



PrimeWest Energy Trust

RENEWAL ANNUAL INFORMATION FORM

For the year ended December 31, 2004

March 28, 2005

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FORWARD-LOOKING STATEMENTS

Except for the historical and present factual information contained herein, the matters set forth in this presentation, including words such as “anticipate”, “continue”, “estimate”, “expect”, “forecast”, “may”, “will”, “should”, “believe”, “project”, “plan”, “outlook” and similar expressions are forward-looking statements.

These forward-looking statements are subject to known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. PrimeWest believes the expectations reflected in 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. Please refer to PrimeWest’s public disclosure documents for more information on these risks and uncertainties as they apply to PrimeWest.

PrimeWest Energy disclaims any responsibility to update these forward-looking statements.

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

All calculations required to convert natural gas to a crude oil equivalent (BOE) have been made using a ratio of 6,000 cubic feet of natural gas to 1 barrel of crude oil. BOE’s may be misleading, particularly if used in isolation. The BOE conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

All figures reported in Canadian dollars unless otherwise stated.

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

NOTE TO READER

The Trust Units were consolidated on a four to one basis on August 16, 2002. Except where otherwise indicated, all amounts relating to the Trust Units contained in this Annual Information Form have been adjusted to give effect to the Consolidation.

ITEM 1: ORGANIZATION

PrimeWest Energy Trust ("**PrimeWest**" or 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 petroleum 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 the "**Trustee**") is the Trustee of the Trust. The head office of PrimeWest is 5100, 150 6th Ave SW, Calgary, Alberta, T2P 3Y7. The registered office of PrimeWest is 4300 888 3rd Street SW, 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 was amalgamated with PrimeWest Management Inc. (the "**Manager**") and Delgrae Energy Corporation on November 6, 2002 and continued as PrimeWest Energy Inc.

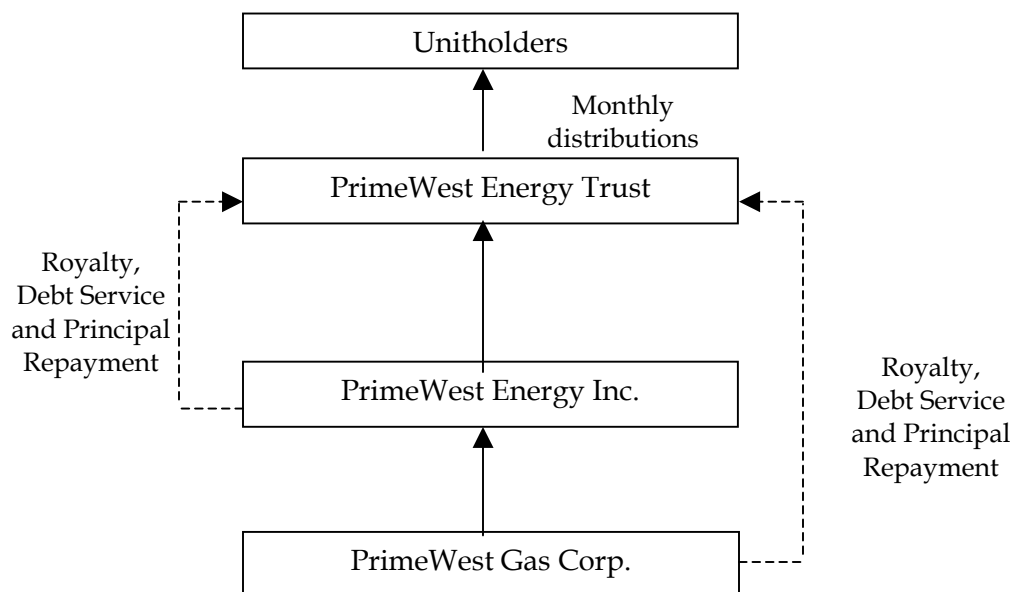
PrimeWest is wholly owned by the Trust. PrimeWest's business is the acquisition, development, exploitation, production and marketing of petroleum and natural gas and granting the Royalty to the Trust.

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 is wholly owned by PrimeWest and is an operating subsidiary of PrimeWest and the Trust.

The principal undertaking of the Trust is to acquire and hold, directly and indirectly, interests in petroleum and natural gas properties. One of the Trust's primary assets is the Royalty granted by PrimeWest and PrimeWest Gas pursuant to the Royalty Agreements. The Royalty entitles the Trust to receive 99% of the net cash flow generated by the petroleum 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 petroleum 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:



Notes:

- (1) The Trust also directly owns certain gross overriding royalty interests.
- (2) PrimeWest, directly and indirectly through its subsidiaries, including PrimeWest Gas, actively manages its oil and gas properties to maximize cash flow and Reserve value.

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. For a complete description of that indenture, reference should be made to the Declaration of Trust, copies of which 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. Furthermore, the Trust is not a trust company and, accordingly, is not registered under any trust and loan company legislation, as it does not carry on or intend to carry on the business of a trust company.

Class A Exchangeable Shares of PrimeWest

An unlimited number of Class A Exchangeable Shares may be issued by the Operating Company, each of which entitles the holder to exchange the Class A Exchangeable Share 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, 2004, each Class A Exchangeable Share was exchangeable for 0.50408 Trust Units.

PrimeWest issued Class A Exchangeable Shares in connection with the acquisitions of the Manager in November 2002, Cypress in March 2001 and Venator in April 2000. Shareholders of the Manager, Cypress and Venator who received Class A Exchangeable Shares could in certain circumstances defer the tax consequences of that exchange. PrimeWest may issue additional Class A Exchangeable Shares in connection with future acquisitions or to address other capital requirements.

The Class A Exchangeable Shares provide holders with economic terms and voting rights which are, as nearly as practicable, equivalent to those of Trust Units. The Class A Exchangeable Shares are maintained economically equivalent to the Trust Units by the progressive increase in the exchange ratio, incorporating the distributions provided to Unitholders and reflecting the right to acquire an ever-increasing number of Trust Units per Class A Exchangeable Share. The Class A Exchangeable Shares are provided equivalent voting rights as Unitholders through a voting trust agreement pursuant to which the holders of Class A Exchangeable Shares can direct Computershare Trust Company of Canada, in its capacity as the voting and exchange trustee, to vote at meetings of Unitholders. The Class A Exchangeable Shares are listed and posted for trading on the 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 and the Class A Exchangeable Shares. 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 holders of Trust Units; 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 2005 annual meeting of Unitholders. 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 and 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. PrimeWest's current policy is to distribute between 70% and 90% of Distributable Income.

The following table sets forth the per Unit amount of monthly cash distributions, adjusted for the Consolidation since 2002.

	Distribution Per Unit ⁽¹⁾ (Cdn\$)
2002	
January	0.40
February	0.40
March	0.40
April	0.40
May	0.40
June	0.40
July	0.40
August	0.40
September	0.40
October	0.40
November	0.40
December	0.40
2003	
January	0.40
February	0.40
March	0.40

	Distribution Per Unit ⁽¹⁾ (Cdn\$)
April	0.40
May	0.40
June	0.40
July	0.32
August	0.32
September	0.32
October	0.32
November	0.32
December	0.32
2004	
January	0.32
February	0.25
March	0.25
April	0.25
May	0.25
June	0.25
July	0.25
August	0.275
September	0.30
October	0.30
November	0.30
December	0.30

⁽¹⁾ Monthly information refers to the month in which the Record Date for the relevant distribution occurs with payment being paid on the 15th of the following month.

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 such 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 and a 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.

Limitation on Non-Resident Ownership and Taxation

The Canadian Government's Budget of March 23, 2004 included a proposal to extend the non-resident ownership restrictions, currently applicable to most mutual fund trusts and mutual fund corporations (but generally not to royalty trusts, and in particular not to PrimeWest), to royalty trusts (including PrimeWest) and to impose a new 15% withholding tax on distributions of capital to non-resident Unitholders.

On December 6, 2004, the Minister of Finance tabled in the House of Commons a Notice of Ways and Means Motion to implement certain of the Budget proposals. The Notice of Ways and Means Motion does not propose any changes to the existing non-resident ownership restrictions applicable to mutual fund trusts and mutual fund corporations. In the announcement that accompanied the Notice of Ways and Means Motion, the Department of Finance stated that further discussions would be pursued with the private sector concerning the appropriate Canadian tax treatment of non-residents investing in resource property through mutual funds. Pending the outcome of such further discussions, PrimeWest continues not to be subject to any restrictions on non-resident ownership of its Trust Units, and there is no specified date on or before which it will become subject to any such restrictions. In the event that the Department of Finance determines to limit the extent to which non-residents are 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 at the last annual meeting held on May 6, 2004, 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) delist 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.

The December Notice of Ways and Means Motion includes legislation, effective January 1, 2005, providing for a special 15% withholding tax on the portion of the distributions to non-resident Unitholders that constitutes a return of capital.

In the past, PrimeWest has withheld 15% of all distributions paid to non-resident Unitholders, since it is not possible to determine, at the time of any particular distribution, what portion

thereof constitutes a return on capital and what portion constitutes a return of capital. After the end of each fiscal year, PrimeWest has sent to each Unitholder a statement indicating what amounts were received as a return on capital and what amounts were received as a return of capital, and a non-resident Unitholder could apply to the Canada Revenue Agency for a refund of the amounts withheld in respect of returns of capital. Under the new legislation, such amounts will now be subject to a 15% non-resident withholding tax, and it will no longer be possible for a non-resident Unitholder to obtain a refund of such withheld amounts (except in certain limited circumstances, where the non-resident Unitholder disposes of Trust Units at a loss). PrimeWest recommends that non-resident Unitholders contact their tax advisors in order to obtain details of the implications arising from the implementation of this new withholding tax.

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 must be 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.

Unitholder Rights Plan

On March 31, 1999, PrimeWest announced that it had adopted a Unitholder 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. The Rights Plan will expire on the date of PrimeWest's annual meeting in 2005, and therefore, PrimeWest plans to request approval of amendments to such Rights Plan to provide that Unitholder approval must be sought for the continuance of the Rights Plan at every annual meeting of Unitholders. PrimeWest also plans to request Unitholders to reconfirm the Rights Plan for a further initial term of one year.

Under the terms of the Rights Plan, a prospective bidder would be encouraged to negotiate the terms of a bid with the board of directors of PrimeWest, or to make a "permitted bid", a take-over bid not requiring the approval of the board of directors of PrimeWest but having terms and conditions designed to provide the board of directors with sufficient time to properly

evaluate the bid and its effects, and to seek alternative bidders or to explore other ways of maximizing Unitholder value.

If a Person acquires more than 20% of the Trust Units other than by way of a permitted bid, other Unitholders may, at the discretion of the board of directors of PrimeWest, acquire a number of Trust Units at 50% of the then prevailing market price, so as to cause significant dilution to the acquiring Person.

The Rights Plan provides that a permitted bid is a take-over bid meeting the following requirements:

- a) The bid must be made to all Unitholders;
- b) The bid must be open for a minimum of 45 days following the date of the bid, and no Trust Units may be taken up prior to such time;
- c) Take-up and payment of Trust Units may not occur unless the bid is accepted by Unitholders holding more than 50% of the outstanding Trust Units, excluding Trust Units held by the bidder and its associates;
- d) Trust Units may be deposited to or withdrawn from the bid at any time prior to the take-up date; and
- e) If the bid is accepted by Unitholders holding the requisite percentage of Trust Units, the bidder must extend the bid for an additional ten business days to permit other Unitholders to tender into the bid, should they so wish.

Decision Making

Unitholders are entitled to direct the election 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 petroleum 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 or the Royalty Agreements and other aspects respecting the relationship between the Trust and PrimeWest, and (d) responding to unsolicited take-over 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 crude oil and natural gas properties.

Since its inception, PrimeWest has been an active acquirer of crude oil and natural gas properties in the Western Canadian Sedimentary Basin. Many of those acquisitions were financed, directly or indirectly, through the issuance of Trust Units and what are now Class A Exchangeable Shares. The following tables summarize the more significant acquisitions and financings completed by PrimeWest, directly or indirectly, since January 1, 2002.

Acquisitions

Date	Company/Properties Acquired	Aggregate Purchase Price (currency)	Reserves and Production Acquired
December 2002	Caroline/Ells	\$45.6 million (cash)	5.7 mmboe ⁽¹⁾ 1,550 boe/day
January 2003	Caroline/Peace River Arch	\$219.1 million (cash)	15.5 mmboe ⁽²⁾ 6,800 boe/day
March 2004	Seventh Energy Ltd.	\$34.8 million (cash) plus assumed debt of \$9.9 million.	3.3 mmboe ⁽²⁾ 1,300 boe/day
September 2004 ⁽³⁾	Assets of Calpine Canada Natural Gas Partnership	\$742 million (cash)	54.8 mmboe ⁽²⁾ 14,500 boe/day
September 2004 ⁽³⁾	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.

