223	9,997	13,323
Processing commitments	1,192	331	313	313	235	–	–
Drilling and completions	25,499	20,137	5,362	–	–	–	–
Decommissioning liability <sup>(5)</sup>	659,714	25,750	26,000	26,000	26,000	26,000	529,964
Office leases	81,796	13,293	12,938	10,854	11,403	11,400	21,908
<b>Total commitments<sup>(6)</sup></b>	<b>\$ 2,256,567</b>	<b>\$ 446,800</b>	<b>\$ 114,289</b>	<b>\$ 407,084</b>	<b>\$ 48,861</b>	<b>\$ 162,805</b>	<b>\$ 1,076,728</b>

(1) US\$ commitments have been converted to CDN\$ using the December 31, 2012 foreign exchange rate of 0.9949.

(2) Accounts payable are generally settled between 30 and 90 days from the balance sheet date.

(3) Dividends declared but not paid at December 31, 2012.

(4) Interest payments have not been included.

(5) Based upon current spending estimates.

(6) Crown and surface royalties, lease rentals and mineral taxes (hydrocarbon production rights) have not been included as amounts paid depend on future ownership, production, prices and the legislative environment.

### (a) Transportation Commitments

Transportation for Enerplus' Bakken crude oil in the U.S. has been contracted for 12,500 bbl/day through January 2014 with 8,500 bbl/day of that continuing through May 2016 and then 7,500 bbl/day through December 2017.

Enerplus has contracted up to 239 MMcf/day of natural gas pipeline capacity in Canada, some of it in series, with contract terms that range anywhere from one month to five years.

### (b) Office Leases

Enerplus has office lease commitments for both its Canadian and U.S. operations that expire in 2019. Annual costs of these lease commitments include rent and operating fees.

### (c) Guarantees

- (i) Corporate indemnities have been provided by Enerplus to all directors and certain officers for various items including costs to settle suits or actions due to their association with Enerplus. Enerplus 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 Enerplus.
- (ii) Enerplus 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 Enerplus from making a reasonable estimate of the maximum potential amounts that may be required to be paid.

## 18. GEOGRAPHICAL INFORMATION

As at and for the year ended December 31, 2012 (\$ thousands)	Canada	U.S.	Total
Oil and gas sales	\$ 817,843	\$ 547,699	\$ 1,365,542
Exploration & evaluation assets	320,367	453,453	773,820
Plant, property and equipment	2,127,044	2,115,403	4,242,447
Goodwill	2,795	148,595	151,390

As at and for the year ended December 31, 2011 (\$ thousands)	Canada	U.S.	Total
Oil and gas sales	\$ 955,722	\$ 408,004	\$ 1,363,726
Exploration & evaluation assets	339,611	535,188	874,799
Plant, property and equipment	2,762,457	1,569,554	4,332,011
Goodwill	2,795	151,896	154,691

# 5 Year Detailed Statistical Review

	2012	2011	2010 <sup>(1)</sup>	2009 <sup>(1)</sup>	2008 <sup>(1)</sup>
<b>Daily Production</b>					
Crude oil (bbls/day)	36,509	30,181	31,135	32,984	34,581
NGLs (bbls/day)	3,627	3,306	3,889	4,157	4,627
Natural gas (Mcf/day)	251,773	251,068	288,692	326,570	338,869
BOE per day	82,098	75,332	83,139	91,569	95,687
<b>Drilling Activity (net wells)</b>	75	107	225	313	643
<b>Average Benchmark Pricing</b>					
WTI crude oil (US\$ per bbl)	\$ 94.21	\$ 95.12	\$ 79.53	\$ 61.80	\$ 99.65
AECO natural gas – monthly (per Mcf)	2.40	3.68	4.13	4.14	8.13
NYMEX natural gas – monthly (US\$ per Mcf)	2.80	4.07	4.42	4.03	8.93
US/CDN exchange rate	1.00	0.99	1.03	1.14	1.07
<b>Realized Pricing</b>					
Crude oil (per bbl)	\$ 78.19	\$ 83.48	\$ 70.38	\$ 58.54	\$ 91.31
Natural gas liquids (per bbl)	53.01	64.99	51.41	41.54	68.93
Natural gas (per Mcf)	2.39	3.72	4.05	3.91	8.17
Average realized Price (per BOE)	44.56	48.85	42.85	36.89	65.79

(\$ thousands, except per share amounts)	2012	2011	2010 <sup>(1)</sup>	2009 <sup>(1)</sup>	2008 <sup>(1)</sup>
<b>Financial<sup>(1)</sup></b>					
Oil and gas sales <sup>(2)</sup>	\$ 1,044,841	\$ 1,315,987	\$ 1,324,177	\$ 1,267,656	\$ 2,370,668
Funds flow	643,911	573,609	728,968	763,386	1,300,966
Cash flow from operating activities	535,077	623,440	696,183	775,786	1,262,782
Cash and stock dividends to shareholders	301,560	388,904	384,127	368,201	786,138
Per share	1.62	2.16	2.16	2.23	5.06
Capital spending	852,843	865,712	536,436	299,111	577,739
Property and land acquisitions	185,337	255,209	1,012,272	271,977	1,772,826
Property dispositions	275,771	641,190	871,458	104,325	504,859
Total net capital expenditures <sup>(3)</sup>	774,250	490,994	681,254	473,517	1,856,305
Total assets	5,412,162	5,723,312	5,489,181	5,905,516	6,230,132
Long-term debt, net of cash	1,064,365	901,465	724,031	485,349	657,421
Adjusted payout ratio <sup>(4)</sup>	174%	212%	123%	85%	101%
Net debt/funds flow ratio	1.7x	1.6x	1.0x	0.6x	0.5x
<b>Oil and Gas Economics</b>					
Net royalty rate	20%	18%	17%	17%	19%
Average realized price <sup>(5)</sup>	\$ 44.56	\$ 48.85	\$ 42.85	\$ 36.89	\$ 65.79
Commodity derivative instruments <sup>(6)</sup>	0.61	(1.21)	1.64	4.66	(2.94)
Average realized price <sup>(2)</sup>	45.17	47.64	44.49	41.55	62.85
Net royalty expense	8.95	8.92	7.36	6.21	12.27
Operating expense <sup>(6)</sup>	10.53	10.33	9.66	9.71	9.51
Operating netback	25.69	28.39	27.47	25.63	41.07
General and administrative expense <sup>(6)</sup>	2.79	2.99	2.76	2.44	1.68
Interest, foreign exchange and other expenses <sup>(6)</sup>	1.42	1.59	1.69	0.34	1.59
Taxes	0.05	2.95	(1.00)	0.01	0.65
Funds flow	\$ 21.43	\$ 20.86	\$ 24.02	\$ 22.84	\$ 37.15

(\$ thousands, except per share amounts)	2012	2011	2010 <sup>(1)</sup>	2009 <sup>(1)</sup>	2008 <sup>(1)</sup>
<b>Reserves</b>					
<b>Proved Reserves<sup>(7)</sup></b>					
Crude oil (Mbls)	124,759	116,664	109,706	120,936	127,692
NGLs (Mbbbls)	9,236	9,215	8,610	10,753	13,052
Natural gas (MMcf)	413,906	476,887	554,090	746,034	1,066,534
Shale gas (MMcf)	146,127	92,682	52,225	8,127	–
MBOE	227,335	220,807	219,369	257,382	318,500
<b>Probable Reserves<sup>(7)</sup></b>					
Crude oil (Mbls)	66,913	54,497	40,147	36,410	38,931
NGLs (Mbbbls)	5,387	4,411	2,966	3,754	4,765
Natural gas (MMcf)	198,727	192,363	198,097	267,146	421,134
Shale gas (MMcf)	78,373	60,861	64,437	16,763	–
MBOE	118,483	101,112	86,868	87,482	113,885
<b>Proved Plus Probable Reserves<sup>(7)</sup></b>					
Crude oil (Mbls)	191,672	171,161	149,853	157,346	166,623
NGLs (Mbbbls)	14,623	13,626	11,576	14,507	17,817
Natural gas (MMcf)	612,634	669,250	752,187	1,013,180	1,487,668
Shale gas (MMcf)	224,500	153,543	116,662	24,890	–
MBOE	345,817	321,919	306,237	344,864	432,385
<b>Reserve Life Index<sup>(8)</sup></b>					
Proved (years)	7.8	7.7	8.2	8.2	9.4
Proved plus probable (years)	10.9	9.8	10.7	10.9	12.1
<b>Trading Information<sup>(9)</sup></b>					
Canadian trading summary <sup>(10)</sup>					
High	\$ 26.94	\$ 32.83	\$ 31.85	\$ 28.00	\$ 49.85
Low	11.53	23.00	18.22	16.75	21.53
Close	12.90	25.85	30.67	24.21	23.96
Volume	270,710	180,917	127,386	98,597	127,679
U.S. trading summary <sup>(11)</sup>					
High	\$ 26.54	\$ 33.29	\$ 31.83	\$ 25.13	\$ 50.63
Low	11.35	21.65	13.76	12.85	17.07
Close	12.96	25.32	30.84	22.96	19.58
Volume	386,690	225,858	168,979	191,405	235,270
Weighted average number of shares outstanding (basic)	195,633	179,889	175,736	169,280	160,589
Number of shares outstanding at December 31	198,684	181,159	176,946	177,061	165,590

(1) 2009 and prior comparatives prepared in accordance with previous Canadian GAAP. 2010 restated in accordance with IFRS.

(2) Net of commodity derivative instruments and transportation.

(3) Includes office capital.

(4) Calculated as the sum of dividends net of DRIP and SDP to shareholders and capital expenditures, divided by funds flow.

(5) Net of transportation and before the effects of commodity derivative instruments.

(6) Does not include non-cash portion of expense.

(7) Company interest reserves consist of gross revenues (as defined in National Instrument 51-101) plus the Company's 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.

(8) 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.

(9) 2011 and 2012 – share trading information. Prior to 2011 – Trust Units trading information.

(10) TSX data prior to 2010, Canadian composite trading data including TSX thereafter.

(11) NYSE data prior to 2008, U.S. composite trading data including NYSE thereafter.

# Supplemental Information

## INDEPENDENT RESERVES EVALUATION

All reserves information, including our U.S. reserves, has been prepared in accordance with Canadian National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (“NI 51-101”) standards. Independent reserve evaluations have been conducted on approximately 88% of the total proved plus probable value (discounted at 10%) of our reserves at December 31, 2012.

McDaniel & Associates Consultants Ltd. (“McDaniel”) evaluated 76% of our Canadian reserves and essentially 100% of the reserves associated with our western U.S. assets. They also reviewed the internal evaluation completed by Enerplus on the remaining 24% of our Canadian assets. Haas Petroleum Engineering Services Inc. (“Haas”) evaluated 100% of our Marcellus shale gas reserves in the U.S.

### Forecast Price Assumptions

The estimated reserve volumes and the net present values of future net revenues (“NPV”) at December 31, 2012 were based upon forecast crude oil and natural gas pricing assumptions prepared by McDaniel as of January 1, 2013. These prices were applied to the reserves evaluated by McDaniel and Haas, along with those evaluated internally by Enerplus and reviewed by McDaniel. The base reference prices and exchange rates used by McDaniel are detailed below. These forecast price assumptions reflect a reduction in the prices of natural gas at AECO and Henry Hub and also a decrease in the prices for our portfolio of crude oil as compared to the price assumptions used to calculate our reserves and NPV at December 31, 2011.

### MCDANIEL JANUARY 2013 FORECAST PRICE ASSUMPTIONS

	WTI Crude Oil US\$/bbl	Light Crude Oil <sup>(1)</sup> Edmonton CDN\$/bbl	Hardisty Heavy Oil 12° API CDN\$/bbl	Henry Hub Gas Price US\$/MMBtu	Natural Gas 30 day spot @ AECO CDN\$/MMBtu	Exchange Rate US\$/CDN\$
2013	92.50	87.50	65.60	3.75	3.35	1.00
2014	92.50	90.50	67.90	4.30	3.85	1.00
2015	93.60	92.60	69.50	4.85	4.35	1.00
2016	95.50	94.50	70.90	5.25	4.70	1.00
2017	97.40	96.40	72.30	5.70	5.10	1.00
Thereafter	**	**	**	**	**	1.00

(1) Edmonton Light Sweet 40 degree API, 0.3% sulphur content crude.

