



PRIMEWEST

PRIMEWEST ENERGY TRUST 2006 QUARTERLY REPORT

FOR THE SIX MONTHS ENDED JUNE 30, 2006

PRIMEWEST ENERGY TRUST ANNOUNCES SECOND QUARTER 2006 RESULTS

CALGARY, AUGUST 2, 2006 (TSX: PWI.UN; PWI.DB.A; PWI.DB.B; PWX; NYSE: PWI) – PRIMEWEST ENERGY TRUST (PRIMEWEST OR THE TRUST) TODAY ANNOUNCES INTERIM OPERATING AND FINANCIAL RESULTS FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2006. UNLESS OTHERWISE NOTED, ALL FIGURES CONTAINED IN THIS REPORT ARE IN CANADIAN DOLLARS.

Second Quarter 2006 Highlights:

- Distributions in the second quarter were \$1.02 per Trust Unit representing a payout ratio of approximately 93% of cash flow from operations compared to first quarter 2006 distributions of \$1.08 per Trust Unit, representing a payout ratio of approximately 84% of cash flow from operations. The distribution was reduced from \$0.36 per Trust Unit to \$0.30 per Trust Unit effective for the distribution paid on July 15, 2006.
- Cash flow from operations for the second quarter was \$88.6 million (\$1.08 per Trust Unit) compared to \$103.2 million (\$1.28 per Trust Unit) in the previous quarter and \$95.5 million (\$1.29 per Trust Unit) in the second quarter of 2005.
- Second quarter 2006 production averaged 37,406 barrels of oil equivalent (BOE) per day, compared to the first quarter 2006 rate of 38,062 BOE per day. Second quarter production volumes include a one-time adjustment to the gross overriding royalty volume accrual, reducing volumes in the quarter by 700 BOE per day. This adjustment is expected to impact annual volumes by approximately 200 BOE per day. PrimeWest expects full year 2006 production volumes to average between 39,000 – 40,000 BOE per day including the effect of the United States (U.S.) asset acquisition in the second half of 2006.
- Operating expense in the second quarter of 2006 was \$31.2 million, down from \$32.7 million in the first quarter, representing a quarter-over-quarter decrease of approximately 4%.
- Development capital expenditures in the second quarter were \$46.1 million with drilling, completion and tie-in expenditures of \$36.7 million resulting in 17 gross wells (8.2 net) being drilled with a success rate of 94%. PrimeWest has an inventory of future development opportunities of approximately \$1.0 billion.
- Net debt to annualized second quarter 2006 cash flow was approximately 1.2 times compared to net debt to annualized first quarter 2006 cash flow of 0.9 times at March 31, 2006.

Subsequent Events:

- On July 6, 2006, PrimeWest, through a U.S. subsidiary, acquired producing oil and gas assets located in Montana, North Dakota and Wyoming for consideration of approximately US\$300 million. The acquisition establishes a new operating area for PrimeWest within the Williston Basin with considerable waterflood and development drilling potential. The acquisition is expected to increase production by approximately 3,200 BOE per day, effective July 6, 2006, comprised of 94% crude oil and 6% natural gas. To protect acquisition economics, PrimeWest has entered into costless collars for the next 18 months for volumes ranging from 1,800 BOE per day for the next two quarters, to 1,400 BOE per day in Q1 2007, 1,300 BOE per day in Q2 2007, 900 BOE per day in Q3 2007 and 800 BOE/day in Q4 2007. The floor price for the collars is US\$70.00/bbl and the ceiling prices range from a low of US\$81.40/bbl to US\$84.25/bbl.

MANAGEMENT'S DISCUSSION AND ANALYSIS AS OF AUGUST 2, 2006

The following is management's discussion and analysis (MD&A) of PrimeWest's operating and financial results for the three and six months ended June 30, 2006, compared with the preceding quarter and the corresponding period in the prior year as well as information and opinions concerning the Trust's future outlook based on currently available information.

Forward-Looking Information

This MD&A contains forward-looking or outlook information with respect to PrimeWest.

Certain statements contained in this MD&A, and any documents incorporated by reference into this MD&A, constitute forward-looking statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "project", "should", "believe", "outlook" and similar expressions are intended to identify forward-looking statements. In addition, statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in our forward-looking statements.

We believe the expectations reflected in these forward-looking statements are reasonable. However, we cannot assure you that these expectations will prove to be correct. You should not unduly rely on forward-looking statements included in, or incorporated by reference into this MD&A. These statements speak only as of the date of this MD&A or as of the date specified in any documents incorporated by reference into this MD&A, as the case may be.

In particular, this MD&A, and any documents incorporated by reference, contain forward-looking statements pertaining to the following:

- the quantity and recoverability of our reserves;
- the timing and amount of future production;
- prices for oil, natural gas and natural gas liquids produced;
- operating and other costs;
- business strategies and plans of management;
- supply and demand for oil and natural gas;
- expectations regarding our ability to raise capital and to add to our reserves through acquisitions and exploration and development;
- our treatment under governmental regulatory regimes;
- the focus of capital expenditures on development activity rather than exploration;
- the sale, farming in, farming out or development of certain exploration properties using third-party resources;
- the objective to achieve a predictable level of monthly cash distributions;
- the intention of maintaining a payout ratio of distributions to cash flow from operations within any range;
- the use of development activity and acquisitions to replace and add to reserves;
- the impact of changes in oil and natural gas prices on cash flow after hedging;
- drilling plans;
- the existence, operations and strategy of the commodity price risk management program;
- the approximate and maximum amount of forward sales and hedging to be employed;
- our acquisition strategy, the criteria to be considered in connection therewith and the benefits to be derived therefrom;
- the impact of the Canadian federal and provincial governmental regulation on us relative to other oil and natural gas issuers of similar size;
- the goal to sustain or grow production and reserves through prudent management and acquisitions;

- the emergence of accretive growth opportunities; and
- our ability to benefit from the combination of growth opportunities and the ability to grow through the capital markets.

With respect to forward-looking statements contained in this MD&A, including any documents incorporated herein by reference, we have made assumptions regarding, among other things:

- future oil and natural gas prices and differentials between light, medium and heavy oil prices;
- the cost of expanding our property holdings;
- our ability to obtain equipment in a timely manner to carry out development activities;
- our ability to market our oil and natural gas successfully to current and new customers;
- the impact of increasing competition;
- our ability to obtain financing on acceptable terms; and
- our ability to add production and reserves through our development and exploitation activities.

Our actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and incorporated by reference into this MD&A:

- volatility in market prices for oil and natural gas;
- the impact of weather conditions on seasonal demand;
- risks inherent in our oil and natural gas operations;
- uncertainties associated with estimating reserves;
- competition for, among other things: capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- general economic conditions in Canada, the U.S. and globally;
- industry conditions, including fluctuations in the price of oil and natural gas;
- royalties payable in respect of our oil and natural gas production;
- government regulation of the oil and natural gas industry, including environmental regulation;
- fluctuation in foreign exchange or interest rates;
- unanticipated operating events that can reduce production or cause production to be shut-in or delayed;
- failure to obtain industry partner and other third-party consents and approvals, when required;
- stock market volatility and market valuations;
- OPEC's ability to control production and balance global supply and demand of crude oil at desired price levels;
- political uncertainty, including the risks of hostilities, in the petroleum producing regions of the world;
- the need to obtain required approvals from regulatory authorities; and
- the other factors discussed under "Risk Factors" contained in this MD&A.

These factors should not be construed as exhaustive. The forward-looking statements contained in this MD&A and any documents incorporated by reference herein are expressly qualified by this cautionary statement. We undertake no obligation to publicly update or revise any forward-looking statements.

PrimeWest does not endorse any analyst or consultant sourced material contained herein.

All figures reported in Canadian dollars unless otherwise stated.

Production figures stated in this MD&A are Company Interest before the deduction of royalties.

Evaluation of Disclosure Controls and Procedures

The Chief Executive Officer, Don Garner, and the Chief Financial Officer, Dennis Feuchuk, evaluated the effectiveness of PrimeWest's disclosure controls and procedures as of June 30, 2006, and concluded that PrimeWest's disclosure controls and procedures were effective to ensure that information PrimeWest is required to disclose:

- in its annual filings, interim filings or other reports (each as defined in National Instrument 52-109 of the Canadian Securities Administrators) filed or submitted by it under provincial securities legislation is recorded, processed, summarized and reported within the time periods specified in the provincial securities legislation and to ensure that information required to be disclosed by PrimeWest in its annual filings, interim filings or other reports filed or submitted under provincial securities legislation is accumulated and communicated to PrimeWest's management, including its chief executive officer and chief financial officer, as appropriate to allow timely decisions regarding required disclosure; and
- in its annual filings, interim filings or other reports with the U.S. Securities and Exchange Commission (SEC) under the Securities Exchange Act of 1934 (Exchange Act) is recorded, processed, summarized and reported, within the time periods specified in the Commission's rules and forms, and to ensure that information required to be disclosed by PrimeWest in the reports that it files under the Exchange Act is accumulated and communicated to PrimeWest's management, including its principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

The evaluation took into consideration PrimeWest's Communications and Disclosure Policy and the functioning of its executive officers, board of directors and board committees. In addition, the evaluation covered PrimeWest's processes, systems and capabilities relating to regulatory filings, public disclosures and the identification and communication of material information.

Changes to Internal Controls Over Financial Reporting

There were no changes to PrimeWest's internal control over financial reporting since March 31, 2006 that have materially affected, or are reasonably likely to materially affect PrimeWest's internal control over financial reporting.

Non-GAAP Measures

This MD&A contains the following measurements that are not defined by Canadian Generally Accepted Accounting Principles (GAAP):

- Cash flow from operations on a total and per Trust Unit basis;
- Distributions per Trust Unit; and
- Net debt per Trust Unit.

These measurements do not have any standardized meaning prescribed by GAAP and are, therefore, unlikely to be comparable to similar measures presented by other entities.

Cash flow from operations is calculated from the Trust's cash flow statement as cash flow from operating activities before changes in working capital. Cash flow from operations per Trust Unit on a basic basis is calculated by dividing cash flow by the weighted average number of Trust Units outstanding plus Trust Units issuable upon the exchange of the outstanding Exchangeable Shares of PrimeWest Energy Inc. (Exchangeable Shares). Cash flow from operations per Trust Unit on a diluted basis is calculated using cash flow and adding back the interest expense on the Convertible Unsecured Subordinated Debentures (Debentures), divided by the diluted weighted average number of Trust Units outstanding in the period. The diluted weighted average number of Trust Units outstanding consists of the weighted average Trust Units plus Trust Units issuable upon the exchange of outstanding Exchangeable Shares and includes the Trust Units issuable pursuant to the conversion of the Debentures, and Trust Units issuable pursuant to PrimeWest's Long Term Incentive Plan (LTIP). Cash flow from operations is a key performance indicator of PrimeWest's ability to generate cash and finance operations and pay monthly distributions.

Distributions per Trust Unit disclose the cash distributions accrued in 2006 based on the number of Trust Units outstanding on the Record Date.