Notes:

(1) Based on evaluations of Established Reserves completed prior to implementation of National Instrument 51-101 in September 2003.

(2) Proved plus Probable Company Interest Reserves.

(3) A Form 51-102F4 – Business Acquisition Report dated November 1, 2004 (the “**Business Acquisition Report**”) was filed on SEDAR in connection with the Calpine transaction. The Business Acquisition Report is specifically incorporated herein by reference.

Public Offerings

Date	No. of Securities Issued	Type of Security	Price per Security	Gross Proceeds (\$ millions)
November 2002	4,200,000	Trust Units	\$ 26.20	\$ 110.0
February 2003	6,000,000	Trust Units	\$ 25.75	\$ 154.5
September 2003	3,100,000	Trust Units	\$ 25.90	\$ 80.3
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⁾	\$ 1,000.00	\$ 150.0
September 2004	100,000	Series II Debentures ⁽²⁾	\$ 1,000.00	\$ 100.0

Notes:

⁽¹⁾ The Convertible Unsecured Subordinated Series I Debentures (“**Series I Debentures**”) bear interest at an annual rate of 7.5%, payable semi-annually and are convertible into Trust Units at \$26.50 per Trust Unit.

⁽²⁾ The Convertible Unsecured Subordinated Series II Debentures (“**Series II Debentures**”) bear interest at an annual rate of 7.75%, payable semi-annually and are convertible into Trust Units at \$26.50 per Trust Unit.

Other significant developments since January 1, 2002 include the following:

- On August 16, 2002 the Trust Units were consolidated on a four-for-one basis.
- On November 4, 2002, Unitholders approved the proposal to eliminate the external management contract and related fees through the purchase of the Manager.
- On November 19, 2002, the Trust Units were listed for trading on the New York Stock Exchange under the symbol “PWI”.
- On December 18, 2002, PrimeWest closed the Caroline asset acquisition for a total purchase price of \$45.6 million. An additional asset swap was also closed on December 20, 2002, which permitted PrimeWest to further consolidate its interest in the Thorsby area, while at the same time disposing of a number of small non-core holdings.
- On December 23, 2002, the board of directors of PrimeWest confirmed the succession of Donald A. Garner to the position of President and Chief Executive Officer, effective January 2, 2003. Kent MacIntyre, the founder of PrimeWest, resigned as Vice-chairman and Chief Executive Officer of PrimeWest effective January 2, 2003, but remains a member of the board of directors of PrimeWest. The board also appointed Tim Granger, PrimeWest’s Vice-president, Operations and Development, as Chief Operating Officer.

- On January 8, 2003, PrimeWest announced the appointment of W. Glen Russell as an independent member of the board of directors.
- On January 23, 2003, PrimeWest closed the purchase of certain natural gas and crude oil properties located primarily in the Caroline and Peace River Arch areas of Alberta for a purchase price of \$219.1 million. The 2002 exit production rate for these properties was approximately 6,800 boe/day.
 - On May 7, 2003, PrimeWest announced that it had entered into a private placement debt financing for US\$125 million of secured notes with a seven-year term and an effective five and one half year average life at a coupon rate of 4.19%.
 - On May 26, 2003, PrimeWest announced the appointment of James W. Patek as an independent member of the board of directors.
 - On October 31, 2003, PrimeWest announced that it had received all regulatory approvals for the implementation of a premium distribution component of its existing Distribution Reinvestment and Optional Trust Unit Purchase Plan. As an alternative to the distribution reinvestment component of the plan, the premium distribution component allows eligible Unitholders to elect to receive a premium cash distribution equal to 102% of the cash that the Unitholder would otherwise have received on the Cash Distribution Date, subject to proration in certain events under the Premium DRIP.
 - On January 27, 2004 PrimeWest announced that PrimeWest Gas had entered into an agreement to acquire all of the outstanding shares of Seventh Energy Ltd. (“**Seventh**”) for cash consideration of \$34.8 million plus assumed debt of \$9.9 million. PrimeWest hedged approximately 70% of the gas production of Seventh at a price of \$6.18/mcf for one year. On February 6, 2004 PrimeWest Gas mailed a formal take-over 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 take-over 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’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 of PrimeWest 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 is also a member of the Audit and Finance Committee of the board.

- 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 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 Convertible 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 14,360 boe/day. Based upon an independent engineering determination as of July 1, 2004, conducted in accordance with National Instrument 51-101, approximately 54.8 mmmboe 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 five-year, Series I Debentures and \$100 million of seven-year, Series II Debentures. The Series I Debentures bear a coupon rate of 7.5% per annum, payable semi-annually and are convertible into Trust Units at \$26.50 per Trust Unit. The Series II Debentures bear a coupon rate of 7.75% per annum, payable semi-annually, and are also convertible into Trust Units at \$26.50 per Trust Unit. Total net proceeds from both the Trust Unit offering and Convertible 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. PrimeWest is evaluating the change to the royalty calculation and its impact as well as any further steps to be taken in relation to the gas over bitumen issue.

- 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, PrimeWest closed sales of assets in the areas of Dawson, northern Alberta, southeast Alberta, southwest Saskatchewan and other miscellaneous non-core areas. The divestitures represent production of approximately 3,000 boe/day, for proceeds of \$104.9 million, which includes \$5.4 million for assets that were held for sale and closed in February 2005.
- 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. PrimeWest expects that details regarding the inclusion process, including the impact on PrimeWest will be announced by mid-year 2005.
- 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 Trust. As of February 24, 2005, PrimeWest sold its 8.3% ownership of Viking Energy Trust for gross proceeds of \$95.8 million.

Other Developments

Pursuant to the Royalty Agreements, PrimeWest has the authority to invest its environmental fund and other cash reserves in certain "Permitted Investments". At the 2005 annual meeting, PrimeWest plans to request Unitholders to approve the amendment of the Royalty Agreements to expand the definition of "Permitted Investments" to include equity securities and debt obligations of entities other than PrimeWest whose debt obligations are rated at least investment grade by a nationally recognized rating agency. See "Additional Information Concerning Abandonment and Reclamation Costs" under Item 4 below.

ITEM 3: NARRATIVE DESCRIPTION OF BUSINESS

The Business of the Trust

General

The undertaking of the Trust is to acquire and hold petroleum and natural gas properties and to distribute the Distributable Income generated therefrom to Unitholders. It is therefore the mandate of PrimeWest to continue to source and acquire petroleum 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

PrimeWest believes that although operatorship of the properties generally involves higher General and Administrative Costs than would be required for non-operated properties, those

higher costs will generally result in more opportunities to enhance value to Unitholders through production enhancement, control of facilities 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 petroleum and natural gas Reserves or increase Reserves through development activities, production from the currently held properties will continually decline. PrimeWest continually reviews opportunities for the acquisition of producing petroleum and natural gas properties. When considering the acquisition of any petroleum 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 & 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:

- a) Political uncertainty, including the risk of hostilities, in the petroleum producing regions of the world;
- b) OPEC's ability to control production to balance global supply and demand at desired price levels;
- c) Global economic growth and the resultant impact on energy demand;
- d) The effect of energy conservation and government regulations;
- e) The impact of weather conditions on seasonal demand;
- f) The price levels and availability of competing alternative fuels;
- g) Increases or decreases in the price differential between light and heavy crude oil;
- h) 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 a portion of these risks, 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 2004, 58% of full-year crude oil production (2003 - 65%) and 54% of full-year natural gas production (2003 - 61%) was hedged, net of royalties. Strategies included the utilization of financial instruments with the primary objective of enhancing the stability of cash distributions. For the year ended December 31, 2004, the cash impact of contracts settling was a \$28.1 million loss comprised of a \$23.1 million loss in crude oil, a \$5.1 million loss in natural gas, a \$0.8 million gain on electrical power and a \$0.7 million loss in interest rate swaps.

PrimeWest also utilized electrical power hedges during 2004. The power hedges consisted of electricity swaps averaging \$46.11 per megawatt hour resulting in a \$0.8 million hedging gain.

The gas hedging instruments consist of swaps, basis 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 are 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 hedging instruments also consist of swaps, costless collars and 3-way deals.

As at March 10, 2005:

- a) PrimeWest has employed hedging structures using swaps and option-based instruments on approximately 63% of anticipated base crude oil production, net of royalties, for 2005 and on 7% of its anticipated base crude oil production, net of royalties, for 2006;
- b) PrimeWest has employed hedging structures using swaps and option-based instruments on approximately 54% of anticipated base natural gas production, net of royalties, for 2005 and on approximately 10% of anticipated base natural gas production, net of royalties, for 2006;
- c) PrimeWest has employed hedging structures using swaps on approximately 25% of anticipated electrical power requirements for 2005 and on none of the anticipated electrical power requirements for 2006;
- d) The intrinsic mark-to-market positions of all hedging contracts in place for the 2005 and 2006 production years represent a net loss of \$15.3 million, as compared to a net loss of \$7.9 million when measured as at December 31, 2004. 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, 2004 and March 10, 2005, respectively; and
- e) The intrinsic plus extrinsic mark-to-market positions of all hedging contracts in place for the 2005 and 2006 production years represent a net loss of \$23.0 million as compared to a net gain of \$0.1 million when measured as at December 31, 2004. 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, 2004 and March 10, 2005, 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 25% of natural gas production is sold to aggregators and approximately 75% 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 these noted 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 2004, PrimeWest's commodity mix was approximately 32% oil and NGLs and 68% natural gas, compared to approximately 33% oil and NGLs and 67% natural gas in 2003. PrimeWest realized hedge losses of \$28.2 million in 2004 and losses of \$30.5 million in 2003.

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. At present, PrimeWest believes that it meets all existing environmental standards and regulations. PrimeWest has created a segregated fund devoted to funding future costs for well abandonment and site cleanup. In 2004, PrimeWest contributed \$0.50 per boe of production, totalling \$6.7 million, which includes interest, while approximately \$4.6 million was paid out for active projects completed. The cash balance in the reclamation fund was \$10.3 million at the end of 2004. The 2005 contribution rate remains \$0.50 per boe. Expenditures for environmental matters or site restoration are not reported as part of the development capital. 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 25, 2005. The effective date of the statement is December 31, 2004 and the preparation date of the statement is December 21, 2004.

General

National Instrument 51-101 ("**NI 51-101**") came into force on September 30, 2003 and reflects a dramatic departure from its predecessor National Policy Statement 2B ("**NP 2B**"), attempting to address the perceived shortcomings of NP 2B by improving the standards and quality of Reserve reporting and achieving a higher industry consistency.

Under NI 51-101, "Proved" Reserves are those Reserves that can be estimated with a high degree of certainty to be recoverable (i.e. it is likely that the actual remaining quantities recovered will exceed the estimated Proved Reserves). In accordance with this definition, the

level of certainty targeted by the reporting company should result in at least a 90% probability that the quantities actually recovered will equal or exceed the estimated Proved Reserves. In the case of "Probable" Reserves, which are by definition less certain to be recovered than Proved Reserves, NI 51-101 states that it must be equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved plus Probable Reserves. In order to report Reserves as Proved plus Probable, 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. The implementation of NI 51-101 has resulted in a more rigorous and uniform standardization of reserve evaluation.

Under NI 51-101, companies are required to report Gross Reserves, which include working interest with no adjustment for royalties payable or royalties receivable. Companies must also report and reconcile Net Reserves, which include working interest and royalties receivable, less royalties payable. As required, PrimeWest has reported its Reserves on both a Gross and a Net basis and reconciled its Reserves on a Net Basis. In addition, for continuity and comparative purposes to prior periods, we have also reported and reconciled our Reserves using the old Company Interest definition, which includes working interest and royalties receivable with no deduction of royalties payable. See "Reconciliation of Changes in Reserves and Future Net Revenue".

