



P R I M E W E S T

ANNUAL INFORMATION FORM

For the year ended December 31, 2006

March 15, 2007

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FORWARD-LOOKING STATEMENTS

Certain statements contained in this Annual Information Form, constitute forward-looking statements with respect to the Trust, including forward-looking statements within the meaning of the United States Private Securities Litigation Reform Act of 1995. 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 this Annual Information Form. These statements speak only as of the date of this Annual Information Form.

In particular, this Annual Information Form 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 regulations 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 Annual Information Form, 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 Annual Information Form:

- 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;
- Changes in 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 could 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;
- Changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry and income trusts, including the effects that such changes may have on Unitholders, and in particular any differential effects relating to a Unitholder's country of resident; and
- The other factors discussed under "Risk Factors" contained in this Annual Information Form.

These factors should not be construed as exhaustive. The forward-looking statements contained in this Annual Information Form are expressly qualified by this cautionary statement. We undertake no obligation to publicly update or revise any forward-looking statements, except as required by law.

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

All figures reported in Canadian dollars unless otherwise stated.

Production figures stated are Company Interest before the deduction of royalties.

ITEM 1: ORGANIZATION

PrimeWest Energy Trust (the "Trust") is an open-end investment trust created under the laws of Alberta pursuant to the Declaration of Trust. The undertaking of the Trust is to issue Trust Units to the public and to invest the Trust's funds, directly or indirectly, in Oil and Natural Gas Properties and assets related thereto. The sole beneficiaries of the Trust are the holders of Trust Units. Computershare Trust Company of Canada ("Computershare") or its successor is the trustee of the Trust (the "Trustee"). The head office of PrimeWest is 5100, 150 – 6th Avenue S.W., Calgary, Alberta, T2P 3Y7. The registered office of PrimeWest is 4300, 888 – 3rd Street S.W., Calgary, Alberta, T2P 5C5.

PrimeWest Energy Inc. ("PrimeWest" or the "Operating Company") was incorporated under the *Business Corporations Act* (Alberta) on March 4, 1996 and was amalgamated with PrimeWest Oil and Gas Corp., PrimeWest Royalty Corp. and PrimeWest Resources Ltd. on January 1, 2002 and continued as PrimeWest Energy Inc.

PrimeWest is wholly owned by the Trust. PrimeWest's business is the acquisition, development, exploitation, Production and marketing of Oil and Natural Gas and granting the Royalty to the Trust.

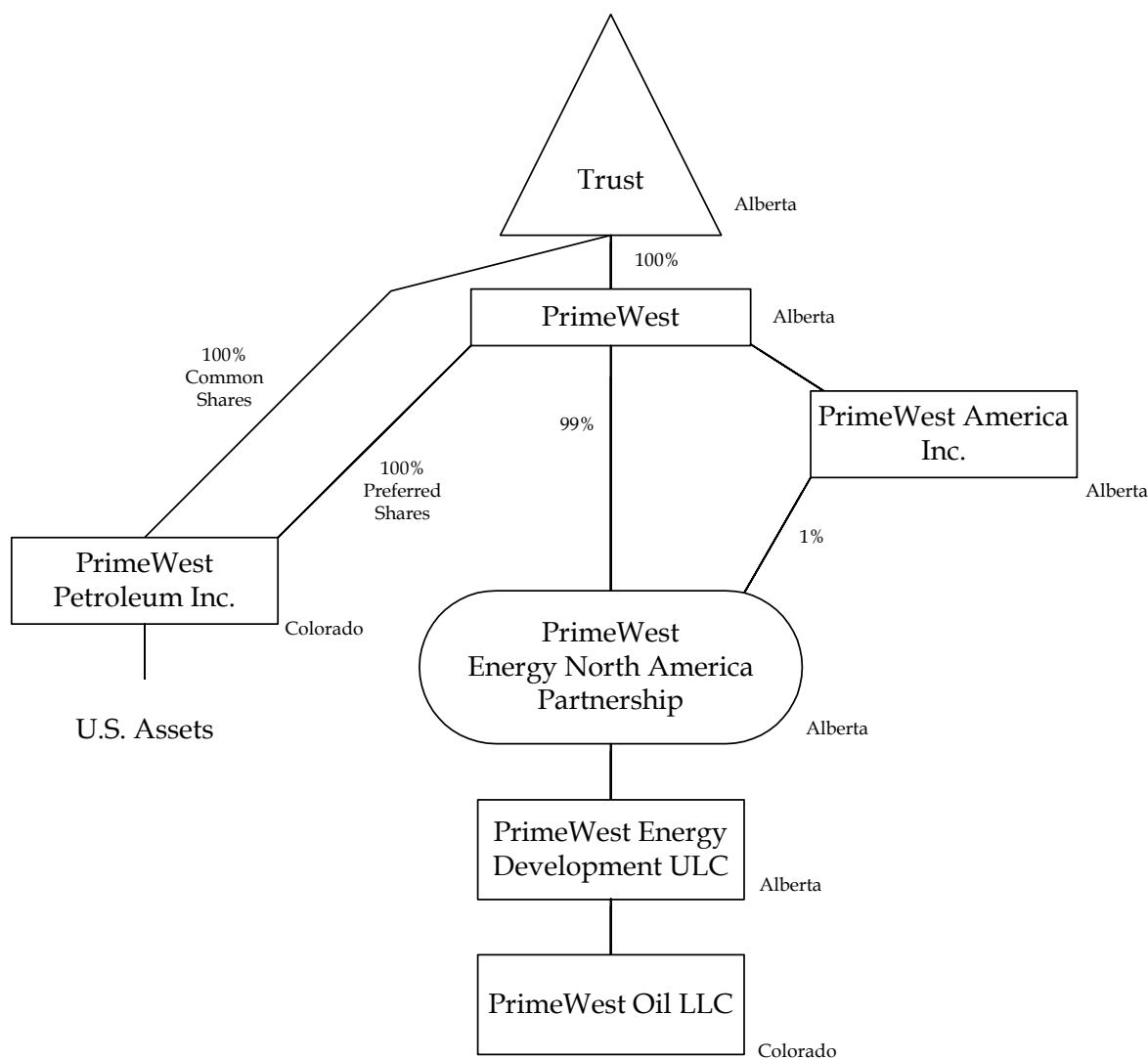
PrimeWest Gas Corp. ("PrimeWest Gas") was amalgamated under the *Business Corporations Act* (Alberta) on January 24, 2003 in connection with the acquisition by PrimeWest of two privately held Canadian corporations. PrimeWest Gas was wholly owned by PrimeWest and was an operating subsidiary of PrimeWest and the Trust. PrimeWest Gas was amalgamated with the Operating Company on January 1, 2006 and continued as PrimeWest.

PrimeWest Petroleum Inc. ("PrimeWest Petroleum"), a Colorado corporation, was incorporated on July 6, 2006, along with various related entities (see Trust Structure below), in conjunction with the acquisition of producing Oil and Gas assets, the majority of which are located in Montana, North Dakota and Wyoming (the "US Assets"), in order to complete such acquisition, and to exploit and operate the US Assets for the benefit of the Trust and the Unitholders. All of the issued and outstanding common shares of PrimeWest Petroleum are owned directly by the Trust, while all of the issued and outstanding preferred shares are owned directly by PrimeWest.

The principal undertaking of the Trust is to acquire and hold, directly and indirectly, interests in Oil and Natural Gas Properties. One of the Trust's primary assets is the Royalty granted by PrimeWest pursuant to the Royalty Agreements. The Royalty entitles the Trust to receive 99% of the Net cash flow generated by the Oil and Natural Gas interests held from time to time by PrimeWest, after certain costs and deductions. The balance of such Net cash flow may be retained by PrimeWest to fund its working capital and other business and operating requirements, or may be passed on to the Trust to support distributions to Unitholders. The Distributable Income resulting from the Royalty and other amounts received by the Trust is then distributed monthly to Unitholders.

TRUST STRUCTURE

The following diagram represents the current structure of the Trust and shows the flow of funds from the Oil and Natural Gas Properties owned, directly or indirectly, by PrimeWest and the gross overriding royalties owned directly by the Trust, as well as the flow of funds to PrimeWest and from the Trust to Unitholders:



THE DECLARATION OF TRUST

The Declaration of Trust, among other things, provides for the calling of meetings of Unitholders, the conduct of business at those meetings, notice provisions, the appointment, resignation and removal of the Trustee and the form of Trust Unit certificates. The Declaration of Trust may be amended from time to time. Substantive amendments to the Declaration of Trust, including extension or early termination of the Trust and the sale or transfer of the property of the Trust as an entirety, or substantially as an entirety, require approval by special resolution of the Unitholders.

The following is a summary of certain provisions of the Declaration of Trust. Complete copies of the Declaration of Trust may be viewed at the offices of, or obtained from, the Trustee.

TRUST UNITS

An unlimited number of Trust Units may be issued pursuant to the Declaration of Trust, each of which represents an equal fractional undivided beneficial interest in the Trust entitling the holder to receive monthly distributions of Distributable Income.

All Trust Units share equally in all distributions from the Trust, carry equal voting rights at meetings of Unitholders and have a right of redemption on terms set out in the Declaration of Trust. No Unitholder is liable to pay any further calls or assessments in respect of the Trust Units.

The Trust Units are not “deposits” within the meaning of the *Canada Deposit Insurance Corporation Act* (Canada) and are not insured under the provisions of that, or any other legislation, as it does not carry on or intend to carry on the business of a trust company.

EXCHANGEABLE SHARES OF PRIMEWEST

An unlimited number of Exchangeable Shares may be issued by the Operating Company, each of which entitles the holder to exchange such Exchangeable Shares at any time into a number of Trust Units, based on an exchange ratio then in effect. The exchange ratio is determined by reference to the distributions paid on Trust Units in a given month and the current market price of the Trust Units. On December 31, 2006, each Exchangeable Share was exchangeable for 0.63765 Trust Units.

PrimeWest issued Exchangeable Shares in connection with the internalization of management in November 2002 and the acquisitions of Cypress Energy Inc. (“Cypress”) in March 2001 and Venator Petroleum Company Ltd. (“Venator”) in April 2000. Shareholders of Cypress, Venator, and others who received Exchangeable Shares could, in certain circumstances, defer the tax consequences of that exchange. PrimeWest may issue additional Exchangeable Shares in connection with future acquisitions or to address other capital requirements.

The Exchangeable Shares provide holders with economic terms and voting rights, which are, as nearly as practicable, equivalent to those of Trust Units. The Exchangeable Shares are maintained economically equivalent to the Trust Units by the progressive increase in an exchange ratio, incorporating the distributions provided to Unitholders and reflecting the right to acquire an ever-increasing number of Trust Units per Exchangeable Share. The Exchangeable Shares are provided voting rights equivalent to those of Unitholders through a voting trust agreement pursuant to which the holders of Exchangeable Shares can direct Computershare, in its capacity as the voting and exchange trustee, to vote at meeting of the Unitholders. The Exchangeable Shares are listed and posted for trading on the Toronto Stock Exchange (“TSX”) under the symbol “PWX”.

TRUSTEE

Computershare is the current Trustee of the Trust and also acts as the transfer agent for the Trust Units, the Exchangeable Shares, the Series I Debentures, the Series II Debentures and the Series III Debentures. The Trustee is responsible for, among other things: (a) accepting subscriptions for Trust Units and issuing Trust Units pursuant thereto; (b) maintaining the books and records of the Trust and providing timely reports to Unitholders; and (c) paying cash distributions to Unitholders.

The Declaration of Trust provides that the Trustee is to exercise its powers and carry out its functions thereunder as Trustee honestly, in good faith and in the best interests of the Trust and the Unitholders, and, in connection therewith, must exercise that degree of care, diligence, and skill that a reasonably prudent trustee would exercise in comparable circumstances.

The current term of the Trustee’s appointment expires at the conclusion of the 2007 annual general meeting of Unitholders that takes place in 2008. Thereafter, the Trustee will be reappointed or changed every third annual meeting as may be determined by a majority of the votes cast at a meeting of the Unitholders. The Trustee may also be removed by a majority vote of the Unitholders in that regard. The Trustee may resign on 60 days’ notice to PrimeWest. That resignation or removal becomes effective on the appointment of a successor trustee along with the acceptance of that appointment and the assumption of the obligations of the Trustee by that successor trustee.

CASH DISTRIBUTIONS

Cash distributions of Distributable Income are made on a monthly basis on the Cash Distribution Date following the end of each month to Unitholders of record on the Record Date in that month. Since August 2003, PrimeWest has followed a strategy of maintaining distributions within approximately 70% to 90% of funds flow from operations, calculated on an annual basis.

Due to the volatile nature of commodity prices, PrimeWest expects that the payout ratio may move outside the target 70% to 90% range from time to time. The Board of Directors 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. Further, the October 31 Proposals discussed below under Taxation of the Trust, have created additional uncertainty with respect to the payout ratio. At this time, PrimeWest is unable to predict what payout ratio it will be able to maintain in the future.

The following table sets forth cash distributions per Trust Unit paid since 2004.

Record Date ⁽¹⁾	Payable Date	Cdn\$ Amount	US/Cdn Exchange Rate ⁽²⁾	US\$ Amount
December 22, 2003	January 15, 2004	\$ 0.320	1.2979	\$ 0.2465
January 22, 2004	February 13, 2004	0.320	1.3163	0.2431
February 20, 2004	March 15, 2004	0.250	1.3340	0.1874
March 22, 2004	April 15, 2004	0.250	1.3432	0.1861
April 22, 2004	May 14, 2004	0.250	1.3902	0.1798
May 21, 2004	June 15, 2004	0.250	1.3688	0.1826
June 22, 2004	July 15, 2004	0.250	1.3246	0.1887
July 22, 2004	August 13, 2004	0.250	1.3089	0.1910
August 23, 2004	September 15, 2004	0.275	1.2972	0.2120
September 22, 2004	October 15, 2004	0.300	1.2526	0.2395
October 22, 2004	November 15, 2004	0.300	1.2005	0.2499
November 23, 2004	December 15, 2004	0.300	1.2247	0.2450
December 22, 2004	January 14, 2005	0.300	1.2156	0.2468
2004 Total		\$ 3.615		\$ 2.7984
January 20, 2005	February 15, 2005	0.300	1.2306	0.2438
February 22, 2005	March 15, 2005	0.300	1.2069	0.2486
March 22, 2005	April 15, 2005	0.300	1.2467	0.2406
April 22, 2005	May 13, 2005	0.300	1.2653	0.2370
May 20, 2005	June 15, 2005	0.300	1.2374	0.2424
June 22, 2005	July 15, 2005	0.300	1.2207	0.2458
July 26, 2005	August 15, 2005	0.300	1.1993	0.2501
August 23, 2005	September 15, 2005	0.300	1.1848	0.2532
September 22, 2005	October 14, 2005	0.300	1.1854	0.2531
October 24, 2005	November 15, 2005	0.300	1.1922	0.2516
November 23, 2005	December 15, 2005	0.300	1.1598	0.2587
December 22, 2005	January 13, 2006	0.360	1.1604	0.3102
2005 Total		\$ 3.660		\$ 3.035
January 23, 2006	February 15, 2006	0.360	1.1583	0.3108
February 23, 2006	March 15, 2006	0.360	1.1546	0.3118
March 22, 2006	April 13, 2006	0.360	1.1509	0.3128
April 24, 2006	May 15, 2006	0.360	1.1135	0.3233
May 23, 2006	June 15, 2006	0.360	1.1128	0.3235
June 22, 2006	July 14, 2006	0.300	1.1173	0.2685
July 21, 2006	August 15, 2006	0.300	1.1377	0.2637
August 22, 2006	September 15, 2006	0.300	1.1152	0.2690
September 22, 2006	October 13, 2006	0.300	1.1368	0.2639
October 23, 2006	November 15, 2006	0.250	1.1390	0.2195
November 22, 2006	December 15, 2006	0.250	1.1574	0.2160
December 22, 2006	January 15, 2007	0.250	1.1682	0.2140
2006 Total		\$3.750		\$3.2968

Notes:

- (1) Monthly information refers to the month in which the Record Date for the relevant distribution occurs with payment being made on the Cash Distribution Date in the following month.
- (2) Exchange rate information is based on the exchange rate in effect on the date of payment.

As of January 2004, Canadian securities law states that the taxability for distributions are on an accrual basis, based on the month the Record Date falls in (i.e. the December record date with a January distribution payment is taxable in the previous year). US securities law states that the taxability for distributions is taxed on an actual basis (i.e. only the payments made in the current tax year are considered taxable).

REDEMPTION RIGHT

Trust Units are redeemable at any time on demand by the holder thereof upon delivery to the Trust of the certificates representing such Trust Units, accompanied by a duly completed and properly executed notice requesting redemption. Upon the receipt of the redemption request, all of the Unitholder's rights to and under the Trust Units tendered for redemption are surrendered and the Unitholder becomes entitled to receive a price per Trust Unit as determined by a market price formula, subject to a monthly aggregate cash cap of \$100,000. The redemption price payable by the Trust may be satisfied by way of a cash payment, or in certain circumstances, such as a payment that would cause the monthly cash cap to be exceeded, by way of an *in specie* distribution.

MEETINGS AND VOTING

Annual meetings of the Unitholders commenced in 1997. Special meetings of Unitholders may be called at any time by the Trustee and will be called by the Trustee on the written request of Unitholders holding in aggregate not less than 20% of the outstanding Trust Units. Notice of all meetings of Unitholders will be given to Unitholders at least 21 days and not more than 50 days prior to the meeting.

Unitholders may attend and vote at all meetings of such Unitholders either in Person or by proxy. The proxy holder need not be a holder of Trust Units. At least two Persons present in person or represented by proxy and representing in the aggregate not less than 5% of the votes attaching to all outstanding Trust Units constitute a quorum for the transaction of business at all of those meetings. Unitholders are entitled to one vote per Trust Unit held.

LIMITATION ON NON-RESIDENT OWNERSHIP

PrimeWest continues to remain exempt from any restrictions on non-resident ownership of its Trust Units, and there is no specified date on or before which it would become subject to any such restrictions. In the event that the Department of Finance determines to limit the extent to which non-residents should be permitted to invest in units of royalty trusts (including PrimeWest), or PrimeWest otherwise becomes subject to the existing limitations in paragraph 132(7)(a) of the *Tax Act* that apply to other mutual fund trusts, the Declaration of Trust, as amended, provides:

- a) If at any time the Board of Directors of PrimeWest determines, in its sole discretion, or becomes aware, that the Trust's ability to continue to rely on paragraph 132(7)(a) of the *Tax Act* for purposes of qualifying as a "mutual fund trust" thereunder is in jeopardy, then the Trust shall not be maintained primarily for the benefit of non-residents of Canada and it shall be the sole responsibility of PrimeWest to monitor the holdings by non-residents of Canada and take such steps as are necessary or desirable to ensure that the Trust is not maintained primarily for the benefit of non-residents of Canada;
- b) PrimeWest may request that the Trustee make reasonable efforts, as practicable in the circumstances, to obtain declarations as to beneficial ownership, perform residency searches of Unitholder and beneficial Unitholder mailing address lists and take such other steps specified by PrimeWest to determine or estimate as best possible the residence of the beneficial owners of Trust Units; and
- c) If at any time the Board of Directors of PrimeWest, in its sole discretion, determines that it is in the best interest of the Trust, PrimeWest may, notwithstanding the ability of the Trust to continue to rely on paragraph 132(7)(a) of the *Tax Act*.

- (i) Require the Trustee to refuse to accept a subscription for Trust Units from, or issue or register a transfer of Trust Units to, a person unless the person provides a declaration to PrimeWest that the Trust Units to be issued or transferred to such person will not when issued or transferred be beneficially owned by a non-resident of Canada;
- (ii) To the extent practicable in the circumstances, send a notice to registered holders of Trust Units which are beneficially owned by non-residents of Canada, chosen in inverse order to the order of acquisition or registration of such Trust Units beneficially owned by non-residents of Canada or in such other manner as PrimeWest may consider equitable and practicable, requiring them to sell their Trust Units which are beneficially owned by non-residents of Canada or a specified portion thereof within a specified period of not less than 60 days. If the Unitholders receiving such notice have not sold the specified number of such Trust Units or provided PrimeWest with satisfactory evidence that such Trust Units are not beneficially owned by non-residents within such period, PrimeWest may, on behalf of such registered Unitholder, sell such Trust Units and, in the interim, suspend the voting and distribution rights attached to such Trust Units and make any distribution in respect of such Trust Units by depositing such amount in a separate bank account in a Canadian chartered bank (net of any applicable taxes). Any sale shall be made on any stock exchange on which the Trust Units are then listed and, upon such sale, the affected holders shall cease to be holders of Trust Units so disposed of and their rights shall be limited to receiving the net proceeds of sale, and any distribution in respect thereof deposited as aforesaid, net of applicable taxes and costs of sale, upon surrender of the certificates representing such Trust Units;
- (iii) De-list the Trust Units from any non-Canadian stock exchange; and
- (iv) Take such other actions as the Board of Directors of PrimeWest determines, in its sole discretion, are appropriate in the circumstances that will reduce or limit the number of Trust Units held by non-resident Unitholders to ensure that the Trust is not maintained primarily for the benefit of non-residents of Canada.

TAXATION OF THE TRUST

On October 31, 2006, the Minister of Finance (Canada) ("Finance") announced proposed changes to the taxation of certain publicly-traded trusts and partnerships and their unitholders. These changes, assuming they are enacted, would apply, in the case of trusts, to a trust that is resident in Canada for purposes of the *Tax Act*, holds one or more "non-portfolio properties", and the units of which are listed on a stock exchange or other public market (a "specified investment flow-through trust", or "SIFT trust"). In the case of a SIFT trust the units of which were already publicly traded on October 31, 2006, the proposed changes generally would not take effect until January 1, 2011, provided the trust experiences only "normal growth" and no "undue expansion" before then. On December 15, 2006 Finance issued guidelines with respect to what would be considered "normal growth" for this purpose, and on December 21, 2006 Finance released draft legislative proposals to implement the changes previously announced on October 31, 2006. On January 30, 2007, Finance confirmed the Government's intention to proceed with these proposals. The October 31, 2006 proposals, December 15, 2006 guidelines and December 21, 2006 draft legislation are hereinafter collectively referred to as the "October 31 Proposals".

Until such time as the October 31 Proposals apply to the Trust, which is not expected to be until January 1, 2011, it is expected that:

- a) the Trust will continue not to be liable for any material amount of Canadian income tax;
- b) returns on capital generally will be taxed as ordinary income or as dividends in the hands of a Unitholder who is resident in Canada for purposes of the *Tax Act*, and will be subject to withholding tax at a rate of 25% (subject to a reduction in such rate under the terms of an applicable tax treaty or convention) when paid to a non-resident Unitholder;

- c) returns of capital paid to a Unitholder who is resident in Canada for purposes of the *Tax Act* generally will not be included in the Unitholder's income but will reduce the adjusted cost base of the Unitholder's Trust Units; and
- d) returns of capital paid to a non-resident Unitholder will be subject to the special 15% Canadian withholding tax under Part XIII.2 of the *Tax Act*.

Pursuant to the October 31 Proposals, commencing January 1, 2011, the Trust will be subject to tax on its income from non-portfolio properties and taxable capital gains from dispositions of non-portfolio properties, that is paid or payable to Unitholders, at a rate of 31.5% (comparable to the projected combined federal and provincial corporate income tax rate in 2011), and distributions of such income to Unitholders will be treated as dividends paid by a taxable Canadian corporation. The Royalty and the shares and notes of PrimeWest will constitute "non-portfolio properties" of the Trust under the October 31 Proposals, with the result that virtually all of the Trust's income, including any taxable capital gains, would be subject to the 31.5% tax, and distributions of such income by the Trust to its Unitholders would be treated as dividends paid by a taxable Canadian corporation. Returns of capital by the Trust to its Unitholders would not be affected by the October 31 Proposals and would continue to be taxed in the same manner as under the current rules.

As noted above, the Trust could become subject to these changes before 2011 if it experiences growth, other than "normal growth", before that time. Under the December 15, 2006 guidelines, the Trust will be considered to have experienced only "normal growth" if its issuances of new equity (which for this purpose includes Trust Units and debt that is convertible into Trust Units, but does not include non-convertible debt) do not exceed, for each of the intervening periods set forth below, a safe harbour measured by reference to the Trust's market capitalization as of the end of trading on October 31, 2006 (measured solely by the value of the Trust's issued and outstanding publicly-traded Trust Units as of that date). The Trust's market capitalization as of October 31, 2006 was approximately \$2.379 billion. The intervening periods and their respective safe harbour amounts are as follows:

- a) November 1, 2006 to December 31, 2007 – 40% of the Trust's market capitalization as of October 31, 2006;
- b) January 1, 2008 to December 31, 2008 – 20% of the Trust's market capitalization as of October 31, 2006;
- c) January 1, 2009 to December 31, 2009 – 20% of the Trust's market capitalization as of October 31, 2006;
- d) January 1, 2010 to December 31, 2010 – 20% of the Trust's market capitalization as of October 31, 2006.

The December 15, 2006 guidelines provide that these annual safe harbour amounts are cumulative, and that replacing debt that was outstanding as of October 31, 2006 with new equity, whether through a debenture conversion or otherwise, will not be considered growth for these purposes. In addition, an issuance of new equity will not be considered growth to the extent that the issuance is made in satisfaction of the exercise by another person of a right in place on October 31, 2006 to exchange an interest in a partnership, or a share of a corporation, for Trust Units.

COMPULSORY ACQUISITION

The Declaration of Trust provides that if a Person, within either 120 days of making an offer to purchase all outstanding Trust Units or the time for acceptance provided in that offer (provided that such offer is open for acceptance for a period of not less than 45 days), whichever period is the shorter, acquires not less than 90% of the outstanding Trust Units (other than those held by that Person and its affiliates), that Person may acquire the Trust Units of the Unitholders who did not accept the offer on the same terms as those offered to those Unitholders who accepted the offer.

TERMINATION OF THE TRUST

The Unitholders may vote to terminate the Trust at any meeting of the Unitholders, provided that the termination is approved by special resolution of the Unitholders.

Unless the Trust is terminated or extended by vote of the Unitholders earlier, the Trustee will commence to wind-up the affairs of the Trust on December 31, 2005. In the event that the Trust is wound-up, the Trustee will liquidate all the assets of the Trust, pay, retire, discharge or make provision for some or all obligations of the Trust and then distribute the remaining proceeds of the liquidation to Unitholders.

UNITHOLDERS RIGHTS PLAN

On March 31, 1999, PrimeWest announced that it had adopted a Unitholder Rights Plan (the "Rights Plan"). Unitholders approved the Rights Plan at the annual meeting of the Unitholders held on May 18, 1999. The Unitholders reconfirmed the Rights Plan at the annual meeting of the Unitholders held on May 21, 2002. At the annual meeting of Unitholders held on May 5, 2005, the Unitholders approved the amendment and restatement of the Rights Plan to provide that Unitholder approval must be sought for the continuance of the Rights Plan at every annual meeting of Unitholders and the Unitholders reconfirmed the Rights Plan for an initial period of one year. The Rights Plan was then set to expire on the date of PrimeWest's annual meeting in 2006, unless Unitholders reconfirmed the Rights Plan for a further term of one year at that time. Prior to the date of such annual meeting, the Board of Directors determined that the Rights Plan was no longer necessary or in the best interests of the Trust and its Unitholders. Therefore, PrimeWest did not request the Unitholders to approve the continuance of the Rights Plan for a further term and, as of the conclusion of the Meeting, the Rights Plan terminated in its entirety.

DECISION MAKING

Unitholders are entitled to direct the election of the Board of Directors of PrimeWest, the approval of the financial statements of PrimeWest, the appointment of its auditors and other matters relating to the business and affairs of PrimeWest and the Trust.

The Board of Directors of PrimeWest is responsible for making significant decisions with respect to PrimeWest, including all decisions relating to, among other things: (a) the acquisition and disposition of significant Oil and Natural Gas Properties; (b) the approval of capital expenditure budgets; (c) the approval of risk management activities; and (d) the establishment of credit facilities. In addition, the Trustee has delegated certain matters regarding the Trust to PrimeWest, including all decisions relating to (a) issuances of Trust Units; (b) the determination of the amount of distributions to be made by the Trust; (c) approvals required with regard to any proposed amendment to the Declaration of Trust of the Royalty Agreements and other aspects respecting the relationship between the Trust and PrimeWest; and (d) responding to unsolicited takeover or merger proposals. The Board of Directors of PrimeWest holds regularly scheduled meetings to review the business and affairs of PrimeWest and the Trust.

ITEM 2: GENERAL DEVELOPMENT OF THE BUSINESS

On October 16, 1996, the Trust completed an initial public offering of 24,900,000 Trust Units (before giving effect to the Consolidation) on an instalment receipt basis of \$6.00 payable on October 16, 1996 and \$4.00 payable one year later, for total gross proceeds of \$249,000,000. The Trust used the net proceeds of that offering, plus the assignment of the right to be paid the final instalment of \$4.00 per Trust Unit, to purchase the Royalty from PrimeWest. PrimeWest used the net proceeds from the sale of the Royalty to the Trust and debt to acquire certain Oil and Natural Gas Properties.

Since inception, PrimeWest has been an active acquirer of Oil and Natural Gas Properties in the Western Canada Sedimentary Basin. In 2006, PrimeWest expanded its geographic range when it acquired the US Assets. . Many of those acquisitions were financed, directly or indirectly, through the issuance of Trust Units and Exchangeable Shares. The following tables summarize the more significant acquisitions and financings completed by PrimeWest, directly or indirectly, since January 1, 2004.