Net debt per Trust Unit is calculated as long-term debt, including Debentures, less working capital, excluding financial derivative assets and liabilities and current future income tax assets and liabilities divided by the number of Trust Units outstanding and includes Trust Units issuable upon the exchange of outstanding Exchangeable Shares and Trust Units issuable pursuant to the LTIP at June 30, 2006.

Business Strategy

PrimeWest is an Alberta based conventional oil and natural gas royalty trust actively managed to generate monthly cash distributions for the holders of Trust Units (Unitholders). The Trust's operations are focused in the Western Canada Sedimentary Basin and Montana, North Dakota and Wyoming in the United States. PrimeWest is one of North America's largest natural gas-weighted energy trusts.

Maximizing total return to Unitholders, in the form of cash distributions and appreciation in unit price, is PrimeWest's overriding objective. Our strategies for asset management and growth, financial management and corporate governance are outlined in this MD&A, along with a discussion of our performance in the second quarter of 2006 and our goals for 2006 and beyond.

We believe that PrimeWest can maximize total return to Unitholders by continuing to develop our core properties, making opportunistic acquisitions that emphasize value creation, exercising disciplined financial management which broadens access to capital while minimizing risk to Unitholders, and complying with strong corporate governance principles to protect the interests of all stakeholders.

Asset Management and Growth

PrimeWest has a strategy to focus expansion efforts on existing core areas and pursue depletion optimization strategies to maximize asset value. We make every effort to obtain operatorship of our asset base and maintain high working interests in core areas. We currently maintain operatorship of 80% of our assets, which allows us to use existing infrastructure and synergies within our core areas. We believe this high level of control can translate into cost efficiencies and timing of capital outlays and projects. The current size of the Trust gives us the ability and critical mass to make acquisitions of significant size, while being able to add value by transacting smaller acquisitions.

Financial Management

PrimeWest strives to maintain a prudent debt position, to allow us to fund smaller acquisitions and to fund ongoing development activities without tapping the capital markets. Our long-term debt is comprised of bank credit facilities through a bank syndicate, US-dollar-denominated Senior Secured Notes (U.S. Secured Notes), Pounds Sterling denominated Senior Secured Notes (U.K. Secured Notes) and the Debentures. Our diversified debt instruments help to reduce our reliance on the bank syndicate. PrimeWest's commodity hedging strategy is designed to reduce the volatility of cash flow by providing some near term downside price protection. Hedging a portion of our production protects acquisition economics and our capital structure and provides partial protection against short-term declines in commodity prices. Since August 2003, PrimeWest has followed a strategy of maintaining a distribution payout ratio within 70-90% of cash flow, calculated on an annual basis, recognizing that during periods of volatile commodity prices the payout ratio may temporarily move out of this range. The Board of Directors of PrimeWest considers a variety of factors in establishing the monthly distribution level including, but not limited to: commodity price outlook, cash flow forecast, capital development plans, debt levels, tax considerations and competitive industry distribution practices.

The second quarter 2006 payout ratio was approximately 93% of operating cash flow. Retained cash flow was utilized to fund a part of the Trust's capital spending program and to repay debt. PrimeWest's net debt to annualized second quarter cash flow ratio was approximately 1.2 times at June 30, 2006.

PrimeWest's dual listing on the Toronto Stock Exchange (TSX) and New York Stock Exchange (NYSE) provides increased liquidity and a broadened investor base. The NYSE listing enables U.S. Unitholders to conveniently trade in our Trust Units, and allows us to access the U.S. capital markets in the future. Our status as a corporation for U.S. tax purposes simplifies tax reporting for our U.S. Unitholders.

For eligible Canadian and U.S. Unitholders, PrimeWest offers participation in the conventional Distribution Reinvestment Plan (DRIP), which represents a convenient way to maximize an investment in PrimeWest. Canadian residents may also participate in the Optional Trust Unit Purchase Plan (OTUPP) and the Premium Distribution Plan (PREP). For alternate investment requirements, PrimeWest also has Exchangeable Shares and Debentures available.

Corporate Governance

PrimeWest remains committed to high standards of corporate governance and upholds the rules of the governing regulatory bodies under which it operates. Full disclosure of our compliance with existing corporate governance rules and regulations is available on our website at www.primewestenergy.com. PrimeWest actively monitors the corporate governance and disclosure environment to ensure compliance with current and future requirements.

Our high standards of corporate governance are not limited to the boardroom. At the field level, PrimeWest proactively manages environmental, health and safety issues. We place a great deal of importance on community involvement and maintaining good relationships with landowners.

Financial Highlights

\$ Millions, except per BOE ⁽¹⁾ and per Trust Unit amounts	Three Months Ended			Six Months Ended	
	Jun 30, 2006	Mar 31, 2006	Jun 30, 2005	Jun 30, 2006	Jun 30, 2005
Gross revenue (net of transportation expense)	160.4	189.2	169.7	349.7	323.0
per BOE	47.14	55.25	46.15	51.20	44.05
Cash flow from operations	88.6	103.2	95.5	191.9	175.2
per BOE	26.04	30.14	25.98	28.10	23.89
per Trust Unit – basic ⁽²⁾	1.08	1.28	1.29	2.37	2.41
per Trust Unit – diluted ⁽³⁾	1.06	1.24	1.21	2.30	2.26
Royalty expense	31.9	44.7	36.8	76.5	72.8
per BOE	9.36	13.04	10.01	11.20	9.93
Operating expense	31.2	32.7	28.1	63.9	52.5
per BOE	9.16	9.54	7.63	9.35	7.16
Cash G&A expense	7.0	5.3	4.8	12.3	10.3
per BOE	2.04	1.55	1.32	1.80	1.41
Non-cash G&A expense	1.5	1.4	1.4	3.0	2.6
per BOE	0.45	0.42	0.38	0.44	0.35
Interest expense ⁽⁴⁾	5.2	4.6	7.7	9.7	16.8
per BOE	1.52	1.34	2.11	1.43	2.29
Distributions to Unitholders	82.8	86.8	66.5	169.5	130.4
per Trust Unit ⁽⁵⁾	1.02	1.08	0.90	2.10	1.80
Net debt ⁽⁶⁾	415.5	364.5	431.9	415.5	431.9
per Trust Unit ⁽⁷⁾	4.98	4.42	5.56	4.98	5.56

⁽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 one barrel of crude oil. BOE's may be misleading, particularly if used in isolation. The BOE conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

⁽²⁾ The basic per Trust Unit calculation includes the weighted average Trust Units and Trust Units issuable upon exchange of the Exchangeable Shares of PrimeWest Energy Inc. (Exchangeable Shares).

⁽³⁾ The diluted per Trust Unit calculation includes the weighted average Trust Units outstanding, Trust Units issuable upon exchange of the outstanding Exchangeable Shares, the deemed conversion of the Debentures and Trust Units issuable pursuant to the LTIP. Interest expense incurred on the Debentures is added back to net income and to cash flow for the diluted per Trust Unit calculation.

⁽⁴⁾ Interest expense includes the interest on the Debentures.

⁽⁵⁾ Based on Trust Units outstanding at the Record Date.

⁽⁶⁾ Net debt is long-term debt including Debentures adjusted for working capital, excluding current financial derivative and future income tax assets and liabilities.

⁽⁷⁾ The net debt per Trust Unit calculation includes outstanding Trust Units, Trust Units issuable upon exchange of the outstanding Exchangeable Shares and Trust Units issuable pursuant to the LTIP at the end of the period.

Operating Highlights

Daily Production Volumes	Three Months Ended			Six Months Ended	
	Jun 30, 2006	Mar 31, 2006	Jun 30, 2005	Jun 30, 2006	Jun 30, 2005
Natural gas (mmcf/day)	164.1	166.0	178.4	165.1	179.5
Crude oil (bbls/day)	6,305	6,867	6,707	6,584	6,827
Natural gas liquids (bbls/day)	3,748	3,525	3,959	3,637	3,762
Total (BOE per day)	37,406	38,062	40,405	37,732	40,510

Average Realized Sales Prices

	Three Months Ended			Six Months Ended	
	Jun 30, 2006	Mar 31, 2006	Jun 30, 2005	Jun 30, 2006	Jun 30, 2005
Natural gas (\$/mcf) ⁽¹⁾⁽²⁾	6.65	9.13	7.52	7.89	7.16
Without hedging	6.29	9.09	7.55	7.69	7.17
Crude oil (\$/bbl) ⁽¹⁾	68.72	54.51	45.61	61.35	43.88
Without hedging	68.78	57.09	55.38	62.72	53.12
Natural gas liquids (\$/bbl)	62.56	59.34	53.57	61.01	52.28
Total Oil Equivalent (\$/BOE) ⁽¹⁾	47.02	55.17	46.03	51.11	43.96
Without hedging	45.46	55.44	47.78	50.47	45.57
Realized hedging gain/(loss) included in prices above (\$/BOE)	1.56	(0.27)	(1.75)	0.64	(1.61)

⁽¹⁾ Includes hedging gains and losses.

⁽²⁾ Excludes sulphur.

Cash Flow Reconciliation

(\$ Millions)	
First quarter 2006 cash flow from operations	\$ 103.2
Volumes	(1.2)
Commodity prices	(34.0)
Net hedging change from prior quarter	6.3
Operating expenses	1.5
Royalties	12.8
General and administrative expenses	(1.7)
Other	1.7
Second quarter 2006 cash flow from operations	\$ 88.6

The above table includes non-GAAP measurements. (Refer to discussion on Non-GAAP Measures on Page 4)

A key performance driver for the Trust is cash flow from operations, which directly affects PrimeWest's ability to pay monthly distributions. Cash flow is generated through the production and sale of crude oil, natural gas and natural gas liquids, and is dependent on production levels, commodity prices, operating expenses, interest expense, general and administrative expense (G&A), hedging gains or losses, royalties and currency exchange rates. Some of these factors such as commodity prices, the currency

exchange rate and royalties are uncontrollable from PrimeWest's perspective. Other factors that are to a certain extent controllable by PrimeWest are production levels and operating expenses, as well as interest and G&A expenses.

Quarterly Performance – Selective Measures

The table below highlights PrimeWest's performance for the second quarter ended June 30, 2006 and the preceding seven quarters through 2004.

(\$ Millions, except per Trust Unit Amounts)	2006				2005			2004
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Net revenues	\$134.9	\$170.0	\$236.4	\$101.5	\$155.3	\$111.2	\$158.2	\$ 84.5
Net income	65.7	68.9	101.5	27.3	54.7	24.0	42.2	27.1
Cash flow from operations	88.6	103.2	132.5	106.4	95.5	79.7	83.3	66.8
Cash flow per Unit – basic	1.08	1.28	1.66	1.36	1.29	1.12	1.17	1.09
Cash flow per Unit – diluted	1.06	1.24	1.60	1.31	1.21	1.04	1.07	1.08
Net income per Unit – basic	0.81	0.85	1.27	0.35	0.74	0.34	0.59	0.44
Net income per Unit – diluted	0.79	0.83	1.23	0.35	0.72	0.34	0.58	0.44

The primary factors that impact net revenues include commodity prices, production volumes, royalties and unrealized gains or losses on derivatives.

Net income and net income per Trust Unit are secondary measures for a royalty trust because they include both cash and non-cash items. The non-cash items, which include depletion, depreciation and amortization (DD&A), non-cash G&A, future income taxes, unrealized foreign exchange gains or losses and unrealized gains or losses on derivatives will not affect PrimeWest's ability to pay a monthly distribution.

Capital Expenditures

(\$ Millions)	Three Months Ended			Six Months Ended	
	Jun 30, 2006	Mar 31, 2006	Jun 30, 2005	Jun 30, 2006	Jun 30, 2005
Land and lease acquisitions	3.5	3.4	6.4	6.9	13.1
Geological and geophysical	0.5	1.5	4.8	2.0	6.4
Drilling and completions	22.3	53.5	23.4	75.8	58.8
Investment in facilities					
Equipping and tie-in	14.4	15.6	8.1	30.0	13.9
Gas gathering and compression	1.1	1.2	1.9	2.3	9.1
Production facilities	3.1	4.7	2.5	7.7	5.2
Capitalized G&A	1.2	1.4	0.8	2.6	1.4
Development capital	46.1	81.3	47.9	127.3	107.9
Corporate/property acquisitions	0.2	0.2	(1.0)	0.4	(0.4)
Dispositions	(0.1)	(3.1)	1.0	(3.2)	(2.3)
Leasehold improvements, furniture and equipment	1.3	1.3	1.5	2.6	2.5
Net capital expenditures	47.5	79.7	49.4	127.1	107.7

During the second quarter of 2006, PrimeWest's development capital expenditures totalled \$46.1 million, compared to \$81.3 million invested in the first quarter of 2006 and \$47.9 million in the second quarter of 2005. Of the \$46.1 million total, \$36.7 million or 80% was invested in drilling, completions and tie-ins, which contribute to new reserve additions and help offset natural production decline.

Through acquisitions as well as development drilling, workovers and re-completion activities, PrimeWest strives to offset natural production declines and add to reserves in order to sustain cash flows. Capital resources are allocated to projects on the basis of anticipated rate of return. At PrimeWest, every capital project is measured against stringent economic evaluation criteria prior to approval. These criteria include expected return, risks and further development opportunities.

Development Capital Update

During the second quarter of 2006, PrimeWest invested \$46.1 million on development opportunities, drilling 17 gross wells (8.2 net) with a success rate of 94%. PrimeWest's key development plays are Conventional Development, Tight Gas, Southeast Alberta Shallow Gas, Coalbed Methane (CBM) and U.S. Assets. PrimeWest's development capital expenditures for 2006 are expected to be approximately \$300 million, allocated \$100 to \$110 million to Conventional Development, \$70 to \$80 million to Tight Gas development, \$30 to \$35 million to Southeast Alberta Shallow Gas development, \$5 to \$10 million to CBM, \$20 to \$25 million to the newly acquired U.S. assets and approximately \$30 million to maintenance capital, land and seismic. PrimeWest's total inventory of development opportunities is approximately \$1.0 billion.

Conventional Development

PrimeWest continues to invest in development opportunities at our conventional plays, which include properties at Lone Pine Creek/Crossfield, Wilson Creek, Boundary, Laprise, Grand Forks and Valhalla. Development expenditures during the second quarter totalled \$25.4 million, comprised of \$10.4 million for drilling and completions, \$2.4 million for land and seismic and \$12.6 million for equipping, tie-in and facilities. A total of 5 gross wells have been drilled during the quarter.

The following provides a description of the Wilson Creek and Lone Pine Creek/Crossfield areas, which are major properties in our conventional development play.

Wilson Creek

In the Wilson Creek area, PrimeWest drilled 1 operated well in the second quarter of 2006, and participated in 3 non-operated wells targeted at various formations including Edmonton, Belly River, Glauconitic, Mannville, and Rock Creek. Development capital expenditures at Wilson Creek were \$8.8 million, comprised of \$5.0 million for drilling and completions, \$1.1 million for land and seismic and \$2.7 million for equipping, tie-in and facilities.

Lone Pine Creek/Crossfield Area

Development capital expenditures at Crossfield of \$2.7 million were comprised of \$1.6 million for drilling and completions, \$0.1 million for land and seismic and \$1.0 million for equipping, tie-in and facilities.

Tight Gas Plays

PrimeWest's Tight Gas plays are located in west central Alberta, and target the deeper Viking, Mannville and Cardium sandstones. Tight Gas wells are characterized by high initial production rates that settle into a low decline stabilized rate and production of high heat content, liquids-rich gas.

PrimeWest continued its development program in its Tight Gas plays in the second quarter 2006. Capital expenditures for the three months ended June 30, 2006 included \$6.0 million for drilling and completions, \$0.8 million for land and seismic and \$3.5 million for equipping, tie-in and facilities. Four gross wells were drilled during the quarter. Previous expenditures on land and seismic have increased PrimeWest's inventory of drilling opportunities. The following provides an overview of activity in the Tight Gas region.

Caroline Area

Development expenditures at Caroline during the second quarter 2006 of \$4.5 million were comprised of \$1.9 million for drilling and completion, \$1.8 million for equipping, tie-in and facilities and \$0.8 million for land and seismic. During the quarter, 3 gross wells were drilled at Caroline.

Columbia Area

Development expenditures at Columbia of \$5.8 million were comprised of \$4.2 million for drilling and completions, and \$1.6 million for equipping, tie-in and facilities. During the quarter, 1 gross well was drilled at Columbia.

Southeast Alberta Shallow Gas

PrimeWest's Southeast Alberta Shallow Gas Play consists of shallow gas pools in the Medicine Hat and Milk River formations plus deeper, more prolific pools in Glauconitic zones. Lying at typical depths of 600 to 1,000 metres, the shallow zones are amenable to a low-risk, low-cost "manufacturing" development approach. The main properties that comprise the Shallow Gas Play are Medicine Hat, Princess/Dinosaur, Bindloss and Brant Farrow. This area has evolved through a combination of development activities and acquisitions. During the second quarter of 2006, development expenditures were \$4.9 million, with \$2.9 million invested in drilling and completions, \$1.6 million in equipping, tie-ins and facilities, and \$0.4 million in land and seismic. Six gross wells were drilled in the second quarter.

The following provides a description of the Brant Farrow area, which is a major property in the Southeast Alberta Shallow Gas play that has evolved to include development of the seismically identified Glauconitic channels.

Brant Farrow Area

Development expenditures at Brant Farrow during the second quarter were \$4.0 million, with \$2.6 million invested in drilling and completions, \$1.1 million in equipping, tie-ins and facilities and \$0.3 million in land and seismic. The drilling program is on schedule, with 2 gross operated wells drilled in the second quarter.

Coalbed Methane

CBM is an emerging resource play in Western Canada. PrimeWest has approximately 124,000 net acres of land on the developing Horseshoe Canyon CBM trend. PrimeWest is involved in preliminary assessments of the area. Acreage is concentrated within three large operated properties with gas plants and extensive field infrastructure.

Daily Production Volumes

Daily Production Volumes	Three Months Ended			Six Months Ended	
	Jun 30, 2006	Mar 31, 2006	Jun 30, 2005	Jun 30, 2006	Jun 30, 2005
Natural gas (mmcf/day)	164.1	166.0	178.4	165.1	179.5
Crude oil (bbls/day)	6,305	6,867	6,707	6,584	6,827
Natural gas liquids (bbls/day)	3,748	3,525	3,959	3,637	3,762
Total (BOE per day)	37,406	38,062	40,405	37,732	40,510

Production Volumes

Production volumes averaged 37,406 BOE per day for the second quarter of 2006 compared to 38,062 BOE per day in the first quarter of 2006. During the quarter, PrimeWest recorded a one-time adjustment to the gross overriding royalty volume accrual, reducing volumes in the quarter by 700 BOE per day. This adjustment is expected to impact annual volumes by approximately 200 BOE per day.

Continued success with our drilling program has resulted in flat production levels quarter-over-quarter. Incremental volume additions in the quarter have offset volume reductions due to maintenance shut-ins and natural decline. In addition, PrimeWest has ongoing regulatory restrictions of 600 BOE per day.

Behind pipe potential at the end of the second quarter was 1,800 BOE per day. It is anticipated that planned maintenance activity at Crossfield will impact volumes by approximately 1,000 – 1,500 BOE per day in the third quarter.

For the three and six months ended June 30, 2006, production volumes have decreased 7% when compared to the same periods in 2005 partially due to the negative adjustment to the GORR volumes. Regulatory changes impacting the Nisku waterflood project at Crossfield, third party unscheduled outages at Princess as well as operational issues at Caroline and Crossfield also impacted production volumes when comparing to the prior year.

Production Outlook

Prime West expects full year 2006 production volumes to average between 39,000 – 40,000 BOE per day, including the impact of the U.S. asset acquisition in the second half of 2006.

Commodity Prices

Benchmark Prices	Three Months Ended			Six Months Ended	
	Jun 30, 2006	Mar 31, 2006	Jun 30, 2005	Jun 30, 2006	Jun 30, 2005
Natural gas					
NYMEX (US\$/mcf)	6.82	9.08	6.80	7.95	6.56
AECO (Cdn\$/mcf)	6.27	9.27	7.38	7.77	6.67
Crude oil WTI (US\$/bbl)	70.70	63.48	53.17	67.09	51.51

Benchmark Commodity Prices

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

	Past Four Quarters (Actual)				Next Four Quarters (Forward Markets) ⁽¹⁾			
	Q3 2005	Q4 2005	Q1 2006	Q2 2006	Q3 2006	Q4 2006	Q1 2007	Q2 2007
Natural gas AECO								
(Cdn\$/mcf)	8.17	11.69	9.27	6.27	5.49	7.61	9.71	7.92
Crude oil WTI								
(US\$/bbl)	63.19	60.02	63.48	70.70	74.93	76.16	76.49	76.28

⁽¹⁾ As at June 30, 2006

Average Realized Sales Prices

	Three Months Ended			Six Months Ended	
	Jun 30, 2006	Mar 31, 2006	Jun 30, 2005	Jun 30, 2006	Jun 30, 2005
Natural gas (\$/mcf) ⁽¹⁾⁽²⁾	6.65	9.13	7.52	7.89	7.16
Without hedging	6.29	9.09	7.55	7.69	7.17
Crude oil (\$/bbl) ⁽¹⁾	68.72	54.51	45.61	61.35	43.88
Without hedging	68.78	57.09	55.38	62.72	53.12
Natural gas liquids (\$/bbl)	62.56	59.34	53.57	61.01	52.28
Total BOE (\$/BOE) ⁽¹⁾	47.02	55.17	46.03	51.11	43.96
Without hedging	45.46	55.44	47.78	50.47	45.57
Realized hedging gain/(loss) included in prices above (\$/BOE)	1.56	(0.27)	(1.75)	0.64	(1.61)

⁽¹⁾ Includes hedging losses.

⁽²⁾ Excludes sulphur.