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. High risk exploration plays, as well as PrimeWest's undeveloped acreage, 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 unitized and non-unitized oil and natural gas production from several major Oil and Natural Gas fields. The following characteristics generally describe the attributes of the properties:

- a) **Reserve Life:** The properties include a mix of long life, lower decline rate Reserves and short life, higher decline Reserves all of which have an average Reserve Life Index (RLI) of approximately 10.3 years based on Company Interest Proved plus Probable Reserves calculated in accordance with NI 51-101;
- b) **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;

- c) **Natural Gas Weighted Portfolio:** For the year ended December 31, 2004 production from the properties is approximately 32% crude oil and natural gas liquids and 68% natural gas, on a barrel-of-oil-equivalent basis. As at December 31, 2004, Proved plus Probable Reserves for the properties are approximately 27% crude oil and natural gas liquids and 73% natural gas on a barrel-of-oil-equivalent basis;
- d) **Diversified Portfolio:** While the properties are diversified from a geographic perspective, they have geological similarities (core platforms), of which PrimeWest generally has the largest working interest in such properties; and
- e) **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, Gilbert Laustsen Jung Associates Ltd. ("GLJ") has prepared the GLJ Report dated January 25, 2005 evaluating, as at December 31, 2004, 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, 2004

Constant Prices and Costs

RESERVES CATEGORY	RESERVES					
	Light And Medium Crude Oil (mdbl)			Heavy Oil (mdbl)		
	Company Interest	Gross	Net	Company Interest	Gross	Net
PROVED						
Developed Producing	16,374	14,801	14,833	2,692	2,680	2,458

RESERVES CATEGORY	RESERVES					
	Light And Medium Crude Oil (mdbl)			Heavy Oil (mdbl)		
	Company Interest	Gross	Net	Company Interest	Gross	Net
Developed Non-Producing	262	262	244	61	61	54
Undeveloped	361	341	282	32	32	28
TOTAL PROVED	16,996	15,404	15,358	2,784	2,773	2,540
PROBABLE	3,606	3,313	3,094	564	562	516
TOTAL PROVED PLUS PROBABLE	20,602	18,717	18,452	3,349	3,335	3,056

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	452.2	442.8	360.0	11,766	11,522	8,304
Developed Non-Producing	38.1	38.0	30.2	1,087	1,087	806
Undeveloped	40.9	40.9	32.0	1,158	1,158	791
TOTAL PROVED	531.2	521.7	422.2	14,011	13,766	9,901
PROBABLE	149.1	147.6	118.0	4,287	4,248	3,003
TOTAL PROVED PLUS PROBABLE	680.3	669.4	540.2	18,298	18,014	12,904

Columns may not add due to rounding

RESERVES CATEGORY	RESERVES		
	Total (mboe)		
	Company Interest	Gross	Net
PROVED			
Developed Producing	106,193	102,800	85,598
Developed Non-Producing	7,756	7,749	6,136
Undeveloped	8,370	8,350	6,437
TOTAL PROVED	122,319	118,899	98,170
PROBABLE	33,305	32,725	26,271
TOTAL PROVED PLUS PROBABLE	155,624	151,624	124,442

Columns may not add due to rounding

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE			
	BEFORE FUTURE INCOME TAX EXPENSES		AFTER FUTURE INCOME TAX EXPENSES	
	DISCOUNTED AT 0%/year (MM\$)	DISCOUNTED AT 10%/year (MM\$)	DISCOUNTED AT 0%/year (MM\$)	DISCOUNTED AT 10%/year (MM\$)
PROVED				
Developed Producing	2,546.9	1,494.5	2,546.9	1,494.5
Developed Non-Producing	179.9	81.9	179.9	81.9
Undeveloped	164.7	72.3	164.7	72.3
TOTAL PROVED	2,891.4	1,648.7	2,891.4	1,648.7
PROBABLE	781.1	290.3	781.1	290.3
TOTAL PROVED PLUS PROBABLE	3,672.6	1,939.0	3,672.6	1,939.0

Columns may not add due to rounding

**Total Future Net Revenue
(Undiscounted)
as of December 31, 2004**

Constant Prices and Costs

Reserves Category	Revenue (MM\$)	Royalties (MM\$)	Operating Costs (MM\$)	Development Costs (MM\$)	Well Abandonment Costs (MM\$)	Future Net Revenue Before Future Income Tax Expenses (MM\$)	Future Income Tax Expenses (MM\$)	Future Net Revenue After Future Income Tax Expenses (MM\$)
Proved Reserves	5,064.6	877.5	1,186.6	72.0	37.1	2,891.4	0	2,891.4
Proved Plus Probable Reserves	6,447.4	1,144.2	1,455.2	135.7	39.7	3,672.6	0	3,672.6

**Future Net Revenue
By Production Group
as of December 31, 2004**

Constant Prices and Costs

Reserves Category	Production Group	Future Net Revenue Before Future Income Tax Expenses (discounted at 10%/year) (MM\$) ⁽³⁾
Proved Reserves	Light and Medium Crude Oil ⁽¹⁾	263.9
	Heavy Oil ⁽¹⁾	29.3
	Natural Gas ⁽²⁾	1,352.3
Proved Plus Probable Reserves	Light and Medium Crude Oil ⁽¹⁾	294.9
	Heavy Oil ⁽¹⁾	34.2
	Natural Gas ⁽²⁾	1,606.3

Notes:

- (1) Including solution gas and other by-products.
- (2) Including by-products but excluding solution gas from oil wells.
- (3) Future Net Revenue values do not represent fair market value.

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, 2004**

Forecast Prices and Costs

RESERVES CATEGORY	RESERVES					
	Light And Medium Crude Oil (mdbl)			Heavy Oil (mdbl)		
	Company Interest	Gross	Net	Company Interest	Gross	Net
PROVED						
Developed Producing	16,272	14,701	14,767	2,780	2,766	2,541
Developed Non-Producing	267	267	249	61	61	54
Undeveloped	354	335	280	32	32	28
TOTAL PROVED	16,893	15,303	15,296	2,872	2,859	2,623
PROBABLE	3,587	3,295	3,098	551	548	503
TOTAL PROVED PLUS PROBABLE	20,480	18,597	18,394	3,423	3,407	3,126

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	450.2	440.8	358.2	11,739	11,494	8,308
Developed Non-Producing	38.1	38.0	30.2	1,089	1,089	808
Undeveloped	40.9	40.9	32.0	1,160	1,160	795
TOTAL PROVED	529.2	519.8	420.4	13,988	13,743	9,911
PROBABLE	148.7	147.3	117.6	4,282	4,243	3,008
TOTAL PROVED PLUS PROBABLE	677.9	667.0	538.0	18,270	17,986	12,919

Columns may not add due to rounding

RESERVES CATEGORY	RESERVES		
	Total (mboe)		
	Company Interest	Gross	Net
PROVED			
Developed Producing	105,825	102,431	85,316
Developed Non-Producing	7,761	7,753	6,143
Undeveloped	8,368	8,349	6,441
TOTAL PROVED	121,954	118,533	97,900
PROBABLE	33,208	32,629	26,207
TOTAL PROVED PLUS PROBABLE	155,162	151,162	124,107

Columns may not add due to rounding

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE									
	BEFORE FUTURE INCOME TAX EXPENSES DISCOUNTED AT (%)					AFTER FUTURE INCOME TAX EXPENSES DISCOUNTED AT (%)				
	0% (MM\$)	5% (MM\$)	10% (MM\$)	15% (MM\$)	20% (MM\$)	0% (MM\$)	5% (MM\$)	10% (MM\$)	15% (MM\$)	20% (MM\$)
PROVED										
Developed Producing	2,263.6	1,655.8	1,331.5	1,129.6	990.8	2,263.6	1,655.8	1,331.5	1,129.6	990.8
Developed Non-Producing	165.2	99.4	71.7	56.6	47.2	165.2	99.4	71.7	56.6	47.2
Undeveloped	137.5	84.1	56.4	40.0	29.2	137.5	84.1	56.4	40.0	29.2
TOTAL PROVED	2,566.2	1,839.3	1,459.6	1,226.1	1,067.2	2,566.2	1,839.3	1,459.6	1,226.1	1,067.2
PROBABLE	731.8	392.1	254.8	184.9	143.3	731.8	392.1	254.8	184.9	143.3
TOTAL PROVED PLUS PROBABLE	3,298.1	2,231.4	1,714.4	1,411.0	1,210.5	3,298.1	2,231.4	1,714.4	1,411.0	1,210.5

Columns may not add due to rounding

**Total Future Net Revenue
(Undiscounted)
as of December 31, 2004**

Forecast Prices and Costs

Reserves Category	Revenue (MM\$)	Royalties (MM\$)	Operating Costs (MM\$)	Development Costs (MM\$)	Well Abandonment Costs (MM\$)	Future Net Revenue Before Future Income Tax Expenses (MM\$)	Future Income Tax Expenses (MM\$)	Future Net Revenue After Future Income Tax Expenses (MM\$)
Proved Reserves	4,890.1	817.7	1,384.1	75.0	47.1	2,566.2	0	2,566.2
Proved Plus Probable Reserves	6,302.5	1,076.7	1,733.0	142.5	52.2	3,298.1	0	3,298.1

**Future Net Revenue
By Production Group
as of December 31, 2004**

Forecast Prices and Costs

Reserves Category	Production Group	Future Net Revenue Before Future Income Tax Expenses (discounted at 10%/year) (MM\$) ⁽³⁾
Proved Reserves	Light and Medium Crude Oil ⁽¹⁾	229.8
	Heavy Oil ⁽¹⁾	42.2
	Natural Gas ⁽²⁾	1,184.4
Proved Plus Probable Reserves	Light and Medium Crude Oil ⁽¹⁾	256.1
	Heavy Oil ⁽¹⁾	48.4
	Natural Gas ⁽²⁾	1,406.3

Notes:

- (1) Including solution gas and other by-products.
(2) Including by-products but excluding solution gas from oil wells.
(3) Future Net Revenue values do not represent fair market value.

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, 2004**

Constant Prices and Costs

	OIL				Natural Gas	EDMONTON LIQUIDS PRICES			Inflation Rates % / year	Exchange Rate \$US / Cdn
	WTI Cushing Oklahoma \$US/bbl	Edmonton Par Price 40° API \$Cdn/ bbl	Hardisty Heavy 12° API \$Cdn/bbl	Cromer Medium 29° API \$Cdn/bbl	AECO Gas Price \$CDN/ mmbtu	Propane \$Cdn./bbl	Butane \$Cdn/bbl	Pentanes Plus \$Cdn/bbl		
Historical (Year End)										
2001	25.97	39.40	23.48	31.56	6.21	31.85	31.17	42.48	2.6	0.6448
2002	26.08	40.33	30.60	35.48	4.04	21.39	27.08	40.73	2.2	0.6376
2003	31.07	43.66	31.18	37.55	6.66	32.14	34.36	44.23	2.8	0.7213
2004 (Year End)	43.45	46.54	24.33	32.12	6.79	29.79	34.44	48.97	0	0.8308
2004 (Average)	41.38	52.96	35.64	45.75	6.88	34.70	39.97	54.07	1.9	0.7734

**Summary of Pricing and Inflation Rate Assumptions
as of December 31, 2004**

Forecast Prices and Costs

Year	OIL				Natural Gas ⁽¹⁾	EDMONTON LIQUIDS PRICES			Inflation Rates % / year	Exchange Rate \$US / Cdn
	WTI Cushing Oklahoma \$US/bbl	Edmonton Par Price 40° API \$Cdn/ bbl	Hardisty Medium 12° API \$Cdn/bbl	Cromer Medium 29° API \$Cdn/bbl	AECO Gas Price \$Cdn/ mmbtu	Propane \$Cdn./bbl	Butane \$Cdn/bbl	Pentanes Plus \$Cdn/bbl		
Forecast										
2005	42.76	50.37	28.60	43.93	6.79	32.11	37.25	51.21	2.17	0.83
2006	40.37	47.46	28.84	41.42	6.52	30.32	34.45	48.28	2.17	0.83
2007	37.36	43.88	27.61	38.32	6.25	28.17	31.95	44.66	2.17	0.83
2008	34.82	40.89	26.20	35.73	5.95	26.34	29.74	41.63	2.17	0.83
2009	33.45	39.20	25.00	34.23	5.79	25.22	28.57	39.93	1.83	0.83
2010	33.21	38.87	24.89	33.92	5.79	24.99	28.26	39.60	1.83	0.83
2011	33.60	39.32	25.23	34.33	5.90	25.34	28.59	40.06	1.83	0.83
2012	34.00	39.81	25.57	34.75	5.96	25.62	28.96	40.58	1.83	0.83
2013	34.56	40.44	25.92	35.33	6.05	25.99	29.38	41.21	1.83	0.83
2014	35.13	41.15	26.55	35.99	6.15	26.44	29.97	41.93	1.83	0.83
2015	35.71	41.78	26.99	36.62	6.27	26.93	30.39	42.56	1.83	0.83
2016	36.40	42.56	27.49	37.22	6.41	27.46	30.93	43.35	1.83	0.83
2017	37.09	43.31	28.08	37.92	6.51	27.87	31.52	44.14	1.83	0.83
2018	37.79	44.07	28.58	38.53	6.66	28.40	32.07	44.90	1.83	0.83
Thereafter	1.17%	1.17%	1.17%	1.17%	1.17%	1.17%	1.17%	1.17%	1.17%	0.83

Weighted Average Realized Sales Prices

(\$Cdn)	2004
Natural Gas (\$/mcf)	6.70
Crude Oil (\$/bbl)	44.46
Natural Gas Liquids (\$/bbl)	43.69

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).

Year	Constant Prices and Costs		Forecast Prices and Costs	
	Proved (\$MM)	Proved plus Probable (\$MM)	Proved (\$MM)	Proved plus Probable (\$MM)
2005	26.5	48.2	26.5	48.3
2006	21.3	38.4	21.7	39.3
2007	7.2	12.3	7.5	12.9
2008	4.5	9.4	4.8	10.0
2009	2.1	2.4	2.3	2.6
Total: Undiscounted	72.0	135.7	75.0	142.5
Total: Discounted at 10%/year	59.2	108.7	60.9	112.4

Columns may not add due to rounding

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 \$75.0 million would be incurred for the Proved Reserves and \$142.5 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 quantity and 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, 2004 using Forecast Price and Cost estimates derived from the GLJ Report as required under NI 51-101 guidelines and format, reconciled to December 31, 2003. Net Reserves include working interest Reserves plus royalties receivable less royalties payable, as stipulated by NI 51-101. See initial discussion above under "Statement of Reserves Data and Other Oil and Gas Information - General".

	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
December 31, 2003	14,284	14,829	2,504	17,333	2,856	2,959	435	3,394
Extensions	460	482	427	909	0	0	0	0
Improved								
Recovery	312	286	17	303	4	4	1	5
Technical								
Revisions	126	5	69	74	(40)	(1)	(14)	(15)
Discoveries	82	82	28	110	0	0	0	0
Acquisitions	2,415	2,602	458	3,060	297	352	74	426
Dispositions	(1,331)	(1,417)	(454)	(1,871)	(454)	(570)	(136)	(706)
Economic								
Factors ⁽¹⁾	268	276	49	325	762	763	143	906
Production	(1,849)	(1,849)	0	(1,849)	(884)	(884)	0	(884)
December 31, 2004	14,767	15,296	3,098	18,394	2,541	2,623	503	3,126

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	Proved	Probable	Proved Plus Probable
December 31, 2003	240.7	269.9	70.1	339.9	5,570	6,381	2,051	8,433
Extensions	7.3	14.9	4.1	19.1	174	205	40	245
Improved								
Recovery	9.5	10.6	5.3	15.9	278	320	214	534
Technical								
Revisions	(0.8)	1.8	(6.1)	(4.4)	(305)	(189)	(259)	(448)

	Associated and Non-Associated Gas (Natural Gas) (bcf)				Natural Gas Liquids (mbbls)			
	Proved Producing	Total Proved	Probable	Proved Plus Probable	Proved Producing	Proved	Probable	Proved Plus Probable
Discoveries	0.9	1.2	0.4	1.6	3	6	2	8
Acquisitions	154.5	179.0	46.6	225.6	3,405	4,021	980	5,001
Dispositions	(9.3)	(12.1)	(2.9)	(15.0)	(37)	(46)	(23)	(69)
Economic Factors								
(1)	(2.4)	(2.6)	0.1	(2.4)	20	13	2	15
Production	(42.2)	(42.2)	0.0	(42.2)	(800)	(800)	0	(800)
December 31, 2004	358.2	420.4	117.6	538.0	8,308	9,911	3,008	12,919

Columns may not add due to rounding

	Total (mmboe)			
	Proved Producing	Proved	Probable	Proved Plus Probable
December 31, 2003	62.8	69.1	16.7	85.8
Extensions	1.9	3.2	1.2	4.3
Improved				
Recovery	2.2	2.4	1.1	3.5
Technical				
Revisions	(0.4)	0.1	(1.2)	(1.1) (2)
Discoveries	0.2	0.3	0.1	0.4
Acquisitions	31.9	36.8	9.3	46.1
Dispositions	(3.4)	(4.1)	(1.1)	(5.2)
Economic				
Factors (1)	0.6	0.6	0.2	0.8
Production	(10.6)	(10.6)	0.0	(10.6)
December 31, 2004	85.3	97.9	26.2	124.1

Columns may not add due to rounding

Notes:

- (1) Economic Factors relate to Reserves that have been shut-in due to the EUB Gas-over-Bitumen issue. Due to the uncertainty of the future production, these Reserves have been removed from the corporate total.
- (2) Approximately 0.8 mmboe of this amount is attributable to the cessation of liquids stripping, resulting in a higher heat content gas stream.

The following table sets forth a reconciliation of the Company Interest Reserves of PrimeWest for the year ended December 31, 2004 derived from the GLJ report using Forecast Price and Cost estimates, and reconciled to December 31, 2003. 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 prior years. See initial discussion above under "Statement of Reserves Data and Other Oil and Gas Information - General".

	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
December 31, 2003	18,854.0	19,554.6	3,324.4	22,879.0	304.9	343.2	89.0	432.2
Capital additions	680.3	704.9	545.4	1,250.3	10.5	19.8	5.6	25.4
Improved Recovery	356.1	329.1	20.1	349.2	11.9	13.2	6.7	19.9
Technical								
Revisions	1,233.5	1,193.9	107.1	1,301.0	(6.3)	(3.2)	(7.7)	(10.9)
Acquisitions	3,033.7	3,306.1	600.4	3,906.5	194.2	224.7	58.7	283.4
Dispositions	(2,074.3)	(2,292.3)	(459.4)	(2,751.7)	(6.6)	(10.1)	(3.1)	(13.2)
Economic								
Factors (1)	0	0	0	0	(5.0)	(5.1)	(0.3)	(5.4)
Production	(3031.3)	(3031.3)	0	(3031.3)	(53.4)	(53.4)	0	(53.4)
December 31, 2004	19,052.0	19,765.0	4,138.0	23,903.0	450.2	529.2	148.7	677.9

	Natural Gas Liquids (mbbls)				Barrel of oil equivalent (mmboe)			
	Proved Producing	Total Proved	Probable	Proved Plus Probable	Proved Producing	Total Proved	Probable	Proved Plus Probable
December 31, 2003	7,798.0	8,975.1	2,887.7	11,862.8	77.5	85.7	21.1	106.8
Capital additions	259.1	294.0	61.3	355.3	2.7	4.3	1.5	5.8
Improved Recovery	398.3	458.6	311.1	769.7	2.7	3.0	1.4	4.4
Technical								
Revisions	(365.4)	(243.5)	(349.0)	(592.5)	(0.2)	0.4	(1.5)	(1.1) ⁽²⁾
Acquisitions	4,838.6	5,706.4	1,406.0	7,112.4	40.3	46.5	11.8	58.3
Dispositions	(52.3)	(65.3)	(35.1)	(100.4)	(3.2)	(4.0)	(1.1)	(5.1)
Economic								
Factors ⁽¹⁾	0	0	0	0	(0.8)	(0.9)	0	(0.9)
Production	(1,137.3)	(1,137.3)	0	(1,137.3)	(13.1)	(13.1)	0	(13.1)
December 31, 2004	11,739.0	13,988.0	4,282.0	18,270.0	105.8	121.9	33.3	155.2

Columns may not add due to rounding

Notes:

- (1) Economic Factors relate to Reserves that have been shut-in due to the EUB Gas-over-Bitumen issue. Due to the uncertainty of the future production, these Reserves have been removed from the corporate total.
- (2) Approximately 0.8 mmboe of this amount is attributable to the cessation of liquids stripping, resulting in a higher heat content gas stream.

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, 2004, 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%

Net Proved Reserves Constant Prices and Costs

Period and Factor	Before Tax 2004 (MM\$)
Estimated Net Present Value at December 31, 2003	993.1
Oil and Gas Sales During the Period Net of Production Costs and Royalties ⁽¹⁾	(312.2)
Changes due to Prices, Production Costs and Royalties Related to Forecast Production ⁽²⁾	144.4
Development Costs During the Period ⁽³⁾	115.0
Changes In Forecast Development Costs⁽⁴⁾	(93.1)
Changes Resulting from Extensions and Improved Recovery ⁽⁵⁾	101.1
Changes Resulting from Discoveries ⁽⁵⁾	5.7
Changes Resulting from Acquisitions of Reserves ⁽⁵⁾	630.4

Period and Factor	Before Tax 2004 (MM\$)
Changes Resulting from Dispositions of Reserves ⁽⁵⁾	(54.4)
Changes Resulting from Technical Reserves Revisions	4.3
Accretion of Discount ⁽⁶⁾	99.3
Net Change in Income Taxes ⁽⁷⁾	-
All Other Changes	15.2
Estimated Net Present Value at End of Period Dec. 31, 2004	1,648.7

Notes:

(1) Company actual before income taxes, excluding G&A.

(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 ("PUD") Reserves of 6,441 mboe as of December 31, 2004, consisting of 280 mbbls oil, 28 mbbls heavy oil, 32 bcf natural gas and 795 mbbls natural gas liquids. Net Probable Undeveloped Reserves were 332 mboe, consisting of 75 mbbls oil, 9 mbbls heavy oil, 1.2 bcf natural gas and 49 mbbls natural gas liquids. PrimeWest invests capital into development work, which moves its PUD Reserves and Probable Undeveloped Reserves into the Proved Developed Producing category. In 2004, \$125.1 million was spent on capital development, and \$125 million has been budgeted for development capital in 2005. Allocating capital to properties and timing of development is based on economics and performance of the asset. PrimeWest's focus for 2005 development will be in the core areas of Caroline, Columbia/Harlech, Wilson Creek, Brant/Farrow, Valhalla, Princess/Hays and Crossfield/Lone Pine Creek.

Of PrimeWest's Net PUD Reserves, 18% are located in Caroline, a primary area in which PrimeWest plans to spend development capital (for specific details on the capital budgets, plans and timing for 2005 development in this area, see "Other Oil and Gas Information"). Other areas with notable Net PUD Reserves include Shallow Gas (20%), Wilson Creek (20%), Columbia (16%) and Crossfield/Lone Pine Creek (12%). PrimeWest's areas with notable total Net Probable Undeveloped Reserves are in Caroline (21%), Thorsby (7%), Wilson Creek (7%) and Crossfield/Lone Pine Creek (17%).

For other properties which have PUD 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 PUD and Probable Undeveloped Reserves to Proved Developed Producing Reserves. In instances where land rights are expected to expire within 1 year, PrimeWest may engage in farm-out arrangements, which would eliminate the potential expiry and possibly result in some PUD and Probable Undeveloped Reserves becoming Proved Developed Producing Reserves.

Other Oil and Natural Gas Information

The discussion below addresses the general attributes of PrimeWest's important properties, plants, facilities and installations by location, disclosing properties to which Reserves are attributed and which are capable of producing but which are not, how long they have been in that condition and their proximity to transportation. Given the significance of the Calpine Acquisition described above under "General Development of the Business", for ease of reference the disclosure has been segregated between PrimeWest's properties prior to the Calpine Acquisition and the properties acquired pursuant to the Calpine Acquisition.

Calpine Acquisition

The following is a description of the principal oil and natural gas properties acquired by PrimeWest pursuant to the Calpine Acquisition. The Calpine assets are located in Canada with all the material properties located in Alberta.

North Alberta

Edson

The Edson area is located in northwest Alberta approximately 200 kilometres west of Edmonton with production from the Bluesky, Gething and Cardium formations. The Edson area comprises 35,040 Gross acres (22,638 Net acres) of land with an average 64% working interest. The average daily production for the period September to December 2004 (from the time of completion of the Calpine acquisition) from the Edson area was 658 boe/day. Current production in Edson of 770 boe/day is processed through third party facilities.

Cecil Charlie Lake

The Calpine Acquisition included the Cecil Charlie Lake Oil property, which forms part of PrimeWest's Boundary Lake group of properties. The pool has been aggressively developed with PrimeWest participating in four wells and construction of a central oil battery subsequent to acquiring the property. PrimeWest holds an average 36% working interest and is in preliminary discussions with partners on implementing secondary recovery.

North - Other

The Calpine Acquisition included a Notikewin gas pool located in Woodrush, B.C., which forms part of PrimeWest's North-Other group of properties.

Central Alberta

Columbia Area (includes Columbia/Minehead/Harlech/Brazeau)

The Columbia area is located in west-central Alberta approximately 175 kilometres southwest of Edmonton with production from primarily low permeability Viking and Cardium sands. The Columbia area comprises 85,600 Gross acres (49,240 Net acres) of land with an average 64% working interest. The average daily production for the period September to December 2004 from the Columbia area was 6.6 mmcf/day of natural gas and 314 bbls/day of oil and natural gas liquids for a total average daily production for 2004 of 1,409 boe/day. For 2005 PrimeWest has budgeted \$20 million to drill up to nine wells and acquire additional seismic and land. Production is expected to commence at Harlech in early 2005.

Ferrier

The Ferrier area is located in West-Central Alberta approximately 200 kilometres southwest of Edmonton with production from the Cardium formation. The Ferrier area comprises 60,320 Gross acres (33,740 Net acres) of land with an average 52% working interest. The average daily production during the period September to December 2004 was 5.0 mmcf/day of natural gas and 198.4 bbls/day of oil and natural gas liquids for a total average for the fourth quarter of 2004 of 1,030 boe/day. Production at Ferrier is processed through a third party facility.

Wilson Creek and Gilby

The Wilson Creek and Gilby areas are located adjacent to each other in west-central Alberta approximately 200 kilometres northwest of Calgary with production from a number of zones, including the Belly River, Viking, Glauconitic and Pekisko formations. The areas comprise an aggregate of 41,478 Gross acres (26,942 Net acres) of land with an average 57% working interest at Wilson Creek and an average working interest of 77% at Gilby. The average production for the period September to December 2004 was 19.6 mmcf/day of natural gas and 896 bbls/day of oil and natural gas liquids for a total average for 2004 of 4,169 boe/day. Production in the Wilson Creek, Willesden Green, Modeste and Gilby areas is processed through a third party facility and the Wilson Creek unit facility. In 2005 a budget of \$17 million has been allocated to drill up to 13 wells and acquire 3D seismic and land. It is also anticipated that PrimeWest will participate in approximately 12 partner-operated wells in these properties.

South Alberta

Princess

The Princess area is located in east-central Alberta approximately 175 kilometres southeast of Calgary, adjacent to PrimeWest's Dinosaur property and properties acquired when PrimeWest purchased Seventh Energy Ltd. in the first quarter of 2004. Production is obtained from the Milk River, Medicine Hat and Second White Specs zones. The Princess area comprises 13,191 Gross acres (6,933 Net acres) of land with an average 54% working interest. The average daily production for the period September to December 2004 was 2.4 mmcf/day of natural gas. Current production in Princess of 2.3 mmcf/day is processed through owned and operated facilities. A successful 25 well drilling program was completed in the fourth quarter of 2004.

Bindloss

The Bindloss area is located in eastern Alberta approximately 230 kilometres east of Calgary, with the majority of current production coming from Viking sands in Bindloss Unit No. 1 and with potential natural gas production from the Milk River, Medicine Hat and Second White Specs zones. The Bindloss area comprises 91,920 Gross acres (78,370 Net acres) of land with an average 86% working interest. The average daily production for the period September to December 2004 was 4.3 mmcf/day of natural gas. Current production in Bindloss of 4.6 mmcf/day is processed through owned and operated facilities. The 2005 budget contains plans for a potential downspacing program at Bindloss.

Irricana

The Irricana area is located in central Alberta approximately 50 kilometres northeast of Calgary and adjacent to PrimeWest's Crossfield/Lone Pine Creek area with production from the Pekisko, Wabamun and Mannville formations. The Irricana area comprises 37,055 Gross acres (20,369 Net acres) of land with an average 76% working interest. The average daily production during the period September to December 2004 from the Irricana area was 11.1 mmcf/day of natural gas and 186 bbls/day of oil and natural gas liquids for a total average daily production for the period of 2,041 boe/day. Current production in Irricana of 2,063 boe/day is processed through the East Crossfield gas processing facility and third party gas processing facilities.

The Calpine acquisition resulted in an increase in PrimeWest's interest in the East Crossfield facility from 28.8% to 55.5%.

PrimeWest Properties - (Excluding those acquired pursuant to the Calpine Acquisition)

The following is a description of the principal oil and natural gas properties of PrimeWest excluding those acquired pursuant to the Calpine Acquisition. The PrimeWest assets are located in Canada with all the material properties located in Alberta.

*North**Boundary Lake*

Boundary Lake, discovered in 1955, is located on the B.C.-Alberta border about 40km northeast of Fort St. John, B.C. PrimeWest operates and has 100% working interest in Boundary Lake Project No. 1 North and South and Project No. 2, plus smaller adjoining working interests in several wells and a production unit. Excluding the Projects, PrimeWest has an average working interest of 92%. Infrastructure consists of two oil batteries including solution gas compression. For the year ended December 31, 2004, PrimeWest produced an average of 1,008 boe/day, primarily light oil (33 degree API) from the Boundary Lake Member of the Charlie Lake Formation.

Boundary Lake, an area that affords year-round access, has been a key development property for PrimeWest. After shooting 3-D seismic in early 2001, PrimeWest drilled 10 wells, which doubled production in that same year. Since 2001, PrimeWest has reviewed seismic specific to the western extent of the pool to assess trapped oil in the area, and during 2004 continued development work on managing a waterflood. In 2004, PrimeWest also consolidated from three to two oil batteries, added solution gas conservation, converted two additional wells to water injection and drilled four wells on the western edge of the pool. Future work in Boundary Lake will focus on additional drilling and waterflood optimization.

Laprise

Laprise is a natural gas asset that during 2004 produced an average of 1,710 boe/day of marginally sour natural gas from the Baldonnel Formation. This winter-access area lies about 160 km northwest of Fort St. John, B.C. 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 B.C.'s larger natural gas pools. PrimeWest also has 100% interest in one producing non-unit gas well. Facilities consist of two natural gas compressors with a separator and a dehydrator. In 2004, three new wells were tied-in and major overhauls of the booster and sales gas compressors were carried out. In 2005, PrimeWest will complete an infrastructure-modeling project and has budgeted \$7.3 million to drill five wells and add additional field compression.

Valhalla

This major natural gas asset, acquired in early 2003 as part of the Caroline/Peace River Arch acquisition, produces predominantly sour natural gas from the Montney formation. Uphole Baldonnel gas, Doig oil and Gething gas adds to PrimeWest's production base. PrimeWest's working interest averages 82%, and production averaged 1,763 boe/day during 2004. PrimeWest has 100% ownership in a natural gas processing facility, which consists of two sour gas compressors and one sweet gas compressor. In 2004, the gas plant was upgraded using biological desulphurisation technology, which is currently in the commissioning phase. Capital expenditures in 2004 totalled \$11.8 million and included the drilling of four wells, and significant facilities work. Due to the high netback gas and multizone development, PrimeWest sees significant upside opportunities at Valhalla. A \$10.2 million capital program has been budgeted for 2005, the majority of which will be used for drilling 6 wells with associated infrastructure and facilities.

Stowe

PrimeWest holds an average 87% working interest at Stowe, which includes lands in the Hotchkiss, Naylor and Sutton areas, grouped about 120 km northwest of Peace River, in the north-western corner of Alberta. The fields produce natural gas from numerous shallow to medium-depth horizons, including the Bluesky and Mississippian formations.

Production at Stowe averaged approximately 1,302 boe/day during 2004. Field facilities at this winter-access area include a refrigeration site with 2 compressors, an oil battery and 1 additional field compressor. Maintenance capital expenditures have been budgeted for 2005 in this area offering high netback gas.

North - Other

During 2004, production from other North properties not discussed above totalled approximately 5,900 boe/day. Included in these areas are non-operated interests in the long-life units at Rycroft, Spirit River and Progress, which in 2004 produced a combined average 527 boe/day of oil and natural gas from the Halfway, Charlie Lake and Doe Creek formations respectively. PrimeWest's average working interest in these three properties is 35%. Production is processed by third parties and PrimeWest does not operate any infrastructure in the fields. For 2005, PrimeWest has budgeted \$0.9 million to upgrade non-operated unit facilities and drill 4 new wells within the Spirit River and Rycroft oil units. Numerous other properties make up the balance of the North Group, the most significant of which are Seal, a Mississippian and Cretaceous gas area; and Kaybob South, where PrimeWest operates Triassic Unit No. 1 (42.5% working interest) and Triassic Unit No. 2 (20.1% working interest).

*Central**Caroline*

Significant acquisitions, infrastructure modifications, and drilling at Caroline, approximately 98 km northwest of Calgary, Alberta, have strengthened PrimeWest's position in this core property and resulted in operating cost reductions and development potential. This liquids rich gas-prospective area is now one of PrimeWest's most important properties, in terms of both its current production and its growth potential. It offers multizone gas drilling prospects, with current production from the Cardium, Viking, Elkton and Mannville formations.

In late 2002 and early 2003, PrimeWest completed two acquisitions for a combined purchase price of \$264.7 million. The transactions increased PrimeWest's Reserves and production at Caroline, and gave PrimeWest control of key infrastructure. This included 100% ownership of the Sundre natural gas processing plant, with inlet capacity of 30 mmcf/day.

At year-end 2004, following the acquisitions completed during the year, PrimeWest's average working interest in area wells, facilities and lands was approximately 80%. Operating costs per unit of production have been reduced by approximately 50% since late 2002. Average production for 2004 totalled approximately 5,529 boe/day, primarily natural gas. This represents an increase of 9.5% from year-end 2003. In addition, PrimeWest derived further revenues through gas processing for third parties.

Caroline is a core asset for PrimeWest offering upside potential for incremental production and Reserves through low-risk development drilling and acquisitions. Capital expenditures are budgeted at \$27 million for 2005 and will include 9 to 12 new development wells, recompletions, infrastructure expansion, and the acquisition of additional lands and seismic to lay the foundation for future growth of the property.

Thorsby

PrimeWest has a high working interest in Thorsby, located about 30 km southwest of Edmonton. Production averaged 3,365 boe/day for 2004 and consisted of a mix of natural gas and crude oil primarily from the Ellerslie and Glauconitic sandstones. Infrastructure in Thorsby includes two 100% owned gas plants and an extensive gathering system.

For 2005, PrimeWest has budgeted \$2.4 million in capital investments in this area for infrastructure and well optimization projects. In addition, \$1 million will be utilized to investigate the potential for coalbed methane on the Thorsby lands. The opportunity to consolidate processing with other operators in the area to reduce operating costs is also being pursued.

South

Crossfield/Lone Pine Creek

The Crossfield/Lone Pine Creek area produces both natural gas and light to medium crude oil and is located approximately 30 km northwest of Calgary. Production net to PrimeWest averaged 1,927 boe/day in 2004, from the Wabamun (Crossfield), Leduc, and Nisku formations.

Central to PrimeWest's success at Crossfield/Lone Pine Creek is the operatorship of the East Crossfield gas processing facility. PrimeWest became plant operator in January 2000 with a 28.8% interest in the facility. After the Calpine Acquisition in September 2004, PrimeWest's interest in the East Crossfield gas processing facility increased to 55.5%.

Gaining operatorship of this 142 mmcf/day plant enabled PrimeWest to implement efficiency measures and modernization, significantly reducing unit operating costs, improving operating netbacks, generating third-party processing fees and extending the plant's economic life by at least 10 years. PrimeWest has a very small interest in the plant's sulphur block.

For 2005, PrimeWest has budgeted \$8.1 million of capital for Crossfield/Lone Pine Creek, including potential development in a Nisku waterflood.

Brant/Farrow

Located about 65 km southeast of Calgary, Brant Farrow is PrimeWest's most active shallow gas property. PrimeWest has an average 63% working interest over lands in the Brant, Farrow, Mossleigh and Herronton fields. This area comprises 183,505 Gross acres (114,787 Net acres) of land. Through capital development, PrimeWest has delivered a constant production profile from the property.

PrimeWest has had success shifting focus from deep, high-decline wells to drilling a larger number of lower-productivity/lower-decline wells in the shallow Belly River and Medicine Hat formations. PrimeWest is also reviewing additional deeper gas/oil potential in the Mississippian, Basal Quartz and Glauconite formations. Major infrastructure at Brant Farrow includes 65% ownership of two processing plants with a combined capacity of 15 mmcf/day.

Capital investment in 2004 totalled \$14 million and included 12 new operated wells. During 2004, production at Brant/Farrow averaged approximately 1,779 boe/day; comprised mainly of sweet, dry natural gas. Exploiting its extensive undeveloped lands and the low exploration risk, PrimeWest has budgeted \$8.5 million for 2005, which will fund drilling of 14 new gas and oil wells to follow up on the success of 2004.

Dinosaur/Medicine Hat

The Dinosaur and Medicine Hat properties are shallow gas plays in eastern Alberta with low operating costs, stable production and a long Reserve Life Index. At Dinosaur, about 177 km east of Calgary, PrimeWest owns a 51% operated interest in the Patricia Gas Unit No. 1 and the Dinosaur Gas Unit No. 1. At Medicine Hat, 40 km northeast of the city of the same name, PrimeWest is a 50% working interest owner and operator of the Medicine Hat Consolidated Unit No. 2. Production from the Dinosaur/Medicine Hat properties during 2004 averaged 679 boe/day of sweet dry natural gas. Field infrastructure at the three units includes compression and gas processing facilities. Capital for downspacing in the Dinosaur area is included in the 2005 budget.

Grand Forks Area (includes Hays, Taber, Alderson)

During 2004, production at Grand Forks averaged 2,446 boe/day of crude oil (approximately 25 degrees API), primarily from the Sawtooth and Arcs formations. This property, 70 km west of Medicine Hat, is PrimeWest's fourth largest producer. PrimeWest has 37,036 Gross Acres (23,031 Net Acres) of land with an average 62% working interest in this property and operates most of the property. Grand Forks has been one of PrimeWest's most successful acquisition areas on a rate of return basis. Through its drilling program and sound reservoir management, PrimeWest has held the property's net asset value relatively constant for the past five years. PrimeWest's strategy going forward is continued cost-containment to maximize the economic life of Grand Forks.

Capital spending for 2005 is limited to some potential pool delineation in the Arcs and operating cost savings initiatives.

Jumping Pound West/Whiskey Creek

PrimeWest has a 14.6% working interest in the non-operated, low decline Jumping Pound Unit No. 2, located approximately 50 km west of Calgary. Production from the unitized zone in the Rundle Formation commenced in 1972 and in 2004 averaged 395 boe/day of natural gas and natural gas liquids from 12 producing wells. Production is processed at the adjacent Jumping Pound Unit No. 1 plant facilities on a custom-processing-fee basis.

At the newer Whiskey Creek property, PrimeWest's average working interest is approximately 36%. The Whiskey Creek property comprises 1,120 Gross Acres (400 Net Acres) of land. However, PrimeWest's natural gas production is currently shut-in at Whiskey Creek as a result of the operator increasing the amount of production that other producers direct to the production facility, which displaced PrimeWest's production volumes. With no alternate facilities in the area, a portion of PrimeWest's production will remain behind-pipe until the operator permits additional capacity at the facility, which is expected to occur near the middle of 2005.

Gross Overriding Royalty (GORR) Interests

These interests entitle PrimeWest to a share of the gross sales price 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 risks to the Unitholders.

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 in 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, 2004, PrimeWest's interests in Producing and non-Producing wells, including those acquired pursuant to the Calpine Acquisition.

	Producing Wells				Non-Producing Wells			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	1,665	530	2,178	1,148	1,362	871	1,536	1,049
British Columbia	226	11	44	30	47	42	18	12
Saskatchewan	850	41	420	40	604	87	0	0
Total	<u>2,741</u>	<u>582</u>	<u>2,642</u>	<u>1,218</u>	<u>2,013</u>	<u>1,000</u>	<u>1,554</u>	<u>1,062</u>

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, absent further action, expire within one year.

Area	Gross Acres	Net Acres	Net Acres Expiring Within One Year
North			
Boundary Lake	8,465	3,611	652
Laprise	6,647	4,565	0
Valhalla	12,960	8,478	2,560
Stowe	122,880	106,734	42,080
Thunder	32,320	15,195	1,386
North Other	541,088	230,395	89,095
Central			
Caroline	120,934	102,877	20,868
Columbia	16,448	10,754	1,280
Thorsby/Modeste	81,699	57,481	13,352
Wilson Creek/Willesden Green/Gilby	66,545	42,541	14,814
Brazeau/Minehead/Harlech	42,880	24,037	12,405
Ferrier	32,320	21,232	11,765

Area	Gross Acres	Net Acres	Net Acres Expiring Within One Year
Red Deer	39,567	37,080	17,927
Central Other	76,659	57,216	19,916
South			
Crossfield/Lone Pine Creek	12,490	7,576	1,678
Irricana	37,784	29,248	16,076
Jumping Pound/Whiskey Creek	4,800	399	0
Grand Forks	43,676	25,461	5,354
Brant Farrow	101,240	77,854	23,045
Princess/Bindloss/Dinosaur/Medicine Hat	14,721	10,805	3,968
Saskatchewan	12,662	5,144	1,443
South Other	42,380	42,202	9,119
Non-Core			
Kaybob	4,320	1,308	0
Meekwap	3,520	1,513	0
Seal	3,520	2,560	0
Other	23,746	17,399	4,961
GORR	146,444		0
<i>Total:</i>	1,652,715	943,665	313,744

Additional Information Concerning Abandonment and Reclamation Costs

The following table discloses the abandonment and reclamation costs PrimeWest anticipated incurring as at December 31, 2004, 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 44 Net wells during 2005. PrimeWest currently has approximately 600 reclamation projects underway, in varying stages of completion. Due to weather conditions, project unknowns, landowner issues, and changing regulations, it is technically impossible to determine the number of reclamation projects that will be completed in a given year with any level of accuracy.

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. Funding is provided out of cash flow into a segregated cash account. The funding level is reviewed and approved by the Board of Directors annually based on estimated future liabilities and the applicable spending profile. In 2004, PrimeWest contributed \$0.50/boe of production, totalling \$6.7 million, which includes interest, into this fund. As of December 31, 2004, there was an unused cash balance of \$10.3 million in the fund.

The 2005 contribution rate for the environmental fund has been set at \$0.50/boe.

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, 2004	238,601	16,525
Anticipated to be paid in 2005	6,213	5,648
Anticipated to be paid in 2006	5,755	4,756
Anticipated to be paid in 2007	5,555	4,173

Tax Horizon

As a result of PrimeWest's tax efficient structure, annual taxable income is transferred from its operating entities 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 subsidiaries. Therefore, PrimeWest should not incur any income tax liability for as long as the organization maintains this corporate tax structure.

Costs Incurred

The following table discloses Property Acquisition Costs, Exploration Costs and Development Costs for PrimeWest for the year ended December 31, 2004.

	Property Acquisition Costs			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
Total (\$M)	755.3	52.1	8.2	116.9

Exploration and Development Activities

The following table discloses the number of Exploratory Wells and Development Wells, both Gross and Net, completed by PrimeWest for the year ended December 31, 2004 and which of those were completed as oil wells, natural gas wells, Service Wells and dry holes.

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
North Area				
Oil	-	-	14	7.5
Natural Gas	-	-	19	6.2
Service Wells	-	-	2	2
Dry Holes	2.0	1.5	5	4.1
Total	2.0	1.5	40	19.8
Central Area				
Oil	-	-	1	0.2
Natural Gas	-	-	18	13.7
Service Wells	-	-	0	0
Dry Holes	-	-	0	0
Total	-	-	19	13.9
South Area				
Oil	-	-	11	10

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Natural Gas	-	-	78	40
Service Wells	-	-	0	0
Dry Holes	-	-	3	3
Total	-	-	92	53

PrimeWest does not actively pursue high-risk exploration and therefore only drilled 2 (1.5 Net) Exploratory Wells in 2004. PrimeWest engages in development drilling along with acquisitions to offset natural production decline and add to Reserves. Specific details on development plans and 2005 capital budgets for each of PrimeWest's important properties are described under "Other Oil and Gas Information".

Estimated Production

The following table discloses for each product type the total volume of Proved plus Probable production estimated by GLJ for 2005 using Forecast Prices and Costs. At December 31, 2004, PrimeWest estimates its 2005 production will average approximately 41,000 boe/day.

	Light and Medium Crude Oil (mdbl)	Heavy Oil (mdbl)	Natural Gas (mmcf)	Natural Gas Liquids (mdbl)
2005 Estimated Total Production	2,163	597	69,776	1,764

Production History

The following table discloses, on a quarterly basis for the year ended December 31, 2004, 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.

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	7,864	\$ 39.44	\$ 6.75	\$ 6.92	\$ 21.26
2 nd Quarter	7,699	43.14	7.77	6.89	21.11
3 rd Quarter	8,447	48.58	7.67	6.56	25.72
4 th Quarter	9,108	46.03	8.45	6.95	21.05
Natural Gas (mcf/day)					
1 st Quarter	123,851	\$ 6.62	\$ 1.45	\$ 1.15	\$ 4.02
2 nd Quarter	125,501	6.82	1.56	1.15	3.93

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⁾
3 rd Quarter	143,503	6.31	1.50	1.09	3.63
4 th Quarter	187,207	6.98	1.69	1.16	4.46
Natural Gas Liquids (bbls/day)					
1 st Quarter	2,696	\$ 38.54	\$ 8.84	\$ 6.92	\$ 22.77
2 nd Quarter	2,569	41.36	10.58	6.89	23.89
3 rd Quarter	3,096	45.30	11.00	6.56	27.74
4 th Quarter	4,059	47.32	15.21	6.73	25.43

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 basis.

The following table discloses for each of PrimeWest's important fields, non-core fields, and in total, the production volumes for each product type for the year ended December 31, 2004.

Field	Light, Medium & Heavy Crude Oil (mbbls)	Natural Gas (mmcf)	Natural Gas Liquids (mbbls)	Average Daily Production (boe/d)
NORTH	1,187	17,680	202	11,847
Laprise	10	3,244	75	1,710
Dawson	255	1,934	2	1,582
Edson	2	863	23	460
Boundary Lake	415	609	7	1,430
Valhalla	21	2,943	36	1,496
Other Arch	122	2,070	26	1,347
North Non-core Other	363	6,019	33	3,823
CENTRAL	359	18,579	721	11,409
Caroline	130	9,178	379	5,569
Ferrier	4	609	20	344
Columbia/Minehead/Harlech	6	802	32	470
Thorsby	146	5,470	208	3,456
Wilson Creek/Willesden				
Green/Modeste/Gilby	73	2,491	82	1,558
Central Non-Core Other	-	29	-	13
SOUTH	1,297	14,808	174	10,763
Brant/Farrow	36	3,684	5	1,790
Crossfield/LPC /Irricana	57	4,807	90	2,590

Field	Light, Medium & Heavy Crude Oil (mbbls)	Natural Gas (mmcf)	Natural Gas Liquids (mbbls)	Average Daily Production (boe/d)
Grand Forks	796	435	24	2,438
Jumping Pd & Whiskey Creek	-	796	31	447
Princess/Bindloss/Dinosaur/Medicine Hat	16	4,601	23	2,201
South Non-core Other	393	486	1	1,298
GORRS	184	1,827	38	1,440
MISC	4	222	3	119
TOTAL CONSOLIDATED	3,031	53,116	1,137	35,578

Production from PrimeWest's non-operated Ells property in Northeast Alberta (included in the "North Non-Core Other" row of the foregoing table) was shut-in by the Alberta Energy and Utilities Board effective July 1, 2004 as a result of the gas-over-bitumen issue. The gas-over-bitumen issue refers to the announcement on June 3, 2003 by the Alberta Energy and Utilities Board ("EUB") proposing a change in policy respecting gas production from the Wabiskaw and McMurray formations in the Athabasca oil sands area of northeast Alberta. The process outlined by the EUB resulted in the shut-in of production of 328 boe/day.

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 of royalties paid by PrimeWest to the Province of Alberta.

An additional shut-in of 300 boe/day at PrimeWest's non-operated Whiskey Creek area is a result of the operator increasing the amount of production that other producers direct to the production facility, which displaced PrimeWest's production volumes. With no alternate facilities in the area, PrimeWest's production will remain behind-pipe until the operator permits additional capacity at the facility, which is expected to occur in mid-2005.

PrimeWest's estimates for 2005 production volumes take into account 1,929 boe/day on a company-wide basis that was behind pipe at December 31, 2004.

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 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 licence from the NEB and the granting of such a licence 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, distance 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 licence from the NEB and the granting of such a licence requires the approval of the Governor in Council.

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 and Incentives

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.

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.

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 Middle East;
- global and domestic economic conditions;
- weather conditions;
- 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 proximity of Reserves to, and capacity of, transportation facilities;
- the effect of worldwide energy conservation measures; and
- government regulations.

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 natural gas and oil 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.

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.

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.

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.

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.

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.

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.

Actual Reserves will vary from reserve estimates, and those variations could be material, and affecting 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 area 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.

If PrimeWest expands its operations beyond oil and natural gas production in western Canada, 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 Canadian Sedimentary Basin. In the future, it may acquire 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 into new areas 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.

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.

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, 2004, 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.

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.

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 of any amounts 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.

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 366 days after that conversion date and the remaining 40% of the aggregate principal amount outstanding repayable on the date which is 365 days after the initial term repayment 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.

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.

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.

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 was ratified by the Canadian Government in December 2002 and will require, among other things, significant reductions in greenhouse gases. The impact of the Kyoto Protocol 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 our estimated future environmental and reclamation obligations based on our 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.

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 Generally Accepted Accounting Principles ("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.

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.

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.

Risks Related to the Trust Structure and the Ownership of Trust Units

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, such as the treatment of mutual fund trusts and resource allowance, 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.

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 be taxed on certain types of income distributed to Unitholders, including income generated by the royalties 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.

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.

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.

The limited liability of Unitholders is uncertain.

Because of 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 enters into and for certain liabilities arising otherwise than out of contracts including claims in tort, claims for taxes and possibly certain other statutory liabilities.

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. Notwithstanding attempts to limit Unitholder liability, Unitholders may not be protected from liabilities of the Trust 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 a new statute entitled the *Income Trusts Liability Act* (Alberta) was proclaimed in force, creating a statutory limitation on the liability of unitholders of Alberta income trusts such as 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.

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.

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.

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 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.

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.

The Trust has adopted a Unitholders' Rights Plan that may discourage a takeover attempt.

Provisions contained in the Trust's Unitholders' Rights Plan could make it more difficult for a third party to acquire the Trust, even if doing so might be beneficial to Unitholders. The Rights Plan imposes various procedural and other requirements on a potential bidder, including a requirement that it keep the bid open for a period of at least 45 days and that the bid be approved by Unitholders holding at least 50% of the Trust Units, other than the Trust Units held by the potential bidder. In addition, if a Unitholder acquires more than 20% of the

outstanding Trust Units, other Unitholders may, at the discretion of the board of PrimeWest, acquire a number of Trust Units at 50% of the then prevailing market price, causing significant dilution to the 20% Unitholder. These rights may have the effect of delaying or deterring a change of control of the Trust, and could limit the price that investors might be willing to pay in the future for Trust Units.

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 Toronto Stock Exchange under the symbol PWI.UN and on the New York Stock Exchange under the symbol PWI. The outstanding Class A Exchangeable Shares of PrimeWest are listed for trading on the Toronto Stock Exchange under the symbol PWX. Five-year Convertible Debentures of PrimeWest trade on the TSX under the symbol "PWI.DB.A" and the seven-year Convertible Debentures trade under the symbol "PWI.DB.B".

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

PrimeWest Trust Units
TSX: PWI.UN (Canadian \$)

2004	High	Low	Close	Average Daily Trading Volume
January	\$ 28.35	\$ 27.32	\$ 27.60	198,125
February	\$ 27.40	\$ 22.70	\$ 24.30	370,178
March	\$ 26.65	\$ 23.69	\$ 26.65	212,121
April	\$ 26.80	\$ 24.22	\$ 24.55	190,046
May	\$ 24.55	\$ 22.18	\$ 23.01	217,868
June	\$ 24.40	\$ 22.69	\$ 23.25	90,383
July	\$ 24.70	\$ 23.29	\$ 24.70	84,822
August	\$ 25.85	\$ 24.43	\$ 24.43	277,869
September	\$ 26.70	\$ 24.53	\$ 26.70	414,966
October	\$ 28.33	\$ 26.15	\$ 26.32	341,284
November	\$ 27.45	\$ 25.80	\$ 26.10	218,946
December	\$ 27.73	\$ 25.06	\$ 26.62	213,427

PrimeWest Trust Units
NYSE: PWI (US\$)

2004	High	Low	Close	Average Daily Trading Volume
January	\$ 22.14	\$ 20.66	\$ 20.92	367,870
February	\$ 20.78	\$ 17.31	\$ 18.26	606,089
March	\$ 20.35	\$ 17.90	\$ 20.31	445,561
April	\$ 20.44	\$ 17.69	\$ 17.90	356,219
May	\$ 18.00	\$ 16.00	\$ 16.92	314,320
June	\$ 17.81	\$ 16.70	\$ 17.43	162,986
July	\$ 18.89	\$ 17.65	\$ 18.55	144,057
August	\$ 19.81	\$ 18.59	\$ 18.60	351,645
September	\$ 21.16	\$ 18.79	\$ 21.16	483,348
October	\$ 22.64	\$ 20.85	\$ 21.62	621,838
November	\$ 27.43	\$ 25.71	\$ 26.16	514,876
December	\$ 27.63	\$ 25.12	\$ 26.65	493,086

PrimeWest Series I Debentures
TSX: PWI.DB.A (Canadian \$)⁽¹⁾

	High	Low	Close
September	\$ 105.00	\$ 101.15	\$ 105.00
October	\$ 107.00	\$ 104.00	\$ 104.00
November	\$ 106.45	\$ 104.26	\$ 105.95
December	\$ 106.74	\$ 104.51	\$ 106.25

PrimeWest Series II Debentures
TSX: PWI.DB.B (Canadian \$)⁽¹⁾

September	\$ 105.00	\$ 100.25	\$ 104.45
October	\$ 107.50	\$ 104.25	\$ 104.25
November	\$ 107.00	\$ 105.00	\$ 107.00
December	\$ 106.75	\$ 105.30	\$ 106.50

PrimeWest Class A Exchangeable Shares
TSX:PWX (Canadian \$)

High	Low	Close	Average Daily Trading Volume
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January	\$ 12.77	\$ 12.25	\$ 12.25	963
February	\$ 12.35	\$ 10.55	\$ 11.00	1,954
March	\$ 11.95	\$ 10.70	\$ 11.95	810
April	\$ 12.00	\$ 12.00	\$ 12.00	205
May	\$ 11.11	\$ 10.32	\$ 10.36	464
June	\$ 11.35	\$ 10.51	\$ 11.35	1,293
July	\$ 11.65	\$ 11.57	\$ 11.60	127
August	\$ 12.00	\$ 11.90	\$ 11.90	67
September	\$ 13.25	\$ 12.50	\$ 13.25	308
October	\$ 13.55	\$ 13.25	\$ 13.47	1,621
November	\$ 14.00	\$ 12.92	\$ 13.67	671
December	\$ 13.82	\$ 12.72	\$ 13.70	1,100

Note:

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

ITEM 8: DIRECTORS AND OFFICERS

The Trust has no directors or officers. The following information pertains to the board of directors of PrimeWest and the 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, 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, 2004, are as follows:

Name and Present Principal Occupation or Employment	Director of PrimeWest Since ⁽⁵⁾	Municipality of Residence	Trust Units
			Beneficially Owned or over which Control or Discretion is Exercised as at December 31, 2004 (# / %) ⁽⁶⁾
HAROLD P. MILAVSKY ⁽¹⁾⁽³⁾ Chair	1996	Calgary, Alberta	17,850 ⁽⁷⁾ /0.02

Name and Present Principal Occupation or Employment	Director of PrimeWest Since ⁽⁵⁾	Municipality of Residence	Trust Units Beneficially Owned or over which Control or Discretion is Exercised as at December 31, 2004 (# / %) ⁽⁶⁾
Quantico Capital Corp. providing Merchant Banking services.			
BARRY E. EMES ⁽³⁾ Partner Stikeman Elliott LLP, a national Law Firm	1996	Calgary, Alberta	6,313 ⁽⁸⁾ /0.008
HAROLD N. KVISLE ⁽²⁾⁽⁴⁾ President & CEO TransCanada Corporation	1996	Calgary, Alberta	24,314 ⁽⁸⁾ /0.03
KENT J. MACINTYRE ⁽⁴⁾ Independent Businessman	1996	Calgary, Alberta	50,408 ⁽⁹⁾ /0.06
MICHAEL W. O'BRIEN ⁽¹⁾⁽³⁾ Corporate Director and Retired businessman	2000	Canmore, Alberta	6,895/0.008
W. GLEN RUSSELL ⁽²⁾⁽⁴⁾ Management Consultant providing advisory services to energy and technology companies	2003	Calgary, Alberta	3,774 ⁽¹⁰⁾ /0.004
JAMES W. PATEK ⁽²⁾⁽⁴⁾ President Patek Energy Consultants, Engineer providing professional services to oil and gas companies	2003	Fripp Island, South Carolina, U.S.A.	1,000/0.001
PETER VALENTINE ⁽¹⁾ Senior Advisor to CEO, Calgary Health Region and Senior Advisor to Dean of Medicine, University of Calgary	2004	Calgary, Alberta	566 ⁽¹⁰⁾ /0.0007

Notes:

- (1) Member of the Audit and Finance Committee.
- (2) Member of the Compensation Committee.
- (3) Member of the Corporate Governance and EH&S Committee.
- (4) Member of the Operations and Reserves Committee.
- (5) The term of office of each director expires at the next annual meeting, unless earlier terminated.
- (6) Percentage of ownership based upon total Units and Class A Exchangeable Shares issued and outstanding, Trust Units issueable pursuant to the conversion of the Convertible Subordinated Unsecured Debentures and Trust Units issueable under the Long Term Incentive Plan, diluted at December 31, 2004 (80,487,151).
- (7) Includes 4,000 Trust Units held through Quantico Capital Corp.
- (8) Includes five-year Convertible Unsecured Subordinated Debentures (Series I) convertible to Trust Units at a price of \$26.50 per Trust Unit, 37.7358 Trust Units per \$1,000.00 Debentures, which, in the case of Mr. Emes,

- consists of 25 Debentures convertible into 943 Trust Units, and, in the case of Mr. Kvisle, consists of 50 Debentures convertible into 1,887 Trust Units.
- (9) Consists of 100,000 Class A Exchangeable Shares (which, at December 31, 2004, were exchangeable into 50,408 Trust Units), all of which were held by Canadian Income Fund Group Inc., a corporation wholly-owned by Mr. McIntyre.
- (10) Consists of five-year Convertible Unsecured Subordinated Debentures (Series I) convertible to Trust Units at a price of \$26.50 per Trust Unit, 37,7358 Trust Units per \$1,000.00 Debenture, which, in the case of Mr. Russell equals 100 Debentures convertible into 3,774 Trust Units, and, in the case of Mr. Valentine, equals 15 Debentures convertible into 566 Trust Units.

Each of the foregoing persons has been engaged in the occupation set forth above or similar occupations with the same employer for the five preceding years, other than: (a) Mr. Kvisle who prior to May 2001 was Senior Vice President, Energy Operations of TransCanada Corporation (October 1999 to May 2001); (b) Mr. MacIntyre who prior to January 2003 was Vice-Chairman and Chief Executive Officer of PrimeWest; (c) Mr. O'Brien who prior to June 2002 was Executive Vice President, Corporate Development and Chief Financial Officer of Suncor Energy Inc. (December 1999 to June 2002); (d) Mr. Patek who prior to June 2000 was President of Fletcher Challenge Energy Canada; and (e) Mr. Valentine who for the period of December 2003 to June 2004 was also Interim Vice-President, Finance and Services, at the University of Calgary and prior to January 2002, served as the Auditor General for the Province of Alberta (March 1995 to January 2002).

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 on December 31, 2004 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, 2004 # / % ⁽¹⁾⁽²⁾
DONALD A. GARNER Calgary, Alberta	President and Chief Executive Officer Since January 2003	68,572 ⁽³⁾ /0.0852
TIMOTHY S. GRANGER Calgary, Alberta	Chief Operating Officer Since January 2003	7,315/0.0091
RONALD J. AMBROZY Calgary, Alberta	Vice-President, Business Development Since October 1997	15,443/0.0192
DENNIS G. FEUCHUK Calgary, Alberta	Vice-President, Finance and Chief Financial Officer Since October 2001	18,237/0.0227

Note:

- (1) Percentage of ownership based upon weighted average Trust Units, Exchangeable Shares, Convertible Unsecured Subordinated Debentures and Trust Units issueable pursuant to Long-Term Incentive Plan. (80,487,151 Units).
- (2) The board of directors and officers of PrimeWest, collectively, own 0.14% of the Trust Units on a diluted basis. (80,487,151 Units)

- (3) Includes 64,686 Class A Exchangeable Shares (which, at December 31, 2004, were exchangeable into 32,607 Trust Units, at a ratio of 0.50408:1).

Donald A. Garner, President and Chief Executive Officer

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 25 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, Chief Operating Officer

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 24 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. From 1980 to 1991, Mr. Granger held various engineering positions at Dynex Petroleum, Canterra Energy and Dome Petroleum. Mr. Granger holds a P.Eng. (Mechanical) from Carlton University.

Ronald J. Ambrozy, Vice-President, Business Development

Mr. Ambrozy has over 29 years of experience in the petroleum 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 people involved in A&D activity.

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

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, Controller of Gulf Canada Resources 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.

Employees

As of December 31, 2004, PrimeWest had a total permanent staff and field operator complement of 258 in the field and in the corporate head office.

Potential Conflicts of Interest

Mr. Emes, a director of PrimeWest, is partner in a law firm that provides services to PrimeWest. The board of directors of PrimeWest does not believe that any of the activities undertaken by Mr. Emes interfere, or could be perceived to interfere, in any material way with his ability to act with a view to the best interests of PrimeWest.

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 Class A Exchangeable Shares and the Series I and Series II Debentures is Computershare Trust Company of Canada at its principal offices in Toronto and Calgary.

Interests of Experts

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

ITEM 9: 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, 2004,

contained in the Annual Report. Additional information relating to the Trust may also be found on SEDAR at www.sedar.com.

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, 2004 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, 2004 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 10: GLOSSARY OF ABBREVIATIONS & TERMS

Abbreviations

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

<i>bbls</i>	Barrels	<i>mcf/day</i>	1,000 cubic feet / day
<i>mmbbls</i>	1,000 barrels	<i>bcf</i>	1,000,000,000 cubic feet
<i>mmbbls</i>	1,000,000 barrels	<i>m³</i>	1000 cubic metres
<i>bbls/day</i>	Barrels / day	<i>boe</i>	barrels of oil equivalent
<i>mcf</i>	1,000 cubic feet	<i>mboe</i>	1,000 barrels of oil equivalent
<i>mmcf</i>	1,000,000 cubic feet	<i>boe/day</i>	barrels of oil equivalent / day
<i>mmcf/day</i>	1,000,000 cubic feet/day	<i>mmboe</i>	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 2004 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.

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, dated on or about March 17, 2005.

Class A Exchangeable Shares means class A exchangeable shares in the capital of PrimeWest.

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;

Computershare means Computershare Trust Company of Canada.

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:

- a) 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, 2004, held constant throughout the estimated lives of the properties to which the estimate applies; 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).

Credit Facility means, collectively, certain credit facilities provided by a syndicate of Canadian chartered banks and term debt provided by certain institutional investors, together offering a maximum aggregate borrowing capability of \$625 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.

Cypress means Cypress Energy Inc.

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 Non-Producing Reserves means those Reserves that either have not been on Production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

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:

- a) 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;
- b) 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;
- c) 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
- d) 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.

Established means in relation to PrimeWest's interest in production or Reserves prior to December 31, 2003, Proved plus half of Probable Reserves (as such terms were defined in NP 2B).

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:

- a) 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”);
- b) 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;
- c) dry hole contributions and bottom hole contributions;
- d) costs of drilling and equipping Exploratory Wells; and
- e) 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):

- a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;
- b) without deducting estimated future costs (for example, Crown royalties) that are not deductible in computing taxable income;
- c) taking into account estimated tax credits and allowances (for example, royalty tax credits); and
- d) 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.

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 Gilbert Laustsen Jung Associates 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, 2004.

Gross means:

- a) in relation to PrimeWest's interest in production or Reserves, its "company gross Reserves", which are PrimeWest's working interest (operated or non-operated) share before deduction of royalties and without including any royalty interests of PrimeWest or the Trust; or
- b) in relation to wells, the total number of wells in which PrimeWest has an interest; or
- c) 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.

Manager means PrimeWest Management Inc.

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.

NEB means the National Energy Board.

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 which are not deductible for income tax purposes to the extent those royalties are not included in the amounts described in paragraph a);
- c) PrimeWest's share of all other revenues which 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,
 - (v) royalties and similar income; and
- d) ARTC applicable to the properties;
less
- e) 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.

Non-Associated Gas means an accumulation of natural gas in a reservoir where there is no crude oil.

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 petroleum, 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 petroleum, natural gas or related hydrocarbons.

Premium DRIP means the Premium Distribution, Distribution Reinvestment and Optional Trust Unit Purchase Plan of the Trust.

PrimeWest means PrimeWest Energy Inc., a wholly owned subsidiary of the Trust.

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:

- a) costs of labour to operate the wells and related equipment and facilities;
- b) costs of repairs and maintenance;
- c) costs of materials, supplies and fuel consumed, and supplies utilized, in operating the wells and related equipment and facilities;
- d) costs of workovers;

- e) property taxes and insurance costs applicable to properties and wells and related equipment and facilities; and
- f) taxes, other than income and capital taxes.

Property includes:

- a) fee ownership or a lease, concession, agreement, permit, licence 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;
- b) 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
- c) 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:

- a) costs of lease bonuses and options to purchase or lease a Property;
- b) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee; and
- c) 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 means the amount obtained by dividing the quantity of Reserves by the production of Petroleum Substances from those Reserves for the year ending December 31, 2004.

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:

- a) analysis of drilling, geological, geophysical and engineering data;
- b) the use of established technology; and
- c) specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

Rights Plan means the Unitholder Rights Plan of the Trust which is embodied in the Unitholder Rights Plan Agreement dated as of March 31, 1999 between the Trust and the Trust Company of Bank of Montreal as rights agent, as amended and restated as of April 5, 2002 between the Trust and Computershare.

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 Corp. 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:

- a) 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;
- b) 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;
- c) net contributions to PrimeWest's reclamation fund; and
- d) 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.

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.

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.

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 means PrimeWest Energy Trust.

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

Trustee means Computershare, or its successor, as trustee of 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.

Venator means Venator Petroleum Company Ltd.

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.

**SCHEDULE A
REPORT ON RESERVES DATA BY**

INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

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

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, 2004. The Reserves data consists of the following:
 - a)
 - (i) proved and proved plus probable oil and gas Reserves estimated as at December 31, 2004 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, 2004 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, 2004, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors.

Description and Preparation Date of Audit/ Evaluation/ Review 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
December 21, 2004	Canada	\$0	\$1,657,186 M	\$57,179 M	\$1,714,365 M

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 this evaluation 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.

Gilbert Laustsen Jung Associates Ltd., Calgary, Alberta, Canada

“signed”

Myron J. Hladyshevsky, P.Eng.

Vice-President

Dated: January 25, 2005

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, 2004 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, 2004 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, 2004.

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 judgements regarding future events, actual results will vary and the variations may be material.

“signed”
Donald A. Garner, President & Chief Executive Officer

“signed”
Tim Granger, Chief Operating Officer

“signed”
Harold N. Kvisle, Director

“signed”
W. Glen Russell, Director

Dated: March 24, 2005

**SCHEDULE C
AUDIT COMMITTEE DISCLOSURE**

PURSUANT TO MULTILATERAL INSTRUMENT 52-110

The Audit and Finance Committee's Charter

1.0 Constitution

A standing committee of the Board of Directors 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, TSX and NYSE listing standards agreements, articles and policies to which the Corporation, PrimeWest Energy Trust (the "Trust") and their business 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

The Audit Committee will assist the Board in fulfilling its oversight responsibilities, including the review and approval of:

- the integrity of the Corporation's financial statements
- the integrity of the financial reporting process
- the system of internal control and management of financial risks
- the external auditors' qualifications and independence
- the external audit process and the Corporation's process for monitoring compliance with laws and regulations
- internal audit & reviews as required or scheduled
- disclosure of any material information
- information systems and the office operation disaster recovery program
- equity offering prospectus

In performing its duties, the Audit Committee will maintain effective working relationships with the Board, Management and the external auditors. 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. So that the Audit Committee can discharge its duties as a whole, all Audit Committee members must be financially literate, and at least one member must have accounting or related financial management expertise.

3.0 Authority

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

- 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);
- 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;
- obtain outside legal or other professional advice and determine the fees payable for such advice without seeking Board approval (however providing notice to the Chair of the Board); and
- determine the level of administrative expenses necessary for the Audit Committee to carry out its duties.

4.0 Organization

The following provisions and regulations shall apply to the composition of the Audit Committee:

- 4.1 the Audit Committee shall consist of not less than three members of the Board of the Corporation;
- 4.2 the members of the Audit Committee shall be unrelated to Management and independent members of the Board as determined in accordance with TSX, Canadian Securities Administrators and NYSE Corporate Governance Guidelines as well as the Sarbanes-Oxley Act and any similar legislation as it becomes applicable to the Corporation;
- 4.3 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;
- 4.4 as a minimum, one member of the Audit Committee must be viewed as a financial expert;
- 4.5 two members of the Audit Committee shall constitute a quorum thereof;
- 4.6 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;
- 4.7 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;

- 4.8 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;
- 4.9 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 may convene a meeting if they consider that it is desirable or necessary;
- 4.10 the proceedings of all meetings will be minuted;
- 4.11 the Audit Committee shall meet separately, at least quarterly, with
- 1) Management
 - 2) external auditors
 - 3) internal auditors (or other such personnel responsible for the internal audit function)
- and at the end of each meeting, by themselves; and
- 4.12 a forward Agenda will be established with Management.

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 of the quarterly and annual financial statements, Management Discussion & Analysis, press releases, annual report, AIF and Management Proxy Circular (salary and related benefit information will be reviewed and approved by the Compensation Committee);
- 5.1.2 review of internal control systems maintained by the Corporation;
- 5.1.3 review of major changes to management information systems;
- 5.1.4 review of spending authority and approval of limits;
- 5.1.5 review of significant accounting and tax compliance issues where there is choice among various alternatives or where application of a policy has a significant effect on the financial results of the Corporation;

- 5.1.6 review of significant proposed non-recurring events such as mergers, acquisitions or divestitures; and
- 5.1.7 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.

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, 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 conclusions to the Board;
- 5.2.6 annually, to assure continuing auditor independence, consider the rotation of lead audit partner or the external auditor itself;
- 5.2.7 where there is a change of auditor, review all issues related to the change, including information to be included in the notice of change of auditors (National Instrument 51-102 as adopted by the Canadian Securities Regulatory Authorities), and the planned steps for an orderly transition;
- 5.2.8 review all reportable events, including disagreements, unresolved issues and consultations, as defined in National Instrument 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.

5.3 Audit

- 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;
- 5.3.5 review the responsibilities, budget, staffing and performance of the Corporation's internal audit function;
- 5.3.6 review audited annual financial statements and quarterly financial statements with Management and the external auditors (including disclosures under "Management Discussion & Analysis"), in conjunction with the report of the external auditors, and obtain explanation from Management of all significant variances between comparative reporting periods;
- 5.3.7 review the auditors' report to Management, containing recommendations of the external auditors', and Management's response and subsequent remedy of any identified weaknesses;
- 5.3.8 prepare an Audit Committee report as required by the United States Securities and Exchange Commission to be included in the Corporation's annual Management Proxy Circular; and
- 5.3.9 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 Risk Management and Controls

- 5.4.1 generally, review the Corporation's risk assessment and risk management policies;

- 5.4.2 review hedging strategies, policies, objectives and controls;
- 5.4.3 review, not less than quarterly, a mark to market assessment of the Corporation's hedge positions and counter party credit risk and exposure;
- 5.4.4 review the Corporation's risk retention philosophy and resulting exposure to the Corporation;
- 5.4.5 review adequacy of insurance coverage, outstanding or pending claims and premium costs;
- 5.4.6 review loss prevention policies and programs in the context of competitive and operational consideration;
- 5.4.7 annually review authority limits for capital expenditures sales and purchases;
- 5.4.8 review the Corporation's procedures for the control, identification and reporting of fraudulent acts; and
- 5.4.9 take the steps necessary to address and resolve all instances or allegations of fraud reported to the Committee Chair by the Corporate Secretary, the designated recipient of complaints received through the Corporation's fraud hotline.

5.5 Audit Committee Evaluation and Complaints

- 5.5.1 annually, in conjunction with the Corporate Governance and EH&S Committee, assess individual Audit Committee member and Chair performance and evaluate the performance of the Audit Committee as a whole, including its processes and effectiveness;
- 5.5.2 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;
- 5.5.3 in conjunction with the Corporate Governance and EH&S Committee, develop and approve Audit Committee member eligibility criteria, identify Directors qualified to become Committee members and recommend appointments to and removals from the Audit Committee;
- 5.5.4 establish procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters; and
- 5.5.5 establish procedures for the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

5.6 Other Duties and Responsibilities

- 5.6.1 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
- 5.6.2 The Audit Committee shall periodically report to the Board the results of all reviews undertaken and any associated recommendations.

Composition of the Audit Committee

The members of the Audit and Finance Committee are Harold P. Milavsky (Chair), Michael W. O'Brien and Peter Valentine. 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. Milavsky, FCA is Chair of Quantico Capital Corp., a privately held company engaged in merchant banking, principal investments and acquisitions. Mr. Milavsky serves as a director of Saskatchewan Wheat Pool and as a director and Chair of the various investment trusts 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. O'Brien is a 35-year veteran of the petroleum business and prior to retirement in 2002, Mr. O'Brien was the Executive Vice-president, Corporate Development and Chief Financial Officer of Suncor Energy Inc. Mr. O'Brien serves, among other responsibilities, as a director and Chair of the Audit Committee of Terasen Inc. and Shaw Communications Inc. and as a director of Suncor Energy Inc. Mr. O'Brien is also a former director of BC Gas Inc. and past Chair of the Nature Conservancy of Canada.

Mr. Valentine, FCA is currently Senior Advisor to the President and Chief Executive Officer of the Calgary Health Region and to the Dean of Medicine at the University of Calgary. He was previously Alberta's Auditor General, 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 and also held senior positions at KPMG. Mr. Valentine is currently Chair of the Canadian Comprehensive Audit Foundation and a director of Fording Canadian Coal Trust, Livingston International Income Fund, Superior Plus Income Fund and a private company, Resmor Trust Company.

Pre-Approval Policies and Procedures

It is within the mandate of PrimeWest's Audit and Finance Committee to approval all audit and non-audit related fees. The Audit and Finance Committee have pre-approved specifically identified non-audit tax-related services, including tax compliance; the review of tax returns;

and tax planning and advisory services relating to common forms of domestic and international taxