PRIMEWEST

PrimeWest Energy Trust 2006 Quarterly Report

FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2006

PRIMEWEST ENERGY TRUST ANNOUNCES THIRD QUARTER 2006 RESULTS

CALGARY, NOVEMBER 7TH, 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 QUARTER ENDED SEPTEMBER 30, 2006. UNLESS OTHERWISE NOTED, ALL FIGURES CONTAINED IN THIS REPORT ARE IN CANADIAN DOLLARS.

Third Quarter 2006 Highlights:

- Distributions in the third quarter were $0.90 per Trust Unit representing a payout ratio of approximately 77% of operating cash flow compared to second quarter 2006 distributions of $1.02 per Trust Unit, which represented a payout ratio of approximately 93% of cash flow from operations.
- On July 6, 2006, PrimeWest, through a U.S. subsidiary, acquired producing oil and gas assets located in Montana, North Dakota, Wyoming and Saskatchewan for consideration of $336.7 million. The acquisition establishes a new operating area for PrimeWest within the Williston Basin with considerable waterflood and development drilling potential. The U.S. assets contributed 2,756 barrels of oil equivalent (BOE) per day to the third quarter production volumes.
- On August 25, 2006, PrimeWest acquired natural gas assets in the Caroline area for a net adjusted purchase price of $31.9 million. The acquisition of these assets, already operated by PrimeWest, represents the conclusion of a farm-in arrangement between PrimeWest and the vendor. Production volumes from the assets are approximately 550 BOE per day.
- Cash flow from operations for the third quarter was $96.6 million ($1.17 per Trust Unit) compared to $88.6 million ($1.08 per Trust Unit) in the previous quarter and $106.4 million ($1.36 per Trust Unit) in the third quarter of 2005.
- Third quarter 2006 production averaged 40,381 BOE per day, compared to the second quarter 2006 rate of 37,406 BOE per day. The increase in volumes is mainly due to the acquisition of the U.S. assets in July. The U.S. volumes offset the loss of production due to the maintenance shut-in at the Crossfield plant in September. PrimeWest expects full year 2006 production volumes to average between 39,000 – 40,000 BOE per day.
- Development capital expenditures in the third quarter were $76.3 million with drilling, completion and tie-in expenditures of $62.5 million resulting in 81 gross wells (56.3 net) being drilled with a success rate of 95%.
- Net debt to annualized third quarter 2006 cash flow from operations was approximately 2.0 times at September 30, 2006 compared to net debt to annualized second quarter 2006 cash flow from operations of 1.2 times at June 30, 2006. This increase is primarily due to additional debt utilized to finance the U.S. asset acquisition.

Subsequent Event

- On October 31, 2006, the federal government announced its intention to change the way that royalty trusts and income funds are taxed, which would take effect January 1, 2011. If the proposals are enacted, a tax will be applied at the trust level on distributions at rates of tax comparable to the combined federal and provincial corporate tax, estimated at 31.5%, and to treat distributions as dividends to the Unitholders. Until such rules are released in legislative form and passed into law, it is uncertain what the impact of such rules will be to the Trust and its Unitholders.

MANAGEMENT'S DISCUSSION AND ANALYSIS AS OF NOVEMBER 7, 2006

The following is management's discussion and analysis (MD&A) of PrimeWest's operating and financial results for the quarter and nine months ended September 30, 2006, compared with the preceding quarter, the corresponding periods in the prior year and the year ended December 31, 2005, 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 those 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.

In particular, this MD&A contains 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, 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 elsewhere in 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 United States 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 "Business 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 herein are expressly qualified by these cautionary statements. 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.

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 September 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 United States Securities and Exchange Commission (SEC) in the United States (U.S.) 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 June 30, 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 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 from operations by the weighted average number of Trust Units outstanding plus Trust Units issueable 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 from operations 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 issueable upon the exchange of outstanding Exchangeable Shares and includes the Trust Units issueable pursuant to the conversion of the Debentures, and Trust Units issueable 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 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. Net debt per Trust Unit is calculated as net debt divided by the number of Trust Units outstanding and includes Trust Units issueable upon the exchange of outstanding Exchangeable Shares and Trust Units issueable pursuant to the LTIP at September 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 third 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 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 2003, PrimeWest has followed a strategy of maintaining a distribution payout ratio within 70-90% of cash flow from operations, calculated on an annual basis, recognizing that during periods of volatile commodity prices the payout ratio may 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 third quarter 2006 payout ratio was approximately 77% of cash flow from operations. Retained cash flow was utilized to fund a part of the Trust's capital spending program. PrimeWest's net debt to annualized third quarter cash flow ratio was 2.0 times at September 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. 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 issued and outstanding.

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

	Three Months Ended			Nine Months Ended	
$ Millions, except per BOE [(1)] and per Trust Unit amounts	**Sep 30, 2006**	Jun 30, 2006	Sep 30, 2005	**Sep 30, 2006**	Sep 30, 2005
Gross revenue (net of transportation expense)	**181.9**	160.4	193.3	**531.6**	516.4
per BOE	**48.98**	47.14	52.38	**50.42**	46.84
Cash flow from operations	**96.6**	88.6	106.4	**288.4**	281.6
per BOE	**26.00**	26.04	28.83	**27.36**	25.54
per Trust Unit – basic [(2)]	**1.17**	1.08	1.36	**3.53**	3.78
per Trust Unit – diluted [(3)]	**1.15**	1.06	1.31	**3.45**	3.55
Royalty expense	**34.5**	31.9	44.4	**111.0**	117.3
per BOE	**9.29**	9.36	12.04	**10.53**	10.64
Operating expense	**34.8**	31.2	31.6	**98.7**	84.1
per BOE	**9.36**	9.16	8.56	**9.36**	7.63
General and administrative expense (G&A)	**6.5**	8.5	7.2	**21.8**	20.1
per BOE	**1.76**	2.49	1.95	**2.06**	1.83
Interest expense [(4)]	**11.9**	5.2	6.0	**21.6**	22.8
per BOE	**3.20**	1.52	1.61	**2.05**	2.07
Distributions to Unitholders	**74.0**	82.8	70.1	**243.5**	200.5
per Trust Unit [(5)]	**0.90**	1.02	0.90	**3.00**	2.70
Net debt [(6)]	**772.4**	415.5	381.8	**772.4**	381.8
per Trust Unit [(7)]	**9.16**	4.98	4.75	**9.16**	4.75

(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 issueable upon exchange of the Exchangeable Shares.

(3) The diluted per Trust Unit calculation includes the weighted average Trust Units outstanding, Trust Units issueable upon exchange of the outstanding Exchangeable Shares, the deemed conversion of the Debentures and Trust Units issueable 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 dates for distributions during the period.

(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 issueable upon exchange of the outstanding Exchangeable Shares and Trust Units issueable pursuant to the LTIP at the end of the period.

Operating Highlights

	Three Months Ended			Nine Months Ended	
Daily Production Volumes	Sep 30, 2006	Jun 30, 2006	Sep 30, 2005	Sep 30, 2006	Sep 30, 2005
Natural gas (mmcf/day)	164.1	164.1	176.8	164.7	178.6
Crude oil (bbls/day)	9,106	6,305	7,037	7,434	6,898
Natural gas liquids (bbls/day)	3,931	3,748	3,616	3,736	3,713
Total (BOE per day)	40,381	37,406	40,121	38,625	40,379

Average Realized Sales Prices

	Three Months Ended			Nine Months Ended	
	Sep 30, 2006	Jun 30, 2006	Sep 30, 2005	Sep 30, 2006	Sep 30, 2005
Natural gas ($/Mcf) (1)(2)	6.69	6.65	8.41	7.49	7.57
Without hedging	6.20	6.29	8.66	7.19	7.66
Crude oil ($/bbl)(1)	69.64	68.72	56.19	64.77	48.11
Without hedging	69.18	68.78	67.48	65.38	58.05
Natural gas liquids ($/bbl)	62.50	62.56	59.83	61.54	54.76
Total Oil Equivalent ($/BOE) (1)	48.96	47.02	52.30	50.35	46.76
Without hedging	46.86	45.46	55.38	49.20	48.85
Realized hedging gain/(loss) included in prices above ($/BOE)	2.10	1.56	(3.08)	1.15	(2.09)

(1) Includes hedging gains and losses.

(2) Excludes sulphur.

