



PrimeWest Energy Trust
2003 Quarterly
Report to the Unitholders

PRIME WEST

For the nine
months ended
September 30, 2003

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CALGARY, November 6, 2003 (TSX: PWI.UN, PWX; NYSE: PWI) -- PrimeWest Energy Trust (PrimeWest) today announced unaudited interim operating and financial results for the third quarter. Unless otherwise noted, all figures contained in this report are in Canadian dollars.

PRIMEWEST ENERGY TRUST ANNOUNCES THIRD QUARTER 2003 RESULTS. CASH FLOW FROM OPERATIONS OF \$1.11 PER UNIT.

THIRD QUARTER HIGHLIGHTS

- Distributions payable for the quarter totalled \$0.96 per unit representing \$0.32 per unit paid in August, September and October. This represents a payout ratio of approximately 86% of cash flow available in the quarter.
- A distribution of \$0.32 per unit is payable on November 14 for unitholders of record on October 31, 2003.
- Production averaged 32,628 barrels of oil equivalent (BOE) per day versus the second quarter rate of 34,004 BOE/day.⁽¹⁾
- Operating costs were reduced from \$6.57 per BOE in the second quarter to \$5.73 per BOE in the third quarter due to operating synergies realized through the rationalization of the recently acquired Caroline properties, declining labour costs resulting from field personnel restructuring and lower power costs.
- Cash flow from operations was \$51.8 million (\$1.11 per unit) compared to \$57.2 million (\$1.24 per unit) in the second quarter of 2003, primarily as a result of lower volumes and commodity prices and the strengthened Canadian dollar.
- PrimeWest issued 3.1 million trust units at a price of \$25.90 per unit raising net proceeds of \$76.3 million. The proceeds were used to reduce bank indebtedness and pursue development opportunities in the Caroline, Valhalla and Brant Farrow areas. Debt levels are now approximately one times annual cash flow. Debt per unit is \$4.68 at the end of the third quarter, versus \$6.17 at the end of the second quarter.
- The Optional Trust Unit Purchase Program raised \$17.6 million from January through September 2003. The program was fully subscribed and will re-commence in January 2004. Subscription is limited by the Toronto Stock Exchange to 2% of the number of units outstanding at the end of the prior year.
- Subsequent to the quarter end, PrimeWest introduced a Premium Distribution Component within its Distribution Reinvestment (DRIP) and Optional Trust Unit Purchase (OTUPP) Plans, which enables eligible Canadian unitholders to elect to receive up to 102% of the normal distribution amount commencing in December, 2003.

CASH FLOW RECONCILIATION (MILLIONS)

The table below provides a reconciliation of the changes to cash flows from the second quarter to the third quarter 2003.

Second quarter 2003 cash flow from operations	\$	57.2
Production volumes		(3.6)
Commodity prices		(9.4)
Reduced hedging loss		3.0
Operating expenses		3.1
Royalties		1.9
Other		(0.4)
Third quarter 2003 cash flow from operations	\$	51.8

⁽¹⁾ All calculations required to convert natural gas to a crude oil equivalent (BOE) have been made using a ratio of 6,000 cubic feet of natural gas to 1 barrel of crude oil.

FINANCIAL & OPERATING HIGHLIGHTS

FINANCIAL HIGHLIGHTS

(millions of dollars except per-BOE
and per Trust Unit amounts)

	Three months ended			Nine months ended	
	Sep 30, 2003	Jun 30, 2003	Sep 30, 2002	Sep 30, 2003	Sep 30, 2002
Net revenue	\$ 77.2	\$ 85.6	\$ 63.8	\$ 256.9	\$ 195.5
per BOE	25.70	27.67	23.00	27.91	23.58
Cash flow from operations	51.8	57.2	40.9	173.7	129.4
per BOE	17.25	18.45	14.71	18.88	15.61
per Trust Unit ⁽¹⁾	1.11	1.24	1.20	3.85	3.86
Royalty expense	23.1	25.0	14.0	80.8	39.2
per BOE	7.70	8.08	5.04	8.77	4.73
Operating expenses	17.2	20.3	14.9	58.2	43.9
per BOE	5.73	6.57	5.38	6.32	5.30
G&A expenses - Cash	3.5	3.2	2.4	10.5	8.0
per BOE	1.15	1.04	0.88	1.14	0.96
G&A expenses - Non-cash	2.3	3.2	(0.9)	5.9	6.0
per BOE	0.76	1.05	(0.34)	0.64	0.73
Interest expense	4.0	3.4	3.0	11.0	7.6
per BOE	1.32	1.11	1.09	1.20	0.92
Management fees - Cash	-	-	1.3	-	4.0
per BOE	-	-	0.47	-	0.48
- Non-cash	-	-	0.4	-	1.4
per BOE	-	-	0.16	-	0.17
Distributions to unitholders	43.7	52.8	38.8	146.3	115.4
per Trust Unit ⁽⁴⁾	0.96	1.20	1.20	3.36	3.60
Net debt ⁽³⁾	233.4	286.4	270.9	233.4	270.9
per Trust Unit ⁽²⁾	4.68	6.17	7.94	4.68	7.94

(1) Weighted average Trust Units & exchangeable shares outstanding (diluted)

(2) Trust Units and exchangeable shares outstanding (diluted)

(3) Net debt is long-term debt & working capital

(4) Based on Trust Units outstanding at date of distribution

OPERATING HIGHLIGHTS	Three months ended			Nine months ended	
	Sep 30, 2003	Jun 30, 2003	Sep 30, 2002	Sep 30, 2003	Sep 30, 2002
DAILY SALES VOLUMES					
Natural gas (MMcf/day)	131.4	137.9	115.5	136.5	113.3
Crude oil (bbls/day)	7,913	8,222	8,975	8,091	9,399
Natural gas liquids (bbls/day)	2,811	2,800	1,950	2,879	2,081
Total (BOE/day)	32,628	34,004	30,169	33,722	30,362
REALIZED COMMODITY PRICES (CDN \$)					
Natural gas (\$/Mcf)	5.59	6.10	4.07	6.21	4.37
Without hedging	5.93	6.69	3.10	6.83	3.35
Crude oil (\$/bbl)	32.65	33.60	35.97	34.85	33.61
Without hedging	34.40	34.82	38.82	37.61	33.58
Natural gas liquids (\$/bbl)	33.06	32.71	28.09	35.62	24.76
Total (\$ per BOE)	33.29	35.54	28.09	36.55	28.40
Without hedging	35.07	38.23	25.24	39.72	24.61

FORWARD-LOOKING INFORMATION

Because forward-looking information addresses future events and conditions, it involves risks and uncertainties that could cause actual results to differ materially from those contemplated by the forward-looking information. These risks and uncertainties include commodity price levels; production levels; the recoverability of reserves; transportation availability and costs; operating and other costs; interest rates and currency exchange rates; and changes in environmental and other legislation and regulations. Please refer to the Trust's annual report for more detail as to the nature of these risks and uncertainties.

MANAGEMENT'S DISCUSSION & ANALYSIS (MD&A)

The following discussion is management's analysis of PrimeWest's operating and financial results for the quarter ended September 30, 2003, compared with the previous quarter and the third quarter of 2002. This discussion also contains information and opinions concerning the Trust's future outlook based on current available information. This discussion should be read in conjunction with the Trust's annual MD&A and audited consolidated financial statements for the years ended December 31, 2001 and 2002, together with the accompanying notes, as contained in the Trust's 2002 Annual Report.

STRATEGY**Asset Growth****YEAR-TO-DATE PERFORMANCE**

- Closed the acquisition of the Caroline / Peace River Arch properties.

CURRENT 2003 OUTLOOK

- Continue to pursue value added acquisitions in existing core areas or to create a new core area, although asset supply is currently limited and the acquisition market is very competitive.

Operating Excellence

- Production year to date is 33,722 BOE/day.
- Third quarter capital spending was \$31.4 million and year to date \$75.6 million.
- Year to date operating expenses are \$6.32 per BOE.

- Average 33,500 BOE/day of production for the calendar year 2003.
- Invest up to \$100 million in value added incremental production through drilling and completions, facility optimization and workovers.
- Operating expenses are targeted to be between \$6.00 - \$6.50 per BOE.

Financial Prudence

- Debt-to-cash flow ratio for the quarter annualized was 1.13 versus 1.25 at the end of the second quarter.
- Un-utilized credit facility of \$129 million at September 30, 2003.
- Distributions payable for the quarter totalled \$0.96 per unit - \$0.32 per unit paid in August, September and October. The year to date payout ratio is 87%.

- Year end debt levels are expected to be conservative and well within our long term strategy of maintaining a debt-to-cash flow ratio of less than 2.0 times.

- Anticipated 2003 payout ratio of approximately 90% relative to our longer term payout ratio target of approximately 70-90%.

Risk Management

- Ongoing hedges continue to reduce volatility; however, strong commodity prices year to date in 2003 have resulted in a hedging loss of \$29.2 million to September 30, 2003. PrimeWest's hedging program has delivered gains of \$37.8 million over the period January 1, 2001 to September 30, 2003.

- At the end of the third quarter, approximately 54% of production for the fourth quarter is hedged. Our hedging strategy is to reduce distribution volatility by maintaining price protection to a maximum of 70% of production net of royalties and development additions.

PRODUCTION VOLUMES

	Three months ended			Nine months ended	
	Sep 30, 2003	Jun 30, 2003	Sep 30, 2002	Sep 30, 2003	Sep 30, 2002
Natural gas (MMcf/day)	131.4	137.9	115.5	136.5	113.3
Crude oil (bbls/day)	7,913	8,222	8,975	8,091	9,399
Natural gas liquids (bbls/day)	2,811	2,800	1,950	2,879	2,081
Total (BOE/day)	32,628	34,004	30,169	33,722	30,362
Gross Overriding Royalty volumes included above (BOE/day)	1,270	1,754	1,560	1,607	1,757

The 4% decrease in production volumes quarter over quarter is due to a prior period gross overriding royalty adjustment (195 BOE/day), shutdown of a third party gas plant forcing the redirection of Caroline volumes (153 BOE/day), facility capacity restraints at Whiskey Creek (153 BOE/day) and natural decline. Through the quarter, approximately 625 BOE/day of incremental production was brought on-line to mitigate decline. Approximately 1,500 BOE/day remain behind pipe at the end of the quarter.

Subject to an ongoing review by the EUB relating to the gas / bitumen issue in NE Alberta, PrimeWest's Ells production of approximately 450 BOE/day remains on-stream. The previously disclosed asset divestment of \$12 million, representing 100 BOE/day, has not closed as anticipated.

Compared to the third quarter of 2002, production volumes are higher, primarily as a result of production acquired in the Caroline/Peace River Arch areas.

PRODUCTION OUTLOOK

PrimeWest continues to expect full year volumes to be approximately 33,500 BOE/day.

REALIZED COMMODITY PRICES

Benchmark prices	Three months ended			Nine months ended	
	Sep 30, 2003	Jun 30, 2003	Sep 30, 2002	Sep 30, 2003	Sep 30, 2002
Natural gas (\$/Mcf AECO)	\$6.29	\$7.00	\$3.25	\$7.07	\$3.67
Crude oil (\$U.S./bbl WTI)	\$30.20	\$28.91	\$28.27	\$30.99	\$25.39

Average PrimeWest realized commodity prices (Cdn dollars)	Three months ended			Nine months ended	
	Sep 30, 2003	Jun 30, 2003	Sep 30, 2002	Sep 30, 2003	Sep 30, 2002
Natural gas (\$/Mcf)	\$5.59	\$6.10	\$4.07	\$6.21	\$4.37
Crude oil (\$/bbl)	32.65	33.60	35.97	34.85	33.61
Natural gas liquids (\$/bbl)	33.06	32.71	28.09	35.62	24.76
Total Oil Equivalent (\$ per BOE)	\$33.29	\$35.54	\$28.09	\$36.55	\$28.40
Realized hedging gain (loss) included in prices above (\$ per BOE)	\$(1.78)	\$(2.69)	\$2.85	\$(3.17)	\$3.71

PrimeWest's hedging program has delivered gains of \$37.8 million over the period January 1, 2001 to September 30, 2003.

PrimeWest uses hedging to reduce volatility in cash flows, protect acquisition economics and to stabilize distributions against the unpredictable commodity price environment. Although hedging is designed to protect from the downside risk, it can result in PrimeWest not participating fully in the upside.

SALES REVENUE ⁽¹⁾

(\$ millions)	Three months ended			Nine months ended	
	Sep 30, 2003	Jun 30, 2003	Sep 30, 2002	Sep 30, 2003	Sep 30, 2002
Natural gas	\$67.6	\$76.5	\$43.2	\$231.5	\$135.1
Crude oil	23.8	25.1	29.7	77.0	86.2
Natural gas liquids	8.6	8.3	5.0	28.0	14.1
Total	\$100.0	\$109.9	\$77.9	\$336.5	\$235.4
Hedging (loss)/gains included above ⁽²⁾	\$(5.4)	\$(8.3)	\$7.9	\$(29.2)	\$30.8

(1) Excludes sulphur

(2) Net of amortized premiums

Revenues for the third quarter of 2003 were \$100 million compared to \$109.9 million in the previous quarter as a result of lower commodity prices and production volumes and the strengthened Canadian dollar.

The recent strength of the Canadian dollar versus its American counterpart continues to negatively impact the oil and gas sector. Oil and gas prices are denominated in U.S. dollars, therefore, a strengthened Canadian dollar translates into lower Canadian revenue for producers.

Revenues for the third quarter of 2003 were 28% higher than the third quarter of 2002. The major factor is the overall higher commodity prices realized thus far in 2003, along with higher production levels associated with the acquisition of the Caroline/Peace River Arch properties.

PRICE OUTLOOK

The following table sets forth benchmark historical and estimated future commodity prices.

Benchmark Commodity Prices	Past Four Quarters (Actual)				Next Four Quarters (Forward Markets) ⁽¹⁾			
	Q4 2002	Q1 2003	Q2 2003	Q3 2003	Q4 2003	Q1 2004	Q2 2004	Q3 2004
Natural gas								
NYMEX (\$U.S./Mcf)	3.99	6.61	5.48	5.10	4.81	5.19	4.74	4.72
AECO (\$Cdn/Mcf)	5.26	7.92	7.00	6.29	5.85	6.14	5.52	5.48
Crude oil WTI (\$U.S./bbl)	28.15	33.86	28.91	30.20	28.74	27.64	26.82	26.25

(1) As at September 30, 2003

Crude oil prices fluctuated during the third quarter reflecting the announced intention of the U.S. to again start the flow of Iraqi oil, the intervention of OPEC, ongoing civil unrest in Nigeria and Venezuela, the low storage levels of crude oil in the contiguous U.S., and the end of the "driving season" in North America. During the quarter, oil reached a low of \$U.S. 26.93 on September 23rd and a high of \$U.S. 32.39 on August 7th. On September 24, 2003 OPEC announced production would be curtailed by some 900,000 barrels per day, and the markets immediately reacted as the price of benchmark WTI closed at \$U.S. 28.05 up over a dollar over the previous day's close. By September month-end, WTI crude had reached over \$U.S. 29.00.

The forward market for crude oil indicates future prices in steady decline over the next four quarters. The forward market for WTI averaged for the next 12 months is \$U.S. 27.36 per barrel, compared to \$U.S. 30.20 per barrel for the third quarter 2003.

Natural gas prices declined about 10% from the second to the third quarter, as a result of higher injection rates of gas into storage and a significant recovery of natural gas inventories. Sustained high natural gas pricing has resulted in ongoing demand destruction in the U.S. gas fired electrical generation and industrial use sectors contributing to higher injection rates. Very high drilling levels, additional pipeline capacity out of the U.S. Rocky Mountain Basin, and additional imports to North America of Liquefied Natural Gas ("LNG") have also resulted in additional natural gas supplies being available to the market.

Despite the rebalancing of supply and demand forces mentioned above, the forward market for natural gas still represents historically high pricing throughout the next four quarters. The forward market for AECO averaged for the next twelve months is \$5.75 per mcf, compared to \$6.29 per mcf for the third quarter 2003.

With oil and gas prices denominated in U.S. dollars, the strengthening Canadian dollar has continued to negatively impact Canadian dollar realizations. During the third quarter of 2003 the foreign exchange rate for the Canadian dollar averaged \$U.S. 0.725 compared to an average exchange rate of \$U.S. 0.64 during the third quarter of 2002. Year to date 2003, the exchange rate for the Canadian dollar has averaged \$U.S. 0.70 compared to \$U.S. 0.637 during the calendar year 2002.

ROYALTIES

	Three months ended			Nine months ended	
	Sep 30, 2003	Jun 30, 2003	Sep 30, 2002	Sep 30, 2003	Sep 30, 2002
Royalty expense (\$ millions)	\$23.1	\$25.0	\$14.0	\$80.8	\$39.2
\$/ BOE	\$7.70	\$8.08	\$5.04	\$8.77	\$4.73
Royalties as % of sales revenue					
- including hedging	23.1%	22.7%	18.0%	24.0%	16.7%
- excluding hedging	21.9%	21.1%	20.0%	22.1%	19.3%

Royalty rates increased in the third quarter compared to the second quarter of 2003 as a result of thirteenth month adjustments from the Crown and revenue adjustments on some properties. Hedging gains do not attract royalties and hedge losses do not provide for royalty reductions.

As a result of significantly higher commodity prices realized in the third quarter of 2003 compared to the same period in 2002, the royalty expense and royalty rates were higher.

OPERATING EXPENSES

	Three months ended			Nine months ended	
	Sep 30, 2003	Jun 30, 2003	Sep 30, 2002	Sep 30, 2003	Sep 30, 2002
Operating expenses (\$ millions)	\$17.2	\$20.3	\$14.9	\$58.2	\$44.0
\$/ BOE	\$5.73	\$6.57	\$5.38	\$6.32	\$5.30

The third quarter operating expenses are significantly lower than the previous quarter due to operating synergies realized through the rationalization of the recently acquired Caroline property, declining labour costs resulting from field personnel restructuring and lower power costs.

Expenses in the third quarter 2003 are \$2.3 million higher than the same period in 2002 due to operating costs associated with the Caroline/Peace River Arch acquisition.

OPERATING EXPENSES OUTLOOK

Operating costs for the full year are expected to be higher than 2002, due to higher power costs and one-time employee and contractor restructuring expenses. We continue to expect full year costs to be approximately \$6.00 to \$6.50 per BOE.

OPERATING MARGIN

(\$ per BOE)	Three months ended			Nine months ended	
	Sep 30, 2003	Jun 30, 2003	Sep 30, 2002	Sep 30, 2003	Sep 30, 2002
Sales price ⁽¹⁾	\$33.40	\$35.75	\$28.04	\$36.68	\$28.31
Royalties	7.70	8.08	5.04	8.77	4.73
Operating costs	5.73	6.57	5.38	6.32	5.30
Operating margin	\$19.97	\$21.10	\$17.62	\$21.59	\$18.28

(1) Including hedging gains and other revenue/losses

The operating margin declined from the second quarter 2003 level reflecting lower natural gas prices and crude oil prices, and a strengthened Canadian dollar offset by reduced hedging losses, lower royalties and lower operating costs.

Operating margins year to date 2003 are higher than the same period in 2002 as a result of higher commodity prices for both oil and natural gas offset by increased royalty, operating costs, and a strengthened Canadian dollar.

GENERAL & ADMINISTRATIVE EXPENSE

	Three months ended			Nine months ended	
	Sep 30, 2003	Jun 30, 2003	Sep 30, 2002	Sep 30, 2003	Sep 30, 2002
G&A expense (\$ millions)	\$3.5	\$3.2	\$2.4	\$10.5	\$8.0
\$/BOE	\$1.15	\$1.04	\$0.88	\$1.14	\$0.96

Third quarter G&A costs were higher than the second quarter of 2003 due to higher salary costs as a result of hiring additional technical staff, and one time costs of approximately \$0.4 million associated with evaluating international opportunities..

Compared to the third quarter of 2002, G&A costs were higher due to higher payouts under the Short-Term Incentive Plan as well as higher salary, benefit, restructuring, information systems and office lease costs.

G&A EXPENSE OUTLOOK

Cash G&A expenses are expected to be approximately \$1.15 per BOE for the year.

MANAGEMENT FEES EXPENSE

	Three months ended			Nine months ended	
	Sep 30, 2003	Jun 30, 2003	Sep 30, 2002	Sep 30, 2003	Sep 30, 2002
Cash management fees (\$ millions)	\$-	\$-	\$1.3	\$-	\$4.0
\$/ BOE	\$-	\$-	\$0.47	\$-	\$0.48
Non-cash management fees					
(\$ millions)	\$-	\$-	\$0.4	\$-	\$1.4
\$/ BOE	\$-	\$-	\$0.16	\$-	\$0.17

On November 4, 2002, unitholders approved the internalization of management effective October 1, 2002. Accordingly, there are no cash or non-cash management fees after that date.

NON-CASH G&A EXPENSES

	Three months ended			Nine months ended	
	Sep 30, 2003	Jun 30, 2003	Sep 30, 2002	Sep 30, 2003	Sep 30, 2002
Non-cash G&A expenses					
(\$ millions)	\$2.3	\$3.2	\$(0.9)	\$5.9	\$6.0
\$/ BOE	\$0.76	\$1.05	\$(0.34)	\$0.64	\$0.73

Non-cash G&A expenses consist mainly of Unit Appreciation Rights. UARs are similar to stock options in a conventional business. The UARs are marked-to-market each quarter and the impact is recognized as an expense or recovery in the income statement of the Trust.

INTEREST EXPENSE

(\$ millions)	Three months ended			Nine months ended	
	Sep 30, 2003	Jun 30, 2003	Sep 30, 2002	Sep 30, 2003	Sep 30, 2002
Interest expense	\$4.0	\$3.4	\$3.0	\$11.0	\$7.6
Period end net debt level	\$233.2	\$286.4	\$270.9	\$233.2	\$270.9
Debt per Trust Unit	\$4.67	\$6.17	\$8.01	\$4.67	\$8.01
Average cost of debt	4.7%	4.4%	4.5%	4.5%	4.3%

The period end net debt level decreased significantly as a result of the equity offering which was used to repay debt.

At September 30, 2003, approximately 98% of the debt was at a fixed rate, with the balance at a floating rate. PrimeWest utilizes interest rate swaps that permit greater flexibility in the maintenance of fixed versus floating interest rates. During the second quarter, PrimeWest completed a \$U.S. 125 million private placement debt financing of secured notes at a coupon rate of 4.19% with a seven year term.

DEPLETION, DEPRECIATION AND AMORTIZATION (DD&A)

	Three months ended			Nine months ended	
	Sep 30, 2003	Jun 30, 2003	Sep 30, 2002	Sep 30, 2003	Sep 30, 2002
Depletion, depreciation & amortization (\$ millions)	\$50.7	\$49.9	\$46.0	\$153.3	\$137.1
\$/ BOE	\$16.91	\$16.13	\$16.56	\$16.66	\$16.49

Year to date 2003 DD&A is higher than 2002 reflecting higher production volumes and reserves as a result of additional volumes associated with the Caroline / Peace River Arch acquisition.

The DD&A rate is inflated relative to the acquisition cost of certain reserves due to the requirement to account for future income tax liabilities associated with the acquisition of those reserves. The offset is in the income tax recovery. Absent this tax adjustment, the DD&A rate would be lower by approximately \$3.50 per BOE in the third quarter of 2003.

SITE RESTORATION AND CLEAN-UP

PrimeWest has contributed \$0.50 per BOE year to date in 2003 to pay for future costs related to well abandonment and site clean-up. The monies are then used to pay for reclamation and abandonment costs as they are incurred. This allows PrimeWest to fund abandonment on an ongoing basis, rather than incur a major cost at the conclusion of the productive life of an oil or gas asset.

CEILING TEST

PrimeWest has performed a ceiling test using commodity prices as at the measurement date of September 30, 2003. Using September 30, 2003, commodity prices of AECO \$5.75 per mcf for natural gas and WTI U.S. \$29.20 per barrel of oil would result in a significant cushion of approximately \$525 million.

INCOME AND CAPITAL TAXES

(\$ millions)	Three months ended			Nine months ended	
	Sep 30, 2003	Jun 30, 2003	Sep 30, 2002	Sep 30, 2003	Sep 30, 2002
Income and capital taxes	\$0.8	\$1.5	\$1.3	\$3.5	\$2.6
Future income taxes recovery	(8.7)	(52.0)	(12.8)	(71.1)	(23.1)
	\$(7.9)	\$(50.5)	\$(11.5)	\$67.6	\$(20.5)

On June 9, 2003, the Canadian Government substantially enacted Federal income tax changes for the oil and gas resource sector as outlined in its 2003 Budget. The Federal income tax changes effectively reduced the statutory tax rates for current and future periods, resulting in a significant increase in the future tax recovery (a non-cash item) compared to the first quarter and prior years. Specifically, the current 100% deductibility of the resource allowance will be completely phased out by the year 2007. During the same time frame, Crown charges will become 100% deductible and resource tax rates will decline from the current 27% to 21%.

NET INCOME (LOSS)

(\$ millions)	Three months ended			Nine months ended	
	Sep 30, 2003	Jun 30, 2003	Sep 30, 2002	Sep 30, 2003	Sep 30, 2002
Net income (loss)	\$7.3	\$61.7	\$8.2	\$91.0	\$8.0

During the second quarter of 2003 substantial income tax recoveries and foreign exchange gains contributed to net income. In addition to these items, third quarter net income is lower than the previous quarter due to lower production levels and commodity prices.

LIQUIDITY AND CAPITAL RESOURCES

(\$ millions)	As at		
	Sep 30, 2003	Jun 30, 2003	Sep 30, 2002
Long-term debt	\$247.7	\$298.4	\$255.0
Working capital deficit/(surplus)	(14.3)	(12.0)	15.9
Net debt	233.4	286.4	270.9
Market value of Trust Units and exchangeable shares outstanding	1,247.3	1,151.7	894.0
Total capitalization	\$1,480.7	\$1,438.1	\$1,164.9
Net debt as a % of total capitalization	15.8%	19.9%	23.25%

Third quarter 2003 debt levels are down significantly when compared to the second quarter of 2003 due to the September equity offering of \$76.3 million which was used to pay down debt.

At September 30, 2003, the long-term debt was comprised of bank credit facilities and senior secured notes for \$79 million and \$168.7 million, respectively. The notes were issued on May 6, 2003 for a principal value of U.S. \$125 million. Debt levels now stand at approximately 1x cash flow, well below our target of 2x cash flow allowing for greater financial flexibility.

CAPITAL SPENDING

(\$ millions)	Three months ended			Nine months ended	
	Sep 30, 2003	Jun 30, 2003	Sep 30, 2002	Sep 30, 2003	Sep 30, 2002
Expenditures on property, plant and equipment	\$ 31.4	\$18.8	\$12.0	\$75.6	\$49.2

Capital spending of \$31.4 million during the third quarter was behind year to date expectations due to timing of capital project execution. Full year capital spending estimates continue to be approximately \$100 million.

Of the \$31.4 million, \$19.0 million was spent on drilling and completions, and \$9.4 million on facilities and infrastructure, with the remainder on lease acquisitions and other. The focus of the development program centered on properties in the Caroline, Valhalla and Brant Farrow areas, with 4, 7 and 8 wells drilled in those areas respectively. During the third quarter PrimeWest drilled a total of 24 gross wells with a success rate of 96%.

HEDGING PROGRAM

Approximate percentage of future anticipated production volumes hedged at September 30, 2003, net of anticipated royalties, reflecting full production declines with no offsetting additions:

	Q4 2003	Q1 2004	Q2 2004
Crude Oil	63%	51%	33%
Natural Gas	49%	49%	18%

The mark-to-market valuation of these hedges was a \$0.5 million loss at September 30, 2003 consisting of a \$0.6 million loss in crude oil and a \$0.1 million gain in natural gas. A summary of contracts in place as at September 30, 2003 is as follows:

Crude Oil (U.S.\$/bbl)

Period	Volume (bbl/d)	Type	WTI Price (U.S.\$/bbl)
Oct – Dec 2003	1,000	3 Way	17.00/20.50/25.50
Oct – Dec 2003	1,000	3 Way	18.50/22.50/27.20
Oct – Dec 2003	500	Swap	27.49
Oct – Dec 2003	500	Swap	29.07
Oct – Dec 2003	500	Swap	30.51
Oct – Dec 2003	500	Costless Collar	24.00/30.00
Oct – Dec 2003	500	Costless Collar	26.00/32.45
Jan – Mar 2004	1000	Swap	27.29
Jan – Mar 2004	500	Swap	28.87
Jan – Mar 2004	500	Costless Collar	22.00/26.70
Jan – Mar 2004	500	Costless Collar	23.00/33.30
Jan – Mar 2004	500	Costless Collar	24.00/31.20
Jan – Mar 2004	500	Costless Collar	25.00/28.16
Apr – Apr 2004	500	Swap	27.02
Apr – Jun 2004	500	Swap	27.21
Apr – Jun 2004	500	Costless Collar	22.00/26.12
Apr – Jun 2004	500	Costless Collar	24.00/30.50
Apr – Jun 2004	500	Costless Collar	25.00/28.07
Jul – Jul 2004	500	Swap	27.12
Jul – Aug 2004	500	Swap	26.08

Natural Gas (Cdn\$/Mcf)

Period	Volume (MMcf/d)	Type	AECO Price (Cdn\$/Mcf)
Oct – Oct 2003	4.7	Fixed Price	4.75
Oct – Oct 2003	4.7	Swap	3.98
Oct – Oct 2003	4.7	Swap	4.17
Oct – Oct 2003	4.7	Swap	5.05
Oct – Oct 2003	4.7	Swap	6.57
Oct – Oct 2003	4.7	Swap	6.45
Oct – Oct 2003	4.7	3 Way	3.17/3.96/5.39
Oct – Oct 2003	4.7	3 Way	3.17/4.48/6.26
Oct – Oct 2003	4.7	3 Way	3.69/4.75/6.65
Oct 2003 – Oct 2004	9.5	3 Way	3.17/4.22/6.09
Nov 2003 – Mar 2004	4.7	Costless Collar	6.33/7.91
Nov 2003 – Mar 2004	4.7	3 Way	4.22/5.28/8.23
Nov 2003 – Mar 2004	4.7	Costless Collar	6.33/11.87
Nov 2003 – Mar 2004	4.7	Costless Collar	5.80/8.23
Nov 2003 – Mar 2004	4.7	Costless Collar	6.33/8.58
Jan 2004 – Mar 2004	4.7	Costless Collar	4.75/7.91
Jan 2004 – Dec 2004	4.7	Swap	6.02

A 3-way option is like a traditional collar, except that PrimeWest has resold the put at a lower price. Utilizing the first 3-way crude oil contract above as an example, PrimeWest has sold a call at \$25.50, purchased a put at \$20.50, and resold

the put at \$17.00. Should the market price drop below \$20.50 PrimeWest will receive \$20.50 until the price is less than \$17.00, at which time PrimeWest would then receive market price plus \$3.00. However, should market prices rise above \$25.50, PrimeWest would receive a maximum of \$25.50. Should the market price remain between \$20.50 and \$25.50, PrimeWest would receive the market price.

Natural Gas Basis Swaps (\$U.S./mcf)

Period	Volume (MMcf/d)	Type	AECO Price Differential (\$U.S./Mcf)
Oct – Oct 2003	5.0	Basis Swap	0.45
Nov 2003 – Mar 2004	7.5	Basis Swap	0.63
Apr – Oct 2004	5.0	Basis Swap	0.71

The AECO basis is the difference between the NYMEX gas price in \$U.S. per mcf and the AECO price in \$U.S. per mcf. Using the first basis swap above as an example, PrimeWest has fixed this price difference between the two markets at \$U.S. 0.45 per mcf for the summer period. If the NYMEX price for the period turned out to be \$U.S. 4.00 per mcf, PrimeWest would receive an AECO equivalent price of \$U.S. 3.55 per mcf.

Electrical Power

Period	Power Amount (MW)	Type	Heat Rate (GJ/MW-hr)
Calendar 2003	2.5	Heat Rate Swap	8.75
Calendar 2003	5.0	Heat Rate Swap	9.0

Period	Power Amount (MW)	Type	Price (\$/MW-hr)
Q1 2004	5.0	Fixed Price Swap	58.50
Q2 2004	7.5	Fixed Price Swap	40.25
Q3 2004	5.0	Fixed Price Swap	45.60
Q4 2004	5.0	Fixed Price Swap	44.00
Calendar 2004	5.0	Fixed Price Swap	45.65

A heat rate swap fixes the amount of natural gas required to generate a corresponding unit of electricity. PrimeWest produces natural gas and consumes power. Using the first heat rate swap as an example, PrimeWest will set aside 8.75 GJ of natural gas for sale at daily market pricing in order to receive 1 MW-hr of electrical power at daily market pricing. For the 2.5 MW of power consumption, this equates to approximately 500 mcf per day of natural gas supply.

PREMIUM DISTRIBUTION, DISTRIBUTION REINVESTMENT AND OPTIONAL TRUST UNIT PURCHASE PLAN

PrimeWest is pleased to offer its eligible Canadian unitholders an opportunity to enhance their returns through participation in the new Premium Distribution Component (PREP) of its existing Distribution Reinvestment (DRIP) and Optional Trust Unit Purchase Plan (OTUPP). As an alternative to the existing DRIP Component of the Plan, which allows eligible Canadian unitholders to reinvest their monthly distributions at a 5% discount to the average market price, the new PREP allows eligible Canadian unitholders to elect to receive a premium cash distribution of up to 102% of the cash that the unitholder would otherwise have received on the distribution date, subject to proration in certain events. Canaccord Capital Corporation will act as Plan Broker under the PREP Component of the Plan. The OTUPP has been fully subscribed for the calendar year 2003 and will re-commence in January 2004. For additional information or to join these

CONSOLIDATED BALANCE SHEETS

(millions of dollars)	<i>(Unaudited)</i> As at Sep 30, 2003	<i>(Audited)</i> As at Dec 31, 2002
ASSETS		
Current assets		
Cash and short term deposits	\$ 21.9	\$ -
Accounts receivable	74.3	71.6
Prepaid expenses	6.6	9.8
Inventory	2.7	2.2
	105.5	83.6
Cash reserved for site restoration and reclamation	6.4	-
Other assets	0.3	14.4
Deferred charges	1.3	-
Property, plant and equipment	1,556.7	1,404.5
Goodwill (note 2)	53.9	-
	\$ 1,724.1	\$ 1,502.5
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities		
Bank overdraft	\$ -	\$ 3.1
Accounts payable & accrued liabilities	76.7	67.3
Accrued distributions to unitholders	14.5	13.9
	91.2	84.3
Long-term debt (note 3)	247.7	225.0
Future income taxes	321.9	339.9
Site restoration and reclamation provision	16.6	6.2
	677.4	655.4
UNITHOLDERS' EQUITY		
Net capital contributions (note 4)	1,553.1	1,300.0
Capital issued but not distributed	0.9	0.9
Long-term incentive plan equity	11.8	10.0
Accumulated income	214.2	123.2
Accumulated cash distributions	(725.2)	(578.9)
Accumulated dividends	(8.1)	(8.1)
	1,046.7	847.1
	\$ 1,724.1	\$ 1,502.5

CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY *(Unaudited)*

For the nine months ended	Sep 30, 2003	Sep 30, 2002
Unitholders' equity, beginning of the period	\$ 847.1	\$ 856.3
Net income for the period	91.0	8.0
Net capital contributions	253.1	20.9
Capital issued but not distributed	-	(0.7)
Long-term incentive plan equity	1.8	2.3
Cash distributions	(146.3)	(115.4)
Dividends	-	(1.2)
Unitholders' equity, end of the period	\$ 1,046.7	\$ 770.2

CONSOLIDATED STATEMENTS OF CASH FLOW (Unaudited)

(millions of dollars)

	Three months ended		Nine months ended	
	Sep 30, 2003	Sep 30, 2002	Sep 30, 2003	Sep 30, 2002
OPERATING ACTIVITIES				
Net income for the period	\$ 7.3	\$ 8.2	\$ 91.0	\$ 8.0
Add/(deduct):				
Items not involving cash from operations				
Depletion, depreciation and amortization	50.7	46.0	153.3	137.1
Non-cash general & administrative	2.3	(0.9)	5.9	6.0
Non-cash foreign exchange gain	0.2	-	(5.4)	-
Non-cash management fees	-	0.4	-	1.4
Future income taxes recovery	(8.7)	(12.8)	(71.1)	(23.1)
Cash flow from operations	51.8	40.9	173.7	129.4
Expenditures on site restoration and reclamation	(0.4)	(1.5)	(0.8)	(2.6)
Change in non-cash working capital	5.4	2.6	0.1	(25.8)
	56.8	42.0	173.0	101.0
FINANCING ACTIVITIES				
Proceeds from issue of Trust Units (net of costs)	80.1	3.6	240.3	7.9
Net cash distributions to unitholders	(40.8)	(35.6)	(137.3)	(107.9)
Dividends	-	(1.2)	-	(1.2)
Increase (decrease) in bank credit facilities	(51.0)	20.0	(146.0)	59.9
Increase in senior secured notes	-	-	174.0	-
Increase in deferred charges	0.1	-	(1.3)	-
Change in non-cash working capital	(2.5)	1.4	0.5	0.7
	(14.1)	(11.8)	130.2	(40.6)
INVESTING ACTIVITIES				
Expenditures on property, plant & equipment	(31.4)	(12.0)	(75.6)	(49.2)
Corporate acquisitions	(0.5)	-	(200.9)	-
Acquisition of capital assets	(0.2)	(26.2)	(4.0)	(26.2)
Proceeds on disposal of property, plant & equipment	0.6	0.9	0.8	3.7
Increase in cash reserved for future site restoration and reclamation	(3.7)	-	(6.4)	-
Change in non-cash working capital	5.2	(2.1)	7.9	-
	(30.0)	(39.4)	(278.2)	(71.7)
INCREASE (DECREASE) IN CASH FOR THE PERIOD				
	12.7	(9.2)	25.0	(11.3)
CASH (BANK OVERDRAFT) BEGINNING OF THE PERIOD				
	9.2	(16.7)	(3.1)	(14.6)
CASH (BANK OVERDRAFT) END OF THE PERIOD				
	\$ 21.9	\$ (25.9)	\$ 21.9	\$ (25.9)
CASH INTEREST PAID				
	\$ 1.2	\$ 2.8	\$ 6.3	\$ 7.3
CASH TAXES PAID				
	\$ 2.6	\$ 0.3	\$ 3.4	\$ 3.1

CONSOLIDATED STATEMENTS OF INCOME (Unaudited)

(millions of dollars, except for per-trust-unit amounts)

	Three months ended		Nine months ended	
	Sep 30, 2003	Sep 30, 2002	Sep 30, 2003	Sep 30, 2002
REVENUES				
Sales of crude oil, natural gas and natural gas liquids	\$ 100.2	\$ 77.8	\$ 337.4	\$ 234.6
Crown and other royalties, net of ARTC	(23.1)	(14.0)	(80.8)	(39.2)
Other income	0.1	-	0.3	0.1
	77.2	63.8	256.9	195.5
EXPENSES				
Operating	17.2	14.9	58.2	43.9
General and administrative	3.5	2.4	10.5	8.0
Non-cash general and administrative	2.3	(0.9)	5.9	6.0
Interest	4.0	3.0	11.0	7.6
Cash management fees	-	1.3	-	4.0
Non-cash management fees	-	0.4	-	1.4
Foreign exchange (gain)/loss	0.1	-	(5.4)	-
Depletion, depreciation and amortization	50.7	46.0	153.3	137.1
	77.8	67.1	233.5	208.0
Income (loss) before taxes for the period	(0.6)	(3.3)	23.4	(12.5)
Income and capital taxes	0.8	1.3	3.5	2.6
Future income taxes recovery	(8.7)	(12.8)	(71.1)	(23.1)
	(7.9)	(11.5)	(67.6)	(20.5)
Net income for the period	\$ 7.3	\$ 8.2	\$ 91.0	\$ 8.0
Net income per Trust Unit	\$ 0.16	\$ 0.24	\$ 2.03	\$ 0.24
Diluted net income per Trust Unit	\$ 0.16	\$ 0.24	\$ 2.02	\$ 0.24

CONSOLIDATED STATEMENTS OF CASH DISTRIBUTIONS (UNAUDITED)

(millions of dollars, except for per-trust-unit and number of units)

	Three months ended		Nine months ended	
	Sep 30, 2003	Sep 30, 2002	Sep 30, 2003	Sep 30, 2002
Net income for the period	\$ 7.3	\$ 8.2	\$ 91.0	\$ 8.0
Add back (deduct) amounts to reconcile to distribution:				
Depletion, depreciation and amortization	50.7	46.0	153.3	137.1
Undistributed cash	(4.0)	(0.6)	(20.2)	(9.8)
Contribution to reclamation fund	(4.1)	(1.1)	(7.2)	(3.1)
Non-cash general and administrative	2.3	(0.9)	5.9	6.0
Non-cash foreign exchange	0.2	-	(5.4)	-
Management fees paid in Trust Units	-	0.4	-	1.4
Future income taxes recovery	(8.7)	(12.8)	(71.1)	(23.1)
	\$ 36.4	\$ 31.0	\$ 55.3	\$ 108.5
	\$ 43.7	\$ 39.2	\$ 146.3	\$ 116.5
Cash Distributions to Trust Unitholders	\$ 43.7	\$ 38.8	\$ 146.3	\$ 115.4
Cash Distributions per Trust Unit	\$ 1.04	\$ 1.20	\$ 3.44	\$ 3.60
Trust Units and exchangeable shares issued and outstanding (diluted)	49,903,296	34,107,072	49,903,296	34,107,072
Weighted average Trust Units and exchangeable shares outstanding (diluted)	46,808,859	33,929,397	45,154,073	33,514,149

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

For the nine months ended September 30, 2003 (millions of dollars except per Trust Unit/share amounts)

1. SIGNIFICANT ACCOUNTING POLICIES

These interim consolidated financial statements of PrimeWest Energy Trust have been prepared in accordance with Canadian generally accepted accounting principles. The specific accounting principles used are described in the annual consolidated financial statements of the Trust appearing on pages 43 through 63 of the Trust's 2002 annual report and should be read in conjunction with these interim financial statements.

Under the revised terms of section 1580 of the CICA handbook, the excess of the cost of the purchase price over the acquiring company's interest in identifiable assets acquired, and liability assumed, should be reflected as goodwill. The tax basis deficiency that would previously be added to the depletable pool is now accounted for as goodwill that would not be subject to amortization. A periodic impairment test is then carried out to prove the validity of the goodwill account.

2. ACQUISITION

On January 23, 2003, PrimeWest Energy Inc. completed the acquisition of two private Canadian companies. The acquisition was accounted for using the purchase method of accounting with net assets acquired and consideration paid as follows:

Net Assets Acquired at Assigned Values		Consideration Paid	
Petroleum and natural gas assets	\$220.9		
Goodwill	53.9		
Working capital, including cash of \$4.0	2.9		
Site restoration provision	(5.4)	Cash	\$212.7
Future income taxes	(53.2)	Costs associated with acquisition	6.4
	\$219.1		\$219.1

3. LONG-TERM DEBT

	2003	2002
Bank credit facilities	\$79.0	\$225.0
Senior secured notes	168.7	-
	\$247.7	\$225.0

Bank Credit Facilities

The facility consists of a revolving term loan of \$188 million and an operating facility of \$25 million. In addition to amounts outstanding under the facility, PrimeWest has outstanding letters of credit in the amount of \$5.0 million (2002 - \$4.3 million). Collateral for the credit facility is provided by a floating-charge debenture covering all existing and after acquired property in the principal amount of \$1.0 billion. Each borrower under the facility has also provided an unconditional full liability guarantee in respect of amounts borrowed under the facility.

Advances under the facility are made in the form of Banker's Acceptances (BA), prime rate loans or letters of credit. In the case of BA, interest is a function of the BA rate plus a stamping fee based on the Trust's current ratio of debt to cash flow. In the case of prime rate loans, interest is charged at the bank's prime rate. For the quarter ended September 30, 2003, the effective rate was 4.7% (2002 - 4.5%).

The credit facility revolves until June 30, 2004, by which time the lender will have conducted its annual borrowing base review. The lender also has the right to re-determine the borrowing base at one other time during the year. During the revolving phase, the facility has no specific terms of repayment. At the end of the revolving period, the lender has the right to extend the revolving period for a further 364-day period to convert the facility to a term facility. If the lender converts to a non-revolving facility, 60% of the aggregate principal amount of the loan shall be repayable on the date that is 366 days after such conversion date and the remaining 40% of the aggregate principal amount outstanding shall be repayable on the date that is 365 days after the initial repayment date.

Senior Secured Notes

On May 7, 2003, PrimeWest replaced a portion of its bank debt with Senior Secured Notes (the "Notes") in the amount of U.S. \$125 million. They have a final maturity of May 7, 2010, and bear interest at 4.19% per annum, with interest paid semi-annually on November 7 and May 7 of each year. The Note Purchase Agreement requires PrimeWest to make four annual principal repayments of U.S. \$31,250,000 commencing May 7, 2007.

The costs incurred in connection with the Notes, in the amount of \$1.4 million, are classified as deferred charges on the balance sheet and are being amortized over the term of the Notes.

The Senior Secured Notes are the legal obligation of PrimeWest Energy Inc. and are guaranteed by PrimeWest Energy Trust.

4. UNITHOLDERS' EQUITY

PrimeWest Energy Trust

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

Trust Units	# of Units	Amounts
Balance at December 31, 2002	37,004,522	\$1,252.2
Issued pursuant to Prospectus Offering	9,100,000	234.8
Issued pursuant to Long-term Incentive Plan	146,180	3.8
Issued pursuant to Dividend Reinvestment Plan	366,004	9.0
Issued pursuant to Optional Trust Issuance Plan	721,209	17.6
Issued on exchange of Exchangeable Shares	483,401	11.2
Issue of units due to Odd Lot Program	42	-
Issue expenses incurred	-	(12.1)
Balance at September 30, 2003	47,821,358	1,516.5

The per unit amount of distributions paid or declared reflects distributions paid for units outstanding on the record dates.

PrimeWest Exchangeable Class A Shares

The exchangeable shares are exchangeable into PrimeWest Trust Units at any time up to March 29, 2010; based on an exchange ratio that adjusts each time PrimeWest makes a distribution to unitholders. The exchange ratio, which was 1:1 on the date the transaction closed, is based on the total monthly distribution, divided by the closing unit price on the distribution payment date. The exchange ratio, effective September 15, 2003, was 0.42720 and December 31, 2002 was 0.37454.

Exchangeable shares	# of Shares	Amounts
Balance at December 31, 2002	5,179,278	\$47.7
Exchanged for Trust Units	(1,211,268)	(11.1)
Balance at September 30, 2003	3,968,010	\$36.6

5. TRUST UNIT INCENTIVE PLAN

Under the terms of the Trust Unit Incentive Plan, a maximum of 1,800,000 Trust Units are reserved for issuance pursuant to the exercise of Unit Appreciation Rights (UARs) granted to employees. Payouts under the plan are based on total unitholder return, calculated using both the change in the Trust Unit price as well as cumulative distributions paid. The plan requires that a hurdle return of 5% per annum be achieved before payouts accrue. UARs have a term of up to six years and vest equally over a three-year period, except for the members of the Board, whose UARs vest immediately. The Board of Directors has the option of settling payouts under the plan in PrimeWest Trust Units or in cash. To date, all payouts under the plan have been in the form of Trust Units.

<i>As at September 30, 2003</i>	UARs issued and outstanding	UARs vested	Current return per UAR	Total equity ⁽¹⁾	Trust Unit outstanding dilution
1998 grants	88,022	88,022	\$41.07	\$3.6	143,508
1999 grants	94,297	94,297	27.34	2.6	102,352
2000 grants	149,054	142,151	11.91	1.8	68,352
2001 grants	424,182	269,073	4.13	1.5	38,092
2002 grants	975,534	443,659	2.14	1.6	26,945
2003 grants	1,072,740	141,896	1.44	0.7	7,555
	2,803,829	1,179,098		\$11.8	386,804

⁽¹⁾Includes vested and unvested units "in the money"

Cumulative to September 30, 2003, 836,843 UARs have been exercised resulting in the issuance of 504,946 Trust Units from treasury. The 386,804 Trust Unit outstanding dilution represents less than 1% of the total Trust Units outstanding as at September 30, 2003.

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