

PRIMEWEST 2

CALGARY, July 29, 2002 (TSX: PWLUN; PWX) -- PrimeWest Energy Trust (PrimeWest) today announced unaudited interim operating and financial results for the second quarter.

PRIMEWEST ENERGY TRUST PRODUCTION VOLUMES IN TARGET RANGE FOR QUARTER, CASH FLOW \$0.31 PER TRUST UNIT

SECOND QUARTER HIGHLIGHTS

- Cash flow from operations of \$40.2 million (\$0.31 per unit) compared to \$48.3 million for the first quarter, reflecting lower volumes and increased royalties for the second quarter. Distributions remained unchanged from the first quarter at \$0.30 per unit. This level of distribution represents a 17% cash-on-cash yield based on the July 26th closing price of \$6.90.
- Production averaged 29,559 barrels of oil equivalent per day (BOE/day) for the second quarter, within the target range of 29,000 - 30,000 BOE/day, but 6% below the first quarter result. Scheduled turnarounds for facility maintenance and new well tie-ins as well as unplanned outages at certain non-operated facilities contributed to the decrease.
- Operating expenses increased to \$5.44 per BOE for the quarter compared to \$5.10 per BOE for the first quarter. Lower volumes and turnaround maintenance expenses led to the increase.
- Royalty expenses increased to \$14.6 million in the second quarter from \$10.7 million in the first quarter, reflecting higher operating revenues before hedging gains. Also, the first quarter benefited from a one-time \$1.8 million mineral tax adjustment.
- Net debt increased to \$240.9 million at June 30, 2002 from \$234.4 million at March 31, 2002. Capital expenditures of \$12.4 million were partially offset by proceeds from the Distribution Reinvestment and Optional Trust Unit Purchase programs. The debt-to-cash flow ratio increased to 1.5 times at June 30 compared to 1.2 times at March 31.

"Production volumes were lower in the second quarter, reflecting several scheduled maintenance outages combined with several third party processing outages," said Don Garner, President and Chief Operating Officer. "Based on the success of our development program, we remain confident that we will meet our target of 29,000 - 30,000 BOE/day average production for the full year 2002."

CASH FLOW RECONCILIATION (thousands)

First quarter cash flow	\$48,301
Production volume	(3,531)
Commodity price	15,762
Hedging gain	(16,736)
Royalty expense	(3,900)
Other	330
Second quarter cash flow	<u>\$40,226</u>



We are one of North America's largest conventional oil and gas royalty trusts. We manage PrimeWest carefully for the ongoing benefit of our unitholders, and in doing so are guided by the operating principle of responsible stewardship. Our main objective is to deliver predictable and sustainable cash distributions monthly, within the context of a commodity-based business environment.

PrimeWest Energy Trust
FINANCIAL & OPERATING HIGHLIGHTS



FINANCIAL HIGHLIGHTS

(thousands of dollars except per-BOE and per-trust-unit amounts)

	Three months ended			Six months ended	
	Jun. 30, 2002	Mar. 31, 2002	Jun. 30, 2001	Jun. 30, 2002	Jun. 30, 2001
Net revenue	\$62,198	\$69,442	\$87,974	\$131,640	\$144,964
Per BOE	23.13	24.60	27.35	23.88	30.62
Cash flow from operations	40,226	48,301	61,825	88,527	105,359
Per BOE	14.95	17.11	19.22	16.06	22.25
Royalty expense	14,566	10,666	27,650	25,232	43,301
Per BOE	5.41	3.78	8.59	4.58	9.14
Operating expenses	14,639	14,393	15,704	29,033	24,044
Per BOE	5.44	5.10	4.88	5.27	5.08
G&A expenses - Cash	2,915	2,635	2,795	5,549	5,068
Per BOE	1.08	0.93	0.87	1.01	1.07
- Non-cash	1,623	5,351	2,294	6,973	7,489
Per BOE	0.60	1.90	0.71	1.26	1.58
Management fees - Cash	1,264	1,418	1,862	2,682	3,131
Per BOE	0.47	0.50	0.58	0.49	0.66
- Non-cash	485	479	528	965	1,011
Per BOE	0.18	0.17	0.16	0.17	0.21
Cash distributed to unitholders	38,418	38,131	70,288	76,548	111,072
Per Trust Unit	0.30	0.30	0.66	0.60	1.26
Cash flow from operations					
Per Trust Unit	0.31	0.37	0.58	0.69	1.19
Net debt ⁽¹⁾	240,913	234,415	290,233	240,913	290,233
Per Trust Unit	1.79	1.77	2.40	1.79	2.40

(1) Net debt is long-term debt plus negative working capital.

OPERATING HIGHLIGHTS

	Three months ended			Six months ended	
	Jun. 30, 2002	Mar. 31, 2002	Jun. 30, 2001	Jun. 30, 2002	Jun. 30, 2001
Daily sales volumes					
Natural gas (MMcf/day)	111.09	113.31	127.72	112.19	88.86
Crude oil (bbls/day)	8,990	10,244	11,453	9,614	9,233
Natural gas liquids (bbls/day)	2,055	2,240	2,614	2,147	2,117
Total (BOE/day)	29,559	31,370	35,353	30,460	26,160
Prices (Cdn \$)					
Natural gas (\$/Mcf)	4.47	4.57	6.21	4.52	7.37
Crude oil (\$/bbl)	32.96	32.09	33.59	32.50	33.12
Natural gas liquids (\$/bbl)	25.77	20.87	35.35	23.23	37.19
Total (\$ per BOE)	28.61	28.49	35.94	28.55	39.73



The following discussion is management's analysis of PrimeWest's operating and financial results for the quarter ended June 30, 2002 compared with the previous quarter and the second quarter of 2001 as well for the six month periods ended June 30, 2002 and June 30, 2001. This discussion also contains information and opinions concerning the Trust's future outlook based on currently 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 2000, together with the accompanying notes, as contained in the Trust's 2001 Annual Report.

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.

STRATEGY	2002 OBJECTIVES	YEAR-TO-DATE PERFORMANCE
Asset Growth	<ul style="list-style-type: none"> - Use the low cycles in the commodity price environment and strong balance sheet to add high quality reserves to our asset base. - Maintain or increase our reserve life index. 	<ul style="list-style-type: none"> - Low commodity price cycle short-lived. Available acquisition targets generally poor quality in nature. No acquisitions in the first half of 2002. - Development program successful in adding reserves and production.
Operating Excellence	<ul style="list-style-type: none"> - Moderate natural production decline through prudent capital development. - Add incremental production through drilling, completions and workovers. - Reduce per BOE operating expenses from 2001 levels. 	<ul style="list-style-type: none"> - Production met expectations for the second quarter of 2002. - Second quarter development success with 9 gross wells drilled at a 78% success rate. - Operating expenses increased to \$5.44 per BOE (\$5.10 in the first quarter of 2002). Year-to-date, per BOE costs of \$5.27, below the \$5.42 full year 2001 result.
Financial Prudence	<ul style="list-style-type: none"> - Maintain a strong financial position as measured by net debt per Trust Unit and debt-to-cash flow ratio. 	<ul style="list-style-type: none"> - Debt-to-cash flow ratio has increased to 1.50 at June 30, 2002 from 1.21 at March 31, 2002. Net debt per trust unit \$1.79 at June 30, 2002 compared to \$1.72 at December 31, 2002
Risk Management	<ul style="list-style-type: none"> - Use hedging to stabilize and protect distribution levels; manage distribution rates as commodity prices cycle. 	<ul style="list-style-type: none"> - Stabilized at \$0.10 per month through October of 2002.



PRODUCTION VOLUMES

	Three months ended			Six months ended	
	Jun. 30, 2002	Mar. 31, 2002	Jun. 30, 2001	Jun. 30, 2002	Jun. 30, 2001
Natural gas (MMcf/day)	111.09	113.31	127.72	112.19	88.86
Crude oil (bbls/day)	8,990	10,244	11,453	9,614	9,233
Natural gas liquids (bbls/day)	2,055	2,240	2,614	2,147	2,117
Total (BOE/day)	29,559	31,370	35,353	30,460	26,160
Gross Overriding Royalty volumes included above (BOE/day)	1,571	2,076	2,043	1,857	1,971

Production volumes fell from first quarter levels as a result of scheduled turnarounds for facility maintenance, planned production outages to accommodate new gas well tie-ins, unplanned outages at several non-operated properties and minor dispositions.

Despite these outages, gas volumes fell only 2% compared to the first quarter of 2002. Successful development activities, particularly at Dawson, mitigated the impact of the outages.

Oil volumes fell 12% when compared to the first quarter of 2002. Approximately 42% of this decrease is the result of reduced GORR volumes. The first quarter of 2002 GORR volumes included an adjustment to reflect underaccrued volumes at the end of 2001. A further 20% related to a temporary production curtailment at Dawson. The balance reflects minor asset dispositions late in the first quarter (200BOE/day) and natural decline as our 2002 development program is focused on natural gas.

During the quarter, scheduled turnarounds were performed by PrimeWest at the East Crossfield Gas Plant (occurs every two years) and the Laprise Creek gas processing facility. The Dawson (Roxanna) and Brant Farrow gathering and processing facilities were also shut-in to facilitate pipeline tie-ins and compressor modifications to add incremental capacity for new gas wells drilled by PrimeWest over the past six months. The production impairment related to these scheduled activities was approximately 545 BOE/day for the quarter.

Unplanned outages at third party operated gas processing or gas transmission facilities, since resolved in the third quarter, restricted production at the Caroline, Medicine Hat and Brant Farrow areas by 180 BOE/day. A pipeline failure at Whiskey Creek resulted in approximately 400 BOE/day production being shut-in in May and June. The operator has advised PrimeWest that the necessary pipeline system modifications required to resume production should be completed by year-end. At Dawson (Normandville), production curtailments resulted in 250 bbls/day of oil production being shut-in by the operator through the quarter pursuant to temporary allowable restrictions imposed by regulatory authorities pending completion of a gas conservation and waterflood project.

Compared to the second quarter of 2001, volumes are lower, primarily as a result of significant dispositions in the second half of 2001 combined with the outages noted above.



PRODUCTION OUTLOOK

PrimeWest maintains its prior guidance that it expects third quarter and full year volumes to fall within the 29,000– 30,000 BOE/day target range.

Only the Whiskey Creek and Normandville outages are expected to impact volumes for the balance of 2002. Volumes should increase from all other areas impacted by second quarter maintenance activities. These volumes, together with further development activities, are expected to mitigate natural decline.

REALIZED COMMODITY PRICES

Benchmark prices	Three months ended			Six months ended	
	Jun. 30, 2002	Mar. 31, 2002	Jun. 30, 2001	Jun. 30, 2002	Jun. 30, 2001
Natural gas (\$/Mcf AECO)	4.42	3.34	7.08	3.88	8.99
Crude oil (\$U.S./bbl WTI)	26.25	21.64	27.96	23.95	28.34
Average PrimeWest realized selling prices (Cdn dollars)	Three months ended			Six months ended	
	Jun. 30, 2002	Mar. 31, 2002	Jun. 30, 2001	Jun. 30, 2002	Jun. 30, 2001
Natural gas (\$/Mcf)	4.47	4.57	6.21	4.52	7.37
Crude oil (\$/bbl)	32.96	32.09	33.59	32.50	33.12
Natural gas liquids (\$/bbl)	25.77	20.87	35.35	23.23	37.19
Total Oil Equivalent (\$ per BOE)	28.61	28.49	35.94	28.55	39.73
Realized hedging gain (loss) included in prices above (\$ per BOE)	1.32	7.06	(1.83)	4.26	(1.37)

Realized prices for natural gas and crude oil in the second quarter of 2002 were little changed from the first quarter of 2002. Although benchmark prices improved in the quarter, PrimeWest's hedging program had assured the benefit of those increases.

PrimeWest's hedging gain fell to \$3.6 million in the second quarter of 2002 compared to \$19.9 million in the first quarter, again reflecting the increase in benchmark prices for crude oil and natural gas in the second quarter.

For the six months ended June 30, prices for 2002 fell 28% compared to the previous year, with natural gas down 39%.

**SALES REVENUE (1)**

(\$ thousands)

	Three months ended			Six months ended	
	Jun. 30, 2002	Mar. 31, 2002	Jun. 30, 2001	Jun. 30, 2002	Jun. 30, 2001
Natural gas	45,186	46,645	72,218	91,831	118,536
Crude oil	26,962	29,585	35,010	56,546	55,343
Natural gas liquids	4,820	4,207	8,408	9,027	14,248
Total	76,968	80,437	115,636	157,404	188,127
Hedging gains (losses) (2) for natural gas and crude oil included above	3,550	19,926	(5,902)	23,491	(6,484)

(1) Excludes sulphur

(2) Net of amortized premiums

Sales revenues were down 4% quarter-over-quarter in 2002, reflecting lower production volumes in the second quarter.

Of the realized hedging gains of \$3.6 million during the second quarter, a \$4.2 million (\$0.42/Mcf) gain was attributable to natural gas offset by a \$0.67 million (\$0.82/bbl) loss attributable to crude oil.

Compared to the first half of 2001, revenues were lower as the benefit of full year to date Cypress volumes was more than offset by significantly weaker prices.

PRICE OUTLOOK

The following table sets forth benchmark future commodity prices.

Benchmark commodity prices	Past Four Quarters (Actual)				Next Four Quarters (Forward Markets) ⁽¹⁾			
	Q3 2001	Q4 2001	Q1 2002	Q2 2002	Q3 2002	Q4 2002	Q1 2003	Q2 2003
Natural gas								
NYMEX (\$U.S./Mcf)	2.98	2.50	2.38	3.37	3.09	3.30	3.21	3.65
AECO (\$Cdn/Mcf)	3.92	3.30	3.34	4.42	3.26	4.21	5.09	4.96
Crude oil (\$U.S./bbl WTI)	26.76	20.43	21.64	26.25	27.43	26.64	25.87	25.20

(1) As at July 18, 2002

The world crude oil supply/demand fundamentals have come back into a close balance. While the crude oil demand recovery is not occurring as quickly as anticipated, OPEC has maintained a level of discipline over their quotas, and Iraq has reduced output over a pricing dispute with the United Nations Oil for Food Program. The balanced fundamentals combined with continued instability in the Middle East has kept oil prices supported over the past quarter and could continue to provide support in the medium term.

Natural gas prices through this summer have experienced some recent softening due to record natural gas storage levels both in Canada and the U.S., although the year-over-year storage overhang has continued to decline over the past several months. The futures prices for the November 2002 to October 2003 gas year have remained firm and pricing beyond October 2003 has increased. This



would suggest that there is likely to be some continued short-term soft gas pricing through the third quarter but that the medium- to long-term fundamentals for gas are still very positive.

ROYALTIES

(\$ thousands)

	Three months ended			Six months ended	
	Jun. 30, 2002	Mar. 31, 2002	Jun. 30, 2001	Jun. 30, 2002	Jun. 30, 2001
Royalty expense	14,566	10,666	27,650	25,232	43,301
Per BOE	5.41	3.78	8.59	4.58	9.14
Royalties as % of sales revenue					
- including hedging	18.9%	13.3%	23.9%	16.0%	23.0%
- excluding hedging	19.8%	17.6%	22.8%	18.8%	22.3%

Royalties as a percent of sales revenue increased from first quarter levels as a result of reduced hedging gains, which do not attract royalties, as well as a one-time mineral tax adjustment of \$1.8 million, which reduced royalty expenses in the first quarter of 2002.

The second quarter and first half of 2001 royalty rates reflect higher gas prices.

OPERATING EXPENSES

(\$ thousands)

	Three months ended			Six months ended	
	Jun. 30, 2002	Mar. 31, 2002	Jun. 30, 2001	Jun. 30, 2002	Jun. 30, 2001
Operating expenses	14,639	14,393	15,704	29,033	24,044
Per BOE	\$5.44	\$5.10	\$4.88	\$5.27	\$5.08

Operating expenses per BOE increased 7% compared to the first quarter of 2002, primarily the result of lower production volumes. Providing for approximately \$500,000 of costs related to the Crossfield and Laprise Creek turnarounds, operating expenses were 2% less than the previous quarter.

The increase in year to date operating expenses reflects six months of Cypress activity compared to only three months in 2001.

OPERATING EXPENSES OUTLOOK

Operating expenses are expected to decrease in the third quarter of 2002, principally as a result of the absence of costs associated with the turnarounds at Laprise Creek and Crossfield incurred in the second quarter of 2002, as well as ongoing cost control measures.

**OPERATING MARGIN**

(\$ per BOE)

	Three months ended			Six months ended	
	Jun. 30, 2002	Mar. 31, 2002	Jun. 30, 2001	Jun. 30, 2002	Jun. 30, 2001
Sales price and other revenue (including hedging)	28.53	28.37	35.94	28.45	39.76
Royalties	5.41	3.78	8.59	4.58	9.14
Operating costs	5.44	5.10	4.88	5.27	5.08
Operating margin	17.68	19.49	22.47	18.60	25.54

Operating margin fell 9% from quarter-to-quarter reflecting higher royalty and operating expenses which are discussed earlier in this MD&A.

Margins were much higher in the second quarter and first half of 2001 as a result of very strong natural gas and natural gas liquids prices.

CASH G&A EXPENSES AND MANAGEMENT FEES

(\$ thousands)

	Three months ended			Six months ended	
	Jun. 30, 2002	Mar. 31, 2002	Jun. 30, 2001	Jun. 30, 2002	Jun. 30, 2001
Cash G&A Expenses	2,915	2,635	2,795	5,549	5,068
Per BOE	\$ 1.08	\$ 0.93	\$ 0.87	\$ 1.01	\$ 1.07
Cash Management Fees	1,264	1,418	1,862	2,682	3,131
Per BOE	\$ 0.47	\$ 0.50	\$ 0.58	\$ 0.49	\$ 0.66

Cash G&A expenses in the second quarter included annual report and related document expenses for printing and mailing to the unitholders along with unitholder meeting costs that totalled an incremental \$250,000. These costs represent the majority of the increase over the first quarter of 2002 as well as the increase over the same period of 2001.

The year over year increase is a result of 2002 representing a full six months of G&A costs associated with the Cypress acquisitions, whereas 2001 reflects only the second quarter costs of Cypress; the transaction closed on March 29, 2001.

Cash management fees for the second quarter were lower compared to the previous quarter and the same period in 2001, in line with lower netbacks.

**NON-CASH G&A EXPENSES AND MANAGEMENT FEES**

(\$ thousands)

	Three months ended			Six months ended	
	Jun. 30, 2002	Mar. 31, 2002	Jun. 30, 2001	Jun. 30, 2002	Jun. 30, 2001
Non-cash G&A Expenses	1,623	5,351	2,294	6,973	7,489
Non-cash Management Fees	485	479	528	965	1,011
Total	2,108	5,830	2,822	7,938	8,500
Per BOE	\$ 0.78	\$ 2.07	\$ 0.87	\$ 1.43	\$ 1.79

Non-cash G&A expenses consists of Unit Appreciation Rights (UARs) under the Trust's long-term incentive program. It has been PrimeWest's practice to expense the cost of the UARs which are similar to granting a stock option in a conventional business. The UARs are marked- to-market each quarter and the impact is recognized as an expense in the income statement of the Trust.

The decrease in non-cash G&A expenses comparing the second quarter of 2002 to the first quarter of 2002 reflects a modest unit price appreciation in the second quarter to \$7.23 from \$7.20 at the end of the first quarter combined with the impact of distributions, offset by the 5% annual hurdle rate. The first quarter expense was higher reflecting a \$6.36 unit price at the end of 2001. The first quarter of 2002 expense also reflects the implementation of the new CICA accounting standard 3870 effective January 1, 2002, whereby vested and unvested UARs are included in the calculation of non-cash G&A expenses. Previously, only the vested UARs were included. The effect of this change was to increase non-cash G&A expenses by \$2.4 million for the six months ended June 30, 2002.

Non-cash G&A expenses in the first half of 2001 reflect a higher Trust Unit price driven by record natural gas and natural gas liquids prices.

Non-cash management fees increased slightly compared to the first quarter reflecting a modest unit price appreciation.

INTEREST EXPENSE

(\$ thousands)

	Three months ended			Six months ended	
	Jun. 30, 2002	Mar. 31, 2002	Jun. 30, 2001	Jun. 30, 2002	Jun. 30, 2001
Interest expense	2,530	2,053	5,115	4,583	6,631
Period end debt level	240,913	234,415	290,233	240,913	290,233
Debt per Trust Unit	\$ 1.79	\$ 1.77	\$ 2.40	\$ 1.79	\$ 2.40
Average cost of debt - %	4.5%	4.0%	6.4%	4.5%	6.5%

Interest expense increased quarter-over-quarter on higher interest rates and increasing debt levels through the quarter. On a per unit basis, debt remained essentially flat quarter-over-quarter, and was down 25% from a year earlier.

At June 30, 2002, approximately 70% of the debt was at a floating rate, with the balance at a fixed rate.

The Cypress acquisition was closed on March 29, 2001, adding incremental debt during the second quarter of 2001.

**DEPLETION, DEPRECIATION AND AMORTIZATION***(Thousands)*

	Three months ended			Six months ended	
	Jun. 30, 2002	Mar. 31, 2002	Jun. 30, 2001	Jun. 30, 2002	Jun. 30, 2001
	<u>45,212</u>	<u>45,895</u>	<u>50,280</u>	<u>91,107</u>	<u>61,700</u>

Depletion, depreciation and amortization (DD&A) for the second quarter of 2002 is down modestly from the first quarter level, in part due to lower production volume in the quarter.

Compared to a year ago, the second quarter DD&A for 2002 is lower than 2001 reflecting reduced volumes as a result of asset dispositions late in 2001 and second quarter 2002 production outages.

For the six months ended June 30, the 2002 figure reflects a full six months of Cypress activity versus only three months in 2001.

CEILING TEST

Principally as a result of very weak spot prices for Alberta gas, \$2.02 per Mcf at June 28, 2002, the ceiling test deficiency increased to \$354 million at quarter end from \$150 million at year end 2001 when the Alberta spot gas price was \$3.67 per Mcf.

Using average prices for the second quarter of 2002 would result in a cushion of \$210 million.