Cash Flow Reconciliation

($ Millions)		
Second quarter 2006 cash flow from operations	$	88.6
Volumes		20.4
Commodity prices		(1.1)
Net hedging change from prior quarter		2.5
Operating expenses		(3.6)
Royalties		(2.6)
G&A		1.9
Interest		(6.7)
Other		2.8
Third quarter 2006 cash flow from operations	$	96.6

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.

Selected Canadian and U.S. Financial Results

($ Millions, except production volumes and per unit prices)	Three Months Ended Sep 30, 2006		
	Canada	U.S.	Total
Daily Production Volumes			
Natural gas (mmcf/day)	162.5	1.6	164.1
Crude oil (bbls/day)	6,659	2,447	9,106
Natural gas liquids (bbls/day)	3,931	-	3,931
Total daily sales (BOE/day)	37,625	2,756	40,381
Pricing (1)			
Natural gas (per mcf)	6.20	6.07	6.20
Crude oil (per bbl)	69.51	68.28	69.18
Natural gas liquids (per bbl)	62.50	-	62.50
Revenues (1)			
Natural gas	92.6	0.9	93.5
Crude oil	42.5	15.5	58.0
Natural gas liquids	22.6	-	22.6
Royalties	(31.1)	(3.4)	(34.5)
Expenses			
Operating	30.8	4.0	34.8
G&A	6.0	0.5	6.5
Depletion, depreciation and amortization	54.8	4.3	59.1
Income and capital taxes	-	0.5	0.5
Capital expenditures			
Development	75.8	0.5	76.3
Acquisition of oil and gas properties	35.1	333.7	368.8
Disposition of oil and gas properties	0.2	-	0.2

(1) Net of transportation expense. Excludes realized hedging gains and losses.

($ Millions, except production volumes and per unit prices)	Nine Months Ended Sep 30, 2006		
	Canada	U.S.	Total
Daily Production Volumes			
Natural gas (mmcf/day)	164.2	0.5	164.7
Crude oil (bbls/day)	6,599	835	7,434
Natural gas liquids (bbls/day)	3,736	-	3,736
Total daily sales (BOE/day)	37,696	929	38,625
Pricing (1)			
Natural gas (per mcf)	7.19	6.07	7.19
Crude oil (per bbl)	65.01	68.28	65.38
Natural gas liquids (per bbl)	61.54	-	61.54
Revenues (1)			
Natural gas	322.4	0.9	323.3
Crude oil	117.2	15.5	132.7
Natural gas liquids	62.8	-	62.8
Royalties	(107.6)	(3.4)	(111.0)
Expenses			

($ Millions, except production volumes and per unit prices)	Nine Months Ended Sep 30, 2006		
Operating	94.7	4.0	98.7
G&A	19.6	0.5	20.1
Depletion, depreciation and amortization	162.2	4.3	166.5
Income and capital taxes	(0.6)	0.5	(0.1)
Capital expenditures			
Development	203.2	0.5	203.7
Acquisition of oil and gas properties	35.4	333.7	369.1
Disposition of oil and gas properties	3.4	-	3.4

(1) Net of transportation expense. Excludes realized hedging gains and losses.

Quarterly Performance – Selective Measures

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

	2006			2005				2004
($ Millions, except per Trust Unit Amounts)	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Net Revenues	160.1	134.9	170.0	236.4	101.5	155.3	111.2	158.2
Net Income	64.0	65.7	68.9	101.5	27.3	54.7	24.0	42.2
Cash Flow from Operations	96.6	88.6	103.2	132.5	106.4	95.5	79.7	83.3
Cash Flow Per Unit – basic	1.17	1.08	1.28	1.66	1.36	1.29	1.12	1.17
Cash Flow Per Unit – diluted	1.15	1.06	1.24	1.60	1.31	1.21	1.04	1.07
Net Income Per Unit – basic	0.78	0.81	0.85	1.27	0.35	0.74	0.34	0.59
Net Income Per Unit – diluted	0.76	0.79	0.83	1.23	0.35	0.72	0.34	0.58

Net revenues are impacted primarily by 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

	Three Months Ended			Nine Months Ended	
($ Millions)	**Sep 30, 2006**	Jun 30, 2006	Sep 30, 2005	**Sep 30, 2006**	Sep 30, 2005
Land and lease acquisitions	**2.0**	3.5	2.7	**8.9**	15.7
Geological and geophysical	**0.5**	0.5	0.3	**2.5**	6.7
Drilling and completions	**53.8**	22.3	22.0	**129.6**	80.9
Investment in facilities					
Equipping and tie-in	**8.7**	14.4	6.4	**38.7**	20.3
Gas gathering and compression	**7.8**	1.1	2.3	**10.1**	11.5
Production facilities	**2.2**	3.1	2.2	**10.0**	7.3
Capitalized G&A	**1.3**	1.2	0.7	**3.9**	2.1
Development capital	**76.3**	46.1	36.6	**203.7**	144.5

Acquisition of oil and gas assets	368.8	0.2	2.6	369.1	2.1
Dispositions	(0.2)	(0.1)	(1.5)	(3.4)	(3.7)
Leasehold improvements, furniture and equipment	0.4	1.3	0.8	3.0	3.4
Net capital expenditures	445.3	47.5	38.5	572.4	146.3

During the third quarter of 2006, PrimeWest's development capital expenditures totalled $76.3 million, compared to $46.1 million invested in the second quarter of 2006 and $36.6 million in the third quarter of 2005. Of the $76.3 million total, $62.5 million or 82% was invested in drilling, completions and tie-ins, which contribute to new reserve additions and help offset natural production decline.

Acquisition of oil and gas assets include $31.9 million for the Caroline assets and $336.3 million for the assets located in Montana, North Dakota, Wyoming and Saskatchewan.

Through acquisitions as well as development drilling, workovers and re-completion activities, PrimeWest strives to offset natural production declines and add 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 third quarter of 2006, PrimeWest invested $76.3 million on development opportunities, drilling 81 gross wells (56.3 net) with a success rate of 95%. PrimeWest's five key development plays are Conventional Development, Tight Gas, Southeast Alberta Shallow Gas, U.S. assets and Coalbed Methane (CBM). PrimeWest's development capital expenditures for 2006 are expected to be $275 million, allocated $85 to $95 million to Conventional Development, $60 to $70 million to Tight Gas development, $25 to $30 million to Southeast Alberta Shallow Gas development, $10 to $15 million to the U.S. assets and $5 to $10 million to CBM. Approximately $30 million will be invested on maintenance capital and seismic in 2006.

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 third quarter totalled $34.2 million, including $21.4 million for drilling and completions, $0.4 million for land and seismic and $11.1 million for equipping, tie-in and facilities. A total of 23 gross wells were 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 9 operated wells in the third quarter of 2006, and participated in 2 non-operated wells targeted at various formations including Edmonton, Belly River, Glauconitic, Mannville, and Rock Creek. Development capital expenditures at Wilson Creek were $13.6 million, including $11.0 million for drilling and completions, $0.01 million for land and $1.9 million for equipping, tie-in and facilities.

Lone Pine Creek/Crossfield Area

Development capital expenditures at Crossfield of $16.0 million were comprised of $8.8 million for drilling and completions, $0.1 million for land and seismic and $7.1 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 third quarter 2006. Capital expenditures for the three months ended September 30, 2006 included $18.2 million for drilling and completions, $1.8 million for land and seismic and $3.5 million for equipping, tie-in and facilities. Fourteen 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 third quarter 2006 were $16.4 million including $12.0 million for drilling and completion, $1.8 million for equipping, tie-in and facilities and $0.6 million for land and seismic. During the quarter, 7 gross wells were drilled at Caroline.

Columbia Area

Development expenditures at Columbia of $6.1 million included $4.3 million for drilling and completions, $1.1 million for equipping, tie-in and facilities and $0.9 million for land and seismic. During the quarter 2 gross wells have been 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 third quarter of 2006, development expenditures were $14.2 million, with $6.2 million invested in drilling and completions, $3.7 million in equipping, tie-ins and facilities, and $0.2 million in land and seismic. Thirty-seven gross wells were drilled in the third 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 third quarter were $5.0 million, with $3.5 million invested in drilling and completions, $1.0 million in equipping, tie-ins and facilities and $0.1 million in land and seismic. The drilling program is on schedule, with 5 gross operated wells drilled in the third quarter.

U.S. Assets

On July 6, 2006, PrimeWest acquired producing oil and gas assets located in Montana, North Dakota and Wyoming. The acquisition established a new operating area within the Williston Basin, providing considerable waterflood and development drilling potential. The major fields acquired are Flat Lake, Dwyer and Goose Lake in Montana; Rival, Grenora, Alexander, Wiley, Glenburn and Sherwood in North Dakota; and Rocky Point in Wyoming.

PrimeWest is planning to invest between $10 - $15 million on well reactivations, injection conversions and the drilling of up to three wells during the remainder of 2006. During the third quarter 2006, PrimeWest incurred $0.5 million on capital development expenditures on the U.S. assets.

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. Commencement on commercial development of the CBM will be evaluated in 2007 and will be contingent on the natural gas price.

Daily Production Volumes

	Three Months Ended			Nine Months Ended	
Daily Production Volumes	Sep 30, 2006	Jun 30, 2006	Sep 30, 2005	Sep 30, 2006	Sep 30, 2005
Natural gas (mmcf/day)	164.1	164.1	176.8	164.7	178.6
Crude oil (bbls/day)	9,106	6,305	7,037	7,434	6,898
Natural gas liquids (bbls/day)	3,931	3,748	3,616	3,736	3,713
Total (BOE per day)	40,381	37,406	40,121	38,625	40,379

PrimeWest's production volumes averaged 40,381 BOE per day in the third quarter of 2006, compared to 37,406 BOE per day in the second quarter 2006. The 8% increase in volumes is mainly due to the acquisition of the U.S. assets early in the third quarter. The U.S. asset's production averaged 2,756 BOE per day for the three months ended September 30, 2006. Production disruptions and planned workover activities reduced third quarter volumes at the U.S. Dwyer and Rival fields. Continued success with the Canadian drilling program resulted in relatively flat production levels quarter over quarter. Incremental volumes offset volume reductions due to maintenance shut-in at the Crossfield gas plant and natural decline.

For the three months ended September 30, 2006 production volumes have remained relatively flat when compared to the same period in 2005.

For the nine months ended September 30, 2006 production volumes have decreased approximately 4% compared to the prior year due to third party unscheduled outages at Princess, regulatory change impacting the Nisku waterflood project at Crossfield, a one time negative adjustment to gross overriding royalty volumes and natural decline. Volumes from the U.S. assets partially offset the decrease with annualized production averaging 929 BOE per day for the nine months ended September 30, 2006.

Production Outlook

PrimeWest expects full year 2006 production volumes to average between 39,000 – 40,000 BOE per day in 2006.

Commodity Prices

	Three Months Ended			Nine Months Ended	
Benchmark Prices	**Sep 30, 2006**	Jun 30, 2006	Sep 30, 2005	**Sep 30, 2006**	Sep 30, 2005
Natural gas					
NYMEX (US$/mcf)	**6.53**	6.82	8.25	**7.47**	7.12
AECO (Cdn$/mcf)	**6.03**	6.27	8.17	**7.19**	7.41
Crude oil WTI (US$/bbl)	**70.48**	70.70	63.19	**68.22**	55.40

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]			
	Q4 2005	Q1 2006	Q2 2006	Q3 2006	Q4 2006	Q1 2007	Q2 2007	Q3 2007
Natural gas AECO (Cdn$/mcf)	11.69	9.27	6.27	6.03	5.74	7.48	6.93	7.22
Crude oil WTI (US$/bbl)	60.02	63.48	70.70	70.48	64.36	66.61	67.90	68.66

(1) As at September 30, 2006

Average Realized Sales Prices

	Three Months Ended			Nine Months Ended	
	Sep 30, 2006	Jun 30, 2006	Sep 30, 2005	**Sep 30, 2006**	Sep 30, 2005
Natural gas ($/Mcf) [(1)(2)]	**6.69**	6.65	8.41	**7.49**	7.57
Without hedging	**6.20**	6.29	8.66	**7.19**	7.66
Crude oil ($/bbl)[(1)]	**69.64**	68.72	56.19	**64.77**	48.11
Without hedging	**69.18**	68.78	67.48	**65.38**	58.05
Natural gas liquids ($/bbl)	**62.50**	62.56	59.83	**61.54**	54.76
Total Oil Equivalent ($/BOE)[(1)]	**48.96**	47.02	52.30	**50.35**	46.76

Without hedging	**48.86**	45.46	55.38	**49.20**	48.85
Realized hedging gain/(loss) included in prices above ($/BOE)	**2.10**	1.56	(3.08)	**1.15**	(2.09)

(1) Includes hedging losses.

(2) Excludes sulphur.

Realized natural gas prices were relatively flat in the third quarter of 2006 compared to the previous quarter, excluding the effect of hedging. Weather continues to play an important role in determining overall gas supply and demand balances, and therefore pricing. Gas storage levels at the end of the 2006 summer injection season approached record levels as a result of a record warm 2005-2006 winter, and the absence of material hurricane activity in the Gulf of Mexico during the summer of 2006. In addition, North American gas production continues to benefit from high drilling activity. Realized natural gas prices were 28% lower during the third quarter of 2006 compared to the third quarter of 2005.

Third quarter realized crude oil prices were slightly higher than the previous quarter, excluding the effect of hedging. WTI prices at the onset of the third quarter increased as a result of perceived gasoline shortages, which many predicted would occur during the height of the summer driving season. Because the shortages did not materialize, WTI prices quickly retreated, falling in excess of US $10.00 per barrel by the end of summer. Prices also continued to be impacted by historically wide differentials to WTI on all grades of crude. High U.S. crude storage levels combined with less seasonal demand for crude products also put downward pressure on WTI prices during the latter part of the third quarter.

Realized oil prices excluding the effect of hedging were 3% higher during the third quarter of 2006 compared to the third quarter of 2005.

Sales Revenue

	Three Months Ended						Nine Months Ended	
Revenue ($ millions) (1) (2)	**Sep 30, 2006**	**% of Total**	Jun 30, 2006	% of Total	Sep 30, 2005	% of Total	**Sep 30, 2006**	Sep 30, 2005
Natural gas	**101.0**	**56**	99.3	62	136.8	71	**336.7**	369.3
Crude oil	**58.3**	**32**	39.4	25	36.4	19	**131.4**	90.6
Natural gas liquids	**22.6**	**12**	21.4	13	19.9	10	**62.8**	55.5
Total	**181.9**	**100**	160.1	100	193.1	100	**530.9**	515.4
Hedging gain/(losses) included above	**7.8**		5.3		(11.4)	12.2	**12.2**	(23.1)

(1) Excludes sulphur.

(2) Net of transportation expenses.

Third quarter 2006 revenues were 14% higher than the previous quarter mainly due to the increases in production volumes resulting from the U.S. asset acquisition and increases in hedging gains.

Third quarter 2006 revenues were 6% lower than the same period in 2005, due to lower natural gas prices offset by increases in realized hedging gains. On a year-to-date basis, September 2006 revenues exceeded September 2005 revenues by 3% due to higher realized crude oil prices offset by lower production volumes.

Approximately 68% of PrimeWest's production on an energy equivalent basis is 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 partial protection against a significant downturn in prices.

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

Production Volumes Hedged (%)	Q4 2006	Q1 2007	Q2 2007	Q3 2007	Q4 2007	Q1 2008
Crude Oil	69	67	56	39	40	7
Natural Gas	67	52	30	26	22	11

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 September 30, 2006 follows:

Crude Oil

Period	Volume (bbls/d)	Type	WTI Price (US$/bbl)
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
Oct – Dec 06	1800	Costless Collar	70.00/83.20
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
Jan – Mar 07	500	Costless Collar	65.00/95.15
Jan – Mar 07	1400	Costless Collar	70.00/83.65
Jan – Mar 07	500	Costless Collar	65.00/90.25
Jan – Mar 07	500	Costless Collar	55.00/74.50
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
Apr – Jun 07	500	Costless Collar	65.00/93.90
Apr – Jun 07	1300	Costless Collar	70.00/84.25
Apr – Jun 07	500	Costless Collar	55.00/75.00
Jul – Sep 07	500	Costless Collar	60.00/92.75
Jul – Sep 07	500	Swap	75.20
Jul – Sep 07	500	Costless Collar	65.00/92.60
Jul – Sep 07	900	Costless Collar	70.00/83.25

Period	Volume (bbls/d)	Type	WTI Price (US$/bbl)
Jul – Sep 07	500	Costless Collar	55.00/77.80
Oct – Dec 07	500	Costless Collar	60.00/90.25
Oct – Dec 07	500	Swap	74.58
Oct – Dec 07	500	Costless Collar	65.00/91.35
Oct – Dec 07	800	Costless Collar	70.00/82.10
Oct – Dec 07	500	Costless Collar	55.00/78.25
Jan – Mar 08	500	Costless Collar	55.00/78.00