\*\* Escalation varies after 2017.

## Reserves Summary

The following table sets out our company interest, gross and net reserve volumes at December 31, 2012 by production type and reserve category under McDaniel's forecast price scenarios. Under different price scenarios, these reserves could vary as a change in price can affect the economic limit and reserves associated with a property. Company interest reserves consist of gross reserves, which are before the deduction of any royalties, plus Enerplus' royalty interests in reserves. It should be noted that tables may not add due to rounding.

<b>RESERVES SUMMARY</b>	<b>Light &amp; Medium Oil (Mbbbls)</b>	<b>Heavy Oil (Mbbbls)</b>	<b>Total Oil (Mbbbls)</b>	<b>Natural Gas Liquids (Mbbbls)</b>	<b>Natural Gas (MMcf)</b>	<b>Shale Gas (MMcf)</b>	<b>Total (MBOE)</b>
<b>Company Interest</b>							
Proved producing	65,300	27,328	92,627	7,383	368,806	73,644	173,752
Proved developed non-producing	2,041	198	2,239	133	9,149	25,489	8,145
Proved undeveloped	25,898	3,995	29,893	1,720	35,951	46,994	45,438
Total proved	93,238	31,521	124,759	9,236	413,906	146,127	227,335
Total probable	55,922	10,991	66,913	5,387	198,727	78,373	118,483
<b>Proved plus probable</b>	<b>149,160</b>	<b>42,512</b>	<b>191,672</b>	<b>14,623</b>	<b>612,634</b>	<b>224,500</b>	<b>345,817</b>
<b>Gross</b>							
Proved producing	64,635	27,316	91,951	7,252	354,911	73,644	170,628
Proved developed non-producing	2,037	198	2,235	133	9,126	25,489	8,137
Proved undeveloped	25,893	3,995	29,889	1,700	34,002	46,994	45,087
Total proved	92,565	31,509	124,074	9,085	398,038	146,127	223,853
Total probable	55,732	10,988	66,720	5,327	192,663	78,373	117,220
<b>Proved plus probable</b>	<b>148,297</b>	<b>42,496</b>	<b>190,793</b>	<b>14,412</b>	<b>590,702</b>	<b>224,500</b>	<b>341,072</b>
<b>Net</b>							
Proved producing	55,337	22,074	77,411	5,211	317,836	59,317	145,481
Proved developed non-producing	1,651	173	1,824	104	7,714	20,667	6,658
Proved undeveloped	21,096	3,031	24,127	1,346	31,179	38,088	37,018
Total proved	78,084	25,278	103,362	6,662	356,729	118,072	189,157
Total probable	45,563	8,507	54,070	4,079	170,977	63,170	97,173
<b>Proved plus probable</b>	<b>123,647</b>	<b>33,784</b>	<b>157,432</b>	<b>10,741</b>	<b>527,705</b>	<b>181,241</b>	<b>286,330</b>

### Future Development Capital

Changes in forecast FDC occur annually as a result of development activities, acquisition and disposition activities and capital cost estimates that reflect the independent evaluator's best estimate of what it will cost to bring the proved undeveloped and probable reserves on production.

The aggregate of the exploration and development costs incurred in the most recent year and the change during the year in estimated future development costs generally reflect the total finding and development costs related to reserve additions for that year.

The significant increase in FDC reported at year-end 2012 is primarily related to the increase in the number of undeveloped drilling locations added in Fort Berthold and the Marcellus along with higher well cost assumptions on previously booked locations mainly in Fort Berthold. F&D and FD&A costs have been calculated both including and excluding FDC.

The following is a summary of the independent reserve evaluators' estimated FDC required to bring total proved and probable reserves on production:

Future Development Capital (\$ millions)	Proved Reserves	Proved Plus Probable Reserves
2013	\$ 420	\$ 487
2014	419	501
2015	153	401
2016	46	282
2017	15	37
Remainder	59	70
Total FDC Undiscounted	\$ 1,113	\$ 1,779
Total FDC Discounted at 10%	\$ 954	\$ 1,475

### F&D AND FD&A COSTS

F&D and FD&A costs have been calculated both including and excluding FDC. The aggregate of the exploration and development costs incurred in the most recent year and the change during that year in estimated future development costs generally reflect the total finding and development costs related to reserve additions for that year. The significant increase in FDC reported at year-end 2012 is primarily related to the increase in the number of undeveloped drilling locations added at Fort Berthold and the Marcellus and higher well cost assumptions on previously booked locations mainly in Fort Berthold.

	2012		2011	
	Excluding FDC	Including FDC	Excluding FDC	Including FDC
(\$ millions except for per BOE amounts)				
<b>Proved Plus Probable Reserves</b>				
<b>Finding &amp; Development Costs</b>				
Capital expenditures	\$ 852.8	\$ 852.8	\$ 829.8	\$ 829.8
Net change in future development capital	—	\$ 534.6	—	\$ 435.9
Company interest reserve additions (MMBOE)	57.3	57.3	48.2	48.2
<b>F&amp;D costs (\$/BOE)</b>	<b>\$ 14.88</b>	<b>\$ 24.21</b>	<b>\$ 17.22</b>	<b>\$ 26.26</b>
<b>Finding, Development &amp; Acquisition Costs</b>				
Capital expenditures and net acquisitions <sup>(1)</sup>	\$ 726.4	\$ 726.4	\$ 370.2	\$ 370.2
Net change in future development capital	—	\$ 509.1	—	\$ 402.7
Company interest reserve additions (MMBOE)	53.9	53.9	43.2	43.2
<b>FD&amp;A costs (\$/BOE)</b>	<b>\$ 13.48</b>	<b>\$ 22.92</b>	<b>\$ 8.57</b>	<b>\$ 17.89</b>
<b>Proved Reserves</b>				
<b>Finding &amp; Development Costs</b>				
Capital expenditures	\$ 852.8	\$ 852.8	\$ 829.8	\$ 829.8
Net change in future development capital	—	\$ 248.3	—	\$ 230.7
Company interest reserve additions (MMBOE)	38.4	38.4	31.5	31.5
<b>F&amp;D costs (\$/BOE)</b>	<b>\$ 22.21</b>	<b>\$ 28.67</b>	<b>\$ 26.34</b>	<b>\$ 33.67</b>
<b>Finding, Development &amp; Acquisition Costs</b>				
Capital expenditures and net acquisitions <sup>(1)</sup>	\$ 726.4	\$ 726.4	\$ 370.2	\$ 370.2
Net change in future development capital	—	\$ 241.3	—	\$ 213.0
Company interest reserve additions (MMBOE)	36.6	36.6	28.9	28.9
<b>FD&amp;A costs (\$/BOE)</b>	<b>\$ 19.85</b>	<b>\$ 26.44</b>	<b>\$ 12.81</b>	<b>\$ 20.18</b>

(1) Capital spending totaled \$852.8, net acquisition capital totaled \$126.4 million and is exclusive of \$37.0 million associated with the Marcellus carry commitment as the full purchase price associated with the Marcellus acquisition was used in the calculation of F&D and FD&A costs in 2009.

## 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, 2011 to December 31, 2012.

### PROVED RESERVES – COMPANY INTEREST VOLUMES (FORECAST PRICES)

<b>CANADA</b>	Light & Medium Oil (Mbbbls)	Heavy Oil (Mbbbls)	Total Oil (Mbbbls)	Natural Gas Liquids (Mbbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Reserves at Dec. 31, 2011	46,437	29,304	75,741	7,781	437,622	–	156,458
Acquisitions	1	–	1	–	1	–	1
Dispositions	(6,333)	–	(6,333)	–	(1,545)	–	(6,590)
Discoveries	–	–	–	–	–	–	–
Extensions & improved recovery	734	4,155	4,889	74	3,268	–	5,507
Economic factors	(108)	(5)	(113)	(228)	(19,597)	–	(3,607)
Technical revisions	(114)	1,253	1,139	448	14,008	–	3,921
Production	(4,371)	(3,186)	(7,557)	(1,187)	(72,599)	–	(20,844)
<b>Proved Reserves at Dec. 31, 2012</b>	<b>36,246</b>	<b>31,521</b>	<b>67,767</b>	<b>6,887</b>	<b>361,158</b>	<b>–</b>	<b>134,847</b>

<b>UNITED STATES</b>	Light & Medium Oil (Mbbbls)	Heavy Oil (Mbbbls)	Total Oil (Mbbbls)	Natural Gas Liquids (Mbbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Reserves at Dec. 31, 2011	40,923	–	40,923	1,434	39,265	92,682	64,349
Acquisitions	3,751	–	3,751	–	6,707	–	4,868
Dispositions	(51)	–	(51)	–	(48)	–	(59)
Discoveries	–	–	–	–	–	–	–
Extensions & improved recovery	12,837	–	12,837	727	4,854	65,464	25,284
Economic factors	–	–	–	–	–	–	–
Technical revisions	5,339	–	5,339	328	6,636	2,866	7,250
Production	(5,805)	–	(5,805)	(140)	(4,665)	(14,885)	(9,204)
<b>Proved Reserves at Dec. 31, 2012</b>	<b>56,993</b>	<b>–</b>	<b>56,993</b>	<b>2,349</b>	<b>52,748</b>	<b>146,127</b>	<b>92,488</b>

<b>TOTAL ENERPLUS</b>	Light & Medium Oil (Mbbbls)	Heavy Oil (Mbbbls)	Total Oil (Mbbbls)	Natural Gas Liquids (Mbbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Reserves at Dec. 31, 2011	87,360	29,304	116,664	9,215	476,887	92,682	220,807
Acquisitions	3,752	–	3,752	–	6,707	–	4,870
Dispositions	(6,384)	–	(6,384)	–	(1,593)	–	(6,650)
Discoveries	–	–	–	–	–	–	–
Extensions & improved recovery	13,571	4,155	17,726	801	8,123	65,464	30,791
Economic factors	(108)	(5)	(113)	(228)	(19,597)	–	(3,607)
Technical revisions	5,224	1,253	6,477	776	20,643	2,866	11,171
Production	(10,177)	(3,186)	(13,362)	(1,327)	(77,265)	(14,885)	(30,048)
<b>Proved Reserves at Dec. 31, 2012</b>	<b>93,238</b>	<b>31,521</b>	<b>124,759</b>	<b>9,236</b>	<b>413,906</b>	<b>146,127</b>	<b>227,335</b>

**PROBABLE RESERVES – COMPANY INTEREST VOLUMES (FORECAST PRICES)**

<b>CANADA</b>	Light & Medium Oil (Mbbbls)	Heavy Oil (Mbbbls)	Total Oil (Mbbbls)	Natural Gas Liquids (Mbbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Probable Reserves at Dec. 31, 2011	13,554	10,090	23,644	2,955	167,346	–	54,491
Acquisitions	–	–	–	–	–	–	–
Dispositions	(1,991)	–	(1,991)	(14)	(2,650)	–	(2,447)
Discoveries	–	–	–	–	–	–	–
Extensions & improved recovery	472	1,277	1,749	202	21,582	–	5,548
Economic factors	(44)	(2)	(45)	(71)	(4,750)	–	(908)
Technical revisions	819	(374)	445	71	(10,001)	–	(1,151)
Production	–	–	–	–	–	–	–
<b>Probable Reserves at Dec. 31, 2012</b>	<b>12,811</b>	<b>10,991</b>	<b>23,802</b>	<b>3,143</b>	<b>171,526</b>	<b>–</b>	<b>55,533</b>

<b>UNITED STATES</b>	Light & Medium Oil (Mbbbls)	Heavy Oil (Mbbbls)	Total Oil (Mbbbls)	Natural Gas Liquids (Mbbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Probable Reserves at Dec. 31, 2011	30,853	–	30,853	1,456	25,017	60,861	46,621
Acquisitions	1,110	–	1,110	–	1,980	–	1,440
Dispositions	(488)	–	(488)	–	(382)	–	(552)
Discoveries	–	–	–	–	–	–	–
Extensions & improved recovery	19,067	–	19,067	1,103	7,349	58,504	31,145
Economic factors	–	–	–	(44)	(4,156)	(3,231)	(1,275)
Technical revisions	(7,431)	–	(7,431)	(272)	(2,608)	(37,761)	(14,431)
Production	–	–	–	–	–	–	–
<b>Probable Reserves at Dec. 31, 2012</b>	<b>43,111</b>	<b>–</b>	<b>43,111</b>	<b>2,243</b>	<b>27,201</b>	<b>78,373</b>	<b>62,950</b>

<b>TOTAL ENERPLUS</b>	Light & Medium Oil (Mbbbls)	Heavy Oil (Mbbbls)	Total Oil (Mbbbls)	Natural Gas Liquids (Mbbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Probable Reserves at Dec. 31, 2011	44,407	10,090	54,497	4,411	192,363	60,861	101,112
Acquisitions	1,110	–	1,110	–	1,980	–	1,440
Dispositions	(2,480)	–	(2,480)	(14)	(3,032)	–	(2,999)
Discoveries	–	–	–	–	–	–	–
Extensions & improved recovery	19,539	1,277	20,815	1,305	28,931	58,504	36,692
Economic factors	(44)	(2)	(45)	(114)	(8,906)	(3,231)	(2,183)
Technical revisions	(6,611)	(374)	(6,985)	(201)	(12,609)	(37,761)	(15,581)
Production	–	–	–	–	–	–	–
<b>Probable Reserves at Dec. 31, 2012</b>	<b>55,922</b>	<b>10,991</b>	<b>66,913</b>	<b>5,387</b>	<b>198,727</b>	<b>78,373</b>	<b>118,483</b>

**PROVED PLUS PROBABLE RESERVES - COMPANY INTEREST VOLUMES (FORECAST PRICES)**

<b>CANADA</b>	<b>Light &amp; Medium Oil (Mbbbls)</b>	<b>Heavy Oil (Mbbbls)</b>	<b>Total Oil (Mbbbls)</b>	<b>Natural Gas Liquids (Mbbbls)</b>	<b>Natural Gas (MMcf)</b>	<b>Shale Gas (MMcf)</b>	<b>Total (MBOE)</b>
Proved Plus Probable Reserves at Dec. 31, 2011	59,991	39,394	99,385	10,736	604,968	–	210,949
Acquisitions	1	–	1	–	1	–	2
Dispositions	(8,324)	–	(8,324)	(14)	(4,195)	–	(9,037)
Discoveries	–	–	–	–	–	–	–
Extensions & improved recovery	1,206	5,431	6,637	276	24,850	–	11,055
Economic factors	(152)	(7)	(159)	(299)	(24,347)	–	(4,515)
Technical revisions	705	879	1,584	519	4,006	–	2,770
Production	(4,371)	(3,186)	(7,557)	(1,187)	(72,599)	–	(20,844)
<b>Proved Plus Probable Reserves at Dec. 31, 2012</b>	<b>49,056</b>	<b>42,512</b>	<b>91,568</b>	<b>10,031</b>	<b>532,684</b>	<b>–</b>	<b>190,380</b>
<b>UNITED STATES</b>	<b>Light &amp; Medium Oil (Mbbbls)</b>	<b>Heavy Oil (Mbbbls)</b>	<b>Total Oil (Mbbbls)</b>	<b>Natural Gas Liquids (Mbbbls)</b>	<b>Natural Gas (MMcf)</b>	<b>Shale Gas (MMcf)</b>	<b>Total (MBOE)</b>
Proved Plus Probable Reserves at Dec. 31, 2011	71,776	–	71,776	2,890	64,282	153,543	110,970
Acquisitions	4,861	–	4,861	–	8,687	–	6,309
Dispositions	(540)	–	(540)	–	(430)	–	(611)
Discoveries	–	–	–	–	–	–	–
Extensions & improved recovery	31,904	–	31,904	1,830	12,204	123,968	56,429
Economic factors	–	–	–	(44)	(4,156)	(3,231)	(1,275)
Technical revisions	(2,092)	–	(2,092)	56	4,028	(34,895)	(7,180)
Production	(5,805)	–	(5,805)	(140)	(4,665)	(14,885)	(9,204)
<b>Proved Plus Probable Reserves at Dec. 31, 2012</b>	<b>100,104</b>	<b>–</b>	<b>100,104</b>	<b>4,592</b>	<b>79,950</b>	<b>224,500</b>	<b>155,438</b>
<b>TOTAL ENERPLUS</b>	<b>Light &amp; Medium Oil (Mbbbls)</b>	<b>Heavy Oil (Mbbbls)</b>	<b>Total Oil (Mbbbls)</b>	<b>Natural Gas Liquids (Mbbbls)</b>	<b>Natural Gas (MMcf)</b>	<b>Shale Gas (MMcf)</b>	<b>Total (MBOE)</b>
Proved Plus Probable Reserves at Dec. 31, 2011	131,767	39,394	171,161	13,626	669,250	153,543	321,919
Acquisitions	4,862	–	4,862	–	8,688	–	6,310
Dispositions	(8,864)	–	(8,864)	(14)	(4,625)	–	(9,648)
Discoveries	–	–	–	–	–	–	–
Extensions & improved recovery	33,110	5,431	38,541	2,106	37,054	123,968	67,484
Economic factors	(152)	(7)	(159)	(342)	(28,503)	(3,231)	(5,790)
Technical revisions	(1,387)	879	(508)	575	8,035	(34,895)	(4,410)
Production	(10,177)	(3,186)	(13,362)	(1,327)	(77,265)	(14,885)	(30,048)
<b>Proved Plus Probable Reserves at Dec. 31, 2012</b>	<b>149,160</b>	<b>42,512</b>	<b>191,672</b>	<b>14,623</b>	<b>612,634</b>	<b>224,500</b>	<b>345,817</b>

## CONTINGENT RESOURCES

The following table provides a breakdown of the best estimate of contingent resources associated with a portion of Enerplus' assets. The evaluation of contingent resources associated with the Wilrich and our leases at Fort Berthold was conducted by Enerplus and audited by McDaniel. Haas evaluated 100% of our Marcellus shale gas assets in the U.S. and provided the estimate of contingent resources. The contingent resource assessments associated with a portion of our waterflood properties were completed internally by qualified reserve evaluators.

Contingent Resources	"Best Estimate" Contingent Resources	Contingent Resource Net Drilling Locations
<b>Canada</b>		
Crude oil – IOR/EOR on a portion of waterfloods (MMbbls)	60.3	158
Natural gas – Wilrich (Bcfe)	282.6	57
<b>Total Canada (MMBOE)</b>	<b>107.4</b>	<b>215</b>
<b>United States</b>		
Crude oil and NGLs – Fort Berthold (MMBOE)	33.5	50
Natural gas – Marcellus (Bcf)	1,336.4	184
<b>Total United States (MMBOE)</b>	<b>256.2</b>	<b>234</b>
<b>Total Company (MMBOE)</b>	<b>363.6</b>	<b>449</b>

## NET PRESENT VALUE OF FUTURE PRODUCTION REVENUE

The following table provides an estimate of the net present value of Enerplus' future production revenue after deduction of royalties, estimated future capital and operating expenditures, and 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 after tax net present value of future production revenues reflects the tax burden on properties on a stand-alone basis and does not consider the business entity-level tax situation or any potential tax planning.

Despite a 7.4% increase in our P+P reserves at December 31, 2012, the estimated before tax NPV using a 10% discount was 11% lower than the NPV 10% at December 31, 2011. This is due primarily to a reduction in both the forecast prices of natural gas and crude oil, and wider crude oil differentials used by our independent reserve evaluators.

### NET PRESENT VALUE OF FUTURE PRODUCTION REVENUE – FORECAST PRICES AND COSTS

Reserves at December 31, 2012 (\$ millions, discounted at)	0%	5%	10%	15%
Proved developed producing	\$5,006	\$3,565	\$2,801	\$2,333
Proved developed non-producing	159	116	90	71
Proved undeveloped	1,083	549	293	147
<b>Total Proved</b>	<b>\$6,249</b>	<b>\$4,230</b>	<b>\$3,183</b>	<b>\$2,552</b>
Probable	4,523	2,344	1,469	1,023
<b>Total Proved Plus Probable Reserves (before tax)</b>	<b>\$10,772</b>	<b>\$6,574</b>	<b>\$4,652</b>	<b>\$3,575</b>
<b>Total Proved Plus Probable Reserves (after tax)</b>	<b>8,191</b>	<b>5,164</b>	<b>3,757</b>	<b>2,954</b>

## NET ASSET VALUE

Enerplus' estimated net asset value is based on the estimated net present value of all future net revenue from our reserves, before taxes, as estimated by our independent reserve engineers, McDaniel and Haas, at year-end plus the estimated value of our undeveloped acreage and other equity investments, less decommissioning liabilities, long-term debt and net working capital. This calculation can vary significantly depending on the oil and natural gas price assumptions used by the independent reserve engineers.

In addition, this calculation does not consider "going concern" value and assumes only the reserves identified in the reserve reports with no further acquisitions or incremental development, including development of contingent resources. At December 31, 2012, the estimate of contingent resources contained within our leases was 364 million BOE. As we execute our capital programs, we expect to convert contingent resources to reserves which could result in a doubling of our booked proved plus probable reserves. The land values described in the Net Asset Value table below do not necessarily reflect the full value of the contingent resources associated with these lands.

### NET ASSET VALUE (FORECAST PRICES AND COSTS AT DECEMBER 31, 2012)

(\$ millions except per share amounts, discounted at)	0%	5%	10%	15%
Total net present value of proved plus probable reserves (before tax)	\$10,772	\$6,574	\$4,652	\$3,575
Undeveloped acreage (2012 Year End) <sup>(1)</sup>	426	426	426	426
Decommissioning liability <sup>(2)</sup>	(345)	(178)	(54)	(24)
Long-term debt, including current portion (net of cash)	(1,064)	(1,064)	(1,064)	(1,064)
Net working capital including deferred financial assets and credits	(91)	(91)	(91)	(91)
Other equity investments <sup>(3)</sup>	12	12	12	12
<b>Net Asset Value of Assets</b>	<b>\$9,710</b>	<b>\$5,679</b>	<b>\$3,881</b>	<b>\$2,834</b>
<b>Net Asset Value per Share<sup>(4)</sup></b>	<b>\$48.87</b>	<b>\$28.58</b>	<b>\$19.53</b>	<b>\$14.26</b>

(1) Acreage acquired in 2009, 2010, 2011 and 2012 valued at acquisition cost. Balance of undeveloped acreage valued at \$100/acre.

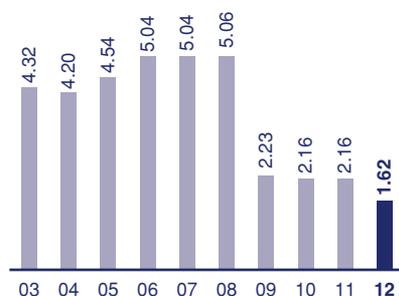
(2) Decommissioning liability does not equal the amount on the balance sheet (\$599.7 million) as the balance sheet amount uses a 2.36% discount rate and a portion of the decommissioning liability costs are already reflected in the present value of reserves computed by the independent engineers.

(3) Other equity investment portfolio is valued at the estimated fair value.

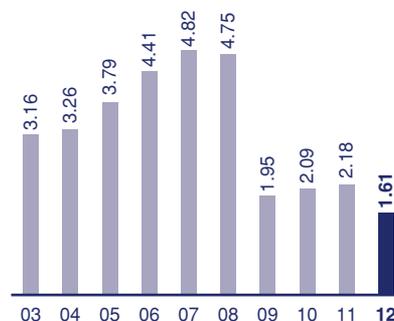
(4) Based on 198,684,000 shares outstanding as at December 31, 2012.

## CASH DIVIDENDS PAID TO SHAREHOLDERS\*

**Cash Dividends Paid to Shareholders – CDN\$**  
(Cdn\$/Share)



**Cash Dividends Paid to Shareholders – US\$**  
(US\$/Share)



\* paid January – December. Prior to 2011, Enerplus paid distributions as an income trust. Since 2011 Enerplus has paid dividends as a corporation.

Amounts paid to U.S. investors are converted to U.S. dollars on the applicable payment date. Amounts shown are prior to any amounts deducted for Canadian withholding tax.

## STOCK DIVIDEND PROGRAM

Enerplus offers a convenient way for all shareholders to accumulate more shares of Enerplus through our Stock Dividend Program (“SDP”). The benefits of the SDP include:

- All shareholders are eligible to participate;
- Shareholders can elect to receive dividends paid in Enerplus shares at a 5% discount to an average market price with no fees or commissions;
- The SDP has certain attributes that make it more attractive than a traditional DRIP to most shareholders who hold their Enerplus shares in taxable accounts
  - Not expected to generate dividend income for Canadian shareholders
  - Generally no withholding tax is applied to stock dividends paid to non-residents of Canada
- It is entirely optional, meaning our shareholders will continue to receive cash dividends unless they elect to receive stock dividends.

Shares held through a broker, investment dealer or other financial intermediary can participate in the SDP. Contact your broker or advisor and direct them to enroll your shares into the program. To obtain more information, please contact our Investor Relations Department at 1 (800) 319-6462 or by email at [investorrelations@enerplus.com](mailto:investorrelations@enerplus.com). Information on the SDP is also available on our website at [www.enerplus.com](http://www.enerplus.com).

# Abbreviations

<b>AECO</b>	a reference to the physical storage and trading hub on the TransCanada Alberta Transmission System (NOVA) which is the delivery point for the various benchmark Alberta Index prices	<b>MMbbl(s)</b>	million barrels
<b>bbl(s)/day</b>	barrel(s) per day, with each barrel representing 34.972 Imperial gallons or 42 U.S. gallons	<b>MMBOE</b>	million barrels of oil equivalent
<b>Bcf</b>	billion cubic feet	<b>MMBtu</b>	million British Thermal Units
<b>Bcfe</b>	billion cubic feet equivalent	<b>MMcf</b>	million cubic feet
<b>BOE</b>	barrels of oil equivalent	<b>MWh</b>	megawatt hour(s) of electricity
<b>Brent</b>	crude oil sourced from the North Sea, the benchmark for global oil trading quoted in \$US dollars.	<b>NGLs</b>	natural gas liquids
<b>D&amp;P</b>	developed and producing	<b>NI 51-101</b>	National Instrument 51-101 Oil and Gas Activities adopted by the Canadian Securities regulatory Authorities (pertaining to reserve reporting in Canada)
<b>E&amp;E</b>	exploration and evaluation	<b>NYMEX</b>	New York Mercantile Exchange, the benchmark for North American natural gas pricing
<b>F&amp;D Costs</b>	finding and development costs	<b>OCI</b>	other comprehensive income
<b>FD&amp;A Costs</b>	finding, development and acquisition costs	<b>PDP Reserves</b>	proved developed producing reserves
<b>FDC</b>	future development capital	<b>P+P Reserves</b>	proved plus probable reserves
<b>IFRS</b>	International Financial Reporting Standards	<b>SDP</b>	stock dividend program
<b>Mbbls</b>	thousand barrels	<b>RLI</b>	reserve life index
<b>MBOE</b>	thousand barrels of oil equivalent	<b>WCS</b>	Western Canadian Select at Hardisty, Alberta, the benchmark for Western Canadian heavy oil pricing purposes
<b>Mcf</b>	thousand cubic feet	<b>WTI</b>	West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing
<b>Mcfe</b>	thousand cubic feet equivalent		

# Definitions

**Adjusted Payout Ratio** Calculated as the sum of dividends to shareholders (net of stock dividends and DRIP proceeds) plus capital spending (including office capital) divided by funds flow.

**Best Estimate of Contingent Resources** An estimate with an equal likelihood that the actual remaining quantities of contingent resources recovered will be greater or less than the best estimate, and if probabilistic methods are used, there should be at least 50% probability that the quantities actually recovered will equal or exceed the best estimate.

**BOE** Barrels of oil equivalent converting 6 Mcf of natural gas to one barrel of oil equivalent and one barrel of natural gas liquids to one barrel of oil equivalent. The factor used to convert natural gas and natural gas liquids to oil equivalent is not based on either energy content or prices but is a commonly used industry benchmark. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

**Contingent Resources** 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. Contingent resources are not, and should not be confused with, oil and gas reserves.

**F&D Costs** Finding and development costs. Calculated as total capital expenditures, exclusive of acquisitions or divestments, and including changes in future development capital, divided by the applicable reserve additions (proved and/or proved plus probable). It is a measure of the effectiveness of a company’s capital program.

**FD&A Costs** Finding, development and acquisition costs. Calculated as total capital expenditures and net acquisitions, including changes in future development capital, divided by reserve additions (proved and/or proved plus probable). It is a measure of a company’s ability to add reserves in a cost effective manner.

**Future Development Capital** Future Development Capital is defined as those costs which reflect the independent evaluator’s best estimate of what it will cost to bring the proved undeveloped and probable reserves on production in the future. Changes to this figure occur annually as a result of development activities, acquisition and disposition activities, and capital cost estimate revisions.

**NGLs** Natural gas liquids – hydrocarbon components that can be recovered from natural gas as liquids, including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

**Oil, Heavy** Oil with a density between 10 to 22.3 degrees API or where a royalty regime exists specific to heavy oil, it is defined based upon that royalty regime.

**Oil, Light & Medium** Oil that has a density of 22.3 degrees API or higher.

**Operating Income** Calculated as revenues from oil and gas sales less cash hedging costs, transportation costs, royalties and operating costs.

**Payout Ratio** Calculated as dividends to shareholders (net of stock dividends and DRIP proceeds) divided by funds flow.

**Production, Gross** Our working interest (operated and non-operated) share of production before the deduction of any royalty interest production. Unless otherwise stated, all production volumes utilized in any discussions or calculations are gross production volumes.

**Proved** Proved production volumes as determined by the independent reserve engineering report for 2003 and forward, and management’s estimate for all prior years.

**Resource Play** Large, aerially extensive accumulations of discovered oil and natural gas with limited geological risk. Resource plays typically cover large geographic areas and require many wells to develop the play over time. With a large number of wells generating relatively predictable production and decline profiles, the timing, cost, and production rates and reserve additions associated with the resource play can be more accurately predicted.

**Reserve Life Index, Proved** Calculated as proved at year-end divided by the following year’s estimated proved production volumes as determined by the independent reserve engineering report.

**Reserve Life Index, Proved plus Probable** Calculated as proved plus probable reserves at year-end divided by the following year's estimated proved plus probable production volumes as determined by the independent reserve engineering report.

**Reserves, Company Interest** Our working interest (operated and non-operated) share of reserves before the deduction of any royalty interest reserves, but inclusive of any royalty interest reserves owned by Enerplus. Unless otherwise stated, reserve volumes utilized in any discussions or calculations are company interest reserves. "Company interest" is not a term defined in National Instrument 51-101 adopted by the Canadian Securities regulatory authorities and does not have a standardized meaning under NI 51-101 and therefore disclosure of our company interest reserves may not be comparable to disclosure of reserves by other issuers.

**Reserves, Gross** Our working interest (operated and non-operated) share of reserves before the deduction of any royalty interest reserves but exclusive of royalty interest reserves owned by Enerplus.

**Reserves, Net** Our working interest (operated and non-operated) share of reserves after the deduction of royalty interest reserves but inclusive of any royalty interest reserves owned by Enerplus.

**Reserves, Probable** Additional reserves, calculated in accordance with NI 51-101, that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

**Reserves, Proved** Reserves that can be estimated with a high degree of certainty to be recoverable in accordance with NI 51-101. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

**Reserves, Proved Developed Non-Producing** Reserves that have either not been on production or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

**Reserves, Proved Developed Producing** Reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

**Reserves, Proved Undeveloped** Reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production.

**Total Return** Calculated using the change in the share price from the start of the period (including any capital appreciation or depreciation) and the total cash dividends paid during the period divided by the starting share price.

# Board of Directors



**Douglas R. Martin**<sup>(1)(2)</sup>  
President  
Corporate Director  
Calgary, Alberta



**Robert B. Hodgins**<sup>(3)(6)</sup>  
Corporate Director  
Calgary, Alberta



**David O'Brien**<sup>(3)</sup>  
Corporate Director  
Calgary, Alberta



**Sheldon B. Steeves**<sup>(5)(11)</sup>  
Corporate Director  
Calgary, Alberta



**David H. Barr**<sup>(9)(11)</sup>  
President & Chief Executive  
Officer  
Logan International Inc.  
Houston, Texas



**Gordon J. Kerr**  
President & Chief Executive  
Officer  
Enerplus Corporation  
Calgary, Alberta



**Elliott Pew**<sup>(5)(8)</sup>  
Corporate Director  
Boerne, Texas



**Edwin V. Dodge**<sup>(9)(12)</sup>  
Corporate Director  
Vancouver, British Columbia



**Susan M. MacKenzie**<sup>(7)(10)</sup>  
Corporate Director  
Calgary, Alberta



**Glen D. Roane**<sup>(4)(5)</sup>  
Corporate Director  
Canmore, Alberta



**James B. Fraser**<sup>(7)(11)</sup>  
Corporate Director  
Polson, Montana



**Donald J. Nelson**<sup>(3)(9)</sup>  
President  
Fairway Resources, Inc.  
Calgary, Alberta



**W. C. (Mike) Seth**<sup>(7)</sup>  
President  
Seth Consultants Ltd.  
Calgary, Alberta

- 1 Chairman of the Board
- 2 *Ex-Officio* member of all Committees of the Board
- 3 Member of the Corporate Governance & Nominating Committee

- 4 Chairman of the Corporate Governance & Nominating Committee
- 5 Member of the Audit & Risk Management Committee
- 6 Chairman of the Audit & Risk Management Committee

- 7 Member of the Reserves Committee
- 8 Chairman of the Reserves Committee
- 9 Member of the Compensation & Human Resources Committee

- 10 Chairman of the Compensation & Human Resources Committee
- 11 Member of the Safety & Social Responsibility Committee
- 12 Chairman of the Safety & Social Responsibility Committee

# Officers

## ENERPLUS CORPORATION



**Gordon J. Kerr**  
President &  
Chief Executive Officer



**Ian C. Dundas**  
Executive Vice President &  
Chief Operating Officer



**Ray J. Daniels**  
Senior Vice President,  
Operations



**Eric G. Le Dain**  
Senior Vice President,  
Strategic Planning,  
Reserves & Marketing



**Robert J. Waters**  
Senior Vice President &  
Chief Financial Officer



**Jo-Anne M. Caza**  
Vice President, Corporate &  
Investor Relations



**Rodney D. Gray**  
Vice President, Finance



**Robert A. Kehrig**  
Vice President,  
Resource Development



**H. Gordon Love**  
Vice President, Technical &  
Operations Services



**David A. McCoy**  
Vice President,  
Corporate Services,  
General Counsel &  
Corporate Secretary



**Brien A. Perry**  
Vice President, Human  
Resources



**Christopher M. Stephens**  
Vice President,  
Canadian Assets



**P. Scott Walsh**  
Vice President,  
Information Systems



**Kenneth W. Young**  
Vice President, Land



**Michael R. Politeski**  
Controller, Finance



**Edward L. McLaughlin**  
President  
Enerplus (USA) Corporation

# Corporate Information

## **Operating Companies Owned by Enerplus Corporation**

Enerplus Resources (USA) Corporation

## **Legal Counsel**

Blake, Cassels & Graydon LLP  
Calgary, Alberta

## **Auditors**

Deloitte & Touche LLP  
Calgary, Alberta

## **Transfer Agent**

Computershare Trust Company of Canada  
Calgary, Alberta  
Toll free: 1.866.921.0978

## **U.S. Co-Transfer Agent**

Computershare Trust Company, N.A.  
Golden, Colorado

## **Independent Reserve Engineers**

McDaniel & Associates Consultants Ltd.  
Calgary, Alberta

Haas Petroleum Engineering Services, Inc.  
Dallas, Texas

## **Stock Exchange Listings and Trading Symbols**

Toronto Stock Exchange: ERF  
New York Stock Exchange: ERF

## **U.S. Office**

950 17<sup>th</sup> Street, Suite 2200  
Denver, Colorado 80202

Telephone: 720.279.5500  
Fax: 720.279.5550

## **Annual General Meeting**

Shareholders are encouraged to attend the Annual General Meeting being held on:

Friday, May 10, 2013  
10:00 am, MT  
The Metropolitan Centre  
Lecture Theatre  
333 - 4<sup>th</sup> Avenue SW  
Calgary, Alberta





**enerPLUS**

The Dome Tower  
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