Realized natural gas prices were 31% lower in the second quarter of 2006 compared to the previous quarter, excluding the effect of hedging. Gas storage levels remain at historically high levels as a result of lower heating requirements during the warm winter of 2005 - 2006 in the United States. The storage situation has also been exacerbated by the partial recovery of shut-in gas production volumes from last years Gulf of Mexico hurricanes, in addition to increases in domestic natural gas production resulting from high

drilling activity. Realized natural gas prices were 17% lower during the second quarter of 2006 compared to the second quarter of 2005.

Realized crude oil prices were 20% higher in the second quarter of 2006 compared to the previous quarter, excluding the effect of hedging. The latter part of the quarter saw differentials to WTI on all grades of crude narrow as refineries came back from the heaviest turnaround season in history. Contributing to the decrease in these differentials was the increase in seasonal demand for heavier oil required for asphalt. The start of the summer driving season also put upward pressure on oil prices during the second quarter. Realized oil prices were 24% higher during the second quarter of 2006 compared to the second quarter of 2005.

Sales Revenue

Revenue (\$ Millions) ^{(1) (2)}	Three Months Ended				Six Months Ended			
	Jun 30, 2006	% of Total	Mar 31, 2006	% of Total	Jun 30, 2005	% of Total	Jun 30, 2006	Jun 30, 2005
Natural gas	99.3	62	136.5	72	122.1	72	235.8	232.5
Crude oil	39.4	25	33.7	18	27.8	17	73.1	54.2
Natural gas liquids	21.4	13	18.8	10	19.3	11	40.2	35.6
Total	160.1	100	189.0	100	169.2	100	349.1	322.3
Hedging (losses)/gains included above	5.3		(0.9)		(6.4)		4.4	(11.8)

⁽¹⁾ Excludes sulphur.

⁽²⁾ Net of transportation expenses.

Second quarter 2006 revenues were 15% lower than the previous quarter mainly due to lower realized natural gas prices and lower production volumes offset by increases in crude oil and natural gas liquids prices and realized hedging gains.

Second quarter 2006 revenues were 5% lower than the same period in 2005, due to lower natural gas prices and production volumes offset by increases in crude oil prices and realized hedging gains. On a year-to-date basis, June 2006 revenues exceeded June 2005 revenues by 8% due to higher realized commodity prices offset by lower volumes.

PrimeWest derives approximately 62% of its revenues from natural gas; therefore, the Trust has greater sensitivity to changes in natural gas prices than crude oil prices.

Financial Derivatives

As part of our financial management strategy, PrimeWest uses a consistent commodity hedging approach. The purpose of the hedging program is to reduce volatility in cash flows, protect acquisition economics and to stabilize cash flow against the unpredictable commodity price environment. The hedging policy reflects a willingness to risk forfeiting a portion of the pricing upside in return for protection against a significant downturn in prices.

The following table sets forth the approximate percentage of future anticipated production volumes hedged at June 30, 2006, net of anticipated royalties, reflecting full production declines with no offsetting additions.

Production Volumes Hedged (%)	Q3 2006	Q4 2006	Q1 2007	Q2 2007	Q3 2007	Q4 2007
Crude Oil	67	70	45	38	20	21
Natural Gas	58	63	38	15	10	5

PrimeWest generally sells its oil and natural gas under short-term market-based contracts. Derivative financial instruments, options and swaps may be used to hedge the impact of oil and gas price fluctuations.

A listing of hedging contracts in place at June 30, 2006 follows:

Crude Oil

Period	Volume (bbls/d)	Type	WTI Price (US\$/bbl)
Jul – Sep 06	500	Costless Collar	50.00/75.30
Jul – Sep 06	1000	Costless Collar	50.00/82.05
Jul – Sep 06	500	Costless Collar	50.00/76.05
Jul – Sep 06	500	Costless Collar	50.00/80.50
Jul – Sep 06	500	Costless Collar	55.00/91.00
Jul – Sep 06	500	Costless Collar	55.00/90.05
Jul – Sep 06	500	Costless Collar	65.00/85.75
Oct – Dec 06	500	Costless Collar	50.00/75.03
Oct – Dec 06	1000	Costless Collar	50.00/81.50
Oct – Dec 06	500	Costless Collar	50.00/75.00
Oct – Dec 06	500	Costless Collar	50.00/81.00
Oct – Dec 06	500	Costless Collar	55.00/91.50
Oct – Dec 06	500	Costless Collar	55.00/90.90
Oct – Dec 06	500	Costless Collar	65.00/88.25
Jan – Mar 07	500	Costless Collar	50.00/76.00
Jan – Mar 07	500	Costless Collar	50.00/80.80
Jan – Mar 07	500	Costless Collar	55.00/91.65
Jan – Mar 07	500	Costless Collar	55.00/90.00
Jan – Mar 07	500	Costless Collar	60.00/97.20
Apr – Jun 07	500	Costless Collar	50.00/80.00
Apr – Jun 07	500	Costless Collar	55.00/91.30
Apr – Jun 07	500	Costless Collar	55.00/90.08
Apr – Jun 07	500	Costless Collar	60.00/95.40
Jul – Sep 07	500	Costless Collar	60.00/92.75
Jul – Sep 07	500	Swap	75.20
Oct – Dec 07	500	Costless Collar	60.00/90.25
Oct – Dec 07	500	Swap	74.58

Natural Gas

Period	Volume (mmcf/d)	Type	AECO Price (Cdn\$/mcf)
Jul – Sep 06	5.0	3 Way	4.22/5.28/9.34
Jul – Sep 06	5.0	Costless Collar	5.28/10.55
Jul – Sep 06	10.0	Costless Collar	6.86/10.55
Jul – Sep 06	5.0	Costless Collar	6.86/10.68
Jul – Sep 06	5.0	Costless Collar	7.39/13.56

Period	Volume (mmcf/d)	Type	AECO Price (Cdn\$/mcf)
Jul – Sep 06	5.0	Costless Collar	8.44/13.98
Jul – Sep 06	5.0	Costless Collar	8.44/15.72
Jul – Sep 06	5.0	Costless Collar	8.44/15.83
Jul – Sep 06	10.0	Costless Collar	8.44/16.30
Jul – Sep 06	5.0	Swap	6.33
Jul – Sep 06	5.0	Costless Collar	5.28/6.54
Oct – Dec 06	5.0	3 Way	5.28/6.33/13.03
Oct – Dec 06	5.0	Costless Collar	6.86/11.92
Oct – Dec 06	10.0	Costless Collar	6.86/12.66
Oct – Dec 06	5.0	3 Way	5.28/6.33/14.19
Oct – Dec 06	5.0	Costless Collar	7.39/15.83
Oct – Dec 06	5.0	Costless Collar	8.44/11.87
Oct – Dec 06	5.0	Costless Collar	8.44/15.83
Oct – Dec 06	5.0	Costless Collar	8.44/17.94
Oct – Dec 06	5.0	Costless Collar	8.44/18.99
Oct – Dec 06	10.0	Costless Collar	8.44/19.25
Oct – Dec 06	5.0	Swap	8.22
Oct – Dec 06	5.0	Costless Collar	6.33/9.97
Jan – Mar 07	5.0	Costless Collar	7.91/12.87
Jan – Mar 07	5.0	Costless Collar	8.44/13.80
Jan – Mar 07	5.0	Costless Collar	8.44/15.88
Jan – Mar 07	5.0	Costless Collar	8.44/18.46
Jan – Mar 07	5.0	Costless Collar	8.44/21.10
Jan – Mar 07	5.0	Costless Collar	8.44/21.21
Jan – Mar 07	5.0	Costless Collar	8.44/12.68
Jan – Mar 07	5.0	Costless Collar	7.39/14.77
Apr – Jun 07	5.0	3 Way	6.33/7.39/11.24
Apr – Jun 07	5.0	Costless Collar	6.33/10.64
Apr – Jun 07	5.0	Costless Collar	6.33/10.23
Jul – Sep 07	5.0	Costless Collar	6.33/11.61
Jul – Sep 07	5.0	Costless Collar	6.33/10.87
Oct – Dec 07	5.0	Costless Collar	7.39/12.28

A 3-way option is similar to a traditional collar, except that PrimeWest has resold the put at a lower price. Utilizing the first 3-way natural gas contract above as an example, PrimeWest has sold a call at \$9.34/mcf, purchased a put at \$5.28/mcf, and resold the put at \$4.22/mcf. Should the market price drop below \$5.28/mcf, PrimeWest will receive \$5.28/mcf until the price is less than \$4.22/mcf, at which time PrimeWest will then receive market price plus \$1.06/mcf. However, if market prices rise above \$9.34/mcf, PrimeWest will receive a maximum of \$9.34/mcf. Should the market price remain between \$5.28 and \$9.34, PrimeWest will receive the market price.

Electrical Power

Period	Power Amount (MW)	Type	Price (\$/MW-hr)
Jul – Sep 06	5.0	Swap	69.00
Jul – Sep 06	5.0	Swap	62.75
Oct – Dec 06	5.0	Swap	70.50
Oct – Dec 06	5.0	Swap	66.00

Foreign Exchange

Period	Amount £	Type	Price
Jun - Jun 16	Principal 63,000 Interest 36,288	Swap	\$2.0748 Cdn per £ 1.00

PrimeWest's derivatives are mark-to-market at the end of each reporting period with the resulting gain or loss reflected in earnings for that period.

The second quarter 2006 income statement includes an unrealized gain of \$3.0 million on derivatives resulting from the change in the mark-to-market valuation of the derivative financial instruments during the period. The gain was comprised of a \$0.9 million loss for crude oil hedges, a \$6.2 million gain for natural gas hedges and a \$2.3 million loss on the foreign exchange hedges. For the six months ended June 30, 2006, the change in the mark-to-market valuation of the derivatives resulted in a gain of \$25.1 million comprised of a \$0.4 million loss for crude oil hedges and a \$27.8 million gain for natural gas hedges and a \$2.3 million loss on the foreign exchange hedges.

The unrealized gain is a point-in-time measurement of PrimeWest's hedging position at the end of the second quarter. The magnitude of the gain or loss will continue to fluctuate with changes in commodity prices and foreign exchange rates.

The mark-to-market valuation of the electrical power swaps is zero at June 30, 2006.

For the three month period ended June 30, 2006 the cash impact of contract settlements was a \$5.3 million gain resulting from natural gas hedges.

For the six month period ended June 30, 2006, the cash impact of contract settlements was a \$4.4 million gain comprised of a \$6.0 million gain in natural gas and a \$1.6 million loss in crude oil.

Royalties

PrimeWest pays royalties to the owners of mineral rights with whom PrimeWest holds leases. PrimeWest has mineral leases with the Crown (Provincial and Federal Governments), freeholders (individuals or other companies) and other operators.

(\$ Millions, except per BOE)	Three Months Ended			Six Months Ended	
	Jun 30, 2006	Mar 31, 2006	Jun 30, 2005	Jun 30, 2006	Jun 30, 2005
Royalty expense	31.9	44.7	36.8	76.5	72.8
Per BOE	9.36	13.04	10.01	11.20	9.93
Royalties as a % of sales revenues					
With hedge loss	19.9%	23.7%	21.8%	21.9%	22.6%
Excluding hedge gain/loss	20.6%	23.5%	21.0%	22.2%	21.8%

Royalty expenses as a percentage of sales excluding the impact of hedges were lower than the previous quarter due to a 13th month Crown adjustment for gas cost allowance of approximately \$2.6 million.

The Crown royalty system is based on a sliding scale structure whereby royalty rates increase with increases in commodity prices. Because of the sliding scale structure of royalty rates, future changes to commodity prices will result in changes in royalty rates and expenses.

Operating Expenses

(\$ Millions, except per BOE)	Three Months Ended			Six Months Ended	
	Jun 30, 2006	Mar 31, 2006	Jun 30, 2005	Jun 30, 2006	Jun 30, 2005
Operating expense	31.2	32.7	28.1	63.9	52.5
Per BOE	9.16	9.54	7.63	9.35	7.16

Second quarter 2006 operating expenses totalled \$31.2 million, down from \$32.7 million in the first quarter of 2006. On a per BOE basis, operating expenses were down 4% over the previous quarter. The reduction in operating expense is attributable to a number of cost reduction initiatives and the decommissioning of the Valhalla bio-desulphurization plant in April. An additional offset to operating expense in the quarter was the receipt of grants related to the Valhalla plant. Further costs were incurred in Laprise and Columbia due to increased volumes and associated third party fees in addition to start-up costs for new Laprise compression.

Year-over-year operating expense increased \$3.1 million or 11% in the second quarter of 2006 compared to the second quarter of 2005 due to industry wide inflationary pressures. On a per BOE basis, operating expenses are higher in the second quarter of 2006 due to higher operating expense and lower production volumes. Operating expenses for the six months ended June 2006 increased over the same period in 2005 due to first quarter 2006 operating issues and inflationary pressures on the price of goods and services. The increase in year-to-date operating costs per BOE compared to the prior year is due to higher operating costs and lower production volumes.

Operating Expense Outlook

Given the record high industry activity levels currently being experienced, PrimeWest expects the price of oilfield goods and services to continue to increase, putting upward pressure on operating expenses throughout the year. However, PrimeWest anticipates that its full year operating expense will be approximately \$9.00 per BOE including the impact of the acquisition of the U.S. assets in the second half of 2006. PrimeWest continues to evaluate and implement operating cost reduction projects in various areas.

Operating Margin

(\$ per BOE)	Three Months Ended			Six Months Ended	
	Jun 30, 2006	Mar 31, 2006	Jun 30, 2005	Jun 30, 2006	Jun 30, 2005
Sales price and other revenue ⁽¹⁾	47.60	55.68	46.14	51.65	44.05
Royalties	(9.36)	(13.04)	(10.01)	(11.20)	(9.93)
Operating expense	(9.16)	(9.54)	(7.63)	(9.35)	(7.16)
Operating margin	29.08	33.10	28.50	31.10	26.96

⁽¹⁾ Includes hedging and sulphur.

The operating margin per BOE decreased in the second quarter of 2006 compared to the previous quarter due mainly to lower realized natural gas prices, offset by lower operating expenses and royalties.

The operating margin was higher in the second quarter of 2006 compared to the same period in 2005 due to higher crude oil and natural gas liquids prices offset by lower natural gas prices and increases to royalties and operating expenses.

On a 2006 year-to-date basis, the operating margin was higher than 2005 due to increases in commodity prices offset by increases to royalties and operating expenses.

Operating margin is an important measure of our business because it gives an indication of the amount of cash flow PrimeWest realizes per BOE that is produced, before head office expenses and financing charges.

General & Administrative Expense

(\$ Millions, except per BOE)	Three Months Ended			Six Months Ended	
	Jun 30, 2006	Mar 31, 2006	Jun 30, 2005	Jun 30, 2006	Jun 30, 2005
Cash G&A expense	7.0	5.3	4.8	12.3	10.3
Per BOE	2.04	1.55	1.32	1.80	1.41
Non-cash G&A expense	1.5	1.4	1.4	3.0	2.6
Per BOE	0.45	0.42	0.38	0.44	0.35

Cash G&A expense in the second quarter of 2006 increased 32% from the previous quarter mainly due to a decrease in overhead recoveries due to lower capital expenditures.

The increase in cash G&A expense for the three and six months ended June 30, 2006 compared to the same periods in 2005 is due to increases to labour costs, fees associated with Sarbanes Oxley initiatives, stock exchange listing fees and information technology expenses.

Included in non-cash G&A expense is \$1.0 million and \$2.0 million relating to the Unit Appreciation Rights (UARs), granted under the LTIP for the three and six months ended June 30, 2006 respectively. UARs in the Trust are similar to stock options in a corporation. The program rewards employees based on total Unitholder return, which is comprised of cumulative distributions on a reinvested basis plus growth in Unit price. No benefit accrues to the UARs until the Unitholders have first achieved a 5% total annual return from the time of grant. PrimeWest continues to pay for the exercise of UARs in Trust Units. Also included in non-cash G&A expense is \$0.5 million and \$0.9 million for the three and six months ended June 30, 2006 respectively related to the Special Employee Retention Plan (SERP). See note 15 to the Consolidated Financial Statements in the 2005 Annual Report.

Interest Expense

(\$ Millions, except per Trust Unit amounts)	Three Months Ended			Six Months Ended	
	Jun 30, 2006	Mar 31, 2006	Jun 30, 2005	Jun 30, 2006	Jun 30, 2005
Interest expense	5.2	4.6	7.7	9.7	16.8
Period end net debt level ⁽¹⁾	415.5	364.5	431.9	415.5	431.9
Debt per Trust Unit	4.98	4.42	5.54	4.98	5.56
Average cost of debt	5.1%	5.0%	5.4%	5.0%	5.4%

(1) Excludes derivative and future income tax assets and liabilities included in current assets or liabilities.

Interest expense, representing interest on bank debt, the U.S. Secured Notes, the U.K. Secured Notes and the Debentures increased in the second quarter of 2006 compared to the first quarter of 2006, due to a higher average net debt balance.

Interest expense was lower for the three and six months ended June 2006 compared to the same periods in 2005 due to lower average debt balances and a lower average cost of debt.

The average cost of debt was lower for the second quarter and year-to-date 2006 compared to the same period in 2005, primarily due to the reduction in the amount of the Series I and Series II Debentures outstanding, which bear interest at 7.5% and 7.75% respectively.

Foreign Exchange

The foreign exchange gain of \$7.5 million for the three months and \$6.8 million for the six months ended June 30, 2006 resulted from the translation of the U.S. Secured Notes and U.K. Secured Notes and related interest payable into Canadian dollars.

Depletion, Depreciation and Amortization

(\$ Millions, except per BOE)	Three Months Ended			Six Months Ended	
	Jun 30, 2006	Mar 31, 2006	Jun 30, 2005	Jun 30, 2006	Jun 30, 2005
Depletion, depreciation and amortization	53.5	53.9	56.0	107.5	113.3
Per BOE	15.73	15.75	15.24	15.74	15.46

The DD&A rate for the three months ended June 30, 2006 was relatively flat when compared to the previous quarter. The DD&A rate will fluctuate from one period to the next depending on the amount and type of capital spending and the amount of reserves added. Expenditures on maintenance capital, land and seismic do not contribute to reserve additions and may cause DD&A rates to increase.

Site Reclamation and Restoration Reserve

Since the inception of the Trust, PrimeWest has maintained a site reclamation fund to pay for future costs related to well abandonment and site clean up. The fund is used to pay for such costs as they are incurred. The 2006 contribution rate for the fund is unchanged from 2005 at \$0.50 per BOE. As at June 30, 2006 the site reclamation fund contained a balance of \$9.1 million.

The abandonment and reclamation costs incurred in the second quarter 2006 were \$1.8 million, compared to \$2.7 million for the same period in 2005, and \$1.9 million for the previous quarter.

Income and Capital Taxes

(\$ Millions, except per BOE)	Three Months Ended			Six Months Ended	
	Jun 30, 2006	Mar 31, 2006	Jun 30, 2005	Jun 30, 2006	Jun 30, 2005
Income and capital taxes	(1.2)	0.6	0.2	(0.6)	1.0
Future income tax expense recovery	(23.0)	(0.7)	(2.1)	(23.7)	(16.6)
Total	(24.2)	(0.1)	(1.9)	(24.3)	(15.6)

The increase in the future income tax recovery for the three months ended June 30, 2006 compared to the previous quarter and the same period in the prior year is mainly due to the reduction in federal statutory tax rates that were substantially enacted in the second quarter of 2006. Income and capital taxes recoveries in the second quarter and year-to-date 2006 reflect the elimination of the large corporation tax effective January 1, 2006 and adjustments upon filing of the prior year's tax returns.

Net Income

(\$ Millions)	Three Months Ended			Six Months Ended	
	Jun 30, 2006	Mar 31, 2006	Jun 30, 2005	Jun 30, 2006	Jun 30, 2005
Net income	\$ 65.7	68.9	54.7	134.7	78.7

Cash flow from operations, as opposed to net income, is the primary measure of performance for an energy trust. The generation of cash flow is critical for an energy trust to continue paying its distributions to Unitholders.

Conversely, net income is an accounting measure impacted by both cash and non-cash items. The largest non-cash items impacting PrimeWest's net income are DD&A, the unrealized gain or loss on derivatives, unrealized foreign exchange gains or losses and future income taxes.

Net income for the three months ended June 30, 2006 of \$65.7 million was 5% lower than the previous quarter net income of \$68.9 million primarily due to the decrease in oil and gas revenues resulting from lower realized natural gas and natural gas liquids prices and lower production volumes, and to a reduced unrealized gain on the mark-to-market value of the derivatives. Lower royalties, lower operating costs and future income tax recoveries had a positive impact on net income.

Net income for the second quarter of 2006 is higher than the same period in the prior year despite lower oil and gas revenues and increases to operating costs due to the increase in future income tax recoveries resulting from reduced income tax rates.

Year-to-date 2006 net income of \$134.7 million is higher than 2005 net income of \$78.7 million due to higher oil and gas revenues, foreign exchange gains and future income tax recoveries, lower DD&A expense and reductions to interest expenses. Higher operating expenses and a lower gain in the sale of marketable securities reduced the net increase.

Liquidity & Capital Resources

Long-Term Debt

(\$ Millions)	As at		
	Jun 30, 2006	Mar 31, 2006	Jun 30, 2005
Long-term debt	400.6	321.6	427.1
Deficit ⁽¹⁾	14.9	42.9	4.8
Net debt	415.5	364.5	431.9
Market value of Trust Units and Exchangeable Shares outstanding ⁽²⁾⁽³⁾	2,751.1	2,681.7	2,366.9
Total capitalization	3,166.6	3,046.2	2,798.8
Net debt as a % of total capitalization	13%	12%	15%

⁽¹⁾ Excludes derivative and future income tax assets and liabilities included in current assets or liabilities.

⁽²⁾ Based on June 30, 2006 Trust Unit closing price of \$33.50 and June 15, 2006 exchange ratio of 0.60132:1.

⁽³⁾ Excludes the Debentures.