Natural Gas

Period	Volume (mmcf/d)	Type	AECO Price (C$/mcf)
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
Oct – Dec 06	5.0	Costless Collar	6.33/12.24
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
Jan – Mar 07	5.0	Costless Collar	5.28/10.87
Jan – Mar 07	5.0	Costless Collar	7.39/17.04
Jan – Mar 07	5.0	Costless Collar	8.44/15.03
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
Apr – Jun 07	5.0	Costless Collar	5.28/9.34
Apr – Jun 07	5.0	Costless Collar	6.33/11.39

Period	Volume (mmcf/d)	Type	AECO Price (C$/mcf)
Apr – Jun 07	5.0	Costless Collar	6.33/11.66
Jul – Sep 07	5.0	Costless Collar	6.33/11.61
Jul – Sep 07	5.0	Costless Collar	6.33/10.87
Jul – Sep 07	5.0	Costless Collar	5.28/10.02
Jul – Sep 07	5.0	Costless Collar	6.33/12.05
Jul – Sep 07	5.0	Costless Collar	6.33/12.45
Oct – Dec 07	5.0	Costless Collar	7.39/12.28
Oct – Dec 07	5.0	Costless Collar	5.28/12.66
Oct – Dec 07	5.0	Costless Collar	7.39/12.77
Oct – Dec 07	5.0	Costless Collar	7.39/13.40
Jan – Mar 08	5.0	Costless Collar	6.33/12.71
Jan – Mar 08	5.0	Costless Collar	8.44/15.67

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 $13.03, purchased a put at $6.33, and resold the put at $5.28. Should the market price drop below $6.33, PrimeWest will receive $6.33 until the price is less than $5.28, at which time PrimeWest will then receive market price plus $1.05. However, should market prices rise above $13.03, PrimeWest will receive a maximum of $13.03. Should the market price remain between $6.33 and $13.03, PrimeWest will receive the market price.

Electrical Power

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

Foreign Exchange

Period	Amount £ (000's)	Type	Price
Oct - Jun 2016	Principal 63,000 Interest 36,288	Swap	$2.0748 Cdn per £ 1.00

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

The third quarter 2006 income statement includes an unrealized gain of $9.7 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 $7.9 million gain on crude oil hedges, a $5.5 million gain on natural gas hedges, $0.1 million gain on electrical power and a $3.8 million loss on the foreign exchange hedge.

For the nine months ended September 30, 2006, the change in Mark-to-Market valuation of the derivatives resulted in a gain of $34.8 million comprised of a $7.4 million gain on crude oil hedges, a $33.4 million gain on natural gas hedges, a $0.1 million gain on electrical power and a $6.1 million loss on the foreign exchange hedge.

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

For the three month period ended September 30, 2006 the cash impact of hedge contract settlements was a $7.8 million gain comprised of a $0.4 million gain on crude oil and a $7.4 million gain on natural gas.

For the nine month period ended September 30, 2006, the cash impact of hedge contract settlements was a $12.2 million gain comprised of a $13.4 million gain on natural gas and a $1.2 million loss on 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.

	Three Months Ended			Nine Months Ended	
($ Millions, except per BOE)	**Sep 30, 2006**	Jun 30, 2006	Sep 30, 2005	**Sep 30, 2006**	Sep 30, 2005
Royalty expense	**34.5**	31.9	44.4	**111.0**	117.3
Per BOE	**9.29**	9.36	12.04	**10.53**	10.64
Royalties as a % of sales revenues					
With hedge gain or loss	**18.9%**	19.9%	23.0%	**20.9%**	22.8%
Excluding hedge gain or loss	**19.8%**	20.6%	21.7%	**21.4%**	21.8%

Third quarter 2006 royalty expense as a percentage of sales, excluding the impact of hedges, decreased when compared to the previous quarter and the same period in the prior year due to a Crown adjustment relating to prior periods of approximately $0.5 million.

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

Operating Expenses

	Three Months Ended			Nine Months Ended	
($ Millions, except per BOE)	**Sep 30, 2006**	Jun 30, 2006	Sep 30, 2005	**Sep 30, 2006**	Sep 30, 2005
Operating expense	**34.8**	31.2	31.6	**98.7**	84.1
Per BOE	**9.36**	9.16	8.56	**9.36**	7.63

Third quarter 2006 operating expense totalled $34.8 million, an increase of 12% from $31.2 million in the second quarter. On a per BOE basis operating expenses increased by 2% over the previous quarter. The increase in operating expense is mainly attributable to the acquisition of the U.S. assets. Operating expense for the U.S. assets was approximately $4.0 million in the third quarter. Excluding the impact of the U.S. assets, operating expense remained relatively flat quarter over quarter. Included in the third quarter 2006 operating expense is approximately $1.8 million related to the turnaround at the Crossfield gas plant.

Year over year operating expense and operating expense per BOE increased in the third quarter of 2006 compared to the third quarter 2005 due to the U.S. asset acquisition.

Operating expense and operating expense per BOE for the nine months ended September 30, 2006 increased over the same period in 2005 due to first quarter 2006 operating issues, the impact of the U.S. assets and inflationary pressures on the price of goods and services.

Operating Expense Outlook

PrimeWest anticipates that its full year operating expense will be approximately $9.25 per BOE.

Operating Margin

	Three Months Ended			Nine Months Ended	
($ per BOE)	**Sep 30, 2006**	Jun 30, 2006	Sep 30, 2005	**Sep 30, 2006**	Sep 30, 2005
Sales price and other revenue [(1)]	**49.27**	47.60	52.38	**50.82**	46.84
Royalties	**(9.29)**	(9.36)	(12.04)	**(10.53)**	(10.64)
Operating expense	**(9.36)**	(9.16)	(8.56)	**(9.36)**	(7.63)

Operating margin	30.62	29.08	31.78	30.93	28.57

(1) Includes hedging and sulphur.

The operating margin per BOE increased in the third quarter of 2006 compared to the previous quarter mainly due to an increase in realized commodity prices offset by higher 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.

Third quarter 2006 operating margin was lower than the same period in 2005 due to lower realized commodity prices and increases in operating costs offset by lower royalties.

General & Administrative Expense

	Three Months Ended			Nine Months Ended	
($ Millions, except per BOE)	Sep 30, 2006	Jun 30, 2006	Sep 30, 2005	Sep 30, 2006	Sep 30, 2005
Cash G&A expense	5.1	7.0	5.7	17.4	16.0
Per BOE	1.39	2.04	1.54	1.65	1.46
Non-cash G&A expense	1.4	1.5	1.5	4.4	4.1
Per BOE	0.37	0.45	0.41	0.41	0.37

Cash G&A expense in the third quarter of 2006 decreased 27% on a gross and 32% on a per BOE basis from the previous quarter due mainly to lower stock exchange listing fees and higher overhead recoveries related to an increase in capital spending. Included in the third quarter 2006 G&A expense is $0.5 million related to the U.S. operations.

Third quarter 2006 cash G&A expenses were 11% lower when compared to the third quarter of 2005. Increases in labour costs and legal fees were offset by lower information technology expenses and increases in overhead recoveries. Cash G&A expense per BOE for the three months ended September 30, 2006 was 31% lower than the same period in the prior year due to lower cash G&A expense and increases to production volumes.

Cash G&A expense for the nine months ended September 30, 2006 exceeded the G&A expense for the same period in 2005 due to higher labour costs, legal and audit fees, offset by increases to overhead recoveries. Cash G&A expense per BOE for the nine months ended September 30, 2006 increased 13% compared to the prior year due to increases to G&A expense and reductions in production volumes.

Included in non-cash G&A expense was $1.2 million and $3.2 million for the three and nine months ended September 30, 2006, respectively, relating to the Unit Appreciation Rights (UARs), granted under the LTIP. 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 $0.2 million and $1.1 million for the three and nine months ended September 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

	Three Months Ended			Nine Months Ended	
($ Millions, except per Trust Unit Amounts)	Sep 30, 2006	Jun 30, 2006	Sep 30, 2005	Sep 30, 2006	Sep 30, 2005
Interest expense	11.9	5.2	6.0	21.6	22.8
Period end net debt level (1)	772.4	415.5	381.8	772.4	381.8
Debt per Trust Unit	9.16	4.98	4.75	9.16	4.75
Average cost of debt	5.9%	5.1%	4.9%	5.6%	4.7%

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

Interest expense, representing interest on bank debt, the U.S. Secured Notes, the U.K. Secured Notes and the Debentures increased in the third quarter of 2006 compared to the second quarter of 2006 and the third quarter of 2005, due to the increase in the average net debt balance resulting from the acquisition of the U.S. assets. Interest expense was also impacted by increases in the average cost of debt.