INCOME AND CAPITAL TAXES*(Thousands)*

	Three months ended			Six months ended	
	Jun. 30, 2002	Mar. 31, 2002	Jun. 30, 2001	Jun. 30, 2002	Jun. 30, 2001
Capital taxes	<u>624</u>	<u>642</u>	<u>673</u>	<u>1,266</u>	<u>731</u>
Future income taxes recovery	<u>(900)</u>	<u>(9,400)</u>	<u>(25,509)</u>	<u>(10,300)</u>	<u>(23,263)</u>
	<u>(276)</u>	<u>(8,758)</u>	<u>(24,836)</u>	<u>(9,034)</u>	<u>(22,532)</u>

The future income tax recovery for the second quarter and the first six months of 2002, has decreased in comparison to the comparable periods of 2001, as a result of lower income before tax and adjustments to the operating company tax pools upon the filing of the tax returns in the second quarter of 2002.

**LIQUIDITY AND CAPITAL RESOURCES**

(\$ thousands)

	As at		
	Jun. 30, 2002	Mar. 31, 2002	Jun. 30, 2001
Long-term debt	235,000	136,670	335,011
(Working capital)/ deficit	5,913	97,745	(44,778)
Net debt	240,913	234,415	290,233
Market value of Trust Units and exchangeable shares outstanding	966,985	954,722	1,053,841
Total capitalization	1,207,898	1,189,137	1,344,074
Net debt as a % of total capitalization	19.94%	19.71%	21.60%

Net debt increased modestly in the quarter reflecting capital spending of \$12.4 million, which was partially funded by proceeds from the DRIP and Optional Trust Unit Purchase programs and minor dispositions.

Unutilized credit facilities were \$58 million at June 30, 2002, compared to \$115 million at March 31, 2002. The credit facility was reduced during the second quarter to \$310 million from \$350 million, reflecting significant property dispositions in late 2001 and reduced commodity pricing assumptions.

Net debt is significantly lower than the second quarter of 2001 as a result of equity issued in the last nine months of 2001 to de-lever the balance sheet, along with the application of proceeds from non-core asset sales.

CAPITAL SPENDING

(\$ thousands)

	Three months ended			Six months ended	
	Jun. 30, 2002	Mar. 31, 2002	Jun. 30, 2001	Jun. 30, 2002	Jun. 30, 2001
	12,415	24,874	16,707	37,289	23,570

Capital spending during the second quarter and first half of 2002 is in line with the Trust's commitment to invest approximately \$70 million during 2002 in development activities.

PrimeWest's capital development program continues to yield results in line with expectations. Although second quarter activities were restricted by spring break-up, PrimeWest participated in the drilling of 9 gross (5 net) wells. Eight wells were cased, with one subsequently abandoned. On a year-to-date basis, 40 gross (25.6 net) wells have been drilled, achieving a 90% success rate. The major areas of development activity in the first half of the year included Dawson and Brant Farrow.

Additional activities in the quarter included completion of upgrades to the Dawson (Roxanna) and Brant Farrow compression facilities and gas gathering systems, as well as the installation of gas conservation and waterflood facilities at Dawson (Normandville).

PrimeWest expects that internally generated retained cash flow, proceeds from the DRIP and the Optional Trust Unit Purchase programs plus unutilized credit facilities will be sufficient to fund the 2002 capital program, assuming no material adverse developments in commodity prices.



HEDGING PROGRAM

Approximate percentage of future anticipated production volumes hedged through June 30, 2002; net of anticipated royalties, reflecting full production declines with no offsetting additions:

	<u>Q3/Q4 2002</u>	<u>2003</u>
Crude Oil	70%	34%
Natural Gas	70%	51%

The mark-to-market valuation of these hedges was a \$4.1 million gain at June 30, 2002.

A summary of contracts in place as at June 30, 2002 is as follows:

CRUDE OIL

Period	Volume (bbl/d)	Type	WTI Price (U.S.\$/bbl)
May - June 2002	2,000	Swap	26.23
July - September 2002	2,000	Swap	25.22
October - December 2002	2,000	Swap	24.45
January - December 2002	1,000	Costless Collar	20.00/25.15
July - December 2002	1,000	Costless Collar	20.50/24.95
July - September 2002	350	Costless Collar	22.00/29.25
October - December 2002	350	Costless Collar	22.00/28.15
January - December 2003	1,000	3 Way	17.00 / 20.50 / 25.50
January - March 2003	1,000	Costless Collar	21.00/27.70
January - June 2003	1,000	3 Way	18.50 / 22.50 / 27.70
July - December 2003	1,000	3 Way	18.50 / 22.50 / 27.20

NATURAL GAS

Period	Volume (MMcf/d)	Type	AECO Price (Cdn\$/Mcf)
May - October 2002	4.7	Fixed Price	6.50
May - October 2002	18.9	Swap	5.28
May - October 2002	18.9	Swap	5.28
May - October 2002	9.5	Swap	4.39
November 2002 - March 2003	4.7	Costless Collar	4.22 by 5.96
November 2002 - March 2003	4.7	3 Way	3.17 / 4.48 / 6.59
November 2002 - March 2003	4.7	3 Way	3.17 / 3.96 / 5.46
November 2002 - March 2003	4.7	3 Way	4.22 / 5.28 / 7.04
November 2002 - March 2003	4.7	Swap	5.43
April - October 2003	4.7	Fixed Price	4.75
April - October 2003	4.7	Swap	5.05
April - October 2003	4.7	3 Way	3.17 / 4.48 / 6.26
April - October 2003	4.7	3 Way	3.17 / 3.96 / 5.39
April - October 2003	4.7	3 Way	3.69 / 4.75 / 6.65
November 2002 - October 2004	9.5	3 Way	3.17 / 4.22 / 6.09
January 2002 - October 2003	4.7	Swap	3.98
January 2002 - October 2003	4.7	Swap	4.17



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 \$3.50. 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.

DISTRIBUTIONS

PrimeWest has distributed \$0.10 per unit monthly year-to-date. PrimeWest has previously announced it will distribute, barring material adverse developments, \$0.10 per unit on each of August 15, September 15 and October 15, 2002.

DISTRIBUTION REINVESTMENT (DRIP) DISCOUNT

PrimeWest's Distribution Reinvestment and Optional Trust Unit Purchase Plan (Plan) enables participants to reinvest their monthly cash distributions and/or purchase additional Trust Units at a 5% discount to the 20-day weighted average monthly market price. There is a \$100,000 per calendar year limit per individual to the purchase of additional Trust Units.

To join the Plan, you must be a registered unitholder or have your units in an account that allows participation. Not all brokerage firms and banks will allow you to participate. Please check directly with your account representative as to their participation.

For further information or to join this Plan, contact our Plan Agent, Computershare Trust Company of Canada, at 1-800-332-0095.

CHAIRMAN HONOURED BY CHARTERED ACCOUNTANTS OF ALBERTA

Harold Milavsky, FCA, Chairman of the Board of Directors and Audit Committee of PrimeWest is the recipient of the Institute of Chartered Accountants of Alberta's Lifetime Achievement Award. This award is reserved for Fellows of the Chartered Accountants (FCA's) who, through their entire career, have rendered meritorious service to the profession, and whose career and achievements in the community have brought honour to the profession.

SECOND QUARTER CONFERENCE CALL AND WEBCAST

PrimeWest will be conducting a conference call and Webcast for interested analysts, brokers, investors and media representatives about its second quarter results and outlook at 10:00 a.m. Mountain daylight time (12:00 p.m. Eastern daylight time) on Tuesday, July 30, 2002.

Callers may dial 1-888-881-4892 a few minutes prior to start and request the PrimeWest conference call. The call also will be available for replay by dialing 1-877-289-8525, and entering pass code 197123 followed by the pound (#) key.



Interested users of the Internet are invited to go to www.newswire.ca/webcast/pages/PrimeWestEnergy20020730/ for the live Webcast and/or replay or access the Webcast at the PrimeWest Web site, www.primewestenergy.com.

QUESTIONS

PrimeWest Energy Trust welcomes questions from unitholders and potential investors; call Investor Relations at 403-234-6600 or toll-free in Canada and the U.S. at 1-877-968-7878; or visit us on the Internet at our Web site, www.primewestenergy.com.

On behalf of the Board of Directors:
July 29, 2002

Kent J. MacIntyre
Vice-chairman and
Chief Executive Officer

PrimeWest Energy Trust
CONSOLIDATED BALANCE SHEET



<i>(thousands of dollars)</i>	Unaudited) As at June 30, 2002	As at Dec. 31, 2001
ASSETS		
Current assets		
Accounts receivable	\$ 55,423	\$ 55,465
Prepaid expenses and inventory	7,102	11,200
	62,525	66,665
Cash reserved for site restoration and reclamation	766	755
Capital assets <i>(note 3)</i>	1,393,924	1,448,661
	\$ 1,457,215	\$ 1,516,081
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities		
Bank overdraft	\$ 16,693	\$ 14,613
Accounts payable and accrued liabilities	38,215	59,944
Accrued distributions to unitholders	11,946	11,980
Due to related company	1,569	10,108
Current portion of long-term debt <i>(note 4)</i>	15	67
	68,438	96,712
Long-term debt <i>(note 4)</i>	235,000	195,000
Future income taxes	352,295	362,595
Site restoration and reclamation provision	6,927	6,113
	662,660	660,420
UNITHOLDERS' EQUITY		
Net capital contributions <i>(note 5)</i>	\$ 1,165,635	\$ 1,152,551
Capital issued but not distributed	485	419
Long-term incentive plan equity <i>(note 6)</i>	11,244	7,932
Accumulated income	122,332	122,550
Accumulated cash distributions	(497,531)	(420,983)
Accumulated dividends	(7,610)	(6,808)
	794,555	855,661
	\$ 1,457,215	\$ 1,516,081

CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY

<i>(thousands of dollars)</i>	(Unaudited) June 30, 2002	June 30, 2001
Unitholders' equity, beginning of the period, as previously reported	\$ 855,661	\$ 298,245
Net income/(loss) for the period	(218)	58,422
Net capital contributions	13,084	641,009
Capital issued but not distributed	66	294
Long-term incentive plan equity	3,312	3,231
Cash distributions	(76,548)	(111,072)
Dividends	(802)	(1,726)
Unitholders' equity, end of the period	\$ 794,555	\$ 888,403



	Three months ended		Six months ended	
	Jun. 30 2002	Jun. 30 2001	Jun. 30 2002	Jun. 30 2001
<i>(thousands of dollars)</i>				
OPERATING ACTIVITIES				
Net income/(loss) for the period	\$ (6,194)	\$ 34,232	\$ (218)	\$ 58,422
Add: Items not involving cash from operations				
Depletion, depreciation and amortization	45,212	50,280	91,107	61,700
Non-cash general and administrative	1,623	2,294	6,973	7,489
Non-cash management fees	485	528	965	1,011
Future income taxes recovery	(900)	(25,509)	(10,300)	(23,263)
Cash flow from operations	40,226	61,825	88,527	105,359
Change in non-cash working capital	(36,101)	(8,126)	(26,060)	2,260
	4,125	53,699	62,467	107,619
FINANCING ACTIVITIES				
Proceeds from issue of Trust Units (net of costs)	4,949	94,253	8,525	95,964
Cash distributions to unitholders	(38,428)	(70,289)	(76,514)	(111,072)
Dividends	-	(986)	-	(1,726)
Increase in long-term debt	29,974	14,975	39,948	77,071
Change in non-cash working capital	(1,244)	4,154	(938)	13,657
	(4,749)	42,107	(28,979)	73,894
INVESTING ACTIVITIES				
Expenditures on capital assets	(12,415)	(16,707)	(37,289)	(23,570)
Corporate acquisitions	-	(4,201)	-	(80,842)
Acquisitions of capital assets	-	(512)	-	(512)
Proceeds on disposal of capital assets	662	2,185	2,843	5,518
Decrease (increase) in cash reserved for future site restoration and reclamation	-	(404)	(11)	(12)
Expenditures on site restoration and reclamation	(395)	(100)	(1,111)	(881)
	(12,148)	(19,739)	(35,568)	(100,299)
INCREASE/(DECREASE) IN CASH FOR THE PERIOD	(12,772)	76,067	(2,080)	81,214
CASH (BANK OVERDRAFT) BEGINNING OF THE PERIOD	(3,921)	4,313	(14,613)	(834)
CASH, (BANK OVERDRAFT) END OF THE PERIOD	\$ (16,693)	\$ 80,380	\$ (16,693)	\$ 80,380
CASH INTEREST PAID	\$ 2,795	\$ 5,122	\$ 4,560	\$ 6,636
CASH TAXES PAID	\$ 2,983	-	\$ 2,983	\$ 10



<i>(thousands of dollars, except for per-trust-unit and number of units)</i>	Three months ended		Six months ended	
	Jun. 30 2002	Jun. 30 2001	Jun. 30 2002	Jun. 30 2001
REVENUES				
Sales of crude oil, natural gas and natural gas liquids	\$ 76,809	\$ 115,609	\$ 156,799	\$ 188,148
Crown and other royalties, net of ARTC	(14,566)	(27,650)	(25,232)	(43,301)
Other income	(45)	15	73	117
	62,198	87,974	131,640	144,964
EXPENSES				
Operating	14,639	15,704	29,033	24,044
Cash general and administrative	2,915	2,795	5,549	5,068
Non-cash general and administrative	1,623	2,294	6,973	7,489
Interest	2,530	5,115	4,583	6,631
Cash management fees	1,264	1,862	2,682	3,131
Non-cash management fees	485	528	965	1,011
Depletion, depreciation and amortization	45,212	50,280	91,107	61,700
	68,668	78,578	140,892	109,074
Income (loss) before taxes for the period	(6,470)	9,396	(9,252)	35,890
Capital taxes	624	673	1,266	731
Future income taxes recovery	(900)	(25,509)	(10,300)	(23,263)
	(276)	(24,836)	(9,034)	(22,532)
Net income/(loss) for the period	(6,194)	34,232	(218)	58,422
Net income/(loss) per Trust Unit	(0.05)	0.33	--	0.71
Diluted net income/(loss) per Trust Unit	(0.05)	0.33	--	0.70

CONSOLIDATED STATEMENTS OF CASH DISTRIBUTIONS (Unaudited)

<i>(thousands of dollars, except for per-trust-unit and number of units)</i>	Three months ended		Six Months ended	
	Jun. 30 2002	Jun. 30 2001	Jun. 30 2002	Jun. 30 2001
Net income/(loss) for the period	\$ (6,194)	\$ 34,232	\$ (218)	\$ 58,422
Add back (deduct) amounts to reconcile to distribution:				
Increase in reserve	(419)	10,205	(9,160)	8,365
Depletion, depreciation and amortization	45,212	50,280	91,107	61,700
Contribution to reclamation fund	(1,001)	(1,032)	(2,046)	(1,530)
Non-cash general and administrative	1,623	2,294	6,973	7,489
Management fees paid in Trust Units	485	528	965	1,011
Future income taxes (recovery)	(900)	(25,509)	(10,300)	(23,263)
	\$ 45,000	\$ 36,766	\$ 77,539	\$ 53,772
	\$ 38,806	\$ 70,998	\$ 77,321	\$ 112,194
Cash Distributions to Trust Unitholders (99%)	\$ 38,418	\$ 70,288	\$ 76,548	\$ 111,072
Cash Distributions per Trust Unit	\$ 0.30	\$ 0.66	\$ 0.60	\$ 1.26
Trust Units issued and outstanding	128,441,771	113,551,534	128,441,771	113,551,534
Weighted average Trust Units and exchangeable shares outstanding (diluted)	134,347,196	103,344,228	133,851,104	81,834,023



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 36 through 53 of the Trust's 2001 annual report and should be read in conjunction with these interim financial statements.

2) AMALGAMATION

Effective January 1, 2002, PrimeWest Oil & Gas Corp. and PrimeWest Energy Inc. and its subsidiaries amalgamated and were continued as PrimeWest Energy Inc. Subsequent to the amalgamation, the common shares of PrimeWest Energy Inc. are 89% owned by the Trust and 11% by PrimeWest Management Inc. The Trust continues to own a royalty entitling it to receive 99% of the net cash flows generated by PrimeWest Energy Inc. The beneficiaries of the Trust are the holders of Trust Units.

3) CAPITAL ASSETS

In accordance with its stated accounting policies, PrimeWest has performed a ceiling test using commodity prices as at the measurement date of June 28, 2002. Using June 28, 2002 (the last business day of the period) commodity prices of AECO \$2.02 per Mcf for natural gas and WTI US\$26.86 per barrel of oil would result in a ceiling test deficiency of \$354 million. However, using the average prices for the second quarter ending June 30, 2002 of AECO \$4.42 per Mcf for natural gas and WTI US\$26.25 per barrel of oil would result in a cushion.

PrimeWest is not required to account for any ceiling test impairment that is not permanent, within the first two years of the Cypress acquisition, therefore no writedown is reflected in the June 30, 2002 financial statements.

4) LONG-TERM DEBT

PrimeWest Energy Inc. and the Trust (as co-borrowers) have a combined revolving credit facility in the amount of \$310 million. The facility consists of a revolving term loan of \$285 million and an operating facility of \$25 million. In addition to amounts outstanding under the facility as indicated in the table below, PrimeWest Energy Inc. has outstanding letters of credit in the amount of \$2.8 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 \$500 million. Each borrower under the facility has also provided an unconditional full liability guarantee in respect of amounts borrowed under the facility.

Revolving credit facility utilized	\$ 251,693
Capital lease obligation	15
	<u>\$ 251,708</u>

Advances under the revolving and operating loan facility are made in the form of Banker's Acceptances (BA's), prime rate loans or letters of credit. In the case of BA's, 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 generally charged at the bank's prime rate.



The credit facility revolves until April 30, 2003 at which time the lender will conduct its annual borrowing base review. The lender 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 or 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 which is 366 days after such conversion date and the remaining 40% of the aggregate principal amount outstanding shall be repayable on the date which is 365 days after the initial term repayment date.

5) UNITHOLDERS' EQUITY

PrimeWest Energy Trust

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

Trust Units	# of units	Amount
Balance at December 31, 2001	125,965,607	\$ 1,115,253
Issued pursuant to Long-term Incentive Plan	561,219	3,672
Issued pursuant to Dividend Reinvestment Plan	1,447,342	8,492
Issued for payment for management fees	132,400	898
Issued on exchange of exchangeable shares	335,203	2,103
Issue expenses incurred	-	22
Balance at June 30, 2002	<u>128,441,771</u>	<u>\$ 1,130,440</u>

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

PrimeWest Exchangeable Class A Shares

In connection with the Cypress acquisition, PrimeWest Oil & Gas Corp. (now amalgamated with PrimeWest Energy Inc.) amended its articles to create an unlimited number of exchangeable 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 June 15, 2002, was 1.36684:1.

Exchangeable shares	# of shares	Amount
Balance at December 31, 2001	3,316,742	\$ 32,338
Exchanged for Trust Units	(146,733)	(1,430)
Conversion of Exchangeable B shares to Exchangeable A shares	710,795	4,287
Balance at June 30, 2002	<u>3,880,804</u>	<u>\$ 35,195</u>

PrimeWest Exchangeable Class B Shares

In connection with the acquisition of Venator Petroleum Company Limited, PrimeWest Resources Ltd. (now amalgamated with PrimeWest Energy Inc.) amended its articles to create an unlimited number of exchangeable shares. At special meetings held in May and June of 2002, holders of Class B



Exchangeable Shares and Class A Exchangeable Shares voted to approve a special resolution amending the articles of the Corporation to convert all Class B Exchangeable Shares to Class A Exchangeable Shares. As at June 14, 2002 649,561 Class B Exchangeable Shares were converted to Class A Exchangeable Shares using an exchange ratio of 1.09427:1

Exchangeable shares	# of shares	Amount
Balance at December 31, 2001	751,532	\$ 4,960
Exchanged for Trust Units	(101,971)	(673)
Conversion of Exchangeable B shares to Exchangeable A shares	(649,561)	(4,287)
Balance at June 30, 2002	-	\$ -

6) TRUST UNIT INCENTIVE PLAN

Under the terms of the Trust Unit Incentive Plan, a maximum of 2,490,000 Trust Units are reserved for issuance pursuant to the exercise of Unit Appreciation Rights (UARs) granted to employees of the Manager. 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 6 years and vest equally over a three-year period, except for the independent 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 June 30, 2002</i>	UARs issued and outstanding	UARs vested	Current return per UAR	Total Equity	Trust Unit dilution
1997 grants	236,786	236,786	\$6.30	1,491	210,610
1998 grants	431,079	431,079	8.98	3,870	535,240
1999 grants	478,483	354,409	6.15	2,943	309,755
2000 grants	826,074	390,607	2.71	1,999	146,925
2001 grants	2,211,504	358,574	0.72	729	16,196
2002 grants	509,662	-	\$1.23	212	-
	4,693,588	1,771,455		\$11,244	1,218,726

Cumulative to June 30, 2002, 2,481,436 UARs have been exercised resulting in the issuance of 1,379,666 Trust Units from treasury.

Effective January 1, 2002 the method of accounting for the long-term incentive plan was changed to comply with new CICA accounting standard 3870. The calculation of the long-term incentive liability now includes vested and unvested UARs. Previously, only vested UARs were included. In addition, the long-term incentive liability has been reclassified as equity on the balance sheet as the Trust intends to settle the liability in the form of Trust Units.

PrimeWest Energy Trust
TRADING PERFORMANCE



<i>For the quarter ended</i>	Jun. 30/02	Mar. 31/02	Dec. 31/01	Sep. 30/01	Jun. 30/01
Trust Unit prices (<i>dollars per Trust Unit</i>)					
High	7.33	7.23	7.51	8.77	10.54
Low	6.45	5.92	5.95	6.42	8.45
Close	7.23	7.20	6.36	6.46	8.85
Volume traded (<i>millions of units</i>)	31.13	34.48	37.59	37.10	60.42
Number of Trust Units outstanding (<i>millions of units</i>)	128.4	127.4	125.9	115.3	113.6
Including exchangeable shares (<i>issued in respect of Venator and Cypress acquisitions</i>)	133.7	132.6	131.1	120.1	119.1
Distribution paid per Trust Unit	<u>\$0.30</u>	<u>\$0.30</u>	<u>\$0.44</u>	<u>\$0.61</u>	<u>\$0.66</u>

For further information please contact:
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