Long-term debt is comprised of bank credit facilities, U.S. Secured Notes, U.K. Secured Notes and Debentures of \$123.0 million, \$104.6 million, \$129.9 million and \$43.1 million respectively. An amount of \$34.9 million relating to the U.S. Secured Notes is included in working capital as a current portion of long-term debt.

PrimeWest had a borrowing base of \$650 million at June 30, 2006. The bank credit facilities consist of an available revolving term loan facility of \$340.5 million and an operating facility of \$35 million, U.S. Secured Notes valued at \$143.8 million based on the U.S. dollar exchange rate at the time of last renewal and U.K. Secured Notes valued at \$130.7 million. In addition to amounts outstanding under the bank credit facility, PrimeWest has outstanding letters of credit in the amount of \$6.7 million (2005 - \$4.8 million).

On June 15, 2006, PrimeWest replaced a portion of its revolving credit facility with U.K. Secured Notes in the amount of £63 million, which bear interest at 5.76% per annum. PrimeWest entered into a currency swap transaction to fix the aggregate principal value and annual interest payments at \$130.7 million and \$3.9 million, respectively. As a result of the swap, the U.K. Secured Notes bear interest at an effective rate of 5.93% per annum with interest payable semi-annually on June 14 and December 14 of each year. The U.K. Secured Notes have a final maturity of June 14, 2016.

At June 30, 2006 PrimeWest's net debt to annualized second quarter cash flow was approximately 1.2 times compared to 0.9 times at March 31, 2006. Net debt as a percentage of total capitalization was 13% at June 30, 2006, compared to 12% at March 31, 2006.

During the second quarter of 2006, \$4.0 million of the Series I Debentures and \$1.6 million of the Series II Debentures long-term debt component were converted to Trust Units. Accretion of \$0.1 million was realized during this period.

The bank credit facility was renewed in July 2006 and the borrowing base was increased to \$750 million.

Unitholders' Equity

At June 30, 2006, the Trust had 81,439,814 Trust Units outstanding. In addition, PrimeWest had 1,135,975 Exchangeable Shares outstanding that are exchangeable into a total of 683,084 Trust Units using the June 15, 2006 exchange ratio of 0.60132:1.

The equity component of the Debentures has been reduced by \$0.1 million due to conversions to Trust Units during the quarter.

During the second quarter of 2006, PrimeWest issued 117,861 Trust Units for \$3.7 million under the DRIP, 291,295 Trust Units for \$9.0 million pursuant to the PREP and 117,733 Trust Units for proceeds of \$3.6 million under the OTUPP.

The DRIP gives Canadian and U.S. Unitholders the opportunity to reinvest their monthly distributions at a 5% discount to the volume-weighted average market price of the Trust Units. As an alternative to the DRIP component of the Plan, the 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. The OTUPP gives Canadian Unitholders an opportunity to purchase additional Trust Units directly from PrimeWest at the same 5% discount. The DRIP and PREP components are mutually exclusive. Participation in the OTUPP requires enrolment in either the DRIP or PREP.

These plan components benefit Unitholders by offering alternatives to maximize their investment in PrimeWest, while providing the Trust with an inexpensive method of raising additional capital. The Trust expects interest in these plans in 2006 to be similar to that experienced in 2005. Proceeds from these plans are used for debt reduction of PrimeWest's credit facility and to help fund ongoing capital development programs.

For additional information or to join the DRIP, OTUPP and PREP plans, contact the Plan Agent, Computershare Trust Company of Canada, at 1-800-564-6253 or visit PrimeWest's website at www.primewestenergy.com.

Exchangeable Shares

Exchangeable Shares were issued in connection with both the Venator Petroleum Company Ltd. acquisition in April 2000 and the Cypress Energy Inc. acquisition in March 2001. These shares were issued to provide a tax-deferred rollover of the adjusted cost base from the shares being exchanged to the Exchangeable Shares. Exchangeable Shares were also issued as part of PrimeWest's internalization transaction (See Note 18 in the Consolidated Financial Statement of the 2005 Annual Report) whereby PrimeWest agreed to issue Exchangeable Shares to the Executive Officers pursuant to the SERP.

Holders of the Exchangeable Shares do not receive cash distributions. In lieu of receiving distributions, the number of Trust Units that the exchangeable shareholder will receive upon exchange increases each month based on the distribution amount divided by the market price of the Trust Units on the 15th day of that month.

At June 30, 2006, there were 1,135,975 Exchangeable Shares outstanding. The exchange ratio on these shares was 0.60132:1 Trust Units for each Exchangeable Share as at June 15, 2006. For purposes of calculating basic per Trust Unit amounts, it is assumed that the Exchangeable Shares have been exchanged into Trust Units at the current exchange ratio.

Cash Distributions

Cash distributions to Unitholders are at the discretion of the Board of Directors and can fluctuate depending on the cash flow generated from operations and other factors. The cash flow available for distribution is dependent upon many factors including commodity prices, production levels, debt levels, capital spending requirements, and factors in the overall industry environment.

The Board of Directors targets a long-term distribution payout ratio that is a percentage of cash flow from operations. However, the actual distribution payout ratio may vary from the target due to fluctuations in commodity prices and their impact on cash flow forecasts, as well as other factors. The current distribution payout ratio is targeted to be approximately 70–90% of annual cash flow from operations. In the second quarter of 2006, cash distributions totalled \$82.8 million, or \$1.02 per Trust Unit representing a payout ratio of approximately 93%, compared to \$66.5 million, or \$0.90 per Trust Unit (70% payout ratio) for the same period in 2005. In the first quarter of 2006, cash distributions totalled \$86.8 million, or \$1.08 per Trust Unit representing a payout ratio of approximately 84%.

Distribution payments to U.S. Unitholders are subject to a 15% Canadian withholding tax, which is deducted from the entire distribution amount prior to deposit into Unitholder accounts.

Contractual Obligations

PrimeWest enters into many contractual obligations as part of conducting day-to-day business. Material contractual obligations include debt obligations, lease rental commitments that run from 2006 through 2009 and various pipeline transportation commitments that run through 2011. The details of the timing of these contractual obligations are included in the following table.

As at June 30, 2006

Payments due by period

(\$ Millions)	Total	Less than 1 year	1-3 years	4-5 years	More than 5 years
Long-term debt obligations	\$ 393.2	\$ 34.9	\$ 192.8	\$ 34.9	\$ 130.7
Debentures	44.5	-	-	26.6	17.9
Lease rental obligations	10.4	3.6	6.8	-	-
Pipeline transportation obligations	7.8	5.8	1.7	0.2	-
Total contractual obligations	\$ 455.9	\$ 44.3	\$ 201.3	\$ 61.7	\$ 148.6

As part of PrimeWest's internalization transaction, which closed on November 6, 2002, PrimeWest agreed to issue 377,360 Exchangeable Shares to certain executive officers pursuant to the SERP. On November 6, 2004 and 2005, 94,340 Exchangeable Shares were issued to those officers. An additional 94,340 Exchangeable Shares will be issued on November 6, 2006 and 2007. For the three and six months ended June 30, 2006, \$0.5 million and \$0.9 million have been recorded in non-cash G&A expenses related to the SERP respectively.

Business Risks

PrimeWest's operations are affected by a number of underlying risks, both internal and external to the Trust. These risks are similar to those affecting others in both the conventional oil and gas royalty trust sector and the conventional oil and gas producers sector. The Trust's financial position, results of operations, and cash available for distribution to Unitholders are directly impacted by these factors. These factors are discussed under two broad categories – "Commodity Price, Foreign Exchange and Interest Rate Risk" and "Operational and Other Business Risks." For additional information on Business Risks, including Risks Related to the Trust Structure and the Ownership of Trust Units, see PrimeWest's most recently filed Annual Information Form.

Commodity Price, Foreign Exchange and Interest Rate Risk

The two most important factors affecting the level of cash distributions available to Unitholders are the level of production achieved by PrimeWest and the price received for its products. These prices are influenced in varying degrees by factors outside the Trust's control. Some of these factors include:

- World market forces, specifically the actions of OPEC and other large crude oil producing countries including Russia and their implications on the supply of crude oil;
- World and North American economic conditions which influence the demand for both crude oil and natural gas and the level of interest rates set by the governments of Canada and the U.S.;
- Weather conditions that influence the demand for natural gas and heating oil;
- The Canadian/U.S. dollar exchange rate that affects the price received for crude oil, as the price of crude oil is referenced in U.S. dollars;
- Transportation availability and costs; and
- Price differentials among World and North American markets based on transportation costs to major markets and quality of production.

To mitigate these risks, PrimeWest has an active hedging program in place based on an established set of criteria that has been approved by the Board of Directors. The results of the hedging program are reviewed against these criteria and the results actively monitored by the Board.

Beyond our hedging strategy, PrimeWest also mitigates risk by having a well-diversified marketing portfolio and by transacting with a number of counterparties and limiting exposure to any single counterparty. For the second quarter of 2006 approximately 16% of natural gas production was sold to aggregators and 84% of production was sold into the Alberta and British Columbia short-term or export long-term markets.

The contracts that PrimeWest has with aggregators vary in length. They represent a blend of domestic and U.S. markets and fixed and floating prices designed to provide price diversification to our revenue stream.

The primary objective of our commodity risk management program is to reduce the volatility of our cash distributions, to lock in the economics on major acquisitions and to protect our capital structure when commodity prices cycle downwards. In the second quarter 2006, PrimeWest realized a \$5.3 million gain from commodity hedges.

Operational And Other Business Risks

PrimeWest is also exposed to a number of risks related to its activities within the oil and gas industry that have an impact on the amount of cash available to Unitholders. These risks, and the manner in which PrimeWest seeks to mitigate these risks include, but are not limited to:

Risk	We Mitigate By
<p>Production</p> <p>Risk associated with the production of oil and gas – includes well operations, processing and the physical delivery of commodities to market.</p>	<p>Performing regular and proactive protective well, facility and pipeline maintenance supported by telemetry, physical inspection and diagnostic tools.</p>
<p>Commodity Price</p> <p>Fluctuations in natural gas, crude oil and natural gas liquids prices.</p>	<p>Hedging. See page 12 of this quarterly report.</p>
<p>Transportation</p> <p>Market risk related to the availability of transportation to market and potential disruption in delivery systems.</p>	<p>Diversifying the transportation systems on which we rely to get our product to market.</p>
<p>Natural Decline</p> <p>Development risk associated with capital enhancement activities undertaken – the risk that capital spending on activities such as drilling, well completions, well workovers and other capital activities will not result in reserve additions or in quantities sufficient to replace annual production declines.</p>	<p>Diversifying our capital spending program over a large number of projects so that large amounts of capital are not risked on any one activity. We also have a highly skilled technical team of geologists, geophysicists and engineers working to apply the latest technology in planning and executing capital programs. Capital is spent only after strict economic criteria for production and reserve additions are assessed.</p>
<p>Acquisitions</p> <p>Acquisition risk associated with acquiring producing properties at low cost to renew our inventory of assets.</p>	<p>Continually scanning the marketplace for opportunities to acquire assets. Our technical acquisition specialists evaluate potential corporate or property acquisitions and identify areas for value enhancement through operational efficiencies or capital investment. All prospects are subjected to rigorous economic review against established acquisition and economic hurdle rates. In some cases we may also hedge commodity prices to protect the acquisition economics in the near term period.</p>
<p>Reserves</p> <p>Reserve risk in respect of the quantity and quality of recoverable reserves.</p>	<p>Contracting our reserves evaluation to a reputable third party consultant, GLJ Petroleum Consultants (GLJ). The Operations and Reserves Committee of the Board of Directors and PrimeWest review the work and independence of GLJ. Our</p>

Risk	We Mitigate By
	strategy is to invest in mature, longer life properties having a higher proved producing component where the reserve risk is generally lower and cash flows are more stable and predictable.
<p>Environmental Health and Safety (EH&S)</p> <p>Environmental, health and safety risks associated with oil and gas properties and facilities.</p>	<p>Establishing and adhering to strict guidelines for EH&S including training, proper reporting of incidents, supervision and awareness. PrimeWest has active community involvement in field locations including regular meetings with stakeholders in the area. PrimeWest carries adequate insurance to cover property losses, liability and business interruption.</p> <p>These risks are reviewed regularly by the Corporate Governance and EH&S Committee of the Board.</p>
<p>Regulation, Tax and Royalties</p> <p>Changes in government regulations including reporting requirements, income tax laws, operating practices, environmental protection requirements and royalty rates.</p>	<p>Keeping informed of proposed changes in regulations and laws to properly respond to and plan for the effects that these changes may have on our operations.</p>
<p>Historical Liability to Unitholders is Uncertain</p> <p>Because of uncertainties in the law prior to July 1, 2004, relating to investments in trusts, there is a risk that a Unitholder could be held personally liable for obligations of the Trust.</p>	<p>On July 1, 2004, a new statute entitled the Income Trusts Liability Act (Alberta) was proclaimed in force, creating a statutory limitation on the liability of Unitholders of Alberta income trusts such as PrimeWest. The legislation provides that a Unitholder is not, as beneficiary, liable for any act, default, obligation or liability of the Trust that arises after July 1, 2004. Similar legislation was proclaimed in force in Ontario in December of 2004.</p>

CONSOLIDATED BALANCE SHEETS

Unaudited (\$ Millions)	As at	
	June 30, 2006	December 31, 2005
ASSETS		
Current assets		
Cash and cash equivalents	\$ 57.2	\$ 36.8
Accounts receivable	86.5	125.0
Derivative assets	18.6	-
Future income taxes	-	3.9
Prepaid expenses	18.4	16.3
Inventory	-	3.5
	180.7	185.5
Cash reserved for site restoration and reclamation	9.1	9.2
Derivative asset	0.1	-
Other assets and deferred charges (note 4)	42.9	8.8
Property, plant and equipment	1,883.1	1,859.9
Goodwill	68.5	68.5
	\$ 2,184.4	\$ 2,131.9
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities		
Accounts payable	\$ 43.1	\$ 50.2
Accrued liabilities	77.7	75.9
Current portion of long-term debt (note 3)	34.9	-
Future income taxes	6.5	-
Derivative liabilities	2.7	11.3
Accrued distributions to Unitholders	21.3	25.0
	186.2	162.4
Long-term debt (note 3)	400.6	354.2
Derivative liabilities	2.3	0.2
Future income taxes	180.7	214.8
Asset retirement obligation (note 2)	41.5	40.4
	811.3	772.0
UNITHOLDERS' EQUITY		
Net capital contributions (note 5)	2,341.9	2,294.3
Capital issued but not distributed	3.1	3.6
Convertible Unsecured Subordinated Debentures	1.4	1.8
Contributed surplus (note 6)	10.0	8.7
Accumulated income	438.5	303.8
Accumulated cash distributions	(1,413.8)	(1,244.3)
Accumulated dividends	(8.0)	(8.0)
	1,373.1	1,359.9
	\$ 2,184.4	\$ 2,131.9

CONSOLIDATED STATEMENTS OF CHANGES IN UNITHOLDERS' EQUITY

Unaudited (\$ Millions)	Six Months Ended	
	June 30, 2006	June 30, 2005
Unitholders' equity, beginning of period	\$ 1,359.9	\$ 1,180.4
Net income for the period	134.7	78.7
Net capital contributions (note 5)	47.6	170.8
Convertible Unsecured Subordinated Debentures	(0.4)	(4.3)
Capital issued but not distributed	(0.5)	(0.6)
Contributed surplus (note 6)	1.3	1.0
Cash distributions	(169.5)	(130.4)
Unitholders' equity, end of period	\$ 1,373.1	\$ 1,295.6

CONSOLIDATED STATEMENTS OF CASH FLOW

Unaudited (\$ Millions)	Three Months Ended		Six Months Ended	
	June 30, 2006	June 30, 2005	June 30, 2006	June 30, 2005
OPERATING ACTIVITIES				
Net income for the period	\$ 65.7	\$ 54.7	\$ 134.7	\$ 78.7
Add/(deduct) items not involving cash from:				
Depletion, depreciation and amortization	53.5	56.0	107.5	113.3
Non-cash general and administrative	1.5	1.4	3.0	2.6
Non-cash foreign exchange loss (gain)	(7.4)	2.1	(6.8)	3.0
Cash distributions from marketable securities	-	0.2	-	1.2
Gain on sale of marketable securities	-	(0.3)	-	(27.2)
Unrealized (gain)/loss on derivatives	(3.0)	(17.8)	(25.1)	17.4
Future income taxes recovery	(23.0)	(2.1)	(23.7)	(16.6)
Accretion on asset retirement obligation	0.7	0.7	1.4	1.3
Other non-cash items	0.6	0.6	0.9	1.5
Cash flow from operations	\$ 88.6	\$ 95.5	\$ 191.9	\$ 175.2
Expenditures on site restoration and reclamation	(1.8)	(2.7)	(3.7)	(3.6)
Change in non-cash working capital	2.6	(3.1)	25.7	(24.9)
	89.4	89.7	213.9	146.7
FINANCING ACTIVITIES				
Increase in Senior Secured Notes (note 3)	130.7	-	130.7	-
Proceeds from issue of Trust Units, net of issue	3.6	6.1	9.3	13.6
Net cash distributions to Unitholders	(71.4)	(58.3)	(145.9)	(112.7)
Decrease in bank credit facilities	(4.0)	15.0	(30.0)	(99.0)
Decrease in deferred charges	(0.7)	-	(0.7)	-
Change in non-cash working capital	(4.3)	(0.4)	(6.6)	0.1
	53.9	(37.6)	(43.2)	(198.0)
INVESTING ACTIVITIES				
Expenditures on property, plant and equipment	(47.6)	(49.4)	(130.3)	(109.6)
Expenditures on future acquisition (note 4)	(34.3)	-	(34.3)	-
Acquisition of capital/corporate assets	-	1.0	-	(0.4)
Proceeds on disposal of property, plant and equipment	0.1	(1.0)	3.2	7.7
Proceeds on sale of marketable securities	-	-	-	94.5
(Decrease)/Increase in cash reserved for future site restoration and reclamation	-	0.7	0.2	(0.2)
Change in non-cash working capital	(7.5)	(6.7)	10.9	10.3
	(89.3)	(55.4)	(150.3)	2.3
Increase/(decrease) in cash for the period	54.0	(3.3)	20.4	(49.0)
Cash beginning of the period	3.2	8.7	36.8	54.4
Cash end of the period	57.2	5.4	57.2	5.4
Cash interest paid	5.3	7.0	8.0	14.5
Cash taxes paid	0.4	0.8	1.1	1.4

CONSOLIDATED STATEMENTS OF INCOME

Unaudited (\$ Millions)	Three Months Ended		Six Months Ended	
	June 30, 2006	June 30, 2005	June 30, 2006	June 30, 2005
REVENUES				
Sales of crude oil, natural gas and natural gas liquids	\$ 162.2	\$ 171.4	\$ 353.3	\$ 326.6
Crown and other royalties, net of Alberta Royalty Tax Credit	(31.9)	(36.8)	(76.5)	(72.8)
Unrealized gain/(loss) on derivatives	3.0	17.8	25.1	(17.4)
Gain on sale of marketable securities	-	0.3	-	27.2
Other income	1.6	2.6	3.1	2.9
	134.9	155.3	305.0	266.5
EXPENSES				
Operating	31.2	28.1	63.9	52.5
Transportation	1.8	1.7	3.6	3.6
General and administrative	8.5	6.2	15.3	12.9
Depletion, depreciation and amortization	53.5	56.0	107.5	113.3
Interest	5.2	7.7	9.7	16.8
Accretion on asset retirement obligation	0.7	0.7	1.4	1.3
Foreign exchange loss	(7.5)	2.1	(6.8)	3.0
	93.4	102.5	194.6	203.4
Income before taxes for the period	41.5	52.8	110.4	63.1
Income and capital taxes	(1.2)	0.2	(0.6)	1.0
Future income taxes recovery	(23.0)	(2.1)	(23.7)	(16.6)
	(24.2)	(1.9)	(24.3)	(15.6)
Net income for the period	\$ 65.7	\$ 54.7	\$ 134.7	\$ 78.7
Net income per Trust Unit – basic	0.81	0.74	1.66	1.08
Net income per Trust Unit – diluted	0.79	0.72	1.62	1.08

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the three and six months ended June 30, 2006, all amounts (except per Trust Unit amounts) are expressed in millions of Canadian dollars unless otherwise indicated.

1. Significant Accounting Policies

These interim consolidated financial statements of PrimeWest 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 52 and 53 of the Trust's 2005 annual report and should be read in conjunction with these interim financial statements.

2. Asset Retirement Obligations

Management has estimated the total future asset retirement obligation based on the Trust's net ownership interest in all wells and facilities. This includes all estimated costs to dismantle, remove, reclaim and abandon the wells and facilities and the estimated time period during which these costs will be incurred in the future.

The following table reconciles the asset retirement obligation associated with the retirement of oil and gas properties:

(\$ Millions)	
Asset Retirement Obligation, December 31, 2005	\$ 40.4
Change in estimate of liability	3.6
Liabilities settled	(3.7)
Accretion expense	1.4
Sale of capital assets	(0.2)
Asset Retirement Obligation, June 30, 2006	\$ 41.5

As at June 30, 2006, the undiscounted amount of estimated cash flows required to settle the obligation is \$225.8 million. The estimated cash flow has been discounted using a credit-adjusted risk free rate of 7.0 percent and an inflation rate of 2.0 percent. Although the expected period until settlement ranges from a minimum of 1 year to a maximum of 50 years, the expectation is that costs will be paid over an average of 33 years. These future asset retirement costs will be funded from the cash reserved for site restoration and reclamation. This cash reserve is currently funded at \$0.50 per BOE from PrimeWest's operating resources.

3. Long-Term Debt

(\$ Millions)	Jun 30, 2006	Dec 31, 2005
Bank credit facilities	\$ 123.0	\$ 153.0
U.S. Senior Secured Notes	104.6	145.4
U.K. Senior Secured Notes	129.9	-
Convertible Unsecured Subordinated Debentures	43.1	55.8
	\$ 400.6	\$ 354.2
Current portion of long-term debt	34.9	-
	\$ 435.5	\$ 354.2

On June 15, 2006, PrimeWest replaced a portion of its revolving credit facility with U.K. Secured Notes in the amount of £63 million, which bear interest at 5.76% per annum. PrimeWest entered into a currency swap transaction to fix the aggregate principal value and annual interest payments at \$130.7 million and \$3.9 million, respectively. As a result of the swap, the U.K. Secured Notes bear interest at an effective rate of 5.93% per annum with interest payable semi-annually on June 14 and December 14 of each year. The U.K. Secured Notes have a final maturity of June 14, 2016.

4. Other Assets and Deferred Charges

(\$ Millions)	Jun 30, 2006	Dec 31, 2005
Deferred charges	\$ 8.3	\$ 8.7
Expenditures incurred on acquisition	34.3	-
Other assets	0.3	0.1
	\$ 42.9	\$ 8.8

PrimeWest incurred \$34.3 million relating to the U.S. acquisition of assets in Montana, North Dakota and Wyoming. The acquisition was closed on July 6, 2006.

5. Unitholders' Equity

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

Trust Units	Number of Units	\$ Millions
Balance, December 31, 2005	79,666,352	2,282.0
Conversion of Convertible Unsecured Subordinated Debentures	504,011	13.4
Issued on exchange of Exchangeable Shares	48,808	0.8
Issued pursuant to Distribution Reinvestment Plan	265,803	8.6
Issued pursuant to the Premium Distribution Plan	492,130	15.6
Issued pursuant to Long-Term Incentive Plan (LTIP)	175,186	0.7
Issued pursuant to Optional Trust Unit Purchase Plan	287,477	9.3
Issued pursuant to Consolidation/Fractional Units	47	-
Balance, June 30, 2006	81,439,814	\$ 2,330.4

The weighted average number of Trust Units and Exchangeable Shares outstanding for the three months ended June 30, 2006 was 81,726,126 (2005 – 73,861,968). For purposes of calculating diluted net income per Trust Unit for the three months ended June 30, 2006, 1,040,106 (2005 – 4,260,034) and 677,300 (2005 – 3,056,495) Trust Units issuable pursuant to the conversion of the Convertible Unsecured Subordinated Debentures Series I and II respectively and 1,302,773 Trust Units (2005 – 797,975) issuable pursuant to the LTIP were added to the weighted average number.

The weighted average number of Trust Units and Exchangeable Shares outstanding for the six months ended June 30, 2006 was 81,013,827 (2005 – 72,557,643). For the purpose of calculating diluted net income per Trust Unit for the six months ended June 30, 2006, 1,111,552 (2005 – 4,843,151) and 724,562 (2005 – 3,365,198) Trust Units issuable pursuant to the conversion of the Convertible Unsecured Subordinated Debentures Series I and Series II respectively and 1,302,773 Trust Units (2005 – 797,975) issuable pursuant to the LTIP were added to the weighted average.

EXCHANGEABLE SHARES

The Exchangeable Shares are exchangeable into Trust Units at any time up to March 29, 2010 based on an exchange ratio that adjusts each time the Trust makes a distribution to its Unitholders. The exchange ratio, which was 1:1 on the date that the Exchangeable Shares were first issued, is based on the total monthly distribution, divided by the closing unit price on the distribution payment date. The exchange ratio effective June 15, 2006 was 0.60132:1.

Exchangeable Shares	Number of Shares	\$ Millions
Balance, December 31, 2005	1,219,335	\$ 12.3
Exchanged for Trust Units	(83,360)	(0.8)
Balance, June 30, 2006	1,135,975	11.5

6. Contributed Surplus

Contributed surplus includes the accumulated unit-based compensation charge in respect of PrimeWest's unexercised Unit Appreciation Rights (UARs) granted under the LTIP on or after January 1, 2002. Upon exercise of the UARs and delivery of the Trust Units, the contributed surplus account is reduced and the amount is transferred to net capital contributions.

(\$ Millions)	
Balance, December 31, 2005	\$ 8.7
Non-cash general and administrative expense	2.0
Unit Appreciation Rights exercised	(0.7)
Balance, June 30, 2006	\$ 10.0

7. Long-Term Incentive Plan

Under the terms of the LTIP, the number of Trust Units that may be reserved for issuance pursuant to the exercise of UARs granted to Directors and employees of PrimeWest is limited to 7.5% of the basic number of issued and outstanding Trust Units at any given time. 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 those issued to the members of the Board, which 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.

Effective January 1, 2005, PrimeWest adopted the fair value method of accounting for its LTIP with respect to UARs granted on or after January 1, 2002. Under this method of accounting, the fair value of the UARs is estimated using a recognized options pricing model on the grant date and is amortized over the vesting period with the amortized amount recorded in non-cash general and administrative expenses offset by an increase to contributed surplus. When the UARs are exercised, contributed surplus is decreased and net capital contributions are increased.

PrimeWest recorded \$1.0 million and \$2.0 million in non-cash general and administrative expense related to the LTIP for the three and six months ended June 30, 2006 respectively using the fair value method of accounting.

PrimeWest uses a recognized options pricing model to calculate the estimated fair value of outstanding UARs issued on or after January 1, 2002. The following assumptions were used to arrive at the estimated fair value:

Weighted Average Assumptions:	Six Months Ended	
	Jun 30, 2006	Jun 30, 2005
Risk-free interest rate	3.85%	3.25%
Expected volatility in Trust Unit price	22.46%	19.8%
Expected time until exercise	3.5 years	3 years
Expected forfeiture rate	10.6%	13.0%
Expected annual dividend yield	zero	zero

Summary of Changes in UARs	Number of UARS	Weighted Average Exercise Price
Balance outstanding at December 31, 2005	4,169,675	\$ 29.92
Granted	544,448	39.66
Forfeited/expired	(151,288)	(30.63)
Exercised	(253,867)	(28.17)
Balance outstanding at June 30, 2006	4,308,968	\$ 31.17

Summary of UARS Outstanding at June 30, 2006

Year of Grant	UARs Issued & Outstanding	UARs Vested	Range of Exercise Prices	Expiry Date
2002 grants	543,723	543,005	25.90 – 33.76	2008
2003 grants	709,259	570,659	25.92 – 32.24	2009
2004 grants	1,189,605	592,554	24.24 – 32.49	2010
2005 grants	1,325,270	318,890	28.90 – 43.17	2011
2006 grants	541,111	-	33.22 – 43.41	2012
Total grants	4,308,968	2,025,108	24.24 – 43.41	

8. Cash Distributions

(\$ Millions, except per Trust Unit amounts)	Three Months Ended		Six Months Ended	
	Jun 30, 2006	Jun 30, 2005	Jun 30, 2006	Jun 30, 2005
Cash flow from operations	\$ 88.6	\$ 95.5	\$ 191.9	\$ 175.2
Deduct amounts to reconcile to distribution:				
Cash retained from cash available for distribution ⁽¹⁾	(4.0)	(27.1)	(18.8)	(41.0)
Contribution to reclamation fund	(1.8)	(1.9)	(3.6)	(3.8)
	\$ 82.8	\$ 66.5	\$ 169.5	\$ 130.4
Cash Distributions to Unitholders	\$ 82.8	\$ 66.5	\$ 169.5	\$ 130.4
Cash Distributions per Trust Unit	\$ 1.02	\$ 0.90	\$ 2.10	\$ 1.80

⁽¹⁾ The Board of Directors determines the cash distribution level, which results in a discretionary amount of cash being retained.

9. Subsequent Event

On July 6, 2006, PrimeWest, through a U.S. subsidiary, acquired producing oil and gas assets located in Montana, North Dakota and Wyoming for consideration of approximately U.S. \$300 million.

TRADING PERFORMANCE

For the quarter ended	Jun 30/06	Mar 31/06	Dec 31/05	Sep 30/05	Jun 30/05
TSX Trust Unit Prices (Cdn\$ per Trust Unit)					
High	\$ 35.30	\$ 38.14	\$ 37.68	\$ 36.42	\$ 31.68
Low	\$ 30.62	\$ 29.82	\$ 30.55	\$ 30.86	\$ 28.35
Close	\$ 33.50	\$ 32.98	\$ 35.90	\$ 36.40	\$ 30.66
Average daily traded volume	258,294	249,527	199,849	183,469	202,225

For the quarter ended	Jun 30/06	Mar 31/06	Dec 31/05	Sep 30/05	Jun 30/05
NYSE Trust Unit Prices (US\$ per Trust Unit)					
High	\$ 31.00	\$ 32.90	\$ 32.57	\$ 31.37	\$ 25.59
Low	\$ 27.25	\$ 25.25	\$ 25.71	\$ 25.15	\$ 22.50
Close	\$ 29.98	\$ 28.39	\$ 30.92	\$ 31.33	\$ 25.05
Average daily traded volume	438,995	463,411	480,603	445,338	377,264
Number of Trust Units outstanding, including Exchangeable Shares (millions of Trust Units)					
	82.1	81.3	80.4	79.1	77.2
Distribution paid per Trust Unit	\$ 1.02	\$ 1.08	\$ 0.96	\$ 0.90	\$ 0.90

TOTAL COMPOUND ANNUAL RETURN (%)⁽¹⁾

	PrimeWest	TSX Oil & Gas index	TSX S&P	S&P 500 Cdn\$	S&P 500 US\$	S&P/TSX CDN Energy Trust Index
Five year	13.6%	27.2	10.5	(3.6)	2.5	30.7
Three year	23.9%	40.7	20.7	4.3	10.8	41.6
One year	22.7%	34.2	19.8	(1.4)	8.6	44.1

(1) Total return = Unit price plus distributions re-invested.

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Email: investor@primewestenergy.com

CORPORATE INFORMATION

Board of Directors

Harold Milavsky ^{1,3} *Chair*

Barry E. Emes ³

Harold N. Kvisle ^{2,4}

Kent J. MacIntyre ⁴

Michael W. O'Brien ^{1,3}

James W. Patek ^{2,4}

W. Glen Russell ^{2,4}

Peter Valentine ¹

¹ Member of the Audit and Finance Committee

² Member of the Compensation Committee

³ Member of the Corporate Governance & EH&S Committee

⁴ Member of the Operations & Reserves Committee

Officers

Donald A. Garner
President and Chief Executive Officer

Ronald J. Ambrozy
Vice-President, Business Development

Dennis G. Feuchuk
Vice-President, Finance and Chief Financial Officer

Timothy S. Granger
Chief Operating Officer

Brian J. Lynam
Vice-President, Operations

Gordon D. Haun
General Counsel and Corporate Secretary

Trust Units and Exchangeable Shares

The Toronto Stock Exchange (PWI.UN; PWX)
The New York Stock Exchange (PWI)

Convertible Debentures

The Toronto Stock Exchange
Series I Debentures (PWI.DB.A)
Series II Debentures (PWI.DB.B)

Registrar and Transfer Agent

Computershare Trust Company of Canada
Toll-free in Canada: 1-800-564-6253

Auditor

PricewaterhouseCoopers LLP
Calgary, Alberta

Engineering Consultants

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

Legal Counsel

Stikeman Elliott LLP
Calgary, Alberta



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