Interest expense was lower for the nine months ended September 30, 2006 compared to the same period in 2005 due to lower average debt balances offset by a higher average cost of debt. The average debt balance for the nine months ended September 30, 2006 was lower than the same period in the prior year mainly due to the conversion of the debentures throughout 2006.

The average cost of debt was higher for the three and nine months ended September 30, 2006 compared to the same periods in 2005, primarily due to the impact of the U.K. Secured Notes and the portion of the bank credit facilities denominated in the London Inter-Bank Offer Rate (LIBOR), which currently bear interest at 5.93% and 6.41% respectively.

Foreign Exchange

The foreign exchange loss of $1.9 million for the three months and the $4.9 million gain for the nine months ended September 30, 2006 resulted from the translation of the U.S. dollar denominated debt, the U.K. Secured Notes and related interest payable into Canadian dollars.

Depletion, Depreciation and Amortization

	Three Months Ended			Nine Months Ended	
($ Millions, except per BOE)	**Sep 30, 2006**	Jun 30, 2006	Sep 30, 2005	**Sep 30, 2006**	Sep 30, 2005
Depletion, depreciation and amortization	**59.1**	53.5	56.5	**166.5**	169.7
Per BOE	**15.90**	15.73	15.30	**15.79**	15.40

The DD&A rate for the three months ended September 30, 2006 increased slightly when compared to the previous quarter and the same period in the prior year. 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. The 2007 contribution rate will be determined early in the New Year. As at September 30, 2006 the site reclamation fund contained a balance of $5.6 million.

The abandonment and reclamation costs incurred in the third quarter 2006 were $5.2 million, compared to $1.3 million for the same period in 2005, and $1.8 million for the previous quarter.

Asset Retirement Obligation

PrimeWest recognizes the fair value of asset retirement costs relating to its petroleum and natural gas properties when a reasonable estimate of the fair value can be made (See note 9 to the consolidated financial statements in 2005 Annual Report). These liabilities will be settled based on the expected life of the underlying assets. These liabilities are subsequently adjusted for the passage of time (accretion) and revisions in either timing or changes to the underlying liability. PrimeWest increased the asset retirement obligation in the third quarter of 2006 by approximately $52.2 million. The increase is mainly the result of a three-year review of actual costs incurred to reclaim wells and to a new directive by the Energy and Utilities Board relating to the remediation of facilities. The additional liability was capitalized to the related asset and will be amortized to earnings over time.

Income and Capital Taxes

	Three Months Ended			Nine Months Ended	
($ Millions, except per BOE)	**Sep 30, 2006**	Jun 30, 2006	Sep 30, 2005	**Sep 30, 2006**	Sep 30, 2005
Income and capital taxes	**0.5**	(1.2)	0.6	**(0.1)**	1.6
Future income tax recovery	**(21.2)**	(23.0)	(22.2)	**(44.8)**	(38.8)
Total	**(20.7)**	(24.2)	(21.6)	**(44.9)**	(37.2)

The future income tax recovery for the three months ended September 30, 2006 was relatively flat compared to the prior quarter and the same period in the prior year.

The increase in the future income tax recovery for the nine months ended September 30, 2006 compared to the nine months ended September 30, 2005 is mainly due to the reduction in federal statutory tax rates that were substantially enacted in the second quarter of 2006.

Income and capital tax expense for the three months ended September 30, 2006 is due to taxable income from the U.S. assets.

Net Income

	Three Months Ended			Nine Months Ended	
($ Millions)	Sep 30, 2006	Jun 30, 2006	Sep 30, 2005	Sep 30, 2006	Sep 30, 2005
Net income	64.0	65.7	27.2	198.7	105.9

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 and future income taxes.

Net income for the three months ended September 30, 2006 of $64.0 million was 3% lower than the previous quarter net income of $65.7 million primarily due to increases in operating expense, DD&A and interest expense offset by increases to oil and gas revenues, all of which are attributable to the acquisition of the U.S. assets.

Net income for the third quarter of 2006 is higher than the same period in the prior year due to an increase in the unrealized gain on derivatives and to lower royalties offset by a decrease in oil and gas revenues resulting from lower commodity prices.

Net income for the nine months ended September 30, 2006 of $198.7 million was 88% higher than the same period in 2005 due mainly to an increase in the unrealized gain on derivatives offset by a reduction in the gain on sale of marketable securities.

Liquidity & Capital Resources

Long-Term Debt

	As at		
($ Millions)	Sep 30, 2006	Jun 30, 2006	Sep 30, 2005
Long-term debt	544.9	400.6	383.8
Deficit/(working capital)[1]	227.5	14.9	(2.0)
Net debt	772.4	415.5	381.8
Market value of Trust Units and Exchangeable Shares outstanding[2][3]	2,281.4	2,751.1	2,878.6
Total capitalization	3,053.8	3,166.6	3,260.4
Net debt as a % of total capitalization	25%	13%	12%

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

(2) Based on September 30, 2006 Trust Unit closing price of $27.35 and September 15, 2006 exchange ratio of 0.61771:1.

(3) Excludes the Debentures.

Long-term debt is comprised of senior bank credit facilities, the U.S. Secured Notes, the U.K. Secured Notes and the Debentures of $269.7 million, $104.8 million, $131.5 million and $38.9 million respectively. $34.9 million relating to the U.S. Secured Notes and $150 million relating to the bridge facility are included in working capital as a current portion of long-term debt. In addition to amounts outstanding under the bank credit facility, PrimeWest has outstanding letters of credit in the amount of $6.8 million (2005 - $4.8 million).

The indebtedness under the senior credit facilities, the U.S. Secured Notes and the U.K. Secured Notes is supported by a borrowing base of $750 million and is comprised of Canadian revolving facilities having a capacity of $220.5 million, the U.S. bank revolving credit facilities having a capacity of Cdn $255.0 million, the U.S. Secured Notes valued at $143.8 million based on a U.S. dollar exchange rate of U.S. $0.87 and the U.K. Secured Notes valued at Cdn $130.7 million. PrimeWest also has a $150 million bridge facility, which is due to expire in March 2007 or earlier if the amount drawn under the facility is paid out.

As a result of the U.S. asset acquisition during the third quarter of 2006, PrimeWest has drawn advances under the U.S. bank revolving credit facilities in U.S. dollars in the form of LIBOR loans that bear interest at LIBOR plus a margin based on PrimeWest's debt to EBITDA ratio. PrimeWest will continue to fund its ongoing operations in Canada with advances from the Canadian revolving facilities utilizing Banker Acceptances (BA) that bear interest at the BA rate plus a stamping fee determined in the same manner as the LIBOR margin.

At September 30, 2006, PrimeWest's net debt to annualized third quarter cash flow was approximately 2.0 times compared to 1.2 times second quarter cash flow at June 30, 2006. Net debt as a percentage of total capitalization was 25% at September 30, 2006 compared to 13% at June 30, 2006.

During the third quarter of 2006, $2.1 million of the Series I Debentures and $2.2 million of the Series II Debentures were converted to Trust Units. Accretion of $0.1 million was realized during the period.

Unitholders' Equity

At September 30, 2006, the Trust had 82,719,272 Trust Units outstanding. In addition, PrimeWest had 1,124,068 Exchangeable Shares outstanding that are exchangeable into a total of 694,348 Trust Units using the September 15, 2006 exchange ratio of 0.61771:1.

The equity component of the Series I and Series II Debentures have each been reduced by $0.1 million and $0.1 million respectively, due to conversions to Trust Units during the quarter.

During the third quarter, PrimeWest issued 599,950 Trust Units for proceeds of $20.3 million pursuant to an "at the market offering" through the facilities of the NYSE under a shelf prospectus issued on May 12, 2006 with a prospectus supplement filed July 28, 2006. During the third quarter of 2006, PrimeWest issued 85,462 Trust Units for $2.7 million under the DRIP, 213,593 Trust Units for $6.8 million pursuant to the PREP and 52,770 Trust Units for proceeds of $1.7 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. 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 certain acquisitions and as part of PrimeWest's management internalization transaction. Exchangeable shares continue to be issued to certain Executive Officers pursuant to a Special Employee Retention Plan (SERP) instituted as part of the management internalization transaction.

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 September 30, 2006, there were 1,124,068 Exchangeable Shares outstanding. The exchange ratio on these shares was 0.61771:1 Trust Units for each Exchangeable Share as at September 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 such targets 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 third quarter of 2006, cash distributions totalled $74.0 million, or $0.90 per Trust Unit representing a payout ratio of approximately 77%, compared to $82.8 million, or $1.02 per Trust Unit (93% payout ratio) in the previous quarter.

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 2013. The details of the timing of these contractual obligations are included in the following table.

As at September 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	691.0	184.9	339.7	34.9	131.5
Debentures	38.4	-	23.7	-	14.7
Lease rental obligations	10.4	3.6	6.8	-	-
Pipeline transportation obligations	7.2	5.8	1.2	0.2	-
Total contractual obligations	747.0	194.3	371.4	35.1	146.2

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. A total of 94,340 additional Exchangeable Shares will be issued on November 6, 2006 and 2007. For the three and nine months ended September 30, 2006, $0.2 million and $1.1 million respectively has been recorded in non-cash G&A expenses related to the SERP.

In October 2006, PrimeWest entered into an agreement containing a new office lease rental commitment that runs from 2010 to 2024. Payments that will become due under this agreement will commence in mid-2010 at approximately $4.7 million per year and will escalate by approximately $0.2 million every three years until 2021, at which point they will increase by $0.1 million for the final three years of the term of the commitment. The agreement contains customary additional obligations regarding the responsibility of PrimeWest for tenant improvements.

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 each counterparty. For the third quarter of 2006 approximately 17% of natural gas production was sold to aggregators and 83% 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 third quarter 2006, PrimeWest realized a $7.8 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
Production Risk associated with the production of oil and gas – includes well operations, processing and the physical delivery of commodities to market.	Performing regular and proactive protective well, facility and pipeline maintenance supported by telemetry, physical inspection and diagnostic tools.
Commodity Price Fluctuations in natural gas, crude oil and natural gas liquids prices.	Hedging. See page **14** of this quarterly report.
Transportation Market risk related to the availability of transportation to market and potential disruption in delivery systems.	Diversifying the transportation systems on which we rely to get our product to market.
Natural Decline 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	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

Risk	We Mitigate By
sufficient to replace annual production declines.	latest technology in planning and executing capital programs. Capital is spent only after strict economic criteria for production and reserve additions are assessed.
Acquisitions Acquisition risk associated with acquiring producing properties at low cost to renew our inventory of assets.	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.
Reserves Reserve risk in respect of the quantity and quality of recoverable reserves.	Contracting our reserves evaluation to a reputable third party consultant, GLJ Petroleum Consultants Ltd (GLJ). The Operations and Reserves Committee of the Board of Directors and PrimeWest review the work and independence of GLJ. Our 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.
Environmental Health and Safety (EH&S) Environmental, health and safety risks associated with oil and gas properties and facilities.	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. These risks are reviewed regularly by the Corporate Governance and EH&S Committee of the Board.
Regulation, Tax and Royalties Changes in government regulations including reporting requirements, income tax laws, operating practices, environmental protection requirements and royalty rates.	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.
Historical Liability to Unitholders is Uncertain 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.	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.

CONSOLIDATED BALANCE SHEETS

Unaudited ($ Millions)	Sep 30, 2006	Dec 31, 2005
ASSETS		
Current assets		
Cash and cash equivalents	$ 15.6	$ 36.8
Accounts receivable	95.5	125.0
Derivative assets	27.1	-
Future income taxes	-	3.9
Prepaid expenses	19.3	16.3
Inventory	0.4	3.5
	157.9	185.5
Cash reserved for site restoration and reclamation (note 2)	5.6	9.2
Derivative assets	2.4	-
Other assets and deferred charges	8.0	8.8
Property, plant and equipment	2,323.4	1,859.9
Goodwill	68.5	68.5
	$ 2,565.8	$ 2,131.9
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 45.3	$ 50.2
Accrued liabilities	106.8	75.9
Current portion of long-term debt	184.9	-
Future income taxes	10.1	-
Derivative liabilities	-	11.3
Accrued distributions to Unitholders	21.4	25.0
	368.5	162.4
Long-term debt (note 4)	544.9	354.2
Derivative liabilities	6.1	0.2
Future income taxes	156.7	214.8
Asset retirement obligation (note 2)	89.7	40.4
	1,165.9	772.0
UNITHOLDERS' EQUITY		
Net capital contributions (note 5)	2,378.3	2,294.3
Capital issued but not distributed	3.4	3.6
Convertible unsecured subordinated debentures	1.2	1.8
Contributed surplus (note 6)	10.7	8.7
Cumulative translation account	(0.4)	-
Accumulated income	502.5	303.8
Accumulated cash distributions	(1,487.8)	(1,244.3)
Accumulated dividends	(8.0)	(8.0)
	1,399.9	1,359.9
	$ 2,565.8	$ 2,131.9

CONSOLIDATED STATEMENTS OF CHANGES IN UNITHOLDERS' EQUITY

	Nine Months Ended	
Unaudited ($ Millions)	Sep 30, 2006	Sep 30, 2005
Unitholders' equity, beginning of period	$ 1,359.9	$ 1,180.4
Net income for the period	198.7	105.9
Net capital contributions (note 5)	84.0	219.2
Convertible Unsecured Subordinated Debentures	(0.6)	(5.6)
Capital issued but not distributed	(0.2)	(0.2)
Cumulative translation account	(0.4)	-
Contributed surplus (note 6)	2.0	1.5
Cash distributions	(243.5)	(200.5)
Unitholders' equity, end of period	$ 1,399.9	$ 1,300.7

CONSOLIDATED STATEMENTS OF CASH FLOW

	Three Months Ended		Nine Months Ended	
Unaudited ($ Millions)	Sep 30, 2006	Sep 30, 2005	Sep 30, 2006	Sep 30, 2005
OPERATING ACTIVITIES				
Net income for the period	$ 64.0	$ 27.2	$ 198.7	$ 105.9
Add/(deduct) items not involving cash from operations				
Depletion, depreciation and amortization	59.1	56.5	166.5	169.7
Non-cash general and administrative	1.4	1.5	4.4	4.1
Non-cash foreign exchange loss/(gain)	1.9	(7.9)	(4.9)	(4.9)
Gain on sale of marketable securities	-	-	-	(27.2)
Unrealized (gain)/loss on derivatives	(9.7)	50.1	(34.8)	67.6
Future income taxes recovery	(21.2)	(22.2)	(44.8)	(38.8)
Accretion on asset retirement obligation	0.7	0.6	2.0	2.0
Other non-cash items	0.4	0.6	1.3	3.2
Cash flow from operations	$ 96.6	$ 106.4	$ 288.4	$ 281.6
Expenditures on site restoration and reclamation	(5.2)	(1.3)	(8.9)	(4.8)
Change in non-cash working capital	(4.8)	(15.1)	21.0	(40.1)
	86.6	90.0	300.5	236.7
FINANCING ACTIVITIES				
Proceeds from issue of Trust Units, net of issue costs	21.9	2.9	31.2	16.5
Increase in senior secured notes	-	-	130.7	-
Net cash distributions to Unitholders	(64.1)	(61.6)	(210.0)	(174.3)
Increase in deferred charges	-	-	(0.7)	-
Increase/(decrease) in bank credit facilities	296.2	-	266.2	(99.0)
Change in non-cash working capital	3.2	1.0	(3.4)	1.1
	257.2	(57.7)	214.0	(255.7)
INVESTING ACTIVITIES				
Expenditures on property, plant and equipment	(76.7)	(38.0)	(206.7)	(148.4)
Acquisition of capital assets	(334.5)	(2.0)	(369.1)	(1.6)
Proceeds on disposal of property, plant and equipment	0.2	1.5	3.4	9.1
Proceeds on sale of marketable securities	-	-	-	94.5
Increase/(decrease) in cash reserved for future site restoration and reclamation	3.4	(0.6)	3.6	(0.8)
Change in non-cash working capital	22.2	(2.5)	33.1	7.9
	(385.4)	(41.6)	(535.7)	(39.3)
Decrease in cash for the period	(41.6)	(9.3)	(21.2)	(58.3)
Cash beginning of the period	57.2	5.4	36.8	54.4
Cash/(Deficit) end of the period	15.6	(3.9)	15.6	(3.9)
Cash interest paid	4.3	3.3	13.8	17.8
Cash taxes paid	0.1	1.6	1.2	3.0

CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended		Nine Months Ended	
Unaudited ($ Millions)	Sep 30, 2006	Sep 30, 2005	Sep 30, 2006	Sep 30, 2005
REVENUES				
Sales of crude oil, natural gas and natural gas liquids	$ 183.8	$ 195.0	$ 537.1	$ 521.7
Crown and other royalties	(34.5)	(44.4)	(111.0)	(117.3)
Unrealized gain/(loss) on derivatives	9.7	(50.1)	34.8	(67.6)
Gain on sale of marketable securities	-	-	-	27.2
Other income	1.1	1.0	4.1	4.0
	160.1	101.5	465.0	368.0
EXPENSES				
Operating	34.8	31.6	98.7	84.1
Transportation	1.9	1.7	5.5	5.3
General and administrative	6.5	7.2	21.8	20.1
Depletion, depreciation and amortization	59.1	56.5	166.5	169.7
Interest	11.9	6.0	21.6	22.8
Accretion on asset retirement obligation	0.7	0.6	2.0	2.0
Foreign exchange loss/(gain)	1.9	(7.7)	(4.9)	(4.7)
	116.8	95.9	311.2	299.3
Income before taxes for the period	43.3	5.6	153.8	68.7
Income and capital taxes	0.5	0.6	(0.1)	1.6
Future income taxes recovery	(21.2)	(22.2)	(44.8)	(38.8)
	(20.7)	(21.6)	(44.9)	(37.2)
Net income for the period	64.0	27.2	198.7	105.9
Net income per Trust Unit – basic	0.78	0.35	2.43	1.42
Net income per Trust Unit – diluted	0.76	0.35	2.39	1.42

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the three months ended September 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.

Foreign Current Translation

The Trust has U.S. dollar operations, which are self-sustaining. The self-sustaining operation is translated into Canadian dollars using the current rate method. Under this method, assets and liabilities are translated using period end exchange rates with revenues and expenses translated using average rates for the period. Gains and losses arising on the translation of assets and liabilities are included in the cumulative translation account under Unitholder's equity.

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:

Asset Retirement Obligation	($ Millions)	
Asset Retirement Obligation, December 31, 2005	$	40.4
Change in estimate of liability		52.2
Liabilities settled		(8.9)
Accretion expense		2.0
Acquisition of U.S. assets		5.9
Sale of capital assets		(1.9)
Asset Retirement Obligation, September 30, 2006	$	89.7

As at September 30, 2006, the undiscounted amount of estimated cash flows required to settle the obligation is $443.6 million. The estimated cash flow has been discounted using a credit-adjusted risk free rate of 7.0 percent and an inflation rate of 1.5 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 34 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.

During the third quarter, PrimeWest reviewed the estimate of its asset retirement obligation and made an upward revision of $52.2 million due mainly to a review of actual costs incurred to reclaim wells and to a directive by the Energy and Utilities Board related to the remediation of facilities. This amount increased the related cost of the underlying assets.

3. Business Acquisition

On July 6, 2006, PrimeWest Energy Trust acquired oil and gas assets located in Montana, North Dakota, Wyoming and Saskatchewan. The acquisition was accounted for as a business acquisition pursuant to EIC 124 and as such the purchase method of accounting was applied. The net assets acquired and consideration paid was as follows:

Net Assets Acquired at Assigned Values	($ Millions)	Consideration Paid	($ Millions)
Petroleum and natural gas assets	$ 342.7	Cash	$ 329.5
Asset Retirement Obligation	(6.0)	Costs associated with acquisition	7.2
	$ 336.7		$ 336.7

4. Long-Term Debt

($ Millions)	Sep 30, 2006	Dec 31, 2005
Bank credit facilities	$ 269.7	$ 153.0
U.S. Senior Secured Notes	104.8	145.4
U.K. Senior Secured Notes	131.5	-
Convertible Unsecured Subordinated Debentures	38.9	55.8
	$ 544.9	$ 354.2
Current portion of long-term debt	184.9	-
	$ 729.8	$ 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 date of June 14, 2016.

On July 6, 2006, PrimeWest drew advances under the U.S. bank revolving credit facilities in U.S. dollars in the form of LIBOR loans that bear interest at LIBOR plus a margin based on PrimeWest's debt to EBITDA ratio. The remaining bank revolving credit facilities continue to utilize BA's that bear interest at the BA rate plus a stamping fee.

In the third quarter PrimeWest also accessed a $150 million bridging facility that is due to expire in March 2007 or earlier if the amount drawn under the facility is repaid. Advances under the facility are made in the form of BA's. Interest charges are a function of the BA rate plus a stamping fee.

The current portion of long-term debt includes $34.9 million relating to the U.S. Secured Notes and $150 million relating to the bridge facility.

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	671,811	17.8
Issued on exchange of Exchangeable Shares	56,036	0.9
Equity offering	599,950	20.3
Issued pursuant to Distribution Reinvestment Plan	351,264	11.3
Issued pursuant to the Premium Distribution Plan	705,723	22.5
Issued pursuant to Long-Term Incentive Plan	327,840	1.2
Issued pursuant to Optional Trust Unit Purchase Plan	340,247	11.0
Issued pursuant to Consolidation/Fractional Units	49	-
Balance, September 30, 2006	82,719,272	$ 2,367.0

The weighted average number of Trust Units and Exchangeable Shares outstanding for the three months ended Sep 30, 2006 was 82,365,441 (2005 –78,222,344). For purposes of calculating diluted net income per Trust Unit for the three months ended Sep 30, 2006, 941,431(2005 –1,975,913) and 584,583 (2005 – 1,475,518) Trust Units issueable pursuant to the conversion of the Convertible Unsecured Subordinated Debentures Series I and II respectively and 913,460 Trust Units (2005 –1,277,819) issueable pursuant to the LTIP were added to the weighted average number.

During the third quarter of 2006, PrimeWest issued 599,950 Trust Units for proceeds of $20.3 million pursuant to an "at the market offering" through facilities of the NYSE under a shelf prospectus issued on May 12, 2006, with a supplement prospectus filed July 28, 2006.

The weighted average number of Trust Units and Exchangeable Shares outstanding for the nine months ended September 30, 2006 was 81,793,030 (2005 – 74,466,505). For the purpose of calculating diluted net income per Trust Unit for the nine months ended September 30, 2006, 1,054,218 (2005 –3,876,893) and 677,386 (2005 –2,728,364) Trust Units issueable pursuant to the conversion of the Convertible Unsecured Subordinated Debentures Series I and Series II respectively and 913,460 Trust Units (2005 –1,277,817) issueable 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 September 15, 2006 was 0.61771:1.

Exchangeable Shares	Number of Shares	($ Millions)
Balance, December 31, 2005	1,219,335	$ 12.3
Exchanged for Trust Units	(95,267)	(1.0)
Balance, September 30, 2006	1,124,068	11.3

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 Long-Term Incentive Plan 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	3.2
Unit Appreciation Rights exercised	(1.2)
Balance, September 30, 2006	$ 10.7

7. Segmented Information

	Three Months Ended Sep 30, 2006		
($ Millions)	Canada	U.S.	Consolidated
Sales of crude oil, natural gas and natural gas liquids	$ 167.4	$ 16.4	$ 183.8
Crown and other royalties	(31.1)	(3.4)	(34.5)
Unrealized gain/(loss) on derivatives	9.7	-	9.7
Gain on sale of marketable securities	-	-	-
Other income	1.1	-	1.1
Operations, transportation, general and administrative	(38.7)	(4.5)	(43.2)
Interest	(8.1)	(3.8)	(11.9)
Depletion, depreciation, amortization and accretion	(55.5)	(4.3)	(59.8)
Foreign exchange gain/(loss)	(1.9)	-	(1.9)
Income and capital tax	-	(0.5)	(0.5)
Future income tax recovery	20.9	0.3	21.2
Net income	$ 63.8	$ 0.2	$ 64.0

($ Millions)	Canada	U.S.	Consolidated
			Three Months Ended Sep 30, 2005
Sales of crude oil, natural gas and natural gas liquids	$ 195.0	$ -	$ 195.0
Crown and other royalties	(44.4)	-	(44.4)
Unrealized gain/(loss) on derivatives	(50.1)	-	(50.1)
Other income	1.0	-	1.0
Operations, transportation, general and administrative	(40.5)	-	(40.5)
Interest	(6.0)	-	(6.0)
Depletion, depreciation, amortization and accretion	(57.1)	-	(57.1)
Foreign exchange gain/(loss)	7.7	-	7.7
Income and capital tax	(0.6)	-	(0.6)
Future income tax recovery	22.2	-	22.1
Net income	$ 27.2	$ -	$ 27.2

($ Millions)	Canada	U.S.	Consolidated
			Nine Months Ended Sep 30, 2006
Sales of crude oil, natural gas and natural gas liquids	$ 520.7	$ 16.4	$ 537.1
Crown and other royalties	(107.6)	(3.4)	(111.0)
Unrealized gain/(loss) on derivatives	34.8	-	34.8
Other income	4.1	-	4.1
Operations, transportation, general and administrative	(121.5)	(4.5)	(126.0)
Interest	(17.8)	(3.8)	(21.6)
Depletion, depreciation, amortization and accretion	(164.2)	(4.3)	(168.5)
Foreign exchange gain/(loss)	4.9	-	4.9
Income and capital tax	0.6	(0.5)	0.1
Future income tax recovery	44.5	0.3	44.8
Net income	$ 198.5	$ 0.2	$ 198.7

($ Millions)	Canada	U.S.	Consolidated
			Nine Months Ended Sep 30, 2005
Sales of crude oil, natural gas and natural gas liquids	$ 521.7	$ -	$ 521.7
Crown and other royalties	(117.3)	-	(117.3)
Unrealized gain/(loss) on derivatives	(67.6)	-	(67.6)
Gain on sale of marketable securities	27.2	-	27.2
Other income	4.0	-	4.0
Operations, transportation, general and administrative	(109.5)	-	(109.5)
Interest	(22.8)	-	(22.8)
Depletion, depreciation, amortization and accretion	(171.7)	-	(171.7)
Foreign exchange gain/(loss)	4.7	-	4.7
Income and capital tax	(1.6)	-	(1.6)

	Nine Months Ended Sep 30, 2005		
Future income tax recovery	38.8	-	38.8
Net income	$ 105.9	$ -	$ 105.9

Additions to Plant, Property and Equipment

	Three Months Ended Sep 30, 2006		
($ Millions)	Canada	U.S.	Consolidated
Development	$ 75.8	$ 0.5	$ 76.3
Acquisitions	35.1	333.7	368.8
Dispositions	(0.2)	-	(0.2)
Leasehold improvements, furniture and equipment	0.4	-	0.4
	$ 111.0	$ 334.2	$ 445.2

	Three Months Ended Sep 30, 2005		
($ Millions)	Canada	U.S.	Consolidated
Development	$ 36.6	$ -	$ 36.6
Acquisitions	2.6	-	2.6
Dispositions	(1.5)	-	(1.5)
Leasehold improvements, furniture and equipment	0.8	-	0.8
	$ 38.5	$ -	$ 38.5

	Nine Months Ended Sep 30, 2006		
($ Millions)	Canada	U.S.	Consolidated
Development	$ 203.2	$ 0.5	$ 203.7
Acquisitions	35.4	333.7	369.1
Dispositions	(3.4)	-	(3.4)
Leasehold improvements, furniture and equipment	3.0	-	3.0
	$ 238.2	$ 334.2	$ 572.4

	Nine Months Ended Sep 30, 2005		
($ Millions)	Canada	U.S.	Consolidated
Development	$ 144.5	$ -	$ 144.5
Acquisitions	2.1	-	2.1
Dispositions	(3.7)	-	(3.7)
Leasehold improvements, furniture and equipment	3.4	-	3.4
	$ 146.3	$ -	$ 146.3

8. 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 Unit Appreciation Rights (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 Long-Term Incentive Plan 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 $1.2 million (2005 - $0.9 million) and $3.2 million (2005 - $2.7 million) in non-cash general and administrative expense related to the Long-Term Incentive Plan for the three and nine months ended September 30, 2006 respectively using the fair value method of accounting.

PrimeWest used a lattice binomial 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:	Sep 30, 2006	Sep 30, 2005
Risk-free interest rate	4.17%	3.18%
Expected volatility in Trust Unit price	22.51%	19.8%
Expected time until exercise	1.5 – 3.5 years	1 - 3 years
Expected forfeiture rate	13.9%	13.0%
Expected annual dividend yield	zero	zero

Summary of Changes in Unit Appreciation Rights	Number of UARS	Weighted Average Strike Price
Balance outstanding at December 31, 2005	4,169,675	$ 29.92
Granted	1,166,192	38.04
Forfeited/expired	(319,923)	(29.54)
Exercised	(452,329)	27.89
Balance outstanding at September 30, 2006	4,563,615	$ 31.94

Summary of UARS Outstanding at September 30, 2006

Year of Grant	UARs Issued & Outstanding	UARs Vested and in the Money	Range of Strike Prices	Expiry Date
2002 grants	529,475	528,919	25.90 – 33.76	2008
2003 grants	647,794	639,413	25.92 – 32.24	2009
2004 grants	1,068,681	715,981	24.24 – 32.49	2010
2005 grants	1,207,604	234,406	28.90 – 43.17	2011
2006 grants	1,110,061	0	30.71 – 43.41	2012
Total grants	4,563,615	2,118,719	24.24 – 43.41	

9. Cash Distributions

	Three Months Ended		Nine Months Ended	
($ Millions, except per Trust Unit amounts)	Sep 30, 2006	Sep 30, 2005	Sep 30, 2006	Sep 30, 2005
Cash flow from operations	$ 96.6	$ 106.4	$ 288.4	$ 281.6
Deduct amounts to reconcile to distribution:				
Cash retained from cash available for distribution [(1)]	(21.4)	(34.4)	(39.7)	(75.4)
Contribution to reclamation fund	(1.2)	(1.9)	(5.2)	(5.7)
	$ 74.0	$ 70.1	$ 243.5	$ 200.5
Cash Distributions to Unitholders	$ 74.0	$ 70.1	$ 243.5	$ 200.5
Cash Distributions per Trust Unit	$ 0.90	$ 0.90	$ 3.00	$ 2.70

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

TRADING PERFORMANCE

For the quarter ended	Sep 30/06	Jun 30/06	Mar 31/06	Dec 31/05	Sep 30/05
TSX Trust Unit Prices (Cdn$ per Trust Unit)					
High	$ 35.42	$ 35.12	38.14	$ 37.68	$ 36.42
Low	$ 27.33	$ 30.92	29.82	$ 30.55	$ 30.86
Close	$ 27.35	$ 33.50	32.98	$ 35.90	$ 36.40
Average daily traded volume	225,732	258,294	249,527	199,849	183,469

For the quarter ended	Sep 30/06	Jun 30/06	Mar 31/06	Dec 31/05	Sep 30/05
NYSE Trust Unit Prices (US$ per Trust Unit)					
High	$ 31.29	$ 30.91	32.90	$ 32.57	$ 31.37
Low	$ 24.45	$ 27.76	25.25	$ 25.71	$ 25.15
Close	$ 24.64	$ 29.98	28.39	$ 30.92	$ 31.33
Average daily traded volume	441,508	438,995	463,411	480,603	445,338
Number of Trust Units outstanding including Exchangeable Shares (millions of Trust Units)	83.4	82.1	81.3	80.4	79.1
Distribution paid per Trust Unit	$ 0.90	$ 1.02	$ 1.08	$ 0.96	$ 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	17.3%	27.6	12.2	(12.5)	(11.1)	20.7
Three year	16.2%	44.6	26.1	9.4	18.0	39.9
One year	(15.6)%	51.1	10.6	6.6	10.8	6.31

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

For Investor Relations inquiries, please contact:
Diane Zuber, CFA
Investor Relations Advisor
(403) 699-7356 Toll-Free: 1-877-968-7878 E-mail: investor@primewestenergy.com

CORPORATE INFORMATION

Board of Directors

Harold Milavsky, [1,3] *Chair*

Barry E. Emes, [1],[3]

Harold N. Kvisle, [2,4]

Kent J. MacIntyre, [2],[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

PRIMEWEST

5100, 150 Sixth Avenue SW, Calgary AB Canada T2P 3Y7
Telephone: (403) 234-6600 Fax: (403) 699-7477 Toll-Free: 1-877-968-7878
Website: www.primewestenergy.com
Email: investor@primewestenergy.com