ACQUISITIONS

Date	Company/Properties Acquired	Aggregate Purchase Price (C\$)	Reserves and Production Acquired
March 2004	Seventh Energy Ltd.	\$34.8 million (cash), plus debt	3.3 mmBOE ⁽¹⁾ 1,300 BOE/day
September 2004	Assets of Calpine Canada Natural Gas Partnership	\$740 million (cash)	54.8 mmBOE ⁽¹⁾ 14,500 BOE/day
September 2004	6.8 million units of Calpine Natural Gas Trust at \$10.89 per unit, representing a 25% equity interest	\$72.7 million (cash)	Investment in marketable securities. Market price at December 31, 2004 was \$13.45 per share.
July 2006	US producing assets in Montana, Wyoming, North Dakota and Saskatchewan	\$336.7 million (cash)	28.9 mmBOE ⁽¹⁾ 3,200 BOE/day
August 2006	Caroline assets of Grey Wolf Exploration Inc.	\$31.9 million (cash)	1.8 mmBOE 550 BOE/day

Note:

(1) Company Interest Proved plus Probable Reserves.

PUBLIC OFFERINGS

Date	Number of Securities Issued	Type of Security	Price per Security	Gross Proceeds (\$ Millions)
April 2004	5,400,000	Trust Units	\$26.30	\$142.0
September 2004	12,300,000	Trust Units	\$24.40	\$300.1
September 2004	150,000	Series I Debentures	\$1,000.00	\$150.0
September 2004	100,000	Series II Debentures	\$1,000.00	\$100.0
July 28, 2006 to September 30, 2006	599,950	Trust Units	Various	\$20.3
January 2007	6,420,000	Trust Units	\$23.35	\$149.9
January 2007	200,000	Series III Debentures	\$1,000.00	\$200.0

Note:

(1) Trust Units issued at prevailing market prices through the facilities of the NYSE from time to time during the quarter pursuant to the Trust's "at-the market" offering under a base shelf prospectus dated May 12, 2006 and a shelf prospectus supplemental on dated July 28, 2006.

Other significant developments since January 1, 2004 include the following:

- On January 27, 2004, PrimeWest announced that PrimeWest Gas had entered into an agreement to acquire all the outstanding shares of Seventh Energy Ltd. ("Seventh") for cash consideration of \$34.8 million plus assumed debt of \$9.9 million. On February 6, 2004, PrimeWest Gas mailed a formal takeover circular to the shareholders of Seventh, and following taking up and paying for 92% of the issued and outstanding shares of Seventh pursuant to the takeover on March 16, 2004, completed the compulsory acquisition of the remaining Seventh shares.
- In February 2004, the Board of Directors of PrimeWest resolved to establish a new board committee called the Operations and Reserves Committee. In April 2004, as a result of the annual assessment of the Board of Director's performance, and in order to reflect the establishment of the Operations and Reserves Committee, the Board of Directors resolved to restructure all of the board committees. The effects of this restructuring were to reduce the number of directors sitting on each committee and to transfer the Reserves functions previously handled by the Audit and Reserves Committee to the Operations and Reserves Committee. The names of certain committees were changed to reflect this restructuring such that the current committees of the Board of Directors consist of the Audit and Finance Committee, the Corporate Governance and EH&S Committee, the Operations and Reserves Committee and the Compensation Committee.
- On April 15, 2004, PrimeWest announced the appointment of Mr. Peter Valentine as an independent member of the Board of Directors. Mr. Valentine was also appointed as a member of the Audit and Finance Committee of the Board of Directors.
- On August 16, 2004, PrimeWest announced that PrimeWest Gas and the Trust had entered into an agreement with Calpine Canada Natural Gas Partnership, Calpine Energy Holdings Limited and Calpine Corporation ("Calpine") for the purchase of all of the Canadian Oil and Natural Gas Reserves and related assets owned by Calpine Canada Natural Gas Partnership and 6,766,540 trust units of Calpine Natural Gas Trust, owned by Calpine Energy Holdings Limited, for a total consideration of \$814.7 million, including closing costs (collectively the "Calpine Acquisition"). The Calpine Acquisition was financed, in part, through a public offering of Trust Units and the Series I Debentures and the Series II Debentures, as discussed in greater detail below. The acquisition closed on September 2, 2004.
- The Calpine Acquisition included approximately 14,500 BOE/day of high quality, predominantly liquids rich Natural Gas Production in west central and southern Alberta, weighted 83% to Natural Gas, 11% to Natural Gas Liquids and 6% to Crude Oil. Current Production from the Calpine Acquisition is approximately 14,406 BOE/day. Based upon an independent engineering determination as of July 1, 2004, conducted in accordance with NI 51-101, approximately 54.8 mmBOE of Proved plus Probable Reserves, including gross overriding royalty interests, were acquired through this transaction. The Proved plus Probable Reserve Life Index of the Calpine Properties is 10.5 years. The Properties are 73% operated; with an average working interest of approximately 60% and more than one half of the Production is concentrated in three key areas that are in proximity to PrimeWest's existing core operations. Undeveloped land holdings of 627,306 Net acres and a seismic database, including all interpreted data, were included with the acquired assets. Full tax pools, up to the purchase price of the assets, were also acquired, reducing the taxability of distributions.
- In conjunction with the Calpine Acquisition, PrimeWest issued 12,300,000 Units at \$24.40 per unit, for gross proceeds of \$300.1 million, pursuant to a bought deal financing. In addition, PrimeWest issued \$150 million of Series I Debentures and \$100 million of Series II Debentures. Total Net proceeds from both the Trust Unit offering and the Series I Debentures and Series II Debentures were approximately \$525 million.
- During the second quarter of 2004, the Alberta Energy and Utilities Board ("EUB") ruled on the Natural Gas over bitumen issue, which resulted in approximately 330 BOE/day of Production at Ells being permanently shut-in effective July 1, 2004. In October 2004, the Government of Alberta enacted amendments to the Natural Gas Royalty Regulations of 2002 specifically with

respect to Gas Production in the affected area. This amendment provides for a technical change to the royalty calculation for Gas producers adversely affected by the EUB shut-in orders. This technical change to the calculation of royalties represents a reduction in royalties paid by PrimeWest to the Province of Alberta.

- During 2004, PrimeWest acquired additional Properties in its core areas of Crossfield and at Princess, which forms part of its Southern Alberta Shallow Gas play. Total consideration paid for both Properties was approximately \$32 million.
- During 2004 and early 2005, PrimeWest closed sales of assets in the areas of Dawson, northern Alberta, southeast Alberta, southwest Saskatchewan and other miscellaneous non-core areas. The divestitures represented Production of approximately 3,000 BOE/day, for proceeds of \$104.9 million.
- On January 26, 2005, Standard & Poor's announced the inclusion of income trusts in the S&P/TSX Composite Index, Canada's benchmark stock index.
- On January 27, 2005 the unitholders of Calpine Natural Gas Trust approved the business combination with Viking Energy Royalty Trust. As a result, PrimeWest's 25% unit ownership of Calpine Natural Gas Trust was converted into an 8.3% unit ownership of Viking Energy Royalty Trust. As of February 24, 2005, PrimeWest sold its 8.3% ownership of Viking Energy Royalty Trust for gross proceeds of \$95.8 million, representing a gain of \$27.1 million.
- On May 5, 2005, Mr. Valentine was appointed as Chair of the Audit and Finance Committee of the Board of Directors.
- On May 5, 2005, the Board of Directors approved, subject to regulatory approval, offering the conventional portion of the DRIP to US resident Unitholders. The offering to US resident Unitholders was officially launched on September 8, 2005. This allows both US resident and Canadian resident Unitholders the option of either reinvesting their monthly distributions in Trust Units or continuing to receive cash payments.
- On December 16, 2005, Standard & Poor's included trusts in the S&P/TSX Composite Index at 50% of each respective trusts' full float. The remaining 50% of the float will be included at the quarterly rebalancing in March 2006. PrimeWest's weighting in the index is approximately 0.116% at December 31, 2005.
- Effective January 1, 2006, PrimeWest Gas was amalgamated into PrimeWest.
- Effective February 23, 2006, Mr. Brian J. Lynam, B.A. Sc., P.Eng. joined the executive team of the Trust in the position of Vice-President, Operations.
- Effective February 23, 2006, Mr. Gordon D. Haun, B.A., LLB, was appointed an officer and General Counsel and Corporate Secretary of the Trust.
- On May 12, 2006, PrimeWest filed a Short Form Base Shelf Prospectus with the securities regulatory authorities in Canada and a registration statement on form F-10 with the SEC. The registration allows PrimeWest to offer and issue Trust Units by way of one or more prospectus supplements at any time during the 25-month period that the base shelf prospectus remains in place. The Trust Units will be issued from time to time at the discretion of PrimeWest, with an aggregate offering amount not to exceed \$750,000,000. Unless otherwise specified in a prospectus supplement, the net proceeds of the offerings will be added to the general funds of the Trust and will be used for general business purposes.
- On June 5, 2006, PrimeWest announced a reduction to the monthly distribution payment, effective July 14, 2006 to \$0.30 per Trust Unit, down from \$0.36 per Trust Unit. The reduction was necessitated by weakening natural gas prices during 2006.
- On June 15, 2006, PrimeWest announced the completion of a U.K. private placement issuance of £63 million Senior Secured Term Notes ("Notes") maturing June 14, 2016 bearing interest at 5.93% per annum. The Notes were purchased by institutional investors in the United Kingdom. Proceeds from the private placement were used to replace a portion of PrimeWest's revolving Credit Facility.

- On July 6, 2006, PrimeWest closed the acquisition of the US business assets for total consideration of approximately \$336.7 million (US\$303 million). The major fields acquired are Flat Lake, Dwyer, and Goose Lake in Montana; Rival, Grenora, Alexander, Wiley, Glenburn and Sherwood in North Dakota; Rocky Point in Wyoming and Saskatchewan. The most prolific field is Flat Lake, which is geologically similar to the producing fields found immediately north of the Canada/US border in the Province of Saskatchewan.
- Based on an independent Reserves evaluation dated April 1, 2006, conducted by GLJ, the remaining Company Interest Reserves of the US Assets are estimated as: 10.9 mmbbls Proved Developed Producing (PDP), 20.4 mmbbls Total Proved (TP) and 28.9 mmbbls Proved plus Probable (P+P) Reserves, consisting of 94% Crude Oil. Refer to Section IV, Statement of Reserves Data for further Reserves information. The assets have over 400 million barrels (mmbbls) of original oil in place (OOIP) with an average recovery to date of 17%. The US Assets are long Reserve Life Index assets (PDP = 9.3 years; TP = 17.4 years; P+P = 23.8 years). The acquisition included a land base of 47,000 Net acres (89% working interest, no value assigned). The purchase price of the acquired assets does not include value expected to be realized from PrimeWest identified waterflood and horizontal drilling upside.
- The acquisition of the US Assets was financed through PrimeWest's existing credit lines plus a supplementary credit line of C\$250 million.
- On July 28, 2006, PrimeWest filed a prospectus supplement to the Short Form Base Shelf Prospectus dated May 12, 2006 with securities regulatory authorities in Canada and with the SEC. The registration allows PrimeWest to offer and sell up to 3,000,000 Trust Units, from time to time through Cantor Fitzgerald & Co., as the Trust's agent for the offer and sale of the Trust Units.
- August 2, 2006, Barry E. Ernes was appointed a member of the Audit and Finance Committee by the Board of Directors and Kent J. MacIntyre was appointed a member of the Compensation Committee.
- Effective August 15, 2006, W. Glen Russell replaced Harold N. Kvisle as Chair of the Compensation Committee. Mr. Kvisle has continued as a member of the Committee. Also effective August 15, 2006, Kent J. Macintyre replaced Mr. Russell as Chair of the Operations and Reserves Committee. Mr. Russell has continued as a member of the Operations and Reserves Committee.
- On August 25, 2006, PrimeWest closed the acquisition of producing Oil and Gas assets located in its Caroline, Alberta core area from Grey Wolf Exploration Inc. for total consideration of approximately \$31.9 million, pursuant to the exercise of the buyback option under the Caroline Farmout Agreement dated January 23, 2003.
- On October 10, 2006, PrimeWest announced a reduction in the distribution level, effective November 15, to \$0.25 per Trust Unit, down from \$0.30 per Trust Unit. The reduction in the distribution reflects the continued weakness in natural gas prices experienced during 2006.
- On October 31, 2006, the Government of Canada announced the proposed Tax Fairness Plan.
- On January 11, 2007, PrimeWest issued 6,420,000 Units at \$23.35 per unit, for gross proceeds of \$149.9 million, pursuant to a bought deal financing. In addition, PrimeWest issued \$200 million of Series III Debentures. Total net proceeds from both the Trust Unit offering and the Series III Debentures were approximately \$334 million and will be used to repay a portion of the \$427.9 million of indebtedness outstanding on October 31, 2006 under PrimeWest's Credit Facility.
- Effective January 31, 2007, Mr. Gordon D. Haun, General Counsel and Corporate Secretary of the Trust, was appointed to the position of Vice President Legal and General Counsel, while maintaining the duties of Corporate Secretary.

ITEM 3: NARRATIVE DESCRIPTION OF THE BUSINESS**THE BUSINESS OF THE TRUST**

The undertakings of the Trust are to acquire and hold Oil and Natural Gas Properties, to produce, market and sell Oil, Natural Gas and Natural Gas Liquids from such Properties and to distribute the Distributable Income generated therefrom to Unitholders. It is therefore the mandate of PrimeWest to continue to source and acquire Oil and Natural Gas Properties both for and on behalf of itself and the Trust, and to enhance the Production from both acquired and existing Properties in order to increase the amount of Distributable Income distributed to Unitholders.

OPERATORSHIP

While operatorship of the Properties generally involves higher General and Administrative Costs than would be required for non-operated Properties, PrimeWest believes that those higher costs will generally result in more opportunities to enhance value to Unitholders through Production enhancement, control of facilities, control of costs and increased access to acquisition opportunities in core areas.

Currently, PrimeWest operates Properties representing approximately 80% of the aggregate daily Production.

ACQUISITIONS

Unless PrimeWest and the Trust are able to acquire additional Oil and Natural Gas Reserves or increase Reserves through development activities, Production from the currently held Properties will continue to decline. PrimeWest continually reviews opportunities for the acquisition of producing Oil and Natural Gas Properties. When considering the acquisition of any Oil and Natural Gas producing Property, PrimeWest focuses on longer-life Reserves, with lower reservoir risk, that may be operated by either PrimeWest or other acceptable operators and that have the potential to increase Distributable Income and enhance the Trust's value through exploitation of those Properties.

RISK MANAGEMENT AND MARKETING

Prices received for Production are impacted in varying degrees by factors outside of the Trust's control. These factors include but are not limited to the following:

- Political uncertainty, including the risk of hostilities, in the petroleum producing regions of the world that may impact petroleum supply;
- OPEC's ability to control Production to balance global supply and demand at desired price levels;
- Global economic growth and the resultant impact on energy demand;
- The effect of energy conservation and government regulations;
- The impact of weather conditions on supply and seasonal demand;
- The price levels and availability of competing alternative fuels;
- Increases or decreases in the price differential between light and Heavy Oil; and
- The impact of US/Canadian currency exchange on the Canadian prices realized by the Trust.

The above factors are outside the control of PrimeWest and can significantly affect the level of cash available for distribution to Unitholders. To mitigate the impact of some of these risks, through its commodity risk management program, PrimeWest actively uses financial hedging instruments to reduce the impact of the volatility of commodity prices. The Audit and Finance Committee, under guidelines approved by the Board of Directors, oversees the commodity risk management program. The effect of hedging activities is reviewed regularly by the Board of Directors and is fully disclosed externally through filings on SEDAR, EDGAR, quarterly releases and our website (www.primewestenergy.com).

As part of PrimeWest's risk-management strategy in 2006, 67% of full-year Crude Oil Production (2005 – 60%) and 49% of full-year Natural Gas Production (2005 – 55%) was hedged, net of royalties. Hedging strategies included the utilization of financial instruments with the primary objective of enhancing the

stability of cash distributions. PrimeWest also utilized an electrical power hedge during 2006. The power hedge consisted of an electricity swap comprised of 7.5 megawatts, representing approximately 38% of PrimeWest's total electrical power requirements. For the year ended December 31, 2006, the cash impact of contracts settling was a \$25.3 million gain comprised of a \$0.9 million gain in Crude Oil, a \$22.7 million gain in Natural Gas and a \$1.7 million gain on electrical power.

The Gas financial instruments consist of swaps, costless collars and 3-way deals. Costless collars involve the simultaneous purchase of a put option and sale of a call option at no cost. 3-way deals consist of the simultaneous purchase of a near the money put option and the sale of both an out of the money put and an out of the money call, all at no cost. The Oil financial instruments consisted of costless collars.

AS AT MARCH 15, 2007:

- PrimeWest has employed hedging structures using option-based instruments on approximately 56% of anticipated base Crude Oil Production, net of royalties, for 2007 and on 18% of its anticipated base Crude Oil Production, net of royalties, for 2008;
- PrimeWest has employed hedging structures using option-based instruments on approximately 55% of anticipated base Natural Gas Production, net of royalties, for 2007 and on approximately 19% of anticipated base Natural Gas Production, net of royalties, for 2008;
- PrimeWest does not currently employ any hedging structures for anticipated electrical power requirements for 2007 or for 2008;
- The intrinsic mark-to-market positions of all hedging contracts in place for the 2007 and 2008 Production years represent a net gain of \$6.5 million, as compared to a net gain of \$16.5 million when measured as at December 31, 2006. The intrinsic mark-to-market value is the aggregate amount of gains or losses that would be realized over time if all hedge positions were settled when they mature at the forward prices at December 31, 2006 and March 15, 2007, respectively; and
- The intrinsic plus extrinsic mark-to-market positions of all hedging contracts in place for the 2007 and 2008 Production years represent a net gain of \$9.4 million as compared to a net gain of \$24.1 million when measured as at December 31, 2006. The intrinsic plus extrinsic mark-to-market value is the amount of gains or losses that would be realized if all hedge positions were closed out on December 31, 2006 and March 15, 2007, respectively.

Beyond the hedging strategy, PrimeWest also mitigates risk by having a well-diversified marketing portfolio for Natural Gas and by transacting with a number of counterparties to limit exposure to any individual counterparty. Approximately 17% of Natural Gas Production is sold to aggregators and approximately 83% of Production is sold into the Alberta short-and long-term markets. The contracts that PrimeWest has in place with aggregators vary in length and represent a blend of domestic and US markets, with fixed and floating prices, which provide price diversification to our revenue stream.

In addition to the foregoing risk-management practices, while PrimeWest's portfolio of assets is weighted to Natural Gas, a significant portion of the portfolio consists of Crude Oil and NGL Reserves. Because Oil and Gas price cycles do not necessarily coincide, such a balance often provides a natural mitigation of price risk.

For 2006, PrimeWest's commodity mix was approximately 30% Oil and NGLs and 70% Natural Gas, compared to approximately 26% Oil and NGLs and 74% Natural Gas in 2005. PrimeWest realized hedge gains of \$23.6 million in 2006 and losses of \$44.3 million in 2005.

IMPACT OF ENVIRONMENTAL PROTECTION REQUIREMENTS

PrimeWest carries out its activities and operations in compliance with all relevant and applicable environmental regulations and good industry practice. PrimeWest has also created a segregated fund devoted to funding future costs for well abandonment and site cleanup. In 2006, PrimeWest contributed \$0.50/BOE of Production, totalling \$7.3 million, including interest and other investment income, while

approximately \$14.3 million was paid out for active projects completed. The cash balance in the reclamation fund was \$2.2 million at the end of 2006. The 2007 contribution rate remains at \$0.50/BOE of Canadian Production. Expenditures for environmental matters and site restoration are not reported as part of development capital or operating expense. Since the environmental standards and regulations to which PrimeWest is subject apply to all participants in the Oil and Gas industry, it is not anticipated that PrimeWest's competitive position within the industry will be adversely affected.

ITEM 4: STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The Statement of Reserves Data and other Oil and Gas information set forth below is dated January 24, 2007. The effective date of the statement is December 31, 2006 with a preparation date of the statement being January 15, 2007. The Report on Reserves Data by GLJ in Form 51-101F2 and the Report of Management and Directors on Reserves Data in Form 51-101F3 are attached as Schedules A and B to this Annual Information Form, respectively.

PRESENTATION OF OUR RESERVE INFORMATION

The SEC generally permits oil and gas companies, in their filings with the SEC, to disclose only Proved Reserves after the deduction of royalties and interests of others which are those Reserves that a company has demonstrated by actual Production or conclusive formation tests to be economically producible under existing economic and operating conditions. In 2003, the securities regulatory authorities in Canada (other than Quebec) adopted NI 51-101, which imposes Oil and Gas disclosure standards for Canadian public issuers engaged in Oil and Gas activities. NI 51-101 permits oil and gas issuers, in their filings with Canadian securities regulators, to disclose not only Proved Reserves but also Probable Reserves, and to disclose Reserves and Production on a Gross basis before deducting royalties. Probable Reserves are of a higher risk and are less likely to be accurately estimated or recovered than Proved Reserves. Because we are permitted to prepare this Annual Information Form in accordance with Canadian disclosure requirements, we have disclosed in this Annual Information Form and in the documents incorporated by reference Reserves designated as "Probable." If this Annual Information Form were required to be prepared in accordance with US disclosure requirements, the SEC's guidelines would prohibit Reserves in these categories from being included. Moreover, in accordance with Canadian practice, we have determined and disclosed estimated future net cash flow from our Reserves using both Forecast Prices and Costs and Constant Prices and Costs; for the Constant Prices and Costs case, prices and costs in effect as of December 31, 2006 were held constant for the economic life of the Reserves. The SEC does not permit the disclosure of estimated future net cash flow from Reserves based on escalating prices and costs and generally requires that prices and costs be held constant at levels in effect at the date of the reserve report. Additional information prepared in accordance with United States Statement of Financial Accounting Standards No. 69 "Disclosures About Oil and Gas Producing Activities" relating to our Oil and Gas Reserves is set forth in our Form 40-F which is available through EDGAR at the SEC's website at www.sec.gov.

Unless otherwise stated, all of the Reserves information contained in this Annual Information Form has been calculated and reported in accordance with NI 51-101.

EXPLORATION AND DEVELOPMENT

The primary focus of PrimeWest is to create value through accretive depletion strategies on existing assets and acquisition of new assets where accretive. Exploration plays not within the Corporation's risk tolerance will continue to be farmed out, sold or exchanged for producing Properties with upside potential. Development efforts will be concentrated on optimizing Production from existing and new Reserves, and developing new Properties in a cost effective manner. PrimeWest will continue its ongoing Property rationalization program and any Property disposition sale proceeds may be used to acquire interests in core areas or new prospects with exploitation opportunities.

ATTRIBUTES OF THE PROPERTIES

The Properties of PrimeWest and the Trust include interests in both non-unitized and unitized Oil and Natural Gas Production from several major Oil and Natural Gas fields. The following characteristics generally describe the attributes of the Properties:

- Reserve Life: The Properties include a mix of long life, lower decline rate Reserves and short life, higher decline rate Reserves all of which have an average Reserve Life Index of approximately 13.4 years based on Company Interest Proved plus Probable Reserves as at December 31, 2006 calculated in accordance with NI 51-101;
- Operated Properties: PrimeWest operates approximately 80% of the total Production from the Properties. In respect of these operated Properties, PrimeWest is able to exercise management and operating influence to maximize value for the benefit of the Trust;
- Natural Gas Weighted Portfolio: For the year ended December 31, 2006 Production from the Properties is approximately 30% Crude Oil and Natural Gas Liquids and 70% Natural Gas, on a barrel-of-oil-equivalent basis. As at December 31, 2006, Proved plus Probable Reserves for the Properties are approximately 35% Crude Oil and Natural Gas Liquids and 65% Natural Gas on a barrel-of-oil-equivalent basis;
- Diversified Portfolio: While the Trust's Properties are diversified from a geographic perspective, they have geological similarities across several core Properties, of which PrimeWest generally has the largest working interest in such core Properties; and
- Upside Potential: Additional opportunities to enhance the value of the Properties have been identified by PrimeWest. These opportunities may not have been included in the valuations provided in the GLJ Report.

RESERVES DATA

In accordance with NI 51-101, GLJ has prepared the GLJ Report dated January 24, 2007 evaluating, as at December 31, 2006, the Reserves of Crude Oil, Natural Gas and associated products attributed to the Properties prior to provision for interest costs and General and Administrative Costs, but after providing for estimated royalties, Production Costs, Development Costs, other income, future capital expenditures, and Well Abandonment Costs for only those wells assigned Reserves by GLJ. It should not be assumed that either the undiscounted or the discounted Future Net Revenue estimated by GLJ represent the fair market value of these Reserves. Other assumptions and qualifications relating to costs, prices for future Production and other matters are summarized in the notes following these tables.

CONSTANT PRICES AND COSTS

The following tables provide Reserves data and a breakdown of Future Net Revenue by component and Production group using Constant Prices and Costs, on a Company Interest, Gross and Net basis.

**SUMMARY OF OIL AND NATURAL GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2006
CONSTANT PRICES AND COSTS**

CONSOLIDATED CANADIAN AND US ASSETS

Reserves Category	Reserves					
	Light And Medium Crude Oil (mdbl)			Heavy Oil (mdbl)		
	Company Interest	Gross	Net	Company Interest	Gross	Net
Proved						
Developed Producing	23,687	22,373	20,544	2,849	2,842	2,612
Developed Non-Producing	2,069	2,065	1,855	37	37	34
Undeveloped	8,275	8,274	7,248	-	-	-
Total Proved	34,031	32,712	29,647	2,886	2,879	2,646
Probable	12,486	12,208	10,816	928	926	815
Total Proved plus Probable	46,517	44,920	40,463	3,814	3,804	3,461

Columns may not add due to rounding.

Reserves Category	Reserves					
	Natural Gas (Bcf)			Natural Gas Liquids (mdbl)		
	Company Interest	Gross	Net	Company Interest	Gross	Net
Proved						
Developed Producing	433.6	422.2	346.6	10,545	10,306	7,458
Developed Non-Producing	29.3	29.2	23.3	652	652	445
Undeveloped	72.9	72.9	58.7	1,740	1,740	1,215
Total Proved	535.7	524.3	428.6	12,937	12,698	9,118
Probable	210.1	207.6	168.1	4,843	4,792	3,372
Total Proved plus Probable	745.8	731.9	596.7	17,780	17,490	12,490

Columns may not add due to rounding.

Reserves Category	Reserves		
	Total (mBOE)		
	Company Interest	Gross	Net
Proved			
Developed Producing	109,342	105,890	88,374
Developed Non-Producing	7,642	7,620	6,221
Undeveloped	22,158	22,157	18,251
Total Proved	139,142	135,667	112,846
Probable	53,274	52,525	43,017
Total Proved plus Probable	192,416	188,192	155,862

Columns may not add due to rounding.

CANADIAN ASSETS ONLY

Reserves Category	Reserves					
	Light And Medium Crude Oil (mdbl)			Heavy Oil (mdbl)		
	Company Interest	Gross	Net	Company Interest	Gross	Net
Proved						
Developed Producing	14,411	13,105	12,552	2,849	2,842	2,612
Developed Non-Producing	567	563	518	37	37	34
Undeveloped	766	765	711	-	-	-
Total Proved	15,744	14,433	13,781	2,886	2,879	2,646
Probable	4,740	4,464	4,131	928	926	815
Total Proved plus Probable	20,484	18,897	17,912	3,814	3,804	3,461

Columns may not add due to rounding.

Reserves Category	Reserves					
	Natural Gas (Bcf)			Natural Gas Liquids (mdbl)		
	Company Interest	Gross	Net	Company Interest	Gross	Net
Proved						
Developed Producing	429.6	418.3	343.2	10,545	10,306	7,458
Developed Non-Producing	28.9	28.8	23.0	652	652	445
Undeveloped	69.4	69.4	55.7	1,740	1,740	1,215
Total Proved	528.0	516.5	421.9	12,937	12,698	9,118
Probable	206.7	204.2	165.2	4,843	4,792	3,372
Total Proved plus Probable	734.7	720.7	587.0	17,780	17,490	12,490

Columns may not add due to rounding.

Reserves Category	Reserves		
	Total (mBOE)		
	Company Interest	Gross	Net
Proved			
Developed Producing	99,409	95,966	79,814
Developed Non-Producing	6,078	6,055	4,829
Undeveloped	14,074	14,073	11,212
Total Proved	119,561	116,094	95,855
Probable	44,967	44,220	35,844
Total Proved plus Probable	164,527	160,314	131,699

Columns may not add due to rounding.

US ASSETS ONLY

Reserves Category	Reserves					
	Light And Medium Crude Oil (mdbl)			Heavy Oil (mdbl)		
	Company Interest	Gross	Net	Company Interest	Gross	Net
Proved						
Developed Producing	9,276	9,268	7,993	-	-	-
Developed Non-Producing	1,502	1,502	1,337	-	-	-
Undeveloped	7,509	7,509	6,537	-	-	-
Total Proved	18,287	18,279	15,867	-	-	-
Probable	7,746	7,744	6,685	-	-	-
Total Proved plus Probable	26,033	26,023	22,551	-	-	-

Columns may not add due to rounding.

Reserves Category	Reserves					
	Natural Gas (Bcf)			Natural Gas Liquids (mdbl)		
	Company Interest	Gross	Net	Company Interest	Gross	Net
Proved						
Developed Producing	3.9	3.9	3.4	-	-	-
Developed Non-Producing	.4	.4	.3	-	-	-
Undeveloped	3.5	3.5	3.0	-	-	-
Total Proved	7.8	7.8	6.7	-	-	-
Probable	3.4	3.4	2.9	-	-	-
Total Proved plus Probable	11.1	11.1	9.7	-	-	-

Columns may not add due to rounding.

Reserves Category	Reserves		
	Total (mBOE)		
	Company Interest	Gross	Net
Proved			
Developed Producing	9,933	9,924	8,560
Developed Non-Producing	1,565	1,565	1,392
Undeveloped	8,084	8,084	7,039
Total Proved	19,582	19,573	16,990
Probable	8,307	8,305	7,173
Total Proved plus Probable	27,889	27,878	24,164

Columns may not add due to rounding.

CONSOLIDATED - INCLUDES CANADIAN AND US ASSETS

Reserves Category	Net Present Values of Future Net Revenue (\$ millions)			
	Before Future Income Tax Expenses		After Future Income Tax Expenses	
	Discounted at 0%/year	Discounted at 10%/year	Discounted at 0%/year	Discounted at 10%/year
Proved				
Developed Producing	2,461.5	1,505.5	2,461.6	1,505.4
Developed Non-Producing	182.5	101.3	169.1	93.8
Undeveloped	453.9	176.8	386.6	136.5
Total Proved	3,098.0	1,783.6	3,017.2	1,735.7
Probable	1,261.4	479.7	1,169.6	438.2
Total Proved plus Probable	4,359.4	2,263.3	4,186.8	2,173.9

Columns may not add due to rounding.

CANADIAN ASSETS ONLY

Reserves Category	Net Present Values of Future Net Revenue (\$ millions)			
	Before Future Income Tax Expenses		After Future Income Tax Expenses	
	Discounted at 0%/year	Discounted at 10%/year	Discounted at 0%/year	Discounted at 10%/year
Proved				
Developed Producing	2,210.8	1,357.1	2,210.8	1,357.1
Developed Non-Producing	136.4	82.3	136.4	82.3
Undeveloped	223.6	74.9	223.6	74.9
Total Proved	2,570.7	1,514.3	2,570.7	1,514.3
Probable	1,020.5	399.2	1,020.5	399.2
Total Proved plus Probable	3,591.2	1,913.5	3,591.2	1,913.5

Columns may not add due to rounding.

US ASSETS ONLY

Reserves Category	Net Present Values of Future Net Revenue (\$ millions)			
	Before Future Income Tax Expenses		After Future Income Tax Expenses	
	Discounted at 0%/year	Discounted at 10%/year	Discounted at 0%/year	Discounted at 10%/year
Proved				
Developed Producing	250.8	148.3	250.8	148.3
Developed Non-Producing	46.2	19.0	32.7	11.5
Undeveloped	230.4	101.9	163.0	61.6
Total Proved	527.3	269.2	446.5	221.4
Probable	240.8	80.6	149.1	39.0
Total Proved plus Probable	768.1	349.8	595.6	260.4

Columns may not add due to rounding.

**TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2006
CONSTANT PRICES AND COSTS**

CONSOLIDATED – INCLUDES CANADIAN AND US ASSETS

(\$ millions)								
Reserve Category	Revenue	Royalties	Operating Costs	Development Costs	Well Abandonment Costs	Future Net Revenue Before Future Income Tax Expenses	Future Income Tax Expenses	Future Net Revenue After Future Income Tax Expenses
Proved	6,524.4	1,143.7	1,948.9	271.4	62.3	3,098.0	80.8	3,017.2
Proved plus Probable	9,007.5	1,606.2	2,555.1	419.3	67.5	4,359.4	172.5	4,186.9

CANADIAN ASSETS ONLY

(\$ millions)								
Reserve Category	Revenue	Royalties	Operating Costs	Development Costs	Well Abandonment Costs	Future Net Revenue Before Future Income Tax Expenses	Future Income Tax Expenses	Future Net Revenue After Future Income Tax Expenses
Proved	5,381.8	923.2	1,650.4	189.7	47.8	2,570.7	0.0	2,570.7
Proved plus Probable	7,376.9	1,289.7	2,132.1	312.5	51.4	3,591.2	0.0	3,591.2

US ASSETS ONLY

(\$ millions)								
Reserve Category	Revenue	Royalties	Operating Costs	Development Costs	Well Abandonment Costs	Future Net Revenue Before Future Income Tax Expenses	Future Income Tax Expenses	Future Net Revenue After Future Income Tax Expenses
Proved	1,142.6	220.5	298.5	81.8	14.4	527.3	80.8	446.5
Proved plus Probable	1,630.5	316.4	423.0	106.9	16.1	768.1	172.5	595.6

**FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2006
CONSTANT PRICES AND COSTS**

Reserves Category	Production Group	Future Net Revenue Before Future Income Tax Expenses (discounted at 10%/year) (\$ millions) ⁽¹⁾
Proved Reserves	Light and Medium Crude Oil ⁽²⁾	578.4
	Heavy Oil ⁽²⁾	49.8
	Natural Gas ⁽³⁾	1,152.6
	Non-conventional ⁽⁴⁾	2.8
Proved plus Probable Reserves	Light and Medium Crude Oil ⁽²⁾	726.5
	Heavy Oil ⁽²⁾	64.7
	Natural Gas ⁽³⁾	1,465.9
	Non-conventional ⁽⁴⁾	6.3

Notes:

- (1) Future Net Revenue values do not represent fair market value.
- (2) Including Solution Gas and other by-products.
- (3) Including by-products but excluding Solution Gas from Oil wells.
- (4) Non-conventional Oil and Gas activities include coalbed methane development activities.

FORECAST PRICES AND COSTS

The following tables provide Reserves data and a breakdown of Future Net Revenue by component and Production group using Forecast Prices and Costs on a Company Interest, Gross and Net basis.

**SUMMARY OF OIL AND NATURAL GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2006
FORECAST PRICES AND COSTS**

CONSOLIDATED - INCLUDES CANADIAN AND US ASSETS

Reserve Category	Reserves					
	Light And Medium Crude Oil (mmbbl)			Heavy Oil (mmbbl)		
	Company Interest	Gross	Net	Company Interest	Gross	Net
Proved						
Developed Producing	23,074	21,761	20,011	2,779	2,772	2,546
Developed Non-Producing	2,012	2,008	1,806	33	32	30
Undeveloped	8,170	8,169	7,158	-	-	-
Total Proved	33,256	31,939	28,975	2,811	2,804	2,576
Probable	12,246	11,968	10,608	904	902	793
Total Proved plus Probable	45,502	43,907	39,583	3,715	3,706	3,370

Columns may not add due to rounding.

Reserve Category	Reserves					
	Natural Gas (Bcf)			Natural Gas Liquids (mdbl)		
	Company Interest	Gross	Net	Company Interest	Gross	Net
Proved						
Developed Producing	437.5	426.2	349.7	10,589	10,351	7,494
Developed Non-Producing	29.6	29.5	23.6	650	649	443
Undeveloped	73.0	73.0	58.7	1,742	1,742	1,215
Total Proved	540.1	528.7	432.0	12,980	12,742	9,152
Probable	212.4	209.9	169.8	4,877	4,826	3,398
Total Proved plus Probable	752.5	738.6	601.8	17,857	17,568	12,551

Columns may not add due to rounding.

Reserve Category	Reserves		
	Total (mBOE)		
	Company Interest	Gross	Net
Proved			
Developed Producing	109,356	105,909	88,333
Developed Non-Producing	7,629	7,608	6,214
Undeveloped	22,082	22,081	18,160
Total Proved	139,066	135,598	112,708
Probable	53,427	52,681	43,103
Total Proved plus Probable	192,493	188,279	155,811

Columns may not add due to rounding.

CANADIAN ASSETS ONLY

Reserve Category	Reserves					
	Light And Medium Crude Oil (mdbl)			Heavy Oil (mdbl)		
	Company Interest	Gross	Net	Company Interest	Gross	Net
Proved						
Developed Producing	14,291	12,986	12,441	2,779	2,772	2,546
Developed Non-Producing	534	530	489	33	32	30
Undeveloped	761	760	706	-	-	-
Total Proved	15,586	14,276	13,637	2,811	2,804	2,576
Probable	4,797	4,521	4,177	904	902	793
Total Proved plus Probable	20,383	18,797	17,814	3,715	3,706	3,370

Columns may not add due to rounding.

Reserve Category	Reserves					
	Natural Gas (Bcf)			Natural Gas Liquids (mmbbl)		
	Company Interest	Gross	Net	Company Interest	Gross	Net
Proved						
Developed Producing	433.6	422.3	346.3	10,589	10,351	7,494
Developed Non-Producing	29.2	29.1	23.3	650	649	443
Undeveloped	69.6	69.6	55.7	1,742	1,742	1,215
Total Proved	532.4	521.0	425.3	12,980	12,742	9,152
Probable	209.1	206.6	166.9	4,877	4,826	3,398
Total Proved Plus Probable	741.5	727.6	592.3	17,857	17,568	12,551

Columns may not add due to rounding.

Reserve Category	Reserves		
	Total (mBOE)		
	Company Interest	Gross	Net
Proved			
Developed Producing	99,923	96,484	80,203
Developed Non-Producing	6,086	6,066	4,842
Undeveloped	14,102	14,101	11,210
Total Proved	120,110	116,651	96,254
Probable	45,427	44,682	36,192
Total Proved plus Probable	165,537	161,333	132,447

Columns may not add due to rounding.

US ASSETS ONLY

Reserve Category	Reserves					
	Light And Medium Crude Oil (mmbbl)			Heavy Oil (mmbbl)		
	Company Interest	Gross	Net	Company Interest	Gross	Net
Proved						
Developed Producing	8,783	8,775	7,569	-	-	-
Developed Non-Producing	1,478	1,478	1,316	-	-	-
Undeveloped	7,409	7,409	6,452	-	-	-
Total Proved	17,670	17,663	15,338	-	-	-
Probable	7,449	7,447	6,431	-	-	-
Total Proved plus Probable	25,119	25,110	21,768	-	-	-

Columns may not add due to rounding.

Reserve Category	Reserves					
	Natural Gas (Bcf)			Natural Gas Liquids (mmbbl)		
	Company Interest	Gross	Net	Company Interest	Gross	Net
Proved						
Developed Producing	3.9	3.9	3.4	-	-	-
Developed Non-Producing	.4	.4	.4	-	-	-
Undeveloped	3.4	3.4	3.0	-	-	-
Total Proved	7.7	7.7	6.7	-	-	-
Probable	3.3	3.3	2.9	-	-	-
Total Proved plus Probable	11.0	11.0	9.6	-	-	-

Columns may not add due to rounding.

Reserve Category	Reserves		
	Total (mBOE)		
	Company Interest	Gross	Net
Proved			
Developed Producing	9,433	9,425	8,131
Developed Non-Producing	1,542	1,542	1,372
Undeveloped	7,980	7,980	6,950
Total Proved	18,956	18,948	16,454
Probable	8,000	7,998	6,910
Total Proved plus Probable	26,956	26,946	23,364

Columns may not add due to rounding.

CONSOLIDATED - INCLUDES CANADIAN AND US ASSETS

Reserve Category	Net Present Values of Future Net Revenue (\$ millions)									
	Before Future Income Tax Expenses Discounted at (%/year)					After Future Income Tax Expenses Discounted at (%/year)				
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
Proved										
Developed Producing	3,112.4	2,280.5	1,824.7	1,538.0	1,340.3	3,112.3	2,280.3	1,824.7	1,537.0	1,340.3
Developed Non-Producing	228.6	160.5	124.0	101.4	86.1	216.9	152.0	117.4	96.0	81.2
Undeveloped	566.1	336.8	218.1	147.8	102.4	509.6	294.1	183.9	120.3	78.3
Total Proved	3,907.2	2,777.7	2,166.8	1,787.2	1,528.8	3,838.8	2,726.5	2,126.0	1,753.3	1,499.8
Probable	1,768.3	951.7	612.8	437.6	333.1	1,673.5	892.8	571.8	406.7	308.6
Total Proved plus Probable	5,675.5	3,729.4	2,779.6	2,224.8	1,861.9	5,512.3	3,619.3	2,697.8	2,160.1	1,808.4

Columns may not add due to rounding.

CANADIAN ASSETS ONLY

Reserve Category	Net Present Values of Future Net Revenue (\$ millions)									
	Before Future Income Tax Expenses Discounted at (%/year)					After Future Income Tax Expenses Discounted at (%/year)				
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
Proved										
Developed Producing	2,877.7	2,106.3	1,683.9	1,418.5	1,235.7	2,877.7	2,106.3	1,683.9	1,418.5	1,235.7
Developed Non-Producing	183.9	133.2	105.8	88.4	76.3	183.9	133.2	105.8	88.4	76.3
Undeveloped	349.5	197.8	123.9	81.3	54.2	349.5	197.8	123.9	81.3	54.2
Total Proved	3,411.1	2,437.4	1,913.6	1,588.2	1,366.2	3,411.1	2,437.4	1,913.6	1,588.2	1,366.2
Probable	1,520.6	822.1	534.4	385.4	296.1	1,520.6	822.1	534.4	385.4	296.1
Total Proved plus Probable	4,931.7	3,259.5	2,448.0	1,973.7	1,662.3	4,931.7	3,259.5	2,448.0	1,973.7	1,662.3

Columns may not add due to rounding.

US ASSETS ONLY

Reserve Category	Net Present Values of Future Net Revenue (\$ millions)									
	Before Future Income Tax Expenses Discounted at (%/year)					After Future Income Tax Expenses Discounted at (%/year)				
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
Proved										
Developed Producing	234.7	174.2	140.9	119.6	104.7	234.6	174.0	140.8	118.5	104.6
Developed Non-Producing	44.7	27.2	18.2	13.0	9.8	33.0	18.8	11.6	7.6	4.9
Undeveloped	216.7	138.9	94.2	66.4	48.2	160.1	96.3	60.0	39.0	24.1
Total Proved	496.1	340.3	253.2	199.0	162.6	427.7	289.1	212.4	165.1	133.6
Probable	247.7	129.6	78.4	52.2	37.0	152.9	70.7	37.4	21.3	12.5
Total Proved plus Probable	743.8	469.9	331.6	251.2	199.6	580.6	359.8	249.8	186.4	146.1

Columns may not add due to rounding.

**TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2006
FORECAST PRICES AND COSTS**

CONSOLIDATED – INCLUDES CANADIAN AND US ASSETS

Reserve Category	(\$ millions)							
	Revenue	Royalties	Operating Costs	Development Costs	Well Abandonment costs	Future Net Revenue Before Future Income Tax Expenses	Future Income Tax Expenses	Future Net Revenue After Future Income Tax Expenses
Proved Reserves	8,201.0	1,458.8	2,461.8	284.5	88.7	3,907.2	68.1	3,839.1
Proved plus Probable Reserves	11,700.0	2,104.9	3,376.5	437.6	105.5	5,675.5	162.7	5,512.8

CANADIAN ASSETS ONLY

Reserve Category	(\$ millions)							
	Revenue	Royalties	Operating Costs	Development Costs	Well Abandonment costs	Future Net Revenue Before Future Income Tax Expenses	Future Income Tax Expenses	Future Net Revenue After Future Income Tax Expenses
Proved Reserves	7,018.6	1,230.7	2,110.2	199.5	67.0	3,411.1	0.0	3,411.1
Proved plus Probable Reserves	9,950.8	1,765.2	2,849.5	325.9	78.5	4,931.7	0.0	4,931.7

US ASSETS ONLY

Reserve Category	(\$ millions)							
	Revenue	Royalties	Operating Costs	Development Costs	Well Abandonment costs	Future Net Revenue Before Future Income Tax Expenses	Future Income Tax Expenses	Future Net Revenue After Future Income Tax Expenses
Proved Reserves	1,182.5	228.1	351.7	85.0	21.6	496.1	68.1	428.0
Proved plus Probable Reserves	1,749.2	339.7	527.0	111.7	27.0	743.8	162.7	581.1

**FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2006
FORECAST PRICES AND COSTS**

Reserve Category	Production Group	Future Net Revenue Before Future Income Tax Expenses (discounted at 10%/year) (\$ millions) ⁽¹⁾
Proved Reserves	Light and Medium Crude Oil ⁽²⁾	573.6
	Heavy Oil ⁽²⁾	48.7
	Natural Gas ⁽³⁾	1,537.2
	Non-conventional ⁽⁴⁾	7.3
Proved plus Probable Reserves	Light and Medium Crude Oil ⁽²⁾	724.1
	Heavy Oil ⁽²⁾	63.4
	Natural Gas ⁽³⁾	1,974.0
	Non-conventional ⁽⁴⁾	18.2

Notes:

- (1) Future Net Revenue values do not represent fair market value.
- (2) Including solution gas and other by-products.
- (3) Including by-products but excluding solution gas from Oil wells.
- (4) Non-conventional Oil and Gas activities include Coalbed methane development activities.

The following tables summarize the pricing assumptions (and in the case of Forecast Prices and Costs only, the inflation assumptions) made in preparing the preceding tables pertaining to PrimeWest's Reserves and Future Net Revenue utilizing either Constant Prices and Costs or Forecast Prices and Costs.

**SUMMARY OF PRICING ASSUMPTIONS
AS OF DECEMBER 31, 2006
CONSTANT PRICES AND COSTS**

Year	Oil				Natural Gas	Edmonton Liquids Prices			Inflation Rates %/ year	Exchange Rate US\$/C\$
	WTI Cushing Oklahoma US\$/bbl	Edmonton Par Price 40° API C\$/ bbl	Hardisty Heavy 12° API C\$/bbl	Cromer Medium 29° API C\$/bbl	AECO Gas Price C\$/ mmbtu	Propane C\$/bbl	Butane C\$/bbl	Pentanes Plus C\$/bbl		
2006	60.85	67.58	47.62	59.47	6.07	43.25	54.06	71.55	0.0	0.8581

**SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
AS OF DECEMBER 31, 2006
FORECAST PRICES AND COSTS**

Year	Oil				Natural Gas	Edmonton Liquids Prices			Inflation Rates %/ year	Exchange Rate US\$/C\$
	WTI Cushing Oklahoma US\$/bbl	Edmonton Par Price 40° API C\$/ bbl	Hardisty Heavy 12° API C\$/bbl	Cromer Medium 29° API C\$/bbl	AECO Gas Price C\$/ mmbtu	Propane C\$/bbl	Butane C\$/bbl	Pentanes Plus C\$/bbl		
2006	66.22	73.16	50.41	62.24	7.02	43.97	66.64	75.69	2.1	0.8820
2007	63.41	71.72	40.48	62.39	7.38	43.11	54.46	73.31	0.00	0.8700
2008	63.34	71.64	41.61	62.30	7.83	43.31	52.97	73.18	2.67	0.8700
2009	60.07	67.90	40.23	59.02	7.77	41.42	50.24	69.41	2.33	0.8700
2010	57.92	65.39	39.56	56.79	7.75	40.11	48.34	66.86	2.00	0.8700
2011	56.33	63.53	38.62	55.21	7.90	39.29	46.96	64.98	2.00	0.8700
2012	57.27	64.58	39.58	56.14	8.11	39.98	47.72	66.07	2.00	0.8700
2013	58.34	65.82	40.39	57.28	8.28	40.80	48.64	67.33	2.00	0.8700
2014	59.54	67.22	41.27	58.44	8.44	41.57	49.74	68.73	2.00	0.8700
2015	60.75	68.51	42.04	59.55	8.62	42.47	50.62	70.15	2.00	0.8700
2016	61.97	69.93	42.91	60.75	8.79	43.29	51.71	71.58	2.00	0.8700
2017	63.22	71.27	43.75	62.00	8.96	44.19	52.67	72.93	2.00	0.8700
2018	64.49	72.74	44.63	63.25	9.15	45.07	53.73	74.43	2.00	0.8700
2019	65.78	74.21	45.52	64.52	9.32	45.97	54.81	75.91	2.00	0.8700
2020	67.09	75.69	46.42	65.80	9.51	46.91	55.91	77.42	2.00	0.8700
2021	68.44	77.19	47.36	67.13	9.71	47.83	57.02	78.98	2.00	0.8700
2022	69.81	78.51	48.31	68.47	9.90	48.78	58.16	80.55	2.00	0.8700
2023	71.21	79.52	49.28	69.84	10.10	49.76	59.32	82.17	2.00	0.8700
2024	72.63	80.55	50.26	71.24	10.30	50.75	60.51	83.81	2.00	0.8700
There-after	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	0.8700

WEIGHTED AVERAGE REALIZED SALES PRICES (C\$)

2006	
Natural Gas (\$/mcf)	\$ 7.09
Crude Oil (\$/bbl)	\$62.42
Natural Gas Liquids (\$/bbl)	\$59.09

FUTURE DEVELOPMENT COSTS

The table below sets out the Development Costs deducted in the estimation of Future Net Revenue attributable to Proved Reserves (using both Constant Prices and Costs and Forecast Prices and Costs) and Proved plus Probable Reserves (using Forecast Prices and Costs only).

CONSOLIDATED – INCLUDES CANADIAN AND US ASSETS

Year	Constant Prices and Costs	Forecast Prices and Costs	
	(\$ millions)	(\$ millions)	
	Proved	Proved	Proved plus Probable
2007	93.2	93.2	154.2
2008	56.2	57.6	94.5
2009	62.7	65.9	94.7
2010	35.3	37.9	51.1
2011	8.1	8.9	11.4
Total: Undiscounted	271.4	284.5	437.6
Total: Discounted at 10%/year	223.7	231.3	359.6

CANADIAN ASSETS ONLY

Year	Constant Prices and Costs	Forecast Prices and Costs	
	(\$ millions)	(\$ millions)	
	Proved	Proved	Proved plus Probable
2007	75.6	75.6	135.4
2008	32.2	33.1	64.4
2009	43.2	45.4	65.0
2010	18.8	20.1	30.7
2011	4.2	4.6	3.5
Total: Undiscounted	189.7	199.5	325.9
Total: Discounted at 10%/year	156.3	161.4	269.7

US ASSETS ONLY

Year	Constant Prices and Costs	Forecast Prices and Costs	
	(\$ millions)	(\$ millions)	
	Proved	Proved	Proved plus Probable
2007	17.7	17.7	18.7
2008	23.9	24.6	30.1
2009	19.5	20.5	29.6
2010	16.6	17.8	20.5
2011	3.9	4.3	7.9
Total: Undiscounted	81.8	85.0	111.7
Total: Discounted at 10%/year	67.4	69.9	89.8

The Future Development Costs are capital expenditures required in the future for PrimeWest to convert Proved Undeveloped Reserves and Probable Undeveloped Reserves into Proved Developed Producing Reserves. Over the estimated life of the Reserves, it is anticipated that expenditures of \$284.5 million would be incurred for the Proved Reserves and \$437.6 million for the Proved plus Probable Reserves categories, based on Forecast Prices and Costs. PrimeWest anticipates using a combination of internally generated cash flow, debt and equity financing to fund these Future Development Costs. Based on the commodity price and cost assumptions adopted for both the Constant Prices and Costs case and the Forecast Prices and Costs case, all of the expenditures included in the future Development Costs are economic as they enhance the net present values of the Proved Developed Reserves.

RECONCILIATION OF CHANGES IN RESERVES AND FUTURE NET REVENUE

Reserves Reconciliation

The following table sets forth the reconciliation of PrimeWest's Net Reserves for the year ended December 31, 2006 using Forecast Price and Cost estimates derived from the GLJ Report as required under NI 51-101 guidelines and format, reconciled to December 31, 2005.

CONSOLIDATED – INCLUDES CANADIAN AND US ASSETS

	Light and Medium Crude Oil (mbbls)				Heavy Oil (mbbls)			
	Proved Producing	Total Proved	Probable	Proved Plus Probable	Proved Producing	Total Proved	Probable	Proved Plus Probable
Dec. 31, 2005	14,098	14,709	3,544	18,253	2,355	2,436	630	3,066
Discoveries	12	12	2	14	-	-	-	-
Drilling Extensions	880	1,438	528	1,966	25	2	-	2
Improved Recovery ⁽¹⁾	26	195	99	294	-	-	-	-
Technical Revisions	(1,074)	(1,252)	(11)	(1,262)	696	646	163	809
Acquisitions	7,975	15,743	6,439	22,183	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-
Economic Factors	-	35	6	40	-	22	1	23
Production	(1,905)	(1,905)	-	(1,905)	(530)	(530)	-	(530)
Dec. 31, 2006	20,011	28,975	10,608	39,583	2,546	2,576	794	3,370

Columns may not add due to rounding.

	Associated and Non-Associated Gas (Natural Gas) (Bcf)				Natural Gas Liquids (mbbls)			
	Proved Producing	Total Proved	Probable	Proved Plus Probable	Proved Producing	Total Proved	Probable	Proved Plus Probable
Dec. 31, 2005	336.4	407.2	131.7	539.0	7,668	9,495	3,234	12,729
Discoveries	-	.1	2.1	2.2	2	4	25	29
Drilling Extensions	22.1	27.3	12.8	40.1	518	708	295	1,003
Improved Recovery ⁽¹⁾	12.2	23.5	10.8	34.3	303	582	226	809
Technical Revisions	18.8	5.2	(2.5)	2.7	(6)	(659)	(445)	(1,104)
Acquisitions	6.1	9.8	6.0	15.8	61	72	66	138
Dispositions	(0.1)	(0.1)	(0.1)	(0.2)	(2)	(2)	(1)	(3)
Economic Factors	-	0.3	0.0	0.3	-	2	(2)	-
Production	(46.2)	(46.2)	-	(46.2)	(1,049)	(1,049)	-	(1,049)
Dec. 31, 2006	349.3	427.1	160.9	588.0	7,494	9,152	3,399	12,551

Columns may not add due to rounding.

	Natural Gas from Coal (mmcf)				Total (mBOE)			
	Proved Producing	Total Proved	Probable	Proved Plus Probable	Proved Producing	Total Proved	Probable	Proved Plus Probable
Dec. 31, 2005	171	606	518	1,124	80,214	94,612	29,450	124,062
Discoveries	-	-	-	-	23	34	382	416
Drilling Extensions	80	4,262	8,600	12,862	5,113	7,401	4,394	11,795
Improved Recovery ⁽¹⁾	132	201	36	237	2,382	4,729	2,125	6,854
Technical Revisions	52	(158)	(220)	(378)	2,755	(417)	(754)	(1,171)
Acquisitions	-	-	-	-	9,057	17,452	7,505	24,957
Dispositions	-	-	-	-	(27)	(27)	(10)	(37)
Economic Factors	-	-	-	-	-	106	12	118
Production	(21)	(21)	-	(21)	(11,183)	(11,183)	-	(11,183)
Dec. 31, 2006	414	4,890	8,935	13,824	88,333	112,707	43,104	155,811

Columns may not add due to rounding.

Note:

(1) Improved recovery includes infill drilling and improved recovery.

CANADIAN ASSETS ONLY

	Light and Medium Crude Oil (mmbbls)				Heavy Oil (mmbbls)			
	Proved Producing	Total Proved	Probable	Proved Plus Probable	Proved Producing	Total Proved	Probable	Proved Plus Probable
Dec. 31, 2005	14,098	14,709	3,544	18,253	2,355	2,436	630	3,066
Discoveries	12	12	2	14	-	-	-	-
Drilling Extensions	880	1,438	528	1,966	25	2	-	2
Improved Recovery ⁽¹⁾	26	195	99	294	-	-	-	-
Technical Revisions	(1,074)	(1,252)	(11)	(1,262)	696	646	163	809
Acquisitions	-	-	10	10	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-
Economic Factors	-	35	6	40	-	22	1	23
Production	(1,499)	(1,499)	-	(1,499)	(530)	(530)	-	(530)
Dec. 31, 2006	12,441	13,637	4,177	17,814	2,546	2,576	794	3,370

Columns may not add due to rounding.

	Associated and Non-Associated Gas (Natural Gas) (Bcf)				Natural Gas Liquids (mmbbls)			
	Proved Producing	Total Proved	Probable	Proved Plus Probable	Proved Producing	Total Proved	Probable	Proved Plus Probable
Dec. 31, 2005	336.4	407.2	131.7	539.0	7,668	9,495	3,234	12,729
Discoveries	-	.1	2.1	2.2	2	4	25	29
Drilling Extensions	22.1	27.3	12.8	40.1	518	708	295	1,003
Improved Recovery ⁽¹⁾	12.2	23.5	10.8	34.3	303	582	226	809
Technical Revisions	18.8	5.2	(2.5)	2.7	(6)	(659)	(445)	(1,104)
Acquisitions	2.5	2.9	3.1	6.0	61	72	66	138
Dispositions	(0.1)	(0.1)	(0.1)	(0.2)	(2)	(2)	(1)	(3)
Economic Factors	-	.3	-	.3	-	2	(2)	-
Production	(46.0)	(46.0)	-	(46.0)	(1,049)	(1,049)	-	(1,049)
Dec. 31, 2006	345.9	420.4	158.0	578.4	7,494	9,152	3,399	12,551

Columns may not add due to rounding.

	Natural Gas from Coal (mmcf)				Total (mBOE)			
	Proved Producing	Total Proved	Probable	Proved Plus Probable	Proved Producing	Total Proved	Probable	Proved Plus Probable
Dec. 31, 2005	171	606	518	1,124	80,214	94,612	29,450	124,062
Discoveries	-	-	-	-	23	34	382	416
Drilling Extensions	80	4,262	8,600	12,862	5,113	7,401	4,394	11,795
Improved Recovery ⁽¹⁾	132	201	36	237	2,382	4,729	2,125	6,854
Technical Revisions	52	(158)	(220)	(378)	2,755	(417)	(754)	(1,171)
Acquisitions	-	-	-	-	486	558	596	1,154
Dispositions	-	-	-	-	(27)	(27)	(10)	(37)
Economic Factors	-	-	-	-	-	106	12	118
Production	(21)	(21)	-	(21)	(10,743)	(10,743)	-	(10,743)
Dec. 31, 2006	414	4,890	8,935	13,824	80,202	96,254	36,193	132,447

Columns may not add due to rounding.

Note:

(1) Improved recovery includes infill drilling and improved recovery.

US ASSETS ONLY

	Light and Medium Crude Oil (mbbls)				Heavy Oil (mbbls)			
	Proved Producing	Total Proved	Probable	Proved Plus Probable	Proved Producing	Total Proved	Probable	Proved Plus Probable
Dec. 31, 2005	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-
Drilling Extensions	-	-	-	-	-	-	-	-
Improved Recovery ⁽¹⁾	-	-	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-	-	-
Acquisitions	7,975	15,743	6,430	22,174	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-
Production	(406)	(406)	-	(406)	-	-	-	-
Dec. 31, 2006	7,570	15,338	6,430	21,768	-	-	-	-

Columns may not add due to rounding.

	Associated and Non-Associated Gas (Natural Gas) (Bcf)				Natural Gas Liquids (mmbbls)			
	Proved Producing	Total Proved	Probable	Proved Plus Probable	Proved Producing	Total Proved	Probable	Proved Plus Probable
Dec. 31, 2005	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-
Drilling Extensions	-	-	-	-	-	-	-	-
Improved Recovery ⁽¹⁾	-	-	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-	-	-
Acquisitions	3.6	6.9	2.9	9.8	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-
Production	(.2)	(.2)	-	(.2)	-	-	-	-
Dec. 31, 2006	3.4	6.7	2.9	9.6	-	-	-	-

Columns may not add due to rounding.

	Natural Gas from Coal (mmcf)				Total (mBOE)			
	Proved Producing	Total Proved	Probable	Proved Plus Probable	Proved Producing	Total Proved	Probable	Proved Plus Probable
Dec. 31, 2005	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-
Drilling Extensions	-	-	-	-	-	-	-	-
Improved Recovery ⁽¹⁾	-	-	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	8,571	16,894	6,910	23,804
Dispositions	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-
Production	-	-	-	-	(440)	(440)	-	(440)
Dec. 31, 2006	-	-	-	-	8,131	16,454	6,910	23,364

Columns may not add due to rounding.

Note:

(1) Improved recovery includes infill drilling and improved recovery.

The following table sets forth a reconciliation of the Company Interest Reserves of PrimeWest for the year ended December 31, 2006 derived from the GLJ Report using Forecast Price and Cost estimates, reconciled to December 31, 2005. PrimeWest's Company Interest Reserves include working interest and royalties receivable by PrimeWest and the Trust, with no deduction of royalties payable. This definition is consistent with the basis on which Reserves were reported in years prior to the implementation of NI 51-101.

CONSOLIDATED – INCLUDES CANADIAN AND US ASSETS

	Light, Medium and Heavy Crude Oil (mbbls)				Natural Gas (Bcf)			
	Proved Producing	Total Proved	Probable	Proved Plus Probable	Proved Producing	Total Proved	Probable	Proved Plus Probable
Dec. 31, 2005	18,073	18,864	4,783	23,646	421.4	510.7	166.6	677.3
Discoveries	15	15	2	17	-	.1	2.5	2.6
Drilling Extensions	1,026	1,594	579	2,173	27.8	39.7	26.0	65.7
Improved Recovery ⁽¹⁾	29	207	106	313	15.9	29.8	13.6	43.4
Technical Revisions	311	100	224	324	25.2	8.4	(3.5)	4.9
Acquisitions	9,253	18,140	7,458	25,598	7.9	12.2	7.2	19.4
Dispositions	-	-	-	-	(.2)	(.2)	(.1)	(.3)
Economic Factors	-	-	-	-	-	-	-	-
Production	(2,853)	(2,853)	-	(2,853)	(60.6)	(60.6)	-	(60.6)
Dec. 31, 2006	25,852	36,068	13,150	49,218	437.5	540.1	212.4	752.5

Columns may not add due to rounding.

	Natural Gas Liquids (mbbls)				Total (mBOE)			
	Proved Producing	Total Proved	Probable	Proved Plus Probable	Proved Producing	Total Proved	Probable	Proved Plus Probable
Dec. 31, 2005	10,864	13,434	4,634	18,068	99,162	117,422	37,181	154,603
Discoveries	3	5	29	34	30	44	439	483
Drilling Extensions	752	1,034	425	1,459	6,416	9,245	5,336	14,581
Improved Recovery ⁽¹⁾	425	812	331	1,143	3,107	5,983	2,708	8,691
Technical Revisions	(144)	(1,011)	(643)	(1,654)	4,370	482	(991)	(509)
Acquisitions	91	108	103	211	10,657	20,277	8,767	29,044
Dispositions	(4)	(4)	(1)	(5)	(34)	(34)	(13)	(47)
Economic Factors	-	-	-	-	-	-	-	-
Production	(1,399)	(1,399)	-	(1,399)	(14,352)	(14,352)	-	(14,352)
Dec. 31, 2006	10,589	12,980	4,877	17,857	109,356	139,066	53,427	192,493

Columns may not add due to rounding.

Note:

(1) Improved recovery includes infill drilling and improved recovery.

CANADIAN ASSETS ONLY

	Light, Medium and Heavy Crude Oil (mbbls)				Natural Gas (Bcf)			
	Proved Producing	Total Proved	Probable	Proved Plus Probable	Proved Producing	Total Proved	Probable	Proved Plus Probable
Dec. 31, 2005	18,073	18,864	4,783	23,646	421.4	510.7	166.6	677.3
Discoveries	15	15	2	17	-	.1	2.5	2.6
Drilling Extensions	1,026	1,594	579	2,173	27.8	39.7	26.0	65.7
Improved Recovery ⁽¹⁾	29	207	106	313	15.9	29.8	13.6	43.4
Technical Revisions	311	100	224	324	25.2	8.4	(3.5)	4.9
Acquisitions	-	-	9	9	3.7	4.2	4.0	8.2
Dispositions	-	-	-	-	(.2)	(.2)	(.1)	(.3)
Economic Factors	-	-	-	-	-	-	-	-
Production	(2,383)	(2,383)	-	(2,383)	(60.4)	(60.4)	-	(60.4)
Dec. 31, 2006	17,070	18,397	5,701	24,098	433.6	532.4	209.1	741.5

Columns may not add due to rounding

	Natural Gas Liquids (mbbls)				Total (mBOE)			
	Proved Producing	Total Proved	Probable	Proved Plus Probable	Proved Producing	Total Proved	Probable	Proved Plus Probable
Dec. 31, 2005	10,864	13,434	4,634	18,068	99,162	117,422	37,181	154,603
Discoveries	3	5	29	34	30	44	439	483
Drilling Extensions	752	1,034	425	1,459	6,416	9,245	5,336	14,581
Improved Recovery ⁽¹⁾	425	812	331	1,143	3,107	5,983	2,708	8,691
Technical Revisions	(144)	(1,011)	(643)	(1,654)	4,370	482	(991)	(509)
Acquisitions	91	108	103	211	714	811	767	1,578
Dispositions	(4)	(4)	(1)	(5)	(34)	(34)	(13)	(47)
Economic Factors	-	-	-	-	-	-	-	-
Production	(1,399)	(1,399)	-	(1,399)	(13,841)	(13,841)	-	(13,841)
Dec. 31, 2006	10,589	12,980	4,877	17,857	99,923	120,110	45,427	165,537

Columns may not add due to rounding.

Note:

(1) Improved recovery includes infill drilling and improved recovery.

US ASSETS ONLY

	Light, Medium and Heavy Crude Oil (mbbls)				Natural Gas (Bcf)			
	Proved Producing	Total Proved	Probable	Proved Plus Probable	Proved Producing	Total Proved	Probable	Proved Plus Probable
Dec. 31, 2005								
Discoveries	-	-	-	-	-	-	-	-
Drilling Extensions ⁽²⁾	-	-	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-	-	-
Acquisitions	9,253	18,140	7,449	25,589	4.1	8.0	3.3	11.3
Dispositions	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-
Production	(470)	(470)	-	(470)	(.2)	(.2)	-	(.2)
Dec. 31, 2006	8,783	17,670	7,449	25,119	3.9	7.7	3.3	11.0

Columns may not add due to rounding.

	Natural Gas Liquids (mbbls)				Total (mBOE)			
	Proved Producing	Total Proved	Probable	Proved Plus Probable	Proved Producing	Total Proved	Probable	Proved Plus Probable
Dec. 31, 2005	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-
Drilling Extension	-	-	-	-	-	-	-	-
Improved Recovery ⁽¹⁾	-	-	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	9,943	19,466	8,000	27,466
Dispositions	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-
Production	-	-	-	-	(510)	(510)	-	(510)
Dec. 31, 2006	-	-	-	-	9,433	18,955	8,000	26,955

Columns may not add due to rounding.

Note:

(1) Improved recovery includes infill drilling and improved recovery.

FUTURE NET REVENUE RECONCILIATION

The following table sets forth the reconciliation of estimated Future Net Revenues attributable to the Net Proved Reserves of PrimeWest for the year ended December 31, 2006, using Constant Price and Cost estimates derived from the GLJ Report and calculated using a discount rate of 10%.

**RECONCILIATION OF CHANGES IN
NET PRESENT VALUES OF FUTURE NET REVENUE
DISCOUNTED AT 10%**

CONSOLIDATED – INCLUDES CANADIAN AND US ASSETS

Period and Factor	Before Tax 2006 (\$ millions)
Estimated Net Present Value of Future Net Revenue at December 31, 2005	2,537.8
Oil and Gas Sales During the Period Net of Production Costs and Royalties ⁽¹⁾	(444.6)
Changes due to Prices, Production Costs and Royalties Related to Forecast Production ⁽²⁾	(808.9)
Development Costs During the Period ⁽³⁾	230.3
Changes In Forecast Development Costs ⁽⁴⁾	(282.7)
Changes Resulting from Extensions and Improved Recovery ⁽⁵⁾	178.1
Changes Resulting from Discoveries ⁽⁵⁾	1.0
Changes Resulting from Acquisitions of Reserves ⁽⁵⁾	281.0
Changes Resulting from Dispositions of Reserves ⁽⁵⁾	(0.7)
Accretion of Discount ⁽⁶⁾	253.8
Net Change in Income Taxes ⁽⁷⁾	0
Changes Resulting from Technical Reserves Revisions	12.7
All Other Changes	(174.3)
Estimated Net Present Value at End of Period Dec. 31, 2006	1783.6

Notes:

- (1) Company actual before income taxes, excluding general and administrative expense.
- (2) The impact of changes in prices and other economic factors on Future Net Revenue.
- (3) Actual capital expenditures relating to the exploration, development and Production of Oil and Gas Reserves.
- (4) The change in forecast Development Costs for the Properties evaluated at the beginning of the period.
- (5) End of period net present value of the related Reserves.
- (6) Estimated as 10% of the beginning of period net present value.
- (7) The difference between forecast income taxes at beginning of period and the actual taxes for the period plus forecast income taxes at the end of period.

CANADIAN ASSETS ONLY

Period and Factor	Before Tax 2006 (\$ millions)
Estimated Net Present Value of Future Net Revenue at December 31, 2005	2537.8
Oil and Gas Sales During the Period Net of Production Costs and Royalties ⁽¹⁾	(426.4)
Changes due to Prices, Production Costs and Royalties Related to Forecast Production ⁽²⁾	(808.9)
Development Costs During the Period ⁽³⁾	225.6
Changes In Forecast Development Costs ⁽⁴⁾	(278.1)
Changes Resulting from Extensions and Improved Recovery ⁽⁵⁾	178.1
Changes Resulting from Discoveries ⁽⁵⁾	1.0
Changes Resulting from Acquisitions of Reserves ⁽⁵⁾	12.7
Changes Resulting from Dispositions of Reserves ⁽⁵⁾	(0.7)
Accretion of Discount ⁽⁶⁾	253.8
Net Change in Income Taxes ⁽⁷⁾	0
Changes Resulting from Technical Reserves Revisions	12.7
All Other Changes	(193.4)
Estimated Net Present Value at End of Period Dec. 31, 2006	1,514.3

Notes:

- (1) Company actual before income taxes, excluding general and administrative expense.

- (2) The impact of changes in prices and other economic factors on Future Net Revenue.
- (3) Actual capital expenditures relating to the exploration, development and Production of Oil and Gas Reserves.
- (4) The change in forecast Development Costs for the Properties evaluated at the beginning of the period.
- (5) End of period net present value of the related Reserves.
- (6) Estimated as 10% of the beginning of period net present value.
- (7) The difference between forecast income taxes at beginning of period and the actual taxes for the period plus forecast income taxes at the end of period.

US ASSETS ONLY

Period and Factor	Before Tax 2006 (\$ millions)
Estimated Net Present Value of Future Net Revenue at December 31, 2005	-
Oil and Gas Sales During the Period Net of Production Costs and Royalties ⁽¹⁾	(18.2)
Changes due to Prices, Production Costs and Royalties Related to Forecast Production ⁽²⁾	-
Development Costs During the Period ⁽³⁾	4.6
Changes In Forecast Development Costs ⁽⁴⁾	(4.6)
Changes Resulting from Extensions and Improved Recovery ⁽⁵⁾	-
Changes Resulting from Discoveries ⁽⁵⁾	-
Changes Resulting from Acquisitions of Reserves ⁽⁵⁾	268.3
Changes Resulting from Dispositions of Reserves ⁽⁵⁾	-
Accretion of Discount ⁽⁶⁾	-
Net Change in Income Taxes ⁽⁷⁾	-
Changes Resulting from Technical Reserves Revisions	-
All Other Changes	19.1
Estimated Net Present Value at End of Period Dec. 31, 2006	269.2

Notes:

- (1) Company actual before income taxes, excluding general and administrative expense.
- (2) The impact of changes in prices and other economic factors on Future Net Revenue.
- (3) Actual capital expenditures relating to the exploration, development and Production of Oil and Gas Reserves.
- (4) The change in forecast Development Costs for the Properties evaluated at the beginning of the period.
- (5) End of period net present value of the related Reserves.
- (6) Estimated as 10% of the beginning of period net present value.
- (7) The difference between forecast income taxes at beginning of period and the actual taxes for the period plus forecast income taxes at the end of period.

UNDEVELOPED RESERVES

The following discussion generally describes the basis on which PrimeWest attributes Proved and Probable Undeveloped Reserves and its plans for developing those Undeveloped Reserves.

PROVED AND PROBABLE UNDEVELOPED RESERVES

According to the GLJ Report using Forecast Prices and Costs, PrimeWest had Net Proved Undeveloped Reserves of 18.2 mmBOE as of December 31, 2006, consisting of 7,158 mbbbls Oil, 58.7 Bcf Natural Gas and 1,215 mbbbls Natural Gas Liquids. Net Probable Undeveloped Reserves were 18.8 mmBOE, consisting of 5,817 mbbbls Oil, 70.1 Bcf Natural Gas and 1,316 mbbbls Natural Gas Liquids. PrimeWest invests capital into development work, which moves its Proved Undeveloped Reserves and Probable Undeveloped Reserves into the Proved Developed Producing category. In 2006, \$261 million was invested on capital development, and approximately \$250 million has been budgeted for development capital in 2007. Allocating capital to Properties and timing of development is based on economics and performance of the asset. PrimeWest's 2007 development focus will be in its key development plays of Tight Gas (including the core areas of Caroline, Columbia), Conventional Development Area (including core areas of Wilson Creek, Valhalla, Laprise, Crossfield/Lone Pine Creek, Shallow Gas) and the US Assets.

Of PrimeWest's Net Proved Undeveloped Reserves, 15.8% are located in Wilson Creek, a core area in which PrimeWest plans to invest development capital (for specific details on the capital budgets, plans and timing for 2007 development in this area, see "Other Oil and Natural Gas Information"). Other areas with notable Net Proved Undeveloped Reserves include Flat Lake US with 27.5%, Columbia with 16.9%, Shallow Gas with 8.1%, BC Gas with 6.4% and Caroline with 5.6%.

For other Properties which have Proved Undeveloped Reserves or Probable Undeveloped Reserves attributed to them, PrimeWest plans to continue pursuing development opportunities such as drilling, completions, and facilities upgrades in order to move those Proved Undeveloped Reserves and Probable Undeveloped Reserves to Proved Developed Producing Reserves.

SIGNIFICANT FACTORS OR UNCERTAINTIES

Our evaluated Oil and Natural Gas Properties have no material extraordinary risks beyond those which are inherent in an Oil and Gas producing company as contained in other publicly filed documents of PrimeWest.

OTHER OIL AND NATURAL GAS INFORMATION

The following discussion provides an overview of selected core Properties, including a discussion of important plants and facilities.

TIGHT GAS

Caroline

Caroline is located approximately 100 kilometres northwest of Calgary. This liquids rich Gas-prospective area offers multi-zone gas drilling prospects, with current production from the Cardium, Viking, Elkton, Belly River and Mannville formations. Caroline comprises 218,056 Gross (159,460 Net) acres of land. Average Production in 2006 totalled 5,631 BOE/day, consisting primarily of Natural Gas. Through significant land and farm-in acquisitions, infrastructure modifications and an active development drilling program, PrimeWest has strengthened its position in this core property, allowing it to control key infrastructure, generate third party processing revenues, realize operating cost reductions and continue to develop low-risk development drilling opportunities for growth. PrimeWest's average working interest in Caroline is approximately 82%. Capital expenditures are budgeted at \$40 million for 2007 and will include drilling up to 19 new Gross Development Wells and facilities upgrades.

Columbia

Columbia is located in west-central Alberta approximately 175 kilometres southwest of Edmonton with Production from primarily low permeability Viking, Cardium, Mannville and Belly River sands. Columbia comprises 57,148 Gross (35,578 Net) acres of land with an average working interest of approximately 84%. In 2006, the average daily Production was 2,196 BOE/day, consisting primarily of Natural Gas, processed at a third party facility. In 2007, PrimeWest plans to spend approximately \$30 million to drill up to 10 Gross wells, install additional gathering facilities for future development and acquire additional seismic and land.

Edson

Edson is located in northwest Alberta approximately 200 kilometres west of Edmonton with Production from the Bluesky, Gething and Cardium formations. Edson comprises 29,120 Gross (17,581 Net) acres of land with an average 96% working interest. In 2006, the average daily Production was 896 BOE/day, consisting primarily of Natural Gas, all processed through a third party facility.

Ferrier

Ferrier is located in west central Alberta approximately 200 kilometres southwest of Edmonton with Production primarily from the Cardium formation. The Ferrier area comprises 52,000 Gross (19,450 Net) acres of land with an average 88% working interest. In 2006, the average daily Production was 1,049 BOE/day, consisting primarily of Natural Gas, all processed through a third party facility, with some volumes compressed at PrimeWest facilities before ultimately being processed at a third party facility.

CONVENTIONAL**BC Gas**

BC Gas is comprised of several Properties that produced an average of 2,260 BOE/day in 2006, the largest of which is the Laprise property. Laprise is a winter-access only area located about 160 kilometres north west of Fort St. John, British Columbia, with Production of marginally sour Natural Gas from the Baldonnel formation. PrimeWest has a 75.6% working interest in the Laprise Creek Baldonnel Unit No. 1, which overlies about 25% of the Laprise Creek Baldonnel "A" Pool, one of the largest Natural Gas pools in the province. PrimeWest also has a 100% interest in one producing non-unit Gas well. In 2006, PrimeWest drilled 6 Gas wells and installed additional compression to lower the field suction pressure and increase Production and Reserves. Up to a total of \$19 million of additional infill drilling is planned for 2007.

Brant Farrow

Brant Farrow is located about 65 kilometres south east of Calgary, with Production from the shallow gas Belly River and Medicine Hat formations and the deeper Mississippian, Basal Quartz and Glauconitic formations. Brant Farrow comprises 177,685 Gross (92,038 Net) acres of land with an average 84% working interest. Major infrastructure at Brant Farrow includes a 65% ownership of two Processing plants with a combined capacity of 15 mmcf/day. In 2006, the average daily Production of primarily sweet, dry Natural Gas was 1,848 BOE/day, mostly processed through owned and operated facilities.

Crossfield / Lone Pine Creek / Irricana

Crossfield / Lone Pine Creek is located approximately 30 kilometres northwest of Calgary and produces both Natural Gas and light to medium Crude Oil from the Wabamun (Crossfield), Leduc and Nisku formations. In 2006, the average daily Production was 1,606 BOE/day. Crossfield / Lone Pine Creek comprises 93,327 Gross (70,480 Net) acres of land. PrimeWest's operatorship of the 142 mmcf/day East Crossfield Gas processing facility (55.5% working interest) is a key success factor for PrimeWest in this area, allowing PrimeWest to implement efficiency measures and modernization, improve operating netbacks, generate third-party processing fees and extend the plant's economic life by at least 10 years. PrimeWest has a very small interest in the plant's sulphur block. In 2006, PrimeWest spent approximately \$25 million to drill up to 6 Gross wells and to conduct a turndown of the gas plant to enhance the long-term plant efficiencies due to the changing composition of the inlet gas stream.

Irricana is located in central Alberta approximately 50 kilometres north east of Calgary and adjacent to PrimeWest's Crossfield / Lone Pine Creek property with Production from the Pekisko, Wabamun and Mannville formations. Irricana comprises 55,936 Gross (33,424 Net) acres of land with an average 67% working interest. In 2006, the average daily Production was 1,591 BOE/day, primarily consisting of Natural Gas processed primarily through PrimeWest's East Crossfield Gas processing facility and some third party Gas processing facilities.

Shallow Gas

PrimeWest has several Shallow Gas Properties in southeastern Alberta with sweet dry Natural Gas Production from the Milk River, Medicine Hat and Second White Specs formations. In 2006, the average daily Production was 2,862 BOE/day. Main producing areas include Bindloss, Medicine Hat and Princess/Dinosaur comprising 197,002 Gross (163,578 Net) acres of land. Most Production is processed through owned and operated facilities and infrastructure.

Valhalla

Valhalla is located 500 kilometres north west of Edmonton with primarily sour Natural Gas Production from the Montney and Halfway formations, as well as some sweet Natural Gas Production from the uphole Baldonnel and Gething formations. There is also some Doig Oil Production at Valhalla. Valhalla comprises 62,080 Gross (35,565 Net) acres of land. PrimeWest has 100% ownership in two Natural Gas processing facilities consisting of two sour Gas compressors and one sweet Gas compressor and an amine sweetening system. In 2006, the biological desulphurisation gas plant was decommissioned increasing the plant's runtime and helping to lower operating expenses. PrimeWest's working interest averages 74% and in 2006 the average daily Production was increased to 2,033 BOE/day with 7 successful wells drilled. PrimeWest plans to spend up to \$19 million to continue to downspace and infill drill this multi-zone area in 2007.

Wilson Creek

Wilson Creek is located in west central Alberta approximately 200 kilometres northwest of Calgary with Production from the Belly River, Viking, Glauconitic, Rock Creek and Pekisko formations. The area comprises 174,455 Gross (100,415 Net) acres of land with an average 74% working interest. In 2006, the average daily Production was 4,293 BOE/day of Natural Gas. Production in the Wilson Creek, Gilby and Willesden Green areas is processed through third party facilities and the Wilson Creek Unit facilities. In 2007, up to \$44 million is planned to drill up to 19 operated Gross wells and 30 non-operated Gross wells.

US ASSETS

Effective July 6, 2006, PrimeWest acquired production assets in the United States with current production of approximately 2,600 BOE/day of primarily light sweet Crude Oil from 10 different fields-mostly operated by PrimeWest. Key producing fields are Flat Lake and Dwyer in Montana, Rival in North Dakota and Rocky Point in Wyoming.

Flat Lake is the most prolific of the fields with current production of approximately 800 BOE/day of production from the Mississippian and Devonian formations. They are similar to the producing fields found north of the Canada/US border in Saskatchewan.

The expansion into the US provided PrimeWest the opportunity to acquire long-life, sweet light oil reserves with significant development potential. The Properties are comprised of approximately 47,000 net acres of land. PrimeWest is the operator of the majority of the lands and holds an average working interest of 95%. The existing reserve life index on the acquired asset is 23.8 years based on total Company Interest Proven and Probable reserves.

Through the last half of 2006, PrimeWest actively pursued well workovers and facility upgrades on the acquired properties. Two new wells were spudded late in 2006 and results are anticipated by the end of the first quarter 2007.

PrimeWest has identified over US\$100 million of future development opportunities including a number of multi-legged infill horizontal drilling locations, waterflood optimization projects and possible future enhanced oil recovery projects.

COALBED METHANE

With over 124,000 net acres of land on the developing Horseshoe Canyon CBM trend, PrimeWest continues to be well positioned to take advantage of the emerging CBM resource play in Western Canada. PrimeWest is in the preliminary assessment stages of its CBM assets in three large concentrated operated areas.

PrimeWest began evaluating the potential of its CBM assets in 2005 with the recompletion of several existing older well bores to test the productivity potential of the thinly inter-bedded Horseshoe Canyon coals. The information gathered from these recompletions, coupled with the results of the delineation drilling completed at Lone Pine Creek in 2006 are expected to provide critical information for PrimeWest to determine the longer-term development potential of its CBM assets. Commercial development of these CBM assets, including initial marketable production volumes, could start in 2007 depending on the strength of the natural gas markets.

GROSS OVERRIDING ROYALTY (GORR) INTERESTS

These interests entitle PrimeWest to a share of the gross sales revenue on Production from underlying Properties held and operated by others, generally without deduction for Crown royalties and operating expenses. PrimeWest's GORR interests were principally acquired through the acquisition of Reserve Royalty Corp. in July 2000, as well as under farm-out agreements at various operated Properties, under which drilling of higher-risk exploration prospects is funded and undertaken by others in order to minimize the risk to the Unitholders. In 2006, the average daily volume was 1,173 BOE/day.

Under GORR arrangements, PrimeWest is not generally responsible for capital costs or abandonment and restoration costs associated with exploration or development activities undertaken by the working interest owner on the lands in question. Under some of the farm-out agreements, PrimeWest is alternatively entitled to convert its GORR to a working interest if successful exploration results, including development drilling, once the original working interest owners have recovered their capital investments.

OIL AND NATURAL GAS PROPERTIES AND WELLS

The following table summarizes, as at December 31, 2006, PrimeWest's interests in producing and non-producing wells.

	Producing Wells				Non-Producing Wells			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	1,036	382	1,587	880	735	404	614	409
British Columbia	119	3	43	32	36	8	7	4
Saskatchewan	754	17	1	1	116	-	-	-
Montana	84	84	-	-	56	56	-	-
North Dakota	111	56	-	-	13	9	-	-
Wyoming	22	22	5	5	8	8	2	2
Total	2,126	564	1,636	918	964	485	623	415

PROPERTIES WITH NO ATTRIBUTED RESERVES

The following table summarizes the Gross and Net acres of Unproved Properties in which PrimeWest has an interest and also the number of Net acres for which PrimeWest's rights to explore, develop or exploit will, in the absence of any further action, expire in 2007.

Play Type	Gross Unproved Acres	Net Unproved Acres	Net Acres Expiring in 2007
Conventional			
BC Gas	27,700	8,620	278
Crossfield/Lone Pine Creek	27,696	17,336	160
Shallow Gas	40,803	33,621	3,094
Thorsby	47,461	31,199	3,316
Valhalla	18,415	12,819	2,832
Wilson Creek	56,610	39,601	7,989
Conventional Other	611,876	320,454	89,713
Tight Gas			
Caroline	104,950	81,011	24,758
Columbia	55,646	29,417	-
Edson	17,630	11,621	5,834
Ferrier	14,567	6,102	640
US Assets			
Rival	3,721	3,721	-
Coalbed Methane ⁽¹⁾			
Brant Farrow CBM	172,878	91,446	19,439
Crossfield/Lone Pine Creek CBM	118,595	92,772	480
Thorsby CBM	114,229	74,202	2,129
GORR			
GORR	270,155	-	-
TOTAL (excludes CBM)	1,297,230	595,523	138,613

(1) Portion of the CBM acreage may also be included in the Conventional acreage count.

ADDITIONAL INFORMATION CONCERNING ABANDONMENT AND RECLAMATION COSTS

The following table discloses the abandonment and reclamation costs PrimeWest anticipates incurring as at December 31, 2006, calculated both undiscounted and at a discount rate of 10%, and the portion thereof anticipated to be paid in each of the next three years. PrimeWest anticipates incurring abandonment costs in respect of approximately 37 Net wells during 2007. PrimeWest currently has a large number of reclamation projects underway, in varying stages of completion. Due to weather conditions, project unknowns, landowner issues and changing regulations, it is difficult to accurately determine the number of reclamation projects that will be completed in a given year.

Since the inception of the Trust, PrimeWest has maintained an environmental fund to pay for future costs related to well abandonment and site cleanup. The fund is used to pay for such costs as they are incurred. Future abandonment and reclamation costs will continue to be funded from the fund and, as required, out of cash flow from operating activities. In 2006, PrimeWest contributed \$0.50/BOE of Production, totalling \$7.3 million, which includes interest, into this fund. As of December 31, 2006, there was an unused cash balance of \$2.2 million in the fund.

CONSOLIDATED – INCLUDES CANADIAN AND US ASSETS

Period	Abandonment and Reclamation Costs Net of Salvage Value Undiscounted (\$M)	Abandonment and Reclamation Costs Net of Salvage Value Discounted at 10% (\$M)
Total as at December 31, 2006	15.7	15.7
Anticipated to be incurred in 2007	10	9
Anticipated to be incurred in 2008	10	9
Anticipated to be incurred in 2009	10	9

CANADIAN ASSETS ONLY

Period	Abandonment and Reclamation Costs Net of Salvage Value Undiscounted (\$M)	Abandonment and Reclamation Costs Net of Salvage Value Discounted at 10% (\$M)
Total as at December 31, 2006	15.4	15.4
Anticipated to be incurred in 2007	9.4	8.5
Anticipated to be incurred in 2008	9.8	8.8
Anticipated to be incurred in 2009	9.9	8.9

US ASSETS ONLY

Period	Abandonment and Reclamation Costs Net of Salvage Value Undiscounted (\$M)	Abandonment and Reclamation Costs Net of Salvage Value Discounted at 10% (\$M)
Total as at December 31, 2006	0.3	0.3
Anticipated to be incurred in 2007	0.6	0.5
Anticipated to be incurred in 2008	0.2	0.2
Anticipated to be incurred in 2009	0.1	0.1

TAX HORIZON

As a result of PrimeWest's tax efficient structure, annual taxable income is transferred from its Canadian operating entity to PrimeWest Energy Trust, and from the Trust to its Unitholders. This is primarily accomplished through the Royalty granted to the Trust, on underlying Oil and Gas Properties held by its operating subsidiary.

COSTS INCURRED

The following table discloses material Property Acquisition Costs, Exploration Costs and Development Costs for PrimeWest for the year ended December 31, 2006.

	Property Acquisition Costs		Exploration Costs	Development Costs
	Proved Properties	Unproved Properties		
Total (\$ millions)	369.6	10.5	3.2	247.2

EXPLORATION AND DEVELOPMENT ACTIVITIES

The following table discloses the number of Exploratory Wells and Development Wells, both Gross and Net, drilled and rig released for the year ended December 31, 2006 and which are Oil wells, Natural Gas wells, Service Wells and dry holes.

	Exploratory Wells ⁽¹⁾		Development Wells	
	Gross	Net	Gross	Net
Conventional				
Oil	8	6.5	18	13.7
Natural Gas	38	23.4	61	33.0
Service Wells	-	-	-	-
Dry Holes	3	2.0	3	2.7
Sub-Total	49	31.9	82	49.4
Tight Gas				
Oil	1	0.1	2	0.5
Natural Gas	20	14.4	4	1.8
Service Wells	-	-	-	-
Dry Holes	-	-	-	-
Sub-Total	21	14.5	6	2.3
Coalbed Methane				
Oil	-	-	1	1.0
Natural Gas	1	0.2	5	5.0
Service Wells	-	-	-	-
Dry Holes	-	-	-	-
Sub-Total	1	0.2	6	6
US Assets				
Oil	-	-	3	3.0
Natural Gas	-	-	-	-
Service Wells	-	-	-	-
Dry Holes	-	-	-	-
Sub-Total	-	-	3	3.0
Total	71	46.6	97	60.7

(1) Exploratory well count is based on the Lahee classification used by the Alberta Energy and Utilities Board and is not reflective of the risk profile associated with these wells.

PrimeWest engages in development drilling along with acquisitions to offset natural Production decline and add to Reserves. Specific details on development plans and 2007 capital budgets for PrimeWest's core Properties are described under "Other Oil and Natural Gas Information."

ESTIMATED PRODUCTION

The following table discloses for each product type the total volume of Company Interest Proved plus Probable Production estimated by GLJ for 2007 using Forecast Prices and Costs and Constant Prices and Costs.

CONSOLIDATED – INCLUDES CANADIAN AND US ASSETS

2007 Estimated Total Production by GLJ	Light and Medium Crude Oil (m bbl)	Heavy Oil (m bbl)	Natural Gas (mmcf)	Natural Gas Liquids (m bbl)	Total (mBOE)
Forecast	3,030	593	69,245	1,625	16,789
Constant	3,030	593	69,256	1,626	16,791

CANADIAN ASSETS ONLY

2007 Estimated Total Production by GLJ	Light and Medium Crude Oil (m bbl)	Heavy Oil (m bbl)	Natural Gas (mmcf)	Natural Gas Liquids (m bbl)	Total (mBOE)
Forecast	1,944	593	68,699	1,625	15,612
Constant	1,944	593	68,710	1,626	15,614

US ASSETS ONLY

2007 Estimated Total Production by GLJ	Light and Medium Crude Oil (m bbl)	Heavy Oil (m bbl)	Natural Gas (mmcf)	Natural Gas Liquids (m bbl)	Total (mBOE)
Forecast	1,086	-	546	-	1,177
Constant	1,086	-	546	-	1,177

At December 31, 2006, PrimeWest estimates its 2007 Production will average 39,500 BOE/day, reflecting the natural decline of the assets and the Production additions from the 2007 capital development program.

PRODUCTION HISTORY

The following table discloses, on a quarterly basis for the year ended December 31, 2006, PrimeWest's share of average daily Production volume, prior to royalties, and the prices received, royalties paid, Production Costs incurred and netbacks on a per unit of volume basis for each product type.

CONSOLIDATED – INCLUDES CANADIAN AND US ASSETS

Product Type	PrimeWest's Share of Average Daily Production Volume ⁽¹⁾	Average per unit of volume (\$/bbl, \$/mcf, \$/BOE)			
		Price Received	Royalties Paid	Production Costs	Netbacks ⁽²⁾
Light, Medium, Heavy Oil	(bbls/day)				
1 st Quarter	6,867	57.09	8.39	9.54	36.58
2 nd Quarter	6,305	68.77	10.80	9.16	48.76
3 rd Quarter	9,106	69.18	9.94	9.36	50.34
4 th Quarter	8,950	55.13	9.46	10.12	38.14
Natural Gas	(mcf/day)				
1 st Quarter	166,021	9.09	2.29	1.59	5.27
2 nd Quarter	164,115	6.29	1.30	1.53	3.84
3 rd Quarter	164,064	6.20	1.35	1.56	3.79
4 th Quarter	169,852	6.79	1.33	1.69	4.37

Product Type	PrimeWest's Share of Average Daily Production Volume ⁽¹⁾	Average per unit of volume (\$/bbl, \$/mcf, \$/BOE)			
		Price Received	Royalties Paid	Production Costs	Netbacks ⁽²⁾
Natural Gas Liquids	(bbls/day)				
1 st Quarter	3,525	59.34	16.45	9.54	33.35
2 nd Quarter	3,748	62.57	18.20	9.16	35.21
3 rd Quarter	3,931	62.50	16.16	9.36	36.98
4 th Quarter	4,127	52.52	13.60	10.12	28.80
Total BOE	(BOE/day)				
1 st Quarter	38,062	55.44	13.04	9.54	32.66
2 nd Quarter	37,406	45.46	9.36	9.16	28.61
3 rd Quarter	40,381	46.86	9.29	9.36	30.33
4 th Quarter	41,386	45.03	8.86	10.12	29.07

Notes:

(1) Before deduction of royalties.

(2) Netbacks are calculated as Revenues less the aggregate of Royalties, Transportation and Operating Costs, on a per BOE (or mcf) basis.

CANADIAN ASSETS ONLY

Product Type	PrimeWest's Share of Average Daily Production Volume ⁽¹⁾	Average per unit of volume (\$/bbl, \$/mcf, \$/BOE)			
		Price Received	Royalties Paid	Production Costs	Netbacks ⁽²⁾
Light, Medium, Heavy Oil	(bbls/day)				
1 st Quarter	6,867	57.09	8.39	9.54	36.58
2 nd Quarter	6,305	68.77	10.80	9.16	48.76
3 rd Quarter	6,628	69.51	8.26	8.90	52.99
4 th Quarter	6,553	55.16	8.49	9.88	36.60
Natural Gas					
1 st Quarter	166,021	9.09	2.29	1.59	5.27
2 nd Quarter	164,115	6.29	1.30	1.53	3.84
3 rd Quarter	162,510	6.20	1.35	1.48	3.86
4 th Quarter	169,118	6.78	1.33	1.65	4.41
Natural Gas Liquids					
1 st Quarter	3,525	59.34	16.45	9.54	33.35
2 nd Quarter	3,748	62.57	18.20	9.16	35.21
3 rd Quarter	3,911	62.64	16.25	8.90	37.50
4 th Quarter	4,049	53.10	13.86	9.88	29.36
Total BOE					
1 st Quarter	38,062	55.44	13.04	9.54	32.66
2 nd Quarter	37,406	45.46	9.36	9.16	28.61
3 rd Quarter	37,624	45.53	8.99	8.90	29.92
4 th Quarter	38,788	44.43	8.67	9.88	28.47

Notes:

(1) Before deduction of royalties.

(2) Netbacks are calculated as Revenues less the aggregate of Royalties, Transportation and Operating Costs, on a per BOE (or mcf) basis.

US ASSETS ONLY

Product Type	PrimeWest's Share of Average Daily Production Volume ⁽¹⁾	Average per unit of volume (\$/bbl, \$/mcf, \$/BOE)			
		Price Received	Royalties Paid	Production Costs	Netbacks ⁽²⁾
Light, Medium, Heavy Oil	(bbls/day)				
1 st Quarter	-	-	-	-	-
2 nd Quarter	-	-	-	-	-
3 rd Quarter	2,477	68.28	14.42	15.71	38.14
4 th Quarter	2,397	55.07	12.14	13.77	39.36
Natural Gas	(mcf/day)				
1 st Quarter	-	-	-	-	-
2 nd Quarter	-	-	-	-	-
3 rd Quarter	1,554	6.07	0.79	2.62	2.66
4 th Quarter	734	8.97	1.58	2.30	5.10
Natural Gas Liquids	(bbls/day)				
1 st Quarter	-	-	-	-	-
2 nd Quarter	-	-	-	-	-
3 rd Quarter	20	34.56	-	15.71	18.85
4 th Quarter	78	22.70	-	13.77	8.93
Total BOE	(BOE/day)				
1 st Quarter	-	-	-	-	-
2 nd Quarter	-	-	-	-	-
3 rd Quarter	2,756	65.04	13.41	15.71	35.92
4 th Quarter	2,598	54.04	11.64	13.77	38.03

Notes:

(1) Before deduction of royalties.

(2) Netbacks are calculated as Revenues less the aggregate of Royalties, Transportation and Operating Costs, on a per BOE (or mcf) basis.

The following table discloses for each of PrimeWest's core and non-core fields, and in total, the Production volumes for each product type for the year ended December 31, 2006.

Conventional	Light, Medium & Heavy Crude Oil (mbbls)	Natural Gas (mmcf)	Natural Gas Liquids (mbbls)	Average Daily Production (BOE/day)
Boundary	316	92	24	974
BC Gas	16	4,200	109	2,260
Valhalla	74	3,699	52	2,033
NWAB Gas	50	2,776	1	1,406
Arch	160	1,861	15	1,332
North Minors	12	164	4	117
Fox Creek	210	243	19	738
Barrhead	11	1,431	16	728
Wilson Creek	200	6,754	241	4,293
Thorsby	169	4,099	150	2,746
Central Non Core	-	36	-	17
Grand Forks	654	259	14	1,949
Brantfarrow	111	3,364	3	1,848
Jumping Pd & Whiskey Creek	-	728	28	409
LPC/Crossfield	78	6,105	72	3,197

Conventional	Light, Medium & Heavy Crude Oil (mmbbls)	Natural Gas (mmcf)	Natural Gas Liquids (mmbbls)	Average Daily Production (BOE/day)
Shallow Gas	31	5,917	28	2,862
South Non Core	13	29	-	50
Total Conventional	2,104	41,756	777	26,958
TIGHT GAS				
Caroline	109	9,744	323	5,631
Columbia	22	3,890	131	2,196
Edson	3	1,654	48	896
Ferrier	9	1,857	65	1,049
Total Tight Gas	143	17,145	566	9,773
COALBED METHANE				
Wilson Creek	-	6	-	3
Red Deer	-	14	-	6
Thorsby	-	70	2	37
Brantfarrow	-	18	-	8
Crossfield	-	-	-	-
Total CBM	-	108	2	54
US ASSETS				
Flat Lake (US)	145	41	-	416
Rocky point (US)	97	18	-	275
Dwyer (US)	78	31	-	228
Rival (US)	40	59	9	160
Non Core (US)	89	62	-	271
Total US Assets	448	210	9	1,349
Total GORRS	157	1,351	46	1,173
Total Miscellaneous	1	27	-	14
TOTAL CONSOLIDATED	2,853	60,597	1,400	39,321

PrimeWest's estimate for 2007 Production volumes includes 1,800 BOE/day on a company-wide basis that was behind pipe at December 31, 2006.

ITEM 5: INDUSTRY CONDITIONS

The Oil and Natural Gas industry is subject to extensive controls and regulations, imposed by various levels of government. It is not expected that any of these controls or regulations will affect the operations of PrimeWest in a manner materially different than they would affect other Oil and Gas companies and trusts of similar size. All current legislation is a matter of public record, and PrimeWest is unable to predict what additional legislation or amendments may be enacted.

PRICING AND MARKETING – NATURAL GAS

In Canada, the price of Natural Gas sold intraprovincially, interprovincially or to the United States is determined by negotiation between buyers and sellers. Natural Gas exported from Canada is subject to regulation by the National Energy Board ("NEB") and the government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the NEB and the government of Canada. Natural Gas exports for a term of less than two years requires a general short term export license while terms greater than two years

require a specific license for the particular Gas sold (in quantities of not more than 30,000 cubic metres/day). Any Natural Gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export license from the NEB and the granting of such a license requires the approval of the Governor in Council.

The governments of Alberta, British Columbia and Saskatchewan also regulate the volumes of Natural Gas, which may be removed from those provinces for consumption elsewhere, based on such factors as Reserve availability, transportation arrangements and market considerations.

PRICING AND MARKETING – OIL

In Canada, producers of oil negotiate sales contracts directly with oil purchasers. Oil prices are primarily based on worldwide supply and demand. The specific price paid depends in part on oil quality, prices of competing fuels, distances to market, the value of refined products and the supply/demand balance. Oil exports may be made pursuant to export contracts with terms not exceeding one year in the case of light crude oil, and not exceeding two years in the case of heavy crude oil, provided that an order approving any such export has been obtained from the NEB. Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export license from the NEB and the granting of such a license requires the approval of the Governor in Council. PrimeWest completes the sale of its oil volumes to the purchasers within Canada and is not responsible for obtaining the export licenses.

The crude oil marketing system in the U.S. is similar to that of Canada where producers negotiate directly with crude oil purchasers regarding the terms and pricing mechanisms. Like in Canada, the price being paid for the crude oil is affected by market factors that influence oil supply and demand, as well as by the quality of the crude production and any trucking/transportation tariffs depending on the distance from market. As the U.S. production is generally closer to market than in Canada, the netback prices to producers are generally better due to the lower tariffs.

THE NORTH AMERICAN FREE TRADE AGREEMENT

On January 1, 1994, the North American Free Trade Agreement (“NAFTA”) among the governments of Canada, the US and Mexico became effective. The NAFTA carries forward most of the material energy terms contained in the Canada-US Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the US or Mexico will be allowed provided that any export restrictions do not: (i) reduce the proportion of energy resource exported relative to domestic use (based upon the proportion prevailing in the most recent 36-month period), (ii) impose an export price higher than the domestic price; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

The NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The agreement also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes, and to minimize disruption of contractual arrangements, which is important for Canadian Natural Gas exports.

ROYALTIES, INCENTIVES AND PRODUCTION TAXES

In addition to federal regulation, each province has legislation and regulations, which govern land tenure, royalties, Production rates, environmental protection and other matters. In all Canadian jurisdictions, producers of Oil and Natural Gas are required to pay annual rental payments in respect of Crown leases and royalties and freehold Production taxes in respect of Oil and Natural Gas produced from Crown and freehold lands, respectively. The royalty regime is a significant factor in the profitability of Oil and Natural Gas Production. Royalties payable on Production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the Gross Production, and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced.

From time to time the governments of Canada, Alberta, British Columbia and Saskatchewan have established incentive programs, which have included royalty-rate reductions, royalty holidays and tax credits for the purpose of encouraging Oil and Natural Gas exploration or enhanced recovery projects. These programs reduce the amount of Crown royalties otherwise payable.

The U.S. properties are located in the states of Montana, North Dakota, and Wyoming. Each of these states has its own rules and regulations as well as production taxes based on a percentage of the revenues received from the wells in that state. Certain states offer incentives to drill by reducing the production tax rates for working interest owners for a certain period of time depending on the type of well drilled. Reduced production tax rates are also offered at times, depending on the production levels and prices received.

In the U.S., the majority of leases are fee leases and a flat royalty rate is negotiated between the mineral owner and the lessee. For the minimal number of federal or state leases, the flat royalty rate is determined by the federal or state government. In most cases, if a well is producing on a lease, no annual rental payment is required to be paid to a land owner. If there is no production, an annual rental is required to be paid to the landowner to hold the lease.

ENVIRONMENTAL REGULATION

The Oil and Natural Gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced in association with certain Oil and Natural Gas industry operations, and can affect the location of wells and facilities and the extent to which exploration and development is permitted. In addition, legislation requires that well and facilities sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of that legislation may result in the imposition of fines or the issuance of clean-up orders.

PrimeWest is committed to meeting its responsibilities to protect the environment wherever it operates, and anticipates making increased expenditures of both a capital and expense nature as a result of the increasingly stringent laws relating to the protection of the environment. PrimeWest's internal procedures are designed to ensure that the environmental aspects of new developments are taken into account prior to proceeding. PrimeWest believes that it is in material compliance with applicable environmental laws and regulations.

KYOTO PROTOCOL

In December of 2002, Canada became a signatory to the 1997 Kyoto Protocol to the United Nation's Framework convention on Climate change, known as the Kyoto Protocol. The implementation of this plan has not been fully defined by the federal government. Until an implementation plan is developed, it is impossible to assess the impact on specific industries and individual businesses within an industry. In fact, the current federal government has stated it will not implement the Kyoto Protocol, but instead has stated its commitment to the development and implementation of a "Made in Canada" plan for reducing greenhouse gases through the *Clean Air Act* and other initiatives. The implications of those initiatives are similarly unclear at present.

ITEM 6: RISK FACTORS

RISKS RELATED TO OUR BUSINESS

Volatility in Oil and Natural Gas prices could have a material adverse effect on results of operations and financial condition, which, in turn, could affect the market price of the Trust Units and the amount of distributions to Unitholders.

Results of operations and financial condition are dependent on the prices received for the Oil and Natural Gas that PrimeWest sells. Historically, the markets for Oil and Natural Gas have been volatile and are likely to continue to be volatile in the future. Oil and Natural Gas prices may fluctuate widely on a daily basis in response to a variety of factors beyond the Trust's control, including:

- Global energy policy, including the ability of OPEC to set and maintain Production levels and prices for Oil;
- Political conditions, including the risk of hostilities in the petroleum producing regions of the world;
- Global and domestic economic conditions;
- Weather conditions, including weather related natural disasters;
- The supply and price of imported Oil and liquefied Natural Gas;
- The Production and storage levels of North American Natural Gas;
- The level of consumer demand;
- The price and availability of alternative fuels;
- The impact of US/Canadian currency exchange on the Canadian prices realized by the Trust;
- The proximity of Reserves to, and capacity of, transportation facilities;
- The effect of worldwide energy conservation measures; and
- Government regulations.

1. Any decline in Crude Oil or Natural Gas prices may have a material adverse effect on PrimeWest's operations, financial condition, borrowing ability, Reserves and the level of expenditures for the development of Reserves. Any resulting decline in PrimeWest's cash flow could reduce distributions and the market price of the Trust Units.

PrimeWest uses financial derivative instruments and other hedging mechanisms to attempt to limit a portion of the adverse effects resulting from changes in Oil and Natural Gas commodity prices. To the extent PrimeWest hedges its commodity price exposure, it foregoes the benefits it would otherwise receive if commodity prices were to increase. In addition, commodity-hedging activities could expose PrimeWest to losses. Such losses could occur under various circumstances, including those in which the other party to a hedge does not perform its obligations under the applicable agreement, the hedge is imperfect or PrimeWest's hedging policies and procedures are not followed. Furthermore, PrimeWest cannot guarantee that its hedging transactions will fully offset the risks of changes in commodities prices.

2. An increase in operating costs or a decline in PrimeWest's Production level could have a material adverse effect on our results of operations and financial conditions and, therefore, could reduce distributions to Unitholders and affect the market price of the Trust Units.

Higher operating costs associated with PrimeWest's Properties will directly decrease the amount of cash flow received by the Trust and, therefore, may reduce distributions to our Unitholders. Electricity, chemicals, supplies, and reclamation, abandonment and labour costs are some of the types of operating costs that are susceptible to material fluctuation.

3. The level of Production from existing Properties may decline at rates greater than anticipated due to unforeseen circumstances, many of which are beyond PrimeWest's control. A significant decline in Production could result in materially lower revenues and cash flow and, therefore, could reduce the amount available for distributions to Unitholders.

4. Distributions may be reduced during periods in which PrimeWest makes capital expenditures or debt repayments using cash flow, which could also affect the market price of the Trust Units.

To the extent that PrimeWest uses cash flow to finance acquisitions, Development Costs and other significant expenditures, the net cash flow that the Trust receives from PrimeWest will be reduced, and, as a consequence, the amount of cash available to distribute to Unitholders will decrease. Distributions may be reduced, or even eliminated, at times when significant capital or other expenditures are made.

The Board of Directors of PrimeWest has the discretion to determine the extent to which cash flow from PrimeWest will be allocated to the payment of debt service charges as well as the repayment of outstanding debt, including debt under the Credit Facility. The amount of funds retained by PrimeWest to pay debt services charges or reduce debt will reduce the amount of cash distributed to Unitholders during those periods in which funds are so retained.

5. A decline in PrimeWest's ability to market its Oil and Natural Gas Production could have a material adverse effect on Production levels or on the price received for Production, which, in turn, could reduce distributions to Unitholders and affect the market price of the Trust Units.

PrimeWest's business depends in part upon the availability, proximity and capacity of Gas gathering systems, pipelines and processing facilities. Canadian federal and provincial, as well as United States federal and state, regulation of Oil and Gas Production, processing and transportation, tax and energy policies, general economic conditions, and changes in supply and demand could adversely affect PrimeWest's ability to produce and market Oil and Natural Gas. If market factors change and inhibit the marketing of PrimeWest's Production, overall Production or realized prices may decline, which could reduce distributions to our Unitholders.

6. Fluctuations in foreign currency exchange rates could adversely affect PrimeWest's business, and could affect the market price of the Trust Units as well as distributions to Unitholders.

The price that PrimeWest receives for a majority of its Oil and Natural Gas is based on United States dollar denominated benchmarks, and therefore the price that PrimeWest receives in Canadian dollars is affected by the exchange rate between the two currencies. A material increase in the value of the Canadian dollar relative to the United States dollar may negatively impact Net Production Revenue by decreasing the Canadian dollars received for a given United States dollar price. PrimeWest could also be subject to unfavourable price changes to the extent that it has engaged, or in the future engages, in risk management activities related to foreign exchange rates, through entry into forward foreign exchange contracts or otherwise.

7. If PrimeWest is unable to acquire additional Reserves, the value of the Trust Units and distributions to Unitholders may decline.

PrimeWest does not actively explore for Oil and Natural Gas Reserves. Instead, PrimeWest adds to its Reserves primarily through development and acquisitions. As a result, future Oil and Natural Gas Reserves are highly dependent on PrimeWest's success in exploiting existing Properties and acquiring additional Properties. PrimeWest also distributes the majority of its net cash flow to Unitholders rather than reinvesting it in Reserve additions. Accordingly, if external sources of capital, including the issuance of additional Trust Units, become limited or unavailable on commercially reasonable terms, PrimeWest's ability to make the necessary capital investments to maintain or expand its Oil and Natural Gas Reserves will be impaired. To the extent that PrimeWest is required to use cash flow to finance capital expenditures or property acquisitions, the level of cash flow available for distribution to Unitholders will be reduced. Additionally, PrimeWest cannot guarantee that it will be successful in developing additional Reserves or acquiring additional Reserves on terms that meet its investment objectives. Without these Reserve additions, PrimeWest's Reserves will deplete and as a consequence, either Production from, or the average Reserve life of, its Properties will decline. Either decline may result in a reduction in the value of Trust Units and in a reduction in cash available for distributions to Unitholders.

8. Actual Reserves will vary from Reserve estimates, and those variations could be material, and affect the market price of the Trust Units and distributions to Unitholders.

The value of the Trust Units depends upon, among other things, the Reserves attributable to PrimeWest's Properties. Estimating Reserves is inherently uncertain. Ultimately, actual Reserves attributable to PrimeWest's Properties will vary from estimates, and those variations may be material. The Reserve figures contained herein are only estimates. A number of factors are considered and a number of assumptions are made when estimating Reserves. These factors and assumptions include, among others:

- Historical Production in the areas in which the Properties are located and Production rates from similar producing areas;
- Future commodity prices, Production and Development Costs, royalties and capital expenditures;
- Initial Production rates;
- Production decline rates;

- Ultimate recovery of Reserves;
- Success of future development activities;
- Marketability of Production;
- Effects of government regulation; and
- Other government levies that may be imposed over the producing life of Reserves.

Reserve estimates are based on the relevant factors, assumptions and prices on the date that such estimates are prepared. Many of these factors are subject to change and are beyond PrimeWest's control. If these factors, assumptions and prices change or prove to be inaccurate, actual results may vary materially from Reserve estimates.

9. If PrimeWest expands its operations beyond Oil and Natural Gas Production in western Canada and the western US, it may face new challenges and risks. If PrimeWest is unsuccessful in managing these challenges and risks, its results of operations and financial condition could be adversely affected, which could affect the market price of the Trust Units and distributions to Unitholders.

PrimeWest's operations and expertise are currently focused on conventional Oil and Gas Production and development in the Western Canada Sedimentary Basin. In the future, it may acquire unconventional Oil and Gas Properties outside this geographic area. In addition, the Declaration of Trust does not limit the activities to Oil and Gas Production and development, and PrimeWest could acquire other energy related assets, such as Oil and Natural Gas processing plants or pipelines. Expansion of PrimeWest's activities may present challenges and risks that it has not faced in the past. If PrimeWest does not manage these challenges and risks successfully, its results of operations and financial condition could be adversely affected.

PrimeWest is in the process of expanding its expertise to the operation and exploitation of the US assets, which are geologically similar to producing properties located in the Western Canada Sedimentary Basin. However, until it completes this process, it may face additional risks and challenges associated with the US Assets themselves, as well as the fact that such Assets are located in a different operating and regulatory environment.

10. In determining the purchase price of acquisitions, PrimeWest relies on assessments relating to estimates of Reserves that may prove to be inaccurate, which could affect the market price of the Trust Units and distributions to Unitholders.

The price PrimeWest is willing to pay for an acquisition is based largely on estimates of the Reserves to be acquired. Actual Reserves could vary materially from these estimates. Consequently, the Reserves PrimeWest acquires may be less than expected, which could adversely impact cash flows and distributions to Unitholders.

An initial assessment of an acquisition may be based on a report by engineers or firms of engineers that have different evaluation methods and approaches than those of PrimeWest's engineers, and these initial assessments may differ significantly from PrimeWest's subsequent assessments.

11. PrimeWest does not operate some of its Properties and therefore, results of operations may be adversely affected by the failure of third-party operators, which could affect the market price of the Trust Units and distributions to Unitholders.

The continuing Production from a property, and to some extent the marketing of that Production, is dependent upon the ability of the operators of those Properties. At December 31, 2006, approximately [20%] of PrimeWest's daily Production came from Properties operated by third parties. To the extent that a third party operator fails to perform its functions efficiently or becomes insolvent, PrimeWest's revenue may be reduced. Third party operations also make estimates of future capital expenditures more difficult.

Further, the operating agreements that govern the Properties not operated by PrimeWest typically require the operator to conduct operations in a good and "workmanlike" manner. These operating agreements generally provide, however, that the operator has no liability to the other non-operating working interest

owners, for losses sustained or liabilities incurred, except for liabilities that may result from gross negligence or wilful misconduct.

12. Delays in business operations could adversely affect distributions to Unitholders and the market price of the Trust Units.

In addition to the usual delays in payment by purchasers of Oil and Natural Gas to PrimeWest and to the operators of PrimeWest's non-operated Properties, and the delays of those operators in remitting payment to PrimeWest, payments between any of these parties may also be delayed by:

- Restrictions imposed by lenders;
- Accounting delays;
- Delays in the sale or delivery of products;
- Delays in the connection of wells to a gathering system;
- Blowouts or other accidents;
- Adjustments for prior periods;
- Recovery by the operator of expenses incurred in the operation of the Properties; or
- The establishment by the operator of Reserves for these expenses.

Any of these delays could reduce the amount of cash available for distribution to Unitholders in a given period and expose PrimeWest to additional third party credit risks.

13. The Trust and PrimeWest's indebtedness may limit the timing or amount of the distributions that are paid to Unitholders, and could affect the market price of the Trust Units.

The payments of interest and principal, and other costs, expenses and disbursements made to the providers of the Credit Facility reduce amounts available for distribution to Unitholders. Variations in interest rates and scheduled principal repayments could result in significant changes to the amount of the cash flow available for payment to the Unitholders in any given period. The agreements governing the Credit Facility provide that if the Trust or PrimeWest are in default under the Credit Facility, exceed certain borrowing thresholds or fail to comply with certain covenants, they must repay the indebtedness at an accelerated rate, and the ability to make distributions to Unitholders may be further restricted.

The lenders under the Credit Facility have been provided with a security interest in substantially all of the Trust and PrimeWest's assets. If the Trust and PrimeWest are unable to pay the debt service charges or otherwise commit an event of default, such as bankruptcy, these lenders may foreclose on and sell the Properties. The proceeds of any sale would be applied to satisfy amounts owed to the creditors. Only after the proceeds of that sale were applied towards the debt would the remainder, if any, be available for distribution to Unitholders.

14. The current Credit Facility and any replacement credit facility may not provide sufficient liquidity.

The amounts available under the existing Credit Facility may not be sufficient for future operations, or the Trust and PrimeWest may not be able to obtain additional financing on economic terms attractive to them, if at all. A portion of the existing Credit Facility is available on a one-year revolving basis. If the lenders do not extend the facility at the end of the annual revolving period, the loan will convert to a term basis with 60% of the aggregate principal amount of the loan repayable on the date which is one year after that conversion date and the remaining 40% of the aggregate principal amount outstanding repayable on the date which is two years after that conversion date. If this occurs, the Trust and PrimeWest may need to obtain alternate financing. Any failure to obtain suitable replacement financing may have a material adverse effect on the business, and distributions to Unitholders may be materially reduced.

15. The Trust may be unable to successfully compete with other organizations in the Trust's industry, which could affect the market price of the Trust Units and distributions to Unitholders.

The Oil and Natural Gas industry is highly competitive. PrimeWest competes for capital, acquisitions of Reserves, undeveloped lands, skilled personnel, access to drilling rigs, service rigs and other equipment, access to processing facilities, pipeline and refining capacity and in many other respects with a substantial number of other organizations, many of which may have greater technical and financial resources than PrimeWest. Some of these organizations explore for, develop and produce Oil and Natural Gas but also carry on refining operations and market Oil and other products on a worldwide basis. As a result of these complementary activities, some of PrimeWest's competitors may have greater and more diverse competitive resources to draw on than PrimeWest does.

16. The industry in which PrimeWest operates exposes the Trust and PrimeWest to potential liabilities that may not be covered by insurance.

PrimeWest's operations are subject to all of the risks associated with the operation and development of Oil and Natural Gas Properties, including the drilling of Oil and Natural Gas wells, and the Production and transportation of Oil and Natural Gas. These risks and hazards include encountering unexpected formations or pressures, blow outs, craterings and fires, all of which could result in personal injury, loss of life, or environmental and other damage to PrimeWest's property and the property of others. PrimeWest cannot fully protect against all of these risks, nor are all of these risks insurable. While PrimeWest's insurance broker is responsible for ensuring that insurance underwriters have the financial strength necessary to respond to claims, PrimeWest may become liable for damages arising from events against which PrimeWest cannot insure or against which PrimeWest may elect not to insure because of high premium costs or other reasons. Any costs incurred to repair these damages or pay these liabilities would reduce funds available for distribution to Unitholders.

17. The operation of Oil and Natural Gas wells could subject PrimeWest to environmental claims and liability.

The Oil and Natural Gas industry is subject to extensive environmental regulation pursuant to local, provincial and federal legislation. A breach of that legislation may result in the imposition of fines or the issuance of "clean up" orders. Legislation regulating the Oil and Natural Gas industry may be changed to impose higher standards and potentially more costly obligations. For example, the Kyoto Protocol will require, among other things, significant reductions in greenhouse gases. The impact of the Kyoto Protocol, or any alternative environmental initiatives, on PrimeWest is uncertain and may result in significant additional costs (future) for PrimeWest's operations. Although PrimeWest has established a reclamation fund for the purpose of funding the estimated future environmental and reclamation obligations based on current knowledge and expectations, PrimeWest cannot guarantee that it will be able to satisfy its actual future environmental and reclamation obligations.

PrimeWest is not fully insured against certain environmental risks, either because such insurance is not available or because of high premium costs. In particular, insurance against risks from environmental pollution occurring over time (as opposed to sudden and catastrophic damages) is not available on economically reasonable terms. Accordingly, PrimeWest's Properties may be subject to liability due to hazards that cannot be insured against, or that have not been insured against due to prohibitive premium costs or for other reasons.

Any site reclamation or abandonment costs actually incurred in the ordinary course of business in a specific period will be funded out of cash flow and, therefore, will reduce the amounts available for distribution to Unitholders. Should PrimeWest be unable to fully fund the cost of remedying an environmental problem, PrimeWest might be required to suspend operations or enter into interim compliance measures pending completion of the required remedy.

18. Lower Oil and Gas prices increase the risk of write-downs of PrimeWest's Oil and Gas Property investments.

Under Canadian accounting rules, the net capitalized cost of Oil and Gas Properties may not exceed a "ceiling limit" that is based, in part, upon estimated future net cash flows from Reserves. If Oil and Natural Gas prices decline, PrimeWest's net capitalized cost may exceed this cost ceiling, ultimately resulting in a charge against PrimeWest's earnings. Under United States GAAP, the cost ceiling is generally lower than under Canadian GAAP because the future net cash flows used in the United States ceiling test are discounted to a present value. Accordingly, PrimeWest would have more risk of a ceiling test write-down in a declining price environment if it reported under United States GAAP. While these write-downs would not affect cash flow, the charge against earnings could be viewed unfavourably in the market.

19. Unforeseen title defects may result in a loss of entitlement to Production and Reserves.

PrimeWest conducts title reviews in accordance with industry practice prior to any purchase of resource assets. However, these reviews do not guarantee that an unforeseen defect in the chain of title will not arise and defeat PrimeWest's title to the purchased assets. If such a defect were to arise, PrimeWest's entitlement to the Production from the affected assets could be jeopardized and, as a result, distributions to Unitholders may be reduced.

20. The economic impact on PrimeWest of claims of aboriginal title is unknown.

Aboriginal people have claimed aboriginal title and rights to a substantial portion of western Canada. PrimeWest is unable to assess the effect, if any, that any such claim would have on its business and operations.

21. The oil and gas industry in Canada operates under federal, provincial and municipal legislation and regulation governing such matters as land tenure, prices, royalties, production rates, environmental protection controls, income, the exportation of crude oil, natural gas and other products, as well as other matters. The industry is also subject to regulation by governments in such matters as the awarding or acquisition of exploration and production rights or other interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields (including restrictions on production) and possibly expropriation or cancellation of contract rights.

Government regulations may be changed from time to time in response to economic or political conditions. The exercise of discretion by governmental authorities under existing regulations, the implementation of new regulations or the modification of existing regulations affecting the oil and gas industry could reduce demand for crude oil and natural gas, increase PrimeWest's costs and have a material adverse impact on PrimeWest.

Before proceeding with a project the participants in the project must obtain all required regulatory approvals. The regulatory approval process can involve stakeholder consultation, environmental impact assessments and public hearings, among other things. In addition, regulatory approvals may be subject to conditions including security deposit obligations and other commitments. Failure to obtain regulatory approvals, or failure to obtain them on a timely basis, could result in delays and abandonment or restructuring of the projects undertaken by PrimeWest and increased costs, all of which could have a material adverse affect on PrimeWest.

22. Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nation wide emissions of carbon dioxide, methane and nitrous oxide greenhouse gases. PrimeWest's business and operations produce some of the greenhouse gases covered by the Convention. The Government of Canada has put forward a Climate Change Plan for Canada which suggested that legislation may be introduced in due course that will set carbon dioxide and other greenhouse gases emission reduction requirements for various industrial activities, including oil sands and cogeneration. Future federal legislation, together with provincial emission reduction requirements, such as those proposed in Alberta's Climate Change and Emissions Management Act, may require the reduction of emissions or emissions

intensity from PrimeWest's business and operations. The reductions may not be technically or economically feasible and the failure to meet such emissions reduction requirements may materially adversely affect PrimeWest's business and result in fines, penalties and the suspension of operations. No assurance can be given that future environmental approvals, laws or regulations will not adversely impact the ability to operate PrimeWest's business or increase or maintain production or will not increase unit costs of production. Equipment from suppliers which can meet future emission standards may not be available on an economic basis and other methods of reducing emissions to required levels in the future may significantly increase operating costs or reduce output. There is a risk that the federal and/or provincial governments could pass legislation which would tax such emissions or require, directly or indirectly, reductions in such emissions produced by energy industry participants for which PrimeWest may be unable to mitigate. Mitigation of the risk of future legislative or regulatory limits on the emission of greenhouse gases may include the acquisition of emission reduction or off set credits from third parties. However, emission reduction or off set credits may not be available for acquisition by PrimeWest or may not be available on an economic basis and may not be recognized or qualify under future legislative or regulatory regimes as mitigation for the emission of greenhouse gases by PrimeWest.

23. PrimeWest's revenue and expenses are directly affected by the royalty regimes applicable to its oil and gas activities. The government of the Province of Alberta or of any other jurisdiction where PrimeWest carries on business could adopt new royalty regimes which will make capital expenditures uneconomic and there can be no assurance that the regime currently in place will remain unchanged.

RISKS RELATED TO THE TRUST STRUCTURE AND THE OWNERSHIP OF TRUST UNITS

1. Changes in tax and other laws may adversely affect Unitholders.

Income tax laws, other laws or government incentive programs relating to the Oil and Gas industry may in the future be changed or interpreted in a manner that adversely affects the Trust and Unitholders. Tax authorities having jurisdiction over the Trust or the Unitholders may disagree with the manner in which the Trust calculates its income for tax purposes or could change their administrative practices to the Trust's detriment or the detriment of its Unitholders.

The October 31 Proposals, if enacted, will apply a tax at the trust level on distributions of certain income from publicly traded mutual fund trusts at rates of tax comparable to the combined federal and provincial corporate tax, and treat such distributions as dividends to the unitholders. It is not expected that the Trust will become subject to the new rules until 2011. However, assuming the October 31 Proposals are ultimately enacted in the form currently proposed, the implementation of such proposals would be expected to result in adverse tax consequences to the Trust and certain Unitholders (including most particularly Unitholders that are tax exempt or non-residents of Canada) and to impact cash distributions from the Trust.

In light of the foregoing, the October 31 Proposals may reduce the value of the Trust Units, which would be expected to increase the cost to PrimeWest of raising capital in the public capital markets. In addition, the October 31 Proposals is expected to substantially eliminate the competitive advantage that PrimeWest and other Canadian energy trusts enjoy relative to their corporate competitors in raising capital and pursuing acquisitions in a tax-efficient manner. As a result, it may become more difficult for PrimeWest to compete effectively for acquisition opportunities. There can be no assurance that PrimeWest will be able to reorganize its legal and tax structure to substantially mitigate the expected impact of the October 31 Proposals.

Further, the October 31 Proposals provide that, while there is no intention to prevent "normal growth" during the transitional period, any "undue expansion" could result in the transition period being revisited, presumably with the loss of the benefit to the Trust of that transitional period. As a result, the adverse tax consequences resulting from the October 31 Proposals could be realized sooner than 2011. On December 15, 2006, the Department of Finance issued guidelines with respect to what would be considered to be "normal growth" in this context. Specifically, the Department of Finance stated that "normal growth" would include equity growth within certain "safe harbour" limits, measured by reference to a SIFT's market capitalization as of the end of trading on October 31, 2006 (which would include only the

market value of the SIFT's issued and outstanding publicly-traded trust units, and not any convertible debt, options or other interests convertible into or exchangeable for trust units). Those safe harbour limits are 40% for the period from November 1, 2006 to December 31, 2007, and 20% each for calendar 2008, 2009 and 2010. These limits are cumulative, so that any unused limit for a period carries over into the subsequent period. Additional details of the Department of Finance's guidelines include the following:

- a) new equity for these purposes includes units and debt that is convertible into units (and may include other substitutes for equity if attempts are made to develop those, but does not include non-convertible debt);
- b) replacing debt that was outstanding as of October 31, 2006 with new equity, whether by a conversion into trust units of convertible debentures or otherwise, will not be considered growth for these purposes and will therefore not affect the safe harbour; and
- c) the exchange, for trust units, of exchangeable partnership units or exchangeable shares that were outstanding on October 31, 2006 will not be considered growth for those purposes and will therefore not affect the safe harbour where the issuance of the trust units is made in satisfaction of the exercise of the exchange right by a person other than the SIFT.

The Trust's market capitalization as of the close of trading on October 31, 2006, having regard only to its issued and outstanding publicly-traded Trust Units, was approximately \$2.379 billion, which means the Trust's "safe harbour" equity growth amount for the period ending December 31, 2007 is approximately \$950 million, and for each of calendar 2008, 2009 and 2010 is an additional approximately \$475 million (in any case, not including equity, including convertible debentures, issued to replace debt that was outstanding on October 31, 2006).

While these guidelines are such that it is unlikely they would affect the Trust's ability to raise the capital required to maintain and grow its existing operations in the ordinary course during the transition period, they could adversely affect the cost of raising capital and the Trust's ability to undertake more significant acquisitions.

It is not known at this time when the October 31 Proposals will be enacted by Parliament or whether the October 31 Proposals will be enacted in the form currently proposed.

2. There would be material adverse tax consequences if the Trust lost its status as a mutual fund trust under Canadian tax laws.

It is intended that the Trust continue to qualify as a mutual fund trust for purposes of the Tax Act. The Trust may not, however, always be able to satisfy any future requirements for the maintenance of mutual fund trust status. Should the status of the Trust as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise for the Trust and Unitholders. Some of the significant consequences of losing mutual fund trust status are as follows:

The Trust would, even ignoring the October 31 Proposals, be taxed on certain types of income distributed to Unitholders, including income generated by the Royalty held by the Trust. Payment of this tax may have adverse consequences for some Unitholders, particularly Unitholders that are not residents of Canada and residents of Canada that are otherwise exempt from Canadian income tax.

Trust Units held by Unitholders that are not residents of Canada would become taxable Canadian property. These non-resident holders would be subject to Canadian income tax on any gains realized on a disposition of Trust Units held by them.

The Trust Units would not constitute qualified investments for Registered Retirement Savings Plans, or "RRSPs," Registered Retirement Income Funds, or "RRIFs," Registered Education Savings Plans, or "RESPs," or Deferred Profit Sharing Plans, or "DPSPs." If, at the end of any month, one of these exempt plans holds Trust Units that are not qualified investments, the plan must pay a tax equal to 1% of the fair

market value of the Trust Units at the time the Trust Units were acquired by the exempt plan. An RRSP or RRIF holding non-qualified Trust Units would be subject to taxation on income attributable to the Trust Units, including the full amount of any capital gain realized on a disposition of non-qualified Trust Units by the RRSP or RRIF. If an RESP holds non-qualified Trust Units, it may have its registration revoked by the Canada Revenue Agency.

3. The Trust may take certain measures in the future to the extent the Trust believes them necessary to ensure that it maintains its status as a mutual fund trust. These measures could be adverse to certain holders of Trust Units.

4. Rights as a Unitholder differ from those associated with other types of investments.

The Trust Units do not represent a traditional investment in the Oil and Natural Gas sector and should not be viewed by investors as shares in the Trust or PrimeWest. The Trust Units represent an equal fractional beneficial interest in the Trust and, as such, the ownership of the Trust Units does not provide Unitholders with the statutory rights normally associated with ownership of shares of a corporation, including, for example, the right to bring "oppression" or "derivative" actions. The unavailability of these statutory rights may also reduce the ability of Unitholders to seek legal remedies against other parties on PrimeWest's behalf.

The Trust Units are also unlike conventional debt instruments in that there is no principal amount owing to Unitholders. The Trust Units will have minimal value when Reserves from PrimeWest's Properties can no longer be economically produced or marketed. Unitholders will only be able to obtain a return of the capital they invested during the period when Reserves may be economically recovered and sold. Accordingly, the distributions received over the life of the investment may not meet or exceed the initial capital investment.

5. The limited liability of Unitholders is uncertain.

Because of prior uncertainties in the law relating to investment trusts, there is a risk that a Unitholder could be held personally liable for obligations of the Trust in respect of contracts or undertakings which the Trust entered into and for certain liabilities arising otherwise than out of contracts including claims in tort, claims for taxes and possibly certain other statutory liabilities arising prior to July 1, 2004. Although every written contract or commitment of the Trust must contain an express disavowal of liability of the Unitholders and a limitation of liability to Trust Property, such protective provisions may not operate to avoid Unitholder liability for the relevant period. Notwithstanding attempts to limit Unitholder liability, Unitholders may not be protected from such liabilities to the same extent that a shareholder is protected from the liabilities of a corporation. Further, although the Trust has agreed to indemnify and hold harmless each Unitholder from any costs, damages, liabilities, expenses, charges and losses suffered by the Unitholder resulting from or arising out of that Unitholder not having limited liability, the Trust cannot guarantee that any assets would be available in these circumstances to reimburse Unitholders for any such liability.

On July 1, 2004 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 the Trust. The legislation provides that a Unitholder is not, as a beneficiary, liable for any act, default, obligation or liability of the Trustee that arises after July 1, 2004.

6. Changes in market-based factors may adversely affect the trading price of Trust Units.

The market price of the Trust Units is primarily a function of anticipated distributions to Unitholders and the value of the Properties owned by PrimeWest and the Trust. The market price of the Trust Units is therefore sensitive to a variety of market-based factors, including, but not limited to, interest rates and the comparability of the Trust Units to other yield oriented securities. Any changes in these market-based factors may adversely affect the trading price of the Trust Units.

7. The operation of the Trust is entirely independent from the Unitholders and loss of key management and other personnel could impact the business.

Unitholders are entirely dependent on the management of the Trust with respect to the acquisition of Oil and Gas Properties and assets, the development and acquisition of additional Reserves, the management and administration of all matters relating to the Properties and the administration of the Trust. The loss of the services of key individuals who currently comprise the management team could have a detrimental effect on the Trust. Investors should carefully consider whether they are willing to rely on the existing management before investing in the Trust Units.

8. There may be future dilution.

One of the Trust's objectives is to continually add to its resource Reserves through acquisitions and through development. Because the Trust does not reinvest the majority of its cash flow, its success is, in part, dependent on its ability to raise capital from time to time by selling Trust Units. Unitholders will suffer dilution as a result of Trust Unit offerings if, for example, the cash flow, Production or Reserves from acquired assets do not reflect the additional number of Trust Units issued to acquire those assets. Dilution may also occur if the deployment of funds raised through the various components of the DRIP does not result in the creation of additional value for Unitholders.

9. There may not always be an active trading market in the United States and/or Canada for the Trust Units.

While there is currently an active trading market for the Trust Units in both the United States and Canada, the Trust cannot guarantee that an active trading market will be sustained in either country.

10. The redemption right of Unitholders is limited.

Unitholders have a limited right to require the Trust to repurchase their Trust Units, which is referred to as a redemption right. It is anticipated that the redemption right will not be the primary mechanism for Unitholders to liquidate their investment. The Trust's ability to pay cash in connection with redemption is subject to limitations. Any securities, which may be distributed in specie to Unitholders in connection with redemption, may not be listed on any stock exchange and a market may not develop for such securities. Also, such securities (or some of them) may not be a qualified investment for RRSPs, RRIFs, DPSPs or RESPs. In addition, there may be resale restrictions imposed by law upon the recipients of the securities pursuant to the redemption right.

ITEM 7: MARKET FOR SECURITIES

The outstanding Trust Units of the Trust are listed for trading on the TSX under the symbol PWI.UN and on the NYSE under the symbol PWI. The outstanding Exchangeable Shares of PrimeWest are listed for trading on the TSX under the symbol PWX. The Series I Debentures of PrimeWest trade on the TSX under the symbol "PWI.DB.A", the Series II Debentures trade under the symbol "PWI.DB.B." and the Series III Debentures trade under the symbol "PWI.DB.C."

The following tables summarize monthly trading activity for each of the securities of PrimeWest.

PRIMEWEST TRUST UNITS TSX: PWI.UN (C\$/TRUST UNIT)

2006	High	Low	Close	Average Daily Trading Volume
January	37.82	35.45	36.98	190,822
February	37.50	33.22	33.22	289,685
March	33.75	31.05	32.98	268,208
April	35.12	32.29	32.39	156,150
May	33.15	31.64	33.15	370,836
June	33.50	30.92	33.50	233,966

2006	High	Low	Close	Average Daily Trading Volume
July	35.42	32.71	35.42	173,217
August	35.19	33.69	33.71	156,150
September	33.65	27.33	27.35	354,787
October	29.21	24.16	28.70	379,282
November	27.50	20.87	25.02	444,539
December	25.25	21.00	21.50	342,915

PRIMEWEST TRUST UNITS: NYSE: PWI (US\$/TRUST UNIT)

2006	High	Low	Close	Average Daily Trading Volume
January	32.88	30.50	32.49	339,105
February	32.80	29.15	29.29	503,511
March	29.37	27.00	28.39	538,378
April	30.91	28.66	29.00	432,600
May	29.88	28.30	29.88	443,945
June	29.98	27.76	29.98	439,568
July	31.29	29.51	31.29	337,300
August	31.16	30.35	30.38	275,013
September	30.40	24.45	24.64	737,185
October	25.94	21.40	25.57	564,173
November	24.99	18.37	22.00	1,166,490
December	22.01	18.03	18.47	664,190

PRIMEWEST SERIES I DEBENTURES TSX: PWI.DB.A (C\$) ⁽¹⁾

2006	High	Low	Close
January	142.00	131.95	139.29
February	140.00	125.69	125.69
March	126.00	113.05	125.00
April	132.00	117.42	117.42
May	123.89	118.50	120.00
June	125.94	115.95	125.94
July	133.00	125.00	133.00
August	135.00	125.00	126.51
September	127.08	105.12	105.52
October	111.07	105.01	109.00
November	108.01	102.67	103.81
December	104.25	103.01	103.01

Note:

(1) The Series I Debentures were issued on September 2, 2004.

PRIMEWEST SERIES II DEBENTURES TSX: PWI.DB.B (C\$) ⁽¹⁾

2006	High	Low	Close
January	141.64	134.00	138.99
February	140.25	125.07	126.00
March	125.00	112.07	123.81
April	133.00	122.31	122.31
May	123.95	119.04	123.95
June	125.00	116.44	122.67
July	130.04	124.46	128.00
August	132.53	126.47	126.47
September	123.65	108.00	108.00
October	115.01	106.01	109.50
November	106.01	103.02	104.02
December	107.99	103.76	107.99

Note:

(1) The Series II Debentures were issued on September 2, 2004.

PRIMEWEST ENERGY INC. – EXCHANGEABLE SHARES TSX: PWX (CDN\$/EXCHANGEABLE SHARE)

2006	High	Low	Close
January	21.00	20.85	21.00
February	23.00	22.00	22.00
March	19.50	18.76	18.76
April	21.00	21.00	21.00
May	21.00	19.94	21.00
June	18.50	18.50	18.50
July	21.20	19.02	21.20
August	21.30	20.75	21.00
September	20.50	18.00	18.00
October	17.25	16.02	17.25
November	17.25	15.26	15.46
December	16.50	14.80	14.80

ITEM 8: STABILITY RATING

DBRS maintains a stability rating system for income funds to provide an indication of both the stability and sustainability of cash distributions per trust unit, which is essentially an assessment of an income fund's ability to generate sufficient cash to pay out a stable level of distributions on a per unit basis over the longer term. The DBRS stability ratings provide opinions and research on funds related to stability and sustainability of distributions over time and are not a recommendation to buy, sell or hold the trust units. In determining a DBRS stability rating, the following factors are evaluated: (1) operating characteristics, (2) asset quality, (3) financial profile, (4) diversification, (5) size and market position, (6) sponsorship/governance, and (7) growth. The rating categories range from STA-1 being the highest stability and sustainability of distributions per unit to STA-7 being poor stability and sustainability with each category refined into further subcategories of high, middle and low providing a total of 21 possible rating categories.

On November 18, 2004, DBRS initiated coverage of the Trust and assigned a stability rating of STA-5 (low) taking into consideration the Calpine Acquisition. The assigned rating reflected that: (a) operating

characteristics were considered “weak” given the price volatility for energy prices, difficulties the Trust had replacing reserves, and the downward trend in production and reserves on a per unit basis; (b) financial flexibility had been significantly reduced after the Calpine transaction; and (c) the Trust was one of the larger oil and gas trusts in Canada and ranked “superior” in size and market position with low operating costs relative to peer averages. The Calpine Transaction added longer-life assets, with development opportunities that were anticipated to better position the Trust to grow internally.

On June 26, 2006, DBRS confirmed the rating of the Trust at STA-5 (low), following the announced agreement to acquire the US Assets for \$336.7 million.

The transaction was viewed by DBRS as positive, and the confirmation reflected the following considerations by DBRS:

- a) the acquired assets represent PrimeWest’s strategic expansion into the U.S. and establish a new core operating area. This acquisition will provide the Trust with a platform to pursue future growth opportunities outside of the highly competitive environment in western Canada;
- b) the acquired long life properties in the U.S. improve overall reserve life index from 8.3 years to an estimated 9.7 years, based on proved reserves, comparing favourably with peer average. In addition, PrimeWest will be the operator of the majority of properties, which is consistent with the Trust’s existing high percentage of operated properties (over 80%); and
- c) the transaction modestly improves the Trust’s production mix balance between natural gas (66%) and crude oil and natural gas liquids (68% natural gas previously). This improves cash flow diversification and lessens the Trust’s exposure to highly volatile North America natural gas prices.

On November 1, 2006, DBRS placed the stability ratings of several dozen Canadian income trusts, including the Trust, and their long-term debt ratings, as well as those of their related entities, “Under Review with Developing Implications”, as a result of the October 31 Proposals. While there is no guarantee that the proposals will pass through the legislative process, the changes would mean existing income trusts would become taxable beginning in 2011.

According to DBRS, for trusts that simply plan to reduce the level of their distributions to unitholders to reflect the additional tax burden, the reduction would be viewed as a one time event and DBRS’s analytical focus would then be on the stability and sustainability of distributions following the adjustments. Under this scenario, the debt and stability ratings would likely be confirmed. However, the proposed tax legislation could encourage certain trusts to develop alternative capitalization or operating strategies. Until DBRS is able to discuss these issues with those trusts, their ratings will remain “Under Review”.

ITEM 9: DIRECTORS AND OFFICERS

The Trust has no directors or executive officers. The following information pertains to the Board of Directors of PrimeWest and the executive officers of PrimeWest.

DIRECTORS

The Trust has the right to nominate and elect the Board of Directors of PrimeWest to serve until the next annual meeting of Unitholders. The names of the nominees for election as Directors, their municipalities of residence, principal occupations, experience and qualifications, memberships on other boards, the year in which each became a director of PrimeWest and numbers of Trust Units beneficially owned or over which control or direction is exercised by such Persons, as at December 31, 2006, are as follows:

Name and Present Principal Occupation or Employment	Director of PrimeWest Since ⁽¹⁾	Municipality of Residence	Trust Units Beneficially Owned or over which Control or Discretion is Exercised as at December 31, 2006 (#/%) ^{(2) (3)}
Harold P. Milavsky ⁽⁴⁾⁽⁵⁾ Chair, Quantico Capital Corp.	1996	Calgary, Alberta	34,113/ 0.0398 ⁽⁶⁾
<p>Mr. Milavsky, B.Comm, CA, FCA, is Chair of Quantico Capital Corp., a privately held company engaged in merchant banking, principal investments and acquisitions. Mr. Milavsky also serves as a Director, member of the Audit Committee and member of the Nominating/Corporate Governance Committee of Saskatchewan Wheat Pool and as a Director, Chair of the Board and Chair of the Audit Committee of the various investment trusts or corporations comprising the Citadel Group of Funds™. Mr. Milavsky was President and Chief Executive Officer of Trizec Corporation from 1976 to 1986 and Chair and Chief Executive Officer from 1986 to 1993. He has been a Director of TransCanada Corporation, Telus Corporation, Northrock Resources Ltd., Encal Energy Ltd., Wascana Energy Inc., ENMAX Corporation and many other corporations. Mr. Milavsky is a Fellow of the Institute of Chartered Accountants of Alberta and, in 2002, he received the Institute's Lifetime Achievement Award. Mr. Milavsky is also a member of the Institute of Corporate Directors and received that Institute's Fellowship Award in 2005.</p>			
Barry E. Emes ^{(4) (5)} Corporate Director	1996	Calgary, Alberta	6,943/ 0.0081 ⁽⁷⁾
<p>Until July 31, 2006, Mr. Emes, B.A., LLB., was a partner with Stikeman Elliott LLP, a leading national and international law firm. Mr. Emes' practice focused on complex corporate commercial matters, including public and private mergers and acquisitions/dispositions, banking, corporate governance matters, commercial real estate transactions, oil and gas transactions, debt restructuring transactions, derivatives and a wide range of other corporate and commercial matters. Prior to concentration on corporate commercial matters, Mr. Emes carried on a high level commercial litigation practice. Mr. Emes was managing partner of the Stikeman Elliott Calgary office for 7 years and was a member of the firm's national partnership board for 7 years. Mr. Emes has also worked for Mobil Oil (Canada) as an economist in their planning group.</p> <p>Mr. Emes has served on audit committees, compensation committees, nominating committees, corporate governance committees and special committees and is currently a Director of Parkbridge Lifestyle Communities Inc. and Realex Properties Corp.</p> <p>In addition to attaining a Bachelor of Arts in Economics, Mr. Emes has completed the Royal Bank of Canada's management training program and undertaken additional studies in accounting and corporate finance. Mr. Emes is also a graduate of the Institute of Corporate Directors Corporate Governance College, Director Education Program.</p>			
Harold N. Kvisle ⁽⁸⁾⁽⁹⁾ President and CEO TransCanada Corporation	1996	Calgary, Alberta	26,805/ 0.0313 ⁽⁷⁾
<p>Mr. Kvisle, B.Sc., MBA, P.Eng., is President, Chief Executive Officer and a Director of both TransCanada Corporation and TransCanada Pipelines Limited and also serves as a Director and member of the Human Resources and Management Compensation Committee of the Bank of Montreal. Prior to May 2001, Mr. Kvisle was Executive Vice-President, Trading and Business Development of TransCanada Pipelines Limited (October 1999 to May 2001).</p>			
Kent J. MacIntyre ^{(8) (9)} Independent Businessman	1996	Calgary, Alberta	180,444/ 0.2104 ⁽¹⁰⁾
<p>Mr. MacIntyre, B.Sc., Eng., MBA, is Chair of the Board of the Canadian Income Fund Group Inc., a private company engaged in capital origination and principal investment activities in the financial services and energy areas. With more than 25 years of oil and gas experience, Mr. MacIntyre has acted as a principal to the formation and start-up of a number of companies, including PrimeWest (having held the office of Vice-Chair of the Board and Chief Executive Officer from inception in 1996 until his retirement in 2003), the various investment trusts or corporations comprising the Citadel Group of Funds™, in which he also serves as a Director, Triad Energy Inc. and Olympia Energy Ventures Ltd. Mr. MacIntyre also serves as a Director of a number of private companies.</p>			

Name and Present Principal Occupation or Employment	Director of PrimeWest Since ⁽¹⁾	Municipality of Residence	Trust Units Beneficially Owned or over which Control or Discretion is Exercised as at December 31, 2006 (#/%) ^{(2) (3)}
Michael W. O'Brien ⁽⁴⁾⁽⁵⁾ Corporate Director	2000	Canmore, Alberta	8,544/ 0.0100
Mr. O'Brien, B.A., MBA, serves, among other responsibilities, as a Director and Chair of the Audit Committee of Shaw Communications Inc., as a Director, member of the Audit Committee and member of the Environment Health and Safety Committee of Suncor Energy Inc. and, as a member of the Advisory Board of CRA International. Mr. O'Brien is also past Chair of the Canadian Petroleum Products Institute, Canada's Voluntary Challenge Registry for Climate Change and the Nature Conservancy of Canada. Prior to retirement in 2002, Mr. O'Brien was the Executive Vice-President, Corporate Development and Chief Financial Officer of Suncor Energy Inc. (December 1999 – June 2002).			
W. Glen Russell ⁽⁸⁾⁽⁹⁾ Management Consultant	2003	Calgary, Alberta	3,425/ 0.0040
Mr. Russell, B.Sc., P.Eng., is principal of Glen Russell Consulting. Mr. Russell serves, among other responsibilities, as a Director and Chair of the Board of Evoco Inc. (a private company), a Director, Chair of the Board, Chair of the Corporate Governance and Human Resources Committee and member of the Operations and Reserves Committee of Petro Andina Resources Inc. (a private company in Argentina) and Director of Insight Limited Partnership (a Micro-Cap Investment Partnership). He was previously President and Chief Operating Officer of Chauvco Resources Limited and Senior Vice President and Chief Operating Officer of Gulf Canada Resources Limited. Mr. Russell also acted as Executive Advisor with regard to mergers and acquisitions and corporate strategy for a major Canadian investment banking firm.			
James W. Patek ⁽⁸⁾⁽⁹⁾ President Patek Energy Consultants	2003	Fripp Island, South Carolina, USA.	1,000/ 0.0012
Mr. Patek, B.Sc., M.Sc., is the President of Patek Energy Consultants, based in the United States. He was previously Chief Executive Officer of Petrocorp Exploration Limited, Chief Executive Officer of Fletcher Challenge Petroleum, Senior Reservoir Engineer at Conoco, Division Engineer and Division Manager of Husky Oil Operations Limited and Operations Manager at Petrocorp Exploration Limited. Prior to June 2000, Mr. Patek was President of Fletcher Challenge Energy Canada.			
Peter Valentine ⁽⁴⁾ Senior Advisor to President and Chief Executive Officer, Calgary Health Region	2004	Calgary, Alberta	577/ 0.0007
Mr. Valentine, B.Comm, FCA, ICD.D, is currently Senior Advisor to the President and Chief Executive Officer of the Calgary Health Region. Mr. Valentine is a Trustee, a member of the Audit Committee and a member of the Governance Committee of Fording Canadian Coal Trust, a Director and Chair of the Audit Committee of Livingston International Income Fund, a Director and member of the Audit Committee of Superior Plus Income Fund and a Director and Chair of the Audit Committee of Resmor Trust Company (a private corporation). Mr. Valentine was previously the Auditor General of the Province of Alberta (March 1995 to January 2002), Chair of the Financial Advisory Committee of the Alberta Securities Commission, member of the Accounting Standards Board and Public Sector Accounting Board of the Canadian Institute of Chartered Accountants, Chair of the Canadian Comprehensive Audit Foundation and also held senior positions at KPMG. In addition, for the period of December 2003 to June 2004, Mr. Valentine was Interim Vice President, Finance and Services at the University of Calgary and, for the period of May 7, 2005 to July 18, 2005, was Interim Chair of the Alberta Securities Commission.			

Notes:

- (1) The term of office of each Director expires at the next annual meeting, unless earlier terminated.
- (2) Number and percentage of ownership based upon number of Trust Units, Class A Exchangeable Shares and Series I Debentures and Series II Debentures (the Series I Debentures and Series II Debentures are collectively referred to as, the "Debentures") beneficially owned, directly or indirectly, or over which control is exercised by each nominee for Director, collectively, relative to the total Trust Units and Class A Exchangeable Shares issued and outstanding, Trust Units issuable pursuant to the conversion of the Debentures and Trust Units issuable under the Long Term Incentive Plan, diluted at

December 31, 2006 (85,772,858 Trust Units). The information as to voting securities beneficially owned, directly or indirectly, is based upon information furnished to us by the nominees.

- (3) In aggregate, the number of Trust Units beneficially owned or over which control or discretion is exercised, as at December 31, 2006 by all Directors and Officers of the Corporation is 435,404/0.5076%
- (4) Member of the Audit and Finance Committee.
- (5) Member of the Corporate Governance and EH&S Committee.
- (6) Trust Units held through Quantico Capital Corp.
- (7) Includes five year Series I Debentures convertible to Trust Units at a price of \$26.50 per Trust Unit, 37.7358 Trust Units per \$1,000.00 Series I Debenture, which, in the case of Mr. Emes, consists of 25 Series I Debentures convertible into 943 Trust Units and, in the case of Mr. Kvisle, consists of 50 Series I Debentures convertible into 1,886 Trust Units.
- (8) Member of the Compensation Committee.
- (9) Member of the Operations and Reserves Committee.
- (10) Consists of 100,000 Class A Exchangeable Shares (which, at December 31, 2006, were exchangeable into 63,765 Trust Units), all of which were held by Canadian Income Fund Group Inc., a corporation wholly owned by Mr. MacIntyre.

OFFICERS

The name, municipality of residence, position held and number of Trust Units beneficially owned or over which each officer of PrimeWest exercises control or direction as of December 31, 2006 are set out below:

Name and Municipality	Principal Occupation	Trust Units Beneficially Owned or over which Control or Discretion is Exercised as at December 31, 2006 (#/%) ^{(1) (2)}
Donald A. Garner Calgary, Alberta	President and Chief Executive Officer Since January 2003	123,273/ 0.1437
Mr. Garner joined PrimeWest in June 2001 and has overall responsibility for leading and overseeing the business direction of the Trust. He has more than 27 years experience in the Oil and Gas industry. He was President and Chief Operating Officer of Northstar Energy Corporation from January 1998 to February 2001. Prior to that Mr. Garner spent a good portion of his career at Imperial Oil Limited in various capacities, including executive responsibility for the Oilsands Business Unit. Mr. Garner is an engineering graduate of the University of Saskatchewan.		
Timothy S. Granger Calgary, Alberta	Chief Operating Officer Since January 2003	14,279/ 0.0166
Mr. Granger joined PrimeWest in June 1999 and has overall responsibility for the day-to-day business and operations of PrimeWest. Mr. Granger has more than 26 years of extensive experience in exploitation, Production operations and asset management. From 1996 to 1999, Mr. Granger held various managerial positions at Pogo Canada Ltd. and Petro-Canada, including Production engineering and upstream information technology. Prior to 1996, Mr. Granger held various management positions at Amerada Hess Canada Ltd. From 1980 to 1991, Mr. Granger held various engineering positions at Dynex Petroleum Ltd., Canterra Energy Ltd. and Dome Petroleum Limited. Mr. Granger holds a P.Eng. (Mechanical) from Carlton University.		
Ronald J. Ambrozy Calgary, Alberta	Vice-President, Business Development Since October 1997	16,898/ 0.0197
Mr. Ambrozy has over 30 years of experience in the Oil and Natural Gas industry. Prior to joining PrimeWest in 1997, Mr. Ambrozy held progressively more senior positions at Gulf Canada Resources Limited, as well as manager of Gulf's asset management group. Mr. Ambrozy has a Bachelor of Science in Engineering from the University of Manitoba. Mr. Ambrozy is currently President of the Petroleum Acquisition and Divestment (A&D) Association, an organization of Oil and Gas individuals involved in A&D activity.		

Name and Municipality	Principal Occupation	Trust Units Beneficially Owned or over which Control or Discretion is Exercised as at December 31, 2006 (#/%) ^{(1) (2)}
Dennis G. Feuchuk Calgary, Alberta	Vice-President, Finance and Chief Financial Officer Since October 2001	15,442/ 0.0180
<p>Mr. Feuchuk joined PrimeWest in October 2001 and is responsible for the general financial operations of PrimeWest including tax and accounting matters, as well as information systems. Mr. Feuchuk has over 30 years of experience in finance, accounting, audit and income tax in the Oil and Natural Gas industry. He was Vice President, Finance and Controller of Gulf Canada Resources Limited from February 1995 to February 2001. Mr. Feuchuk also was Vice President and Treasurer of Athabasca Oil Sands Trust from inception in December 1995 to February 2001. Mr. Feuchuk has a Bachelor of Business Management from Ryerson University, has completed the Richard Ivey School of Business Executive Development Program and is a Certified Management Accountant.</p>		
Brian J. Lynam Calgary, Alberta	Vice-President, Operations Since February, 2006	488/ 0.0006
<p>Mr. Lynam graduated from the University of Toronto with a Bachelor of Applied Science in Chemical Engineering. He has 26 years of extensive experience in the Oil and Gas industry, most recently with Burlington Resources Canada Ltd. where he held leadership positions including Production Optimization Manager and Operations Manager of two operating regions. Previous to that, Mr Lynam was with Gulf Canada Resources Limited. At Gulf Canada, Mr Lynam held a number of operational positions including roles in development engineering, safety and environment, production operations, marketing, regulatory and licensing and joint interest. Mr. Lynam is responsible for the Trust's Production operations, drilling, completions and facilities.</p>		
Gordon D. Haun Calgary, Alberta	Vice President Legal and General Counsel Since January, 2007	3,173/ 0.0037
<p>Mr. Haun joined PrimeWest in 2001 and was appointed an Officer and General Counsel and Corporate Secretary in February, 2006 and Vice President Legal and General Counsel in January, 2007. Mr. Haun is responsible for all legal and corporate secretarial services required by PrimeWest, including those relating to corporate governance, corporate finance, mergers and acquisitions, intellectual property, material agreements and dispute resolution. He has over 17 years of experience in the provision of legal services, spending several years in private practice with two national law firms before moving into the petroleum industry where he has practiced for the last 10 years. Prior to joining PrimeWest in November 2001, Mr. Haun worked for Gulf Canada Resources Limited (1995 to 1997), and, from 1997 to 2001, he was legal counsel for Phillips Petroleum Resources, Ltd. Mr. Haun has a Bachelor of Arts from the University of Calgary, a Bachelor of Laws from the University of Alberta and is an active member of the Law Society of Alberta and the Institute of Corporate Directors.</p>		

Notes:

- (1) Number and percentage of ownership based upon number of Trust Units, Class A Exchangeable Shares and Debentures beneficially owned, directly or indirectly, or over which control is exercised by each officer, collectively, relative to the total Trust Units and Class A Exchangeable Shares issued and outstanding, Trust Units issuable pursuant to the conversion of the Debentures and Trust Units issuable under the Long-Term Incentive Plan, diluted at December 31, 2006 (85,772,858 Units). The information as to voting securities beneficially owned, directly or indirectly, is based upon information furnished to us by the officers.
- (2) In aggregate, the number of Trust Units beneficially owned or over which control or discretion is exercised, as at December 31, 2006 by all Directors and Officers of the Corporation is 435,404 or 0.5076%

EMPLOYEES

As of December 31, 2006, PrimeWest had a total permanent staff and field operator complement of 163 in the corporate head office and 62 in the field for a total of 225 employees.

AUDIT COMMITTEE DISCLOSURE

The disclosure regarding PrimeWest's Audit and Finance Committee required under Multilateral Instrument 52-110 adopted by certain of the Canadian securities regulatory authorities is contained in Schedule "C" to this Annual Information Form.

LEGAL PROCEEDINGS

PrimeWest is engaged in a number of matters of litigation, none of which could reasonably be expected to result in any material adverse consequence.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

To the knowledge of PrimeWest, no Director or Executive Officer of PrimeWest, or an associate or affiliate thereof, had any material interest, direct or indirect, in any transaction within the three most recently completed financial years or has any material interest, direct or indirect, in any transaction during the current financial year, that has materially affected or will materially affect the Trust on a consolidated basis.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Trust Units, the Exchangeable Shares, the Series I Debentures, Series II Debentures and the Series III Debentures is Computershare at its principal offices in Toronto and Calgary.

INTERESTS OF EXPERTS

Reserve estimates contained in this Annual Information Form are based upon the GLJ Report. The principals of GLJ, as a group, own, directly or indirectly, less than 1% of the outstanding Trust Units.

ITEM 10: ADDITIONAL INFORMATION

Additional information, including Directors' and Officers' remuneration and indebtedness, principal holders of the Trust's securities and the interests of insiders in material transactions, where applicable, is contained in the Circular. Additional financial information is provided in the Trust's consolidated comparative financial statements for the year ended December 31, 2006, contained in the Annual Report. Additional information relating to the Trust may also be found on the Trust's website at www.primewestenergy.com, SEDAR at www.sedar.com or EDGAR at the SEC's website at <http://www.sec.gov/>.

Upon request to the Secretary of PrimeWest, the Trust will provide one copy of this Annual Information Form, together with one copy of any document incorporated herein by reference, one copy of the Annual Report (including the consolidated comparative financial statements of the Trust for the year ended December 31, 2006 and accompanying report of the auditors), one copy of any interim financial statements subsequent to the consolidated financial statements for the year ended December 31, 2006 and one copy of the Circular.

When securities of the Trust are in the course of a distribution pursuant to a short form prospectus, or a preliminary short form prospectus has been filed in respect of a distribution of the Trust's securities, copies of the foregoing documents and any other documents that are incorporated by reference into the short form prospectus or preliminary short form prospectus may also be obtained from the Secretary of PrimeWest.

ITEM 11: DISCLOSURE PURSUANT TO THE REQUIREMENTS OF THE NYSE

The Canadian Securities Administrators have prescribed that all entities listed on the TSX must annually disclose their corporate governance practices in accordance with the requirements of National Instrument 58-101 Disclosure of Corporate Governance Practices ("NI 58-101"). PrimeWest has structured its corporate governance so as to be in compliance with NI 58-101 and other applicable legislation and policies, including National Policy 41-201 – Income Trusts and Other Indirect Offerings, Multilateral Instrument 52-110 – Audit Committees ("MI 52-110") and National Policy 58-201 - Corporate Governance Guidelines ("NP 58-201"). In addition, PrimeWest continually reviews its corporate governance to ensure compliance with other published policies, including the corporate governance rules set forth in Section 303A (the "NYSE Rules") of the NYSE Listed Company Manual and the *Sarbanes-Oxley Act of 2002*.

As a Canadian company listed on the NYSE, PrimeWest is not required to comply with most of the NYSE rules and instead may comply with domestic requirements. As a “foreign private issuer”, PrimeWest is only required to comply with four of the NYSE Rules: 1) have an Audit Committee that satisfies the requirement of the *United States Securities Exchange Act of 1934*; 2) the Chief Executive Officer must promptly notify the NYSE in writing after an Executive Officer becomes aware of any material non-compliance with the applicable NYSE Rules; 3) provide a brief description of any significant ways in which its corporate governance practices differ from those followed by domestic companies under the NYSE Rules; and 4) submit to the NYSE an Annual Written Affirmation each year and an Interim Written Affirmation each time there is a change to the Board of Directors or any Committee thereof. However, PrimeWest has voluntarily chosen to adopt corporate governance practices that comply with the NYSE Rules in all significant respects. The differences between PrimeWest’s corporate governance practices and those followed by domestic companies under the NYSE Rules are discussed in the Circular and on PrimeWest’s website at www.primewestenergy.com.

ITEM 12: GLOSSARY OF ABBREVIATIONS AND DEFINITIONS

ABBREVIATIONS

In this Annual Information Form, the abbreviations set forth below have the following meanings:

bbls	Barrels	mcf/day	1,000 cubic feet /day
mbbls	1,000 barrels	bcf	1,000,000,000 cubic feet
mmbbls	1,000,000 barrels	m3	1.0 cubic metre (or 1,000 litres)
bbls/day	Barrels /day	BOE	barrel of oil equivalent
mcf	1,000 cubic feet	mBOE	1,000 barrels of oil equivalent
mmcf	1,000,000 cubic feet	BOE/day	barrels of oil equivalent /day
mmcf/day	1,000,000 cubic feet/day	mmBOE	millions of barrels of oil equivalent

For purposes of this document, and in accordance with NI 51-101, 6 mcf of Natural Gas and 1 bbl of NGLs each equal 1 bbl of Oil. This conversion rate is not based on price or energy content. BOE’s may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

DEFINITIONS

In this Annual Information Form, the capitalized terms set forth below have the following meanings:

Annual Report means the 2006 Annual Report of the Trust filed on SEDAR at www.sedar.com.

ARTC means Alberta royalty tax credit.

Associated Gas means the Gas cap overlying a Crude Oil accumulation in a reservoir.

Board of Directors means the board of directors of PrimeWest.

Cash Distribution Date means the date Distributable Income is paid to Unitholders, currently being the 15th day of a given calendar month, or if such date is not a business day, the immediately preceding business day, subject to any change permitted by, and made pursuant to, the Declaration of Trust.

Circular means the Management Proxy Circular of the Trust, to be dated on or about March 15, 2007.

Company Interest means in relation to PrimeWest’s interest in Production or Reserves, its working interest (operating or non-operating) share before deduction of royalties and including Royalty interests of PrimeWest and the Trust;

Consolidation means the consolidation of the Trust Units on a one-for-four basis, effective August 16, 2002.

Constant Prices and Costs means prices and costs used in an estimate that are:

- PrimeWest's prices (being the ported price for Oil and the spot price for Natural Gas, after historical adjustments for transportation, gravity and other factors) and costs as at December 31, 2006, held constant throughout the estimated lives of the Properties to which the estimate applies; or
- If, and only to the extent that, there are fixed or presently determinable, future prices or costs to which PrimeWest is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

Credit Facility means, Canadian revolving credit facilities, U.S. denominated Secured Notes and U.K. pounds sterling denominated Secured Notes, collectively having a maximum aggregate borrowing capacity of \$750 million.

Crude Oil means a mixture that consists mainly of pentanes and heavier hydrocarbons, which may contain sulphur and other non-hydrocarbon compounds, that is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated. It does not include Solution Gas or Natural Gas Liquids.

DBRS means Dominion Bond Rating Service Limited

Debt Service Costs has the meaning ascribed thereto in the Royalty Agreements.

Declaration of Trust means the declaration of trust dated August 2, 1996 among the Trustee, PrimeWest and the Initial Unitholder (as therein defined), as amended and restated as of November 6, 2002, as amended as of May 6, 2004, and as further amended from time to time.

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

Developed Reserves are those Reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure to put the Reserves on Production. The Developed category may be subdivided into Developed Producing and Developed Non-Producing.

Development Costs means costs incurred to obtain access to Reserves and to provide facilities for extracting, treating, gathering and storing the Oil and Natural Gas from the Reserves. More specifically, Development Costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, Natural Gas lines and power lines, to the extent necessary in developing the Reserves;
- Drill and equip Development Wells, development type stratigraphic test wells and Service Wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;

- Acquire, construct and install Production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and Production storage tanks, Natural Gas cycling and processing plants, and central utility and waste disposal systems; and
- Provide improved recovery systems.

Development Well means a well drilled inside the established limits of an Oil or Natural Gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

Distributable Income means all amounts received by the Trust in respect of the Royalty, ARTC, the gross overriding royalties held by the Trust directly and other income, less certain expenses and other deductions.

Distribution Reinvestment Program or DRIP means the Distribution Reinvestment, Premium Distribution and Optional Trust Unit Purchase Plan of the Trust. The conventional component of the Plan, available to US and Canadian Unitholders, allows Unitholders to reinvest Distributions in order to acquire additional Trust Units at a 5% discount to the Average Market Price defined in the Plan document. Under the premium distribution component, which is only available to Canadian Unitholders, participants are entitled to cash payments equivalent to 102% of the cash distribution that they would otherwise be entitled to receive, subject to proration. Finally, under the Optional Trust Unit Purchase component of the DRIP, which is also only available to Canadian Unitholders, participants can purchase Trust Units valued at up to \$100,000 per annum at a 5% discount to the Average Market Price.

EDGAR means the Electronic Data Gathering, Analysis and Retrieval System on which submissions by companies and others required by law to file forms with the SEC are filed and accessible at www.sec.gov.

Exchangeable Shares means the Exchangeable Shares in the capital of PrimeWest.

Exploration Costs means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain Oil and Natural Gas Reserves, including costs of drilling Exploratory Wells and exploratory type stratigraphic test wells. Exploration Costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

- Costs of topographical, geochemical, geological and geophysical studies, rights of access to Properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as “geological and geophysical costs”);
- Costs of carrying and retaining Unproved Properties, such as delay rentals, taxes (other than income and capital taxes) on Properties, legal costs for title defence, and the maintenance of land and lease records;
- Dry hole contributions and bottom hole contributions;
- Costs of drilling and equipping Exploratory Wells; and
- Costs of drilling exploratory type stratigraphic test wells.

Exploratory Well means a well that is not a Development Well, a Service Well or a stratigraphic test well.

Forecast Prices and Costs means future prices and costs that are:

- a) Generally accepted as being a reasonable outlook for the future; or
- b) If, and only to the extent that, there are fixed or presently determinable future prices or costs to which PrimeWest is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

Future Income Tax Expenses means future income tax expenses estimated (generally, year by year):

- Making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between Oil and Gas activities and other business activities;
- Without deducting estimated future costs that are not deductible in computing taxable income;
- Taking into account estimated tax credits and allowances; and
- Applying to the future pre tax net cash flows relating to PrimeWest's Oil and Gas activities the appropriate year end statutory tax rates, taking into account future tax rates already legislated.

Future Net Revenue means the estimated amount to be received with respect to the development and Production of Reserves (including Synthetic Oil, coal bed methane and other non conventional Reserves) estimated using either Constant Prices and Costs or Forecast Prices and Costs and by deducting from estimated future revenues estimated future royalty obligations, costs related to the development and Production of Reserves, Well Abandonment Costs and Future Income Tax Expenses, unless otherwise specified herein.

GAAP means Generally Accepted Accounting Principles.

General and Administrative Costs means the amount in aggregate representing all expenditures and costs incurred by or in respect of PrimeWest, the Trust or the Royalty or in the management and administration of PrimeWest, the Trust or the Royalty.

GLJ means GLJ Petroleum Consultants Ltd.

GLJ Report means the reserve report prepared by GLJ evaluating the light and medium Oil, Heavy Oil and Associated and Non-Associated Gas Reserves attributable to Properties owned by PrimeWest and the Trust as at December 31, 2006.

Gross means:

- In relation to PrimeWest's interest in Production or Reserves, its "company gross Reserves", which are PrimeWest's working interest (operating or non-operating) share before deduction of royalties and without including any Royalty interests of PrimeWest or the Trust; or
- In relation to wells, the total number of wells in which PrimeWest has an interest; or
- In relation to Properties, the total area of Properties in which PrimeWest has an interest.

Heavy Oil means, in a jurisdiction that has a royalty regime specific to heavy oil, oil that qualifies for royalties specific to heavy oil, or in a jurisdiction that has no such royalty regime, oil with a density between 10 to 22.3 degrees API.

Natural Gas or **Gas** means the lighter hydrocarbons and associated non-hydrocarbon substances (including hydrogen sulphate, carbon dioxide and nitrogen) occurring naturally in an underground reservoir which under atmospheric conditions are essentially gases but which may contain Natural Gas Liquids.

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

Net means:

- a) In relation to PrimeWest's interest in Production or Reserves, PrimeWest's working interest (operated or non-operated) share after deduction of royalty obligations, plus the Royalty interests of PrimeWest and the Trust in Production or Reserves; or

- b) In relation to PrimeWest's interest in wells, the number of wells obtained by aggregating PrimeWest's working interest in each of its Gross wells; or
- c) In relation to PrimeWest's interest in a Property, the total area in which PrimeWest has an interest multiplied by the working interest owned by PrimeWest.

Net Production Revenue in respect of any period for which Net Production Revenue is calculated means the aggregate of:

- a) The amount received or receivable by PrimeWest in respect of the sale of its interest in all Petroleum Substances produced from the Properties;
- b) Crown royalties and other Crown charges;
- c) PrimeWest's share of all other revenues that accrue in respect of the Properties, including, without limitation,
 - (i) Fees and similar payments made by third parties for the processing, transportation, gathering or treatment of their Petroleum Substances in facilities that are part of the Properties,
 - (ii) Proceeds from the sale or licensing of seismic and similar data,
 - (iii) Incentives, rebates and credits in respect of Production Costs or in respect of capital expenditures,
 - (iv) Overhead and other cost recoveries, and
 - (v) Royalties and similar income; less
- d) The amount of non-capital operating costs paid or payable by or on behalf of PrimeWest in respect of operating the Properties including, without limitation, the costs of gathering, compressing, processing, transporting and marketing all Petroleum Substances produced therefrom and all other amounts paid to third parties which are calculated with reference to Production from the Properties including, without limitation, gross overriding royalties and lessors' royalties, but excluding Crown royalties and other Crown charges and any site reclamation and abandonment costs.

NI 51-101 means National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities of the Canadian Securities Administrators.

Non-Associated Gas means an accumulation of Natural Gas in a reservoir where there is no Crude Oil.

NYSE means the New York Stock Exchange.

Oil means Crude Oil or Synthetic Oil.

Person means an individual, a body corporate, a partnership (limited or general), a joint venture, a trust, a pension fund, a union, a government and a governmental agency.

Petroleum Substances means Oil, Natural Gas and related hydrocarbons (except coal) including, without limitation, all liquid hydrocarbons, and all other substances, including sulphur, whether gaseous, liquid or solid and whether hydrocarbon or not, produced in association with Oil, Natural Gas or related hydrocarbons.

Probable Reserves means those additional Reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved plus Probable Reserves. In addition, the level of certainty targeted by the reporting company should result in at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved plus Probable Reserves.

Production means recovering, gathering, treating, field or plant processing and field storage of Oil and Natural Gas.

Production Costs means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. Lifting costs become part of the cost of Oil and Natural Gas produced.

Examples of Production Costs are:

- Costs of labour to operate the wells and related equipment and facilities;
- Costs of repairs and maintenance;
- Costs of materials, supplies and fuel consumed, and supplies utilized, in operating the wells and related equipment and facilities;
- Costs of workovers;
- Property taxes and insurance costs applicable to Properties and wells and related equipment and facilities; and
- Taxes, other than income and capital taxes.

Property/Properties includes:

- Fee ownership or a lease, concession, agreement, permit, license or other interest representing the right of PrimeWest, the Trust or their subsidiaries to extract Oil or Natural Gas subject to such terms as may be imposed by the conveyance of that interest;
- Royalty interests of PrimeWest, the Trust or their subsidiaries, Production payments payable to PrimeWest, the Trust or their subsidiaries in Oil or Natural Gas, and other non operating interests of PrimeWest, the Trust or their subsidiaries in Properties operated by others; and
- An agreement with a foreign government or authority under which PrimeWest, the Trust or any of their subsidiaries participates in the operation of Properties or otherwise serves as “producer” of the underlying Reserves (in contrast to being an independent purchaser, broker, dealer or importer);

but does not include supply agreements, or contracts that represent a right to purchase, rather than extract, Oil or Natural Gas.

Property Acquisition Costs means costs incurred to acquire a Property (directly by purchase or lease, or indirectly by acquiring another corporate entity with an interest in the Property), including:

- Costs of lease bonuses and options to purchase or lease a Property;
- The portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee; and
- Brokers’ fees, recording and registration fees, legal costs and other costs incurred in acquiring Properties.

Proved Property means a Property or part of a Property to which Reserves have been specifically attributed.

Proved Reserves means those Reserves that can be estimated with a high degree of certainty to be recoverable. The reporting company must believe that there is at least a 90% probability that the actual remaining quantities recovered will equal or exceed those estimated Proved Reserves.

Record Date means, in respect of distributions of Distributable Income payable in a given calendar month, the fifth business day following the Cash Distribution Date in the immediately preceding calendar month.

Reserve Life Index or "RLI" means the amount obtained by dividing the quantity of Reserves for the year ending December 31, 2006 by the next year's forecast Production of Petroleum Substances from those Reserves.

Reserves means estimated remaining quantities of Oil and Natural Gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

- Analysis of drilling, geological, geophysical and engineering data;
- The use of established technology; and
- Specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

Royalty means the royalty payable to the Trust pursuant to the Royalty Agreements, which royalty equals 99% of Royalty Income.

Royalty Agreements means the amended and restated royalty agreement dated January 1, 2002 between PrimeWest and the Trustee as trustee for and on behalf of the Trust, and the royalty agreement dated January 24, 2003 between PrimeWest Gas and PrimeWest, which PrimeWest assigned to the Trust, as amended from time to time, regarding the creation and sale of the Royalty.

Royalty Income in respect of any period for which Royalty Income is calculated means Net Production Revenue less the aggregate of:

- The Debt Service Costs, General and Administrative Costs and taxes (other than Crown royalties but including any capital taxes) payable by PrimeWest or the Trust;
- Capital expenditures intended to improve or maintain Production from the Properties or to acquire additional Properties, in excess of amounts borrowed or designated as a deferred purchase price obligation pursuant to the Royalty Agreements, provided that the amount of capital expenditures that can be deducted will not be in excess of 10% of the annual net cash flow from the Properties in the year before the year in which the determination is made;
- Net contributions to PrimeWest's reclamation fund; and
- ARTC applicable to the Properties.

Any income derived from Properties which are not working, royalty or other interests in Canadian resource Properties or which do not relate to Production from working, royalty or other interests in Canadian resource properties, will not be included as Royalty Income and will be used to defray other expenses, capital expenditures of PrimeWest and Debt Service Costs.

SEC means the United States Securities and Exchange Commission.

SEDAR means the System for Electronic Document Analysis and Retrieval established by the Canadian Securities Administrators as the system used for electronically filing most securities related information with the Canadian securities regulatory authorities and accessible at www.sedar.com.

Series I Debentures means the Series I Convertible Unsecured Subordinated Debentures issued on September 2, 2004 that bear interest at an annual rate of 7.5%, payable semi-annually on March 31 and September 30 commencing March 31, 2005. The Series I Debentures are convertible at any time at the

option of the holder into PrimeWest Trust Units at a conversion price of \$26.50 per Trust Unit prior to maturity on September 30, 2009.

Series II Debentures means the Series II Convertible Unsecured Subordinated Debentures issued on September 2, 2004 that bear interest at 7.75%, payable semi-annually on June 30 and December 31 commencing December 31, 2004. The Series II Debentures are convertible at any time at the option of the holder into Trust Units at a conversion price of \$26.50 per Trust Unit prior to maturity on December 31, 2011.

Series III Debentures means the Series III Convertible Unsecured Subordinated Debentures issued on January 11, 2007 that bear interest at 6.50%, payable semi-annually on July 31 and January 31 commencing July 31, 2007. The Series III Debentures are convertible at any time at the option of the holder into Trust Units at a conversion price of \$26.25 per Trust Unit prior to maturity on January 31, 2012.

Service Well means a well drilled or completed for the purpose of supporting Production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (Natural Gas, propane, butane or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for combustion.

Solution Gas means Natural Gas dissolved in Crude Oil.

Standard & Poors means Standard & Poors, a division of The McGraw-Hill Companies, Inc.

Synthetic Oil means a mixture of hydrocarbons derived by upgrading crude bitumen from oil sands or kerogen from oil shales or other substances such as coal.

Tax Act means the *Income Tax Act* (Canada), as amended from time to time.

Trust Units means the units of the Trust, each unit representing an equal undivided beneficial interest in the Trust.

Undeveloped Reserves means those Reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of Production. They must fully meet the requirements of the Reserves classification (Proved, Probable or Possible) to which they are assigned.

Unproved Properties means a Property or part of a Property to which no Reserves have been specifically attributed.

Unitholders means the holders from time to time of one or more Trust Units.

Well Abandonment Costs mean costs of abandoning a well (net of salvage value) and of disconnecting the well from the surface gathering system. They do not include costs of abandoning the gathering system or reclaiming the wellsite.

ITEM 13: SCHEDULE A – REPORT ON RESERVES DATA**BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR****FORM 51-101F2
REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES
EVALUATOR OR AUDITOR**

To the board of directors of PrimeWest Energy Inc. (the "Company"):

1. We have prepared an evaluation of the Company's reserves data as at December 31, 2006. The reserves data consist of the following:
 - (a)
 - (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006, using forecast prices and costs; and
 - (ii) the related estimated future net revenue; and
 - (b)
 - (i) proved oil and gas reserves estimated as at December 31, 2006, using constant prices and costs; and
 - (ii) the related estimated future net revenue.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions in the COGE Handbook.
4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2006, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes 10% discount rate - \$M)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	January 15, 2007	Canada United States	- -	\$2,447,971 \$ 331,633	-	\$2,447,971 \$ 331,633 \$2,779,604

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.
6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.
7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, January 24, 2007

/s/ Myron J. Hladyshevsky
Myron J. Hladyshevsky, P. Eng.
Vice-President

ITEM 14: SCHEDULE B – REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION (FORM 51-101 F3)

Terms to which a meaning is ascribed in National Instrument 51-101 have the same meaning herein.

Management of PrimeWest Energy Inc. (the “Company”) are responsible for the preparation and disclosure, or arranging for the preparation and disclosure of information with respect to the Company’s Oil and Gas activities in accordance with securities regulatory requirements. This information includes Reserves data, which consist of the following:

- a) (i) Proved and Proved plus Probable Oil and Gas Reserves estimated as at December 31, 2006 using Forecast Prices and Costs; and
- (ii) The related estimated Future Net Revenue; and
- b) (i) Proved Oil and Gas Reserves estimated as at December 31, 2006 using Constant Prices and Costs; and
- (ii) The related estimated Future Net Revenue.

Independent qualified Reserves evaluators have evaluated and reviewed the Company’s Reserves data. The report of the independent qualified Reserves evaluators is presented in Schedule B to the Annual Information Form of PrimeWest Energy Trust effective as at December 31, 2006.

The Operations and Reserves Committee of the Board of Directors of the Company has:

- a) Reviewed the Company’s procedures for providing information to the independent qualified Reserves evaluators;
- b) Met with the independent qualified Reserves evaluator(s) to determine whether any restrictions affected the ability of the independent qualified Reserves evaluators to report without reservation; and
- c) Reviewed the Reserves data with Management and the independent qualified Reserves evaluators.

The Operations and Reserves Committee of the Board of Directors has reviewed the Company’s procedures for assembling and reporting other information associated with Oil and Gas activities and has reviewed that information with Management. The Board of Directors has, on the recommendation of the Operations and Reserves Committee, approved:

- a) The content and filing with securities regulatory authorities of the Reserves data and other oil and gas information;
- b) The filing of the report of the independent qualified Reserves evaluator(s) on the Reserves data; and
- c) The content and filing of this report.

Because the Reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

/s/ Donald A. Garner
Donald A. Garner, President & Chief Executive Officer

/s/ Timothy S. Granger
Timothy S. Granger, Chief Operating Officer

/s/ Kent J. MacIntyre
Kent J. MacIntyre, Director

/s/ W. Glen Russell
W. Glen Russell, Director

Dated: February 21, 2007

**ITEM 15: SCHEDULE C – AUDIT COMMITTEE DISCLOSURE
PURSUANT TO MULTILATERAL INSTRUMENT 52-110****AUDIT AND FINANCE COMMITTEE MANDATE****1.0 Constitution**

A standing committee of the Board of Directors (the “Board”) of PrimeWest Energy Inc. (the “Corporation”), consisting of members of the Board, is hereby appointed by the Board from among their number and complying with all other legislation, regulations, agreements, articles and policies to which the Corporation, PrimeWest Energy Trust (the “Trust”) and their businesses are subject, is hereby established and designated as the Audit and Finance Committee (hereinafter referred to as the "Audit Committee"). References to the Corporation in this Mandate shall be deemed to include the Trust, as applicable.

2.0 Overall Purpose/Objectives

- 2.1. The Audit Committee will assist the Board in fulfilling its oversight responsibilities, including the review and approval of:
 - 2.1.1. the integrity of the Corporation’s financial statements;
 - 2.1.2. the Corporation’s compliance with legal and regulatory requirements;
 - 2.1.3. the integrity of the financial reporting process;
 - 2.1.4. the system of internal control and management of financial risks;
 - 2.1.5. the external auditors’ qualifications and independence;
 - 2.1.6. the external audit process and the Corporation’s process for monitoring compliance with laws and regulations;
 - 2.1.7. the performance of the internal auditor & reviews as required or scheduled;
 - 2.1.8. the succession plan for the finance department, including the Internal Auditor;
 - 2.1.9. disclosure of any material information;
 - 2.1.10. management information systems and the office operation disaster recovery program; and
 - 2.1.11. equity offering prospectus.
- 2.2. The Audit Committee should have a clear understanding with the external auditors that the external auditors must maintain an open and transparent relationship with the Audit Committee and the Board, and that the ultimate accountability of the auditors is to the Audit Committee and the Board.
- 2.3. In performing its duties, the Audit Committee will maintain effective working relationships with the Board, management of the Corporation (“Management”), the external auditors and the Internal Auditor. To perform his or her role effectively, each Audit Committee member will obtain an understanding of the Corporation’s business, operations, risks and related legislation, regulations and industry standards.
- 2.4. In order to ensure that the Audit Committee can discharge its duties as a whole, each member of the Audit Committee must be financially literate, within the meaning of Multilateral Instrument 52-110 – Audit Committees (“MI 52-110”) and the New York Stock Exchange (“NYSE”) corporate governance guidelines contained in Section 303A of the NYSE listed company manual (the “NYSE Corporate Governance Guidelines”), or become financially literate within a reasonable period of time after appointment. In addition, and at least one member of the Audit Committee must have accounting or related financial management expertise as required by the NYSE Corporate Governance Guidelines.

3.0 Authority

The Board authorizes the Audit Committee, within its scope of duties and responsibilities, to:

- 3.1. seek any information it requires from employees of the Corporation (which employees are directed to co-operate with any request made by the Audit Committee), and request any officer or employee of the Corporation, or the Corporation's outside counsel or external auditors, to attend a meeting of the Audit Committee or to meet with any members of, or consultants to, the Audit Committee;
- 3.2. seek any information it requires directly from external parties, including the external auditors, and approve the terms of retainer and the fees payable to such parties;
- 3.3. obtain outside legal or other professional advice as it determines necessary or advisable to carry out its duties and determine the fees payable for such advice without seeking Board approval (however providing notice to the Chair of the Board); and
- 3.4. determine the level of administrative expenses necessary for the Audit Committee to carry out its duties.

4.0 Organization

- 4.1. The following provisions and regulations shall apply to the composition of the Audit Committee:
 - 4.1.1. the Audit Committee shall consist of three or more members of the Board, appointed at a meeting of the Board, each of which shall:
 - 4.1.2. be "independent" members of the Board as determined in accordance with National Instrument 58-1-1 – Disclosure of Corporate Governance Practices, National Policy 58-201 – Corporate Governance Guidelines, MI 52-110, the NYSE Corporate Governance Guidelines and Rule 10A-3 of the *United States Securities and Exchange Act* of 1934, as well as, it becomes applicable to the Corporation; and
 - 4.1.3. not be simultaneously serving on the audit committees of more than three public companies, unless the Board first determines that such simultaneous service will not impair the member's ability to effectively serve on the Audit Committee and public disclosure of such determination is made in the Trust's Management Proxy Circular;
- 4.2. the Chair of the Audit Committee shall be determined by the Board of the Corporation or by the members of the Audit Committee if the Chair is absent from the meeting;
- 4.3. any member of the Audit Committee may be removed or replaced at any time by the Board and shall, in any event, cease to be a member of the Audit Committee upon ceasing to be a member of the Board; and where a vacancy occurs at any time in the membership of the Audit Committee, it may be filled by the Board with a candidate as recommended by the Corporate Governance and EH&S Committee;
- 4.4. the quorum for meetings shall be a majority of the members of the Audit Committee, present in person or by telephone or by other telecommunication device that permits all persons participating in the meeting to hear each other;
- 4.5. no business shall be transacted by the Audit Committee except at a meeting of its members at which a quorum is present in person or by telephone or by a resolution in writing signed by all members of the Audit Committee;
- 4.6. the meetings and proceedings of the Audit Committee shall be governed by the provisions of the by-laws of the Corporation that regulate meetings and proceedings of the Board;
- 4.7. the Audit Committee may invite such Directors, Officers or employees of the Corporation and the external auditors as it may see fit, to attend its meetings and take part in the discussion and consideration of the affairs of the Audit Committee;

- 4.8. meetings shall be held not less than four times per year, generally coinciding with the release of interim or year-end financial information. Special meetings may be convened as required upon the request of the Audit Committee or the Officers of the Corporation. The external auditors or Internal Auditor may convene a meeting if they consider that it is desirable or necessary;
- 4.9. the Audit Committee shall meet In Camera, at least quarterly, with:
 - 4.9.1. management;
 - 4.9.2. the external auditors;
 - 4.9.3. the internal auditor;

and at the end of each meeting, by themselves;

- 4.10. the Audit Committee shall meet annually with the Operations and Reserves Committee as part of the year-end review process;
- 4.11. an Audit Committee Forward Agenda will be established with Management;
- 4.12. the Chair shall establish the agenda for the meetings and instruct Management to ensure that properly prepared agenda materials are circulated to the Audit Committee with sufficient time for study prior to the meeting;
- 4.13. the General Counsel and Corporate Secretary, an Audit Committee member, or any other person selected by the Audit Committee, shall be appointed at each meeting to act as Secretary for the purpose of recording the minutes of each meeting; and
- 4.14. the Audit Committee shall provide the Board with a summary of all meetings together with a copy of the minutes from such meetings. Where minutes have not yet been prepared, the Chair shall provide the Board with oral reports on the activities of the Audit Committee. All information reviewed and discussed by the Audit Committee at any meeting shall be retained and made available for examination by the Board upon request to the Chair.

5.0 Duties and Responsibilities

The Board hereby delegates and authorizes the Audit Committee to carry out the following duties and responsibilities to the extent that these activities are not carried out by the Board as a whole:

- 5.1. Corporate Information and Internal Control
 - 5.1.1. review and recommend for approval the quarterly and annual financial statements, Management's Discussion & Analysis, press releases, Annual Reports, AIF's and Management Proxy Circulars (salary and related benefit information will be reviewed and approved by the Compensation Committee);
 - 5.1.2. as part of the year-end review process, jointly with the Operations and Reserves Committee, review and recommend for approval the year end Reserves and Net Asset Value ("NAV") reports;
 - 5.1.3. review of the internal control systems maintained by the Corporation;
 - 5.1.4. review within required time periods, or more frequently if in the Audit Committee's discretion such review is necessary or advisable, with the Chief Executive Officer and Chief Financial Officer of the Corporation and the external auditors, the "disclosure controls and procedures" (as defined in Multilateral Instrument 52-109 – Certification of Disclosure in Issuers' Annual and Interim Filings ("MI 52-109")) adopted by the Corporation; evaluate the effectiveness thereof at least annually and in conjunction with the preparation of annual financial statements; and disclose or cause to be disclosed the conclusions about the effectiveness of those disclosure controls and procedures in the annual Management's Discussion and Analysis;

- 5.1.5. review within required time periods, or more frequently if in the Audit Committee's discretion such review is necessary or advisable, with the Chief Executive Officer and Chief Financial Officer of the Corporation and the external auditors the "internal control over financial reporting" (as defined in MI 52-109) adopted by the Corporation; and disclose or cause to be disclosed in the corresponding Management's Discussion and Analysis any changes in the Corporation's internal control over financial reporting that occurred during the Corporation's most recent interim period that has materially affected, or is reasonably likely to materially affect, the Corporation's internal control over financial reporting;
 - 5.1.6. review of major changes to management information systems;
 - 5.1.7. review of spending authority and approval of limits;
 - 5.1.8. review of significant accounting and tax compliance issues where there is choice among various alternatives, or where the application of a policy has a significant effect on the financial results of the Corporation;
 - 5.1.9. review of significant proposed non-recurring events such as mergers, acquisitions or divestitures;
 - 5.1.10. review press releases and other publicly circulated documents containing financial and earnings information, including financial information and earnings guidance provided to analysts and rating agencies, and "pro forma" and non-GAAP financial information;
 - 5.1.11. review and discuss with Management the minutes of all meetings of the Corporation's Disclosure Committee;
 - 5.1.12. review and approve all related party transactions;
 - 5.1.13. review with the full Board any issues that have arisen with respect to the quality or integrity of the Corporation's financial statements, the Corporation's compliance with legal or regulatory requirements, the performance and independence of the Corporation's independent auditors or the performance of the Internal Auditor; and
 - 5.1.14. prepare a succession plan for the Finance Department, including the Internal Auditor, and review the succession planning process and the succession plan on an annual basis.
- 5.2. External Auditors
- 5.2.1. retain and terminate the external auditors (subject to unitholder approval);
 - 5.2.2. review the terms of the external auditors' engagement and the appropriateness and reasonableness of the proposed engagement fees;
 - 5.2.3. annually, obtain and review a report by the external auditors describing: the firm's internal quality control procedures; any material issues raised by the most recent internal quality control review (or peer review) of the firm, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the firm and any steps taken to deal with such issues;
 - 5.2.4. annually, review and approve a certificate attesting to the external auditors' independence, identifying all relationships between the external auditors and the Corporation;
 - 5.2.5. annually, evaluate the external auditors' qualifications, performance and independence, taking into account the opinions of Management and the Corporation's Internal Auditor, and present the conclusions to the Board;

- 5.2.6. annually, to assure continuing auditor independence, confirm that the “lead partner” the “concurring partner” and the other “audit partner” rotation requirements of applicable securities laws have been complied with, and consider whether, in order to assure continuing auditor independence, it is appropriate to adopt a policy of rotating the independent auditors on a more regular basis;
 - 5.2.7. where there is a change of external auditor, review all issues related to the change, including information required to be disclosed in the notice of change of auditors (including those contained in National Instrument 51-102 Continuous Disclosure Obligations (“NI 51-102”)), and the planned steps for an orderly transition;
 - 5.2.8. review all reportable events, including disagreements, unresolved issues and consultations, as defined in NI 51-102, on a routine basis, whether or not there is a change of auditors;
 - 5.2.9. pre-approve engagements for non-audit services provided by the external auditors or their affiliates, together with estimated fees and potential issues of independence; and
 - 5.2.10. set clear hiring policies for employees or former employees of the external auditors or former external auditors.
- 5.3. AUDITORS
- 5.3.1. review the audit plan for the coming year with the external auditors and with Management;
 - 5.3.2. review with Management and the external auditors major issues regarding accounting principles and financial statement presentation, including any proposed changes in major accounting policies, the presentation and impact of significant risks and uncertainties, and key estimates and judgements of Management that may be material to financial reporting;
 - 5.3.3. question Management and the external auditors regarding significant financial reporting issues during the fiscal period and the method of resolution of such issues;
 - 5.3.4. review any problems experienced by the external auditors in performing the audit, as set out in an internal control letter issued by the auditor or otherwise, including any restrictions imposed by Management or significant accounting issues in which there was a disagreement with Management, and Management’s response thereto;
 - 5.3.5. review audited annual financial statements and quarterly financial statements with Management and the external auditors (including disclosures under “Management’s Discussion & Analysis”), in conjunction with the report of the external auditors, and obtain the explanation of Management of all significant variances between comparative reporting periods;
 - 5.3.6. review the external auditors’ report to Management, containing recommendations of the auditors’, and Management’s response and subsequent remedy of any identified weaknesses; and
 - 5.3.7. confirm with the external auditors, grants and payouts made, from time to time, under the Corporation’s Long Term Incentive Plan, including those made to the Officers of the Corporation.
- 5.4. Internal Auditor
- 5.4.1. ensure that the Corporation’s Internal Auditor has the qualifications and experience necessary to comply with the Corporation’s job description for this

- position, including systems experience, an appropriate designation and membership in the Institute of Internal Auditors;
- 5.4.2. review and approve the responsibilities, budget and staffing of the internal audit function;
 - 5.4.3. review and approve an annual audit plan and ensure that the Chair of the Audit Committee and the Chief Executive Officer of the Corporation jointly conduct annual reviews of the performance of the Internal Auditor;
 - 5.4.4. ensure that the Corporation's Internal Auditor is present at all Audit Committee meetings; and
 - 5.4.5. review and forward to the Board summary reports prepared by the Internal Auditor with respect to the review of compliance and testing of internal controls, general audit reviews, special audits and other audit functions.
- 5.5. Risk Management and Controls
- 5.5.1. generally, review the Corporation's risk assessment and risk management policies;
 - 5.5.2. 5.5.2. annually, review an update of the Corporation's Enterprise Risk Assessment Action Plan including, the identification of new risks, the prioritization of risks and the steps to be taken to minimize such risks;
 - 5.5.3. review hedging strategies, policies, objectives and controls;
 - 5.5.4. review, not less than quarterly, a mark to market assessment of the Corporation's hedge positions and counter party credit risk and exposure;
 - 5.5.5. review the Corporation's risk retention philosophy and resulting exposure to the Corporation;
 - 5.5.6. review the adequacy of insurance coverage, outstanding or pending claims and premium costs;
 - 5.5.7. review loss prevention policies and risk management programs in the context of competitive and operational consideration, ensuring that the Corporation is adequately protected from losses without impairing its business or its ability to compete in the industry;
 - 5.5.8. annually review authority limits for capital expenditures, sales and purchases;
 - 5.5.9. review the Corporation's procedures for the control, identification and reporting of fraudulent acts; and
 - 5.5.10. take the steps necessary to address and resolve all instances or allegations of fraud reported to the Committee Chair by the General Counsel and Corporate Secretary or other designated recipient of complaints received through the Corporation's Code of Business Conduct and Ethic Confidence Line.

6.0 Audit Committee Evaluation and Complaints

- 6.1.1. review and reassess the adequacy of and compliance with the Audit Committee Mandate annually and recommend to the Corporate Governance and EH&S Committee and to the Board any changes to the Mandate deemed appropriate by the Audit Committee;
- 6.1.2. annually, in conjunction with the Corporate Governance and EH&S Committee and the Chair of the Board, assess Audit Committee Chair performance and evaluate the performance of the Audit Committee as a whole, including its processes and effectiveness;

- 6.1.3. annually make determinations as to whether any Audit Committee member's simultaneous service on audit committees of other boards impairs the member's ability to effectively serve on the Audit Committee;
- 6.1.4. in conjunction with the Corporate Governance and EH&S Committee, develop and approve Audit Committee member eligibility criteria, identify Directors qualified to become Audit Committee members and recommend appointments to and removals from the Audit Committee;
- 6.1.5. establish and publish procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters;
- 6.1.6. establish and publish procedures for the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters, including submission through the Corporation's Code of Business Conduct and Ethic Confidence Line, which shall be reported to the Audit Committee Chair by the General Counsel and Corporate Secretary or other designated recipient;
- 6.1.7. establish and publish procedures for the taking of the steps necessary to address and resolve complaints and concerns relating to accounting, internal control and auditing matters; and
- 6.1.8. review and approve any amendment to or waiver of the Corporation's Code of Business Conduct and Ethics for the Chief Executive Officer, the Chief Executive Officer and other senior officers; and review and approve any public disclosure required to be made regarding such changes or waivers.

7.0 Other Duties and Responsibilities

- 7.1.1. The responsibilities, practices and duties of the Audit Committee outlined herein are not intended to be comprehensive. The Board may, from time to time, charge the Audit Committee with the responsibility of reviewing items of a financial, control or of a risk management nature; and
- 7.1.2. the Audit Committee shall periodically report to the Board the results of all reviews undertaken and any associated recommendations.

8.0 Authorization

- 8.1. This Audit Committee Mandate is hereby approved on behalf of the Board of Directors of PrimeWest Energy Inc. on the 3rd day of May, 2006.

COMPOSITION OF THE AUDIT COMMITTEE

The members of the Audit and Finance Committee are Peter Valentine, as Chair, Harold P. Milavsky, Michael W. O'Brien and Barry E. Emes. Mr. Emes was appointed as a member of this Committee on August 2, 2006. Each member of the Audit and Finance Committee is independent and financially literate within the meaning of Multilateral Instrument 52-110.

RELEVANT EDUCATION AND EXPERIENCE

Mr. Valentine, B.Comm, FCA, ICD.D, is currently Senior Advisor to the President and Chief Executive Officer of the Calgary Health Region. Mr. Valentine is a trustee, a member of the Audit Committee and a member of the Governance Committee of Fording Canadian Coal Trust, a Director and Chair of the Audit Committee of Livingston International Income Fund, a Director and member of the Audit Committee of Superior Plus Income Fund and a Director and Chair of the Audit Committee of Resmor Trust Company (a private corporation).

Mr. Valentine was previously the Auditor General of the Province of Alberta (March 1995 to January 2002), Chair of the Financial Advisory Committee of the Alberta Securities Commission, member of the Accounting Standards Board and Public Sector Accounting Board of the Canadian Institute of Chartered

Accountants, Chair of the Canadian Comprehensive Audit Foundation and also held senior positions at KPMG. In addition, for the period of December 2003 to June 2004, Mr. Valentine was Interim Vice President, Finance and Services at the University of Calgary and, for the period of May 7, 2005 to July 18, 2005, was Interim Chair of the Alberta Securities Commission.

Mr. Milavsky, B.Comm, CA, FCA, is Chair of Quantico Capital Corp., a privately held company engaged in merchant banking, principal investments and acquisitions. Mr. Milavsky also serves as a Director, member of the Audit Committee and member of the Nominating/Corporate Governance Committee of Saskatchewan Wheat Pool and as a Director, Chair of the Board and Chair of the Audit Committee of the various investment trusts or corporations comprising the Citadel Group of FundsTM. Mr. Milavsky was President and Chief Executive Officer of Trizec Corporation from 1976 to 1986 and Chair and Chief Executive Officer from 1986 to 1993. He has been a Director of TransCanada Corporation, Telus Corporation, Northrock Resources Ltd., Encal Energy Ltd., Wascana Energy Inc., ENMAX Corporation and many other corporations. Mr. Milavsky is a Fellow of the Institute of Chartered Accountants of Alberta and, in 2002, he received the Institute's Lifetime Achievement Award. Mr. Milavsky is also a member of the Institute of Corporate Directors and received that Institute's Fellowship Award in 2005.

Mr. O'Brien, B.A., MBA, serves, among other responsibilities, as a Director and Chair of the Audit Committee of Shaw Communications Inc., as a Director, member of the Audit Committee and member of the Environment Health and Safety Committee of Suncor Energy Inc. and, as a member of the Advisory Board of CRA International. Mr. O'Brien is also past Chair of the Canadian Petroleum Products Institute, Canada's Voluntary Challenge Registry for Climate Change and the Nature Conservancy of Canada. Prior to retirement in 2002, Mr. O'Brien was the Executive Vice President, Corporate Development and Chief Financial Officer of Suncor Energy Inc. (December 1999 – June 2002)

Until July 31, 2006, Mr. Emes, B.A., LLB., was a partner with Stikeman Elliott LLP, a leading national and international law firm. Mr. Emes' practice focused on complex corporate commercial matters, including public and private mergers and acquisitions/dispositions, banking, corporate governance matters, commercial real estate transactions, oil and gas transactions, debt restructuring transactions, derivatives and a wide range of other corporate and commercial matters. Prior to concentration on corporate commercial matters, Mr. Emes carried on a high level commercial litigation practice. Mr. Emes was managing partner of the Stikeman Elliott Calgary office for 7 years and was a member of the firm's national partnership board for 7 years. Mr. Emes has also worked for Mobil Oil (Canada) as an economist in their planning group.

Mr. Emes has served on audit committees, compensation committees, nominating committees, corporate governance committees and special committees and is currently a Director of Parkbridge Lifestyle Communities Inc. and Realex Properties Corp.

In addition to attaining a Bachelor of Arts in Economics, Mr. Emes has completed the Royal Bank of Canada's management training program and undertaken additional studies in accounting and corporate finance. Mr. Emes is also a graduate of the Institute of Corporate Directors, Corporate Governance College, Director Education Program.

Prior to his retirement effective July 31, 2006, Mr. Emes was a partner in Stikeman Elliott LLP, a law firm that provides legal services to PrimeWest and that receives advisory fees in connection therewith. The Board of Directors previously affirmatively determined that this relationship did not interfere with Mr. Emes' ability to exercise his independent judgment, that such relationship was not a material relationship with PrimeWest and that none of the per se bars applicable for purposes other than those relating to audit committees applied to Mr. Emes. Therefore, Mr. Emes was considered to be an Independent Director for the purposes of NI 58-101 and the NYSE Rules that do not apply to audit committees. While Mr. Emes was not considered to be an Independent Director for the purposes of either MI 52-110 or the NYSE Rules that apply to audit committees because of the application of a per se bar relating to his position as a partner in Stikeman Elliott LLP, his retirement from the partnership had the effect of terminating his entire relationship with Stikeman Elliott LLP. Therefore, Mr. Emes is no longer subject to that per se bar and he is now considered to be an Independent Director for the purposes of all

of the Independence Tests, including those under Multilateral Instrument 52-110 and the NYSE Rules that apply to audit committees. Based on this determination, the Board of Directors appointed Mr. Emes as a member of the Audit and Finance Committee of PrimeWest effective August 2, 2006.

As a result of his retirement from Stikeman Elliott LLP, which retirement has had the effect of terminating the entire relationship between Mr. Emes and Stikeman Elliott LLP, Mr. Emes is no longer subject to the per se bar relating to the direct or indirect acceptance of any consulting, advisory or other compensatory fee from the Corporation. Therefore, Mr. Emes is now considered to be independent for the purposes of Multilateral Instrument 52-110 and all of the NYSE Rules.

PRE-APPROVAL POLICIES AND PROCEDURES

It is within the mandate of PrimeWest's Audit and Finance Committee to approve all audit and non-audit related fees. The engagement for the annual audit of PrimeWest's consolidated financial statements is specifically approved on an annual basis by the execution of an audit engagement letter with the auditors. In addition, the Audit and Finance Committee has pre-approved a range of specifically identified routine non-audit services, up to a pre-determined maximum annual limit of \$100,000, provided that non-routine services and routine services, the cost of which will exceed the \$100,000 maximum on an aggregate basis, require the specific prior approval of the Committee. PrimeWest or its auditors may also seek pre-approval by the Audit and Finance Committee of the engagement of the auditors to provide particular services in certain cases. The Audit and Finance Committee will be informed routinely as to the routine non-audit services actually provided by the auditors pursuant to the pre-approval process. The auditors also present the estimate for the annual audit related services to the Committee for approval prior to undertaking the annual audit of the consolidated financial statements. The Audit and Finance Committee approved all of the Audit Fees, Audit-Related Fees, Tax Fees and All Other Fees relating to the services provided by PriceWaterhouseCoopers LLP in 2006.

EXTERNAL AUDITOR SERVICE FEES

The aggregate fees paid by PrimeWest to PricewaterhouseCoopers LLP, the auditors of PrimeWest, for professional services rendered in the Trust's last two fiscal years are as follows:

Auditor Fees Paid	Year ended December 31, 2006	Year ended December 31, 2005
Audit fees ⁽¹⁾	\$768,521	\$492,000
Audit related fees ⁽²⁾	\$8,750	\$9,000
Tax fees ⁽³⁾	\$8,800	\$22,300
All other fees ⁽⁴⁾	-	\$95,000
TOTAL	\$786,071	\$618,300

Notes:

- (1) Audit fees were for professional services rendered by PricewaterhouseCoopers LLP for the audit of the Trust's annual financial statements and reviews of the Trust's quarterly financial statements, as well as services provided in connection with prospectus fees, compliance with the Sarbanes-Oxley Act of 2002, statutory and regulatory filings or engagements.
- (2) Audit related fees are those fees billed for prospectus related work and related services by PricewaterhouseCoopers LLP that are reasonably related to the performance of the audit or review of the Trust's financial statements but not included in Audit Fees.
- (3) Tax fees were for tax compliance, tax advice and tax planning. The fees were for services performed by the Trust's auditors' tax division except those tax services related to the audit.
- (4) All other fees are those fees billed for products and services provided by PricewaterhouseCoopers LLP, other than Audit Fees, Audit-related Fees and Tax Fees. In 2005, the fees relate to the Trust's enterprise risk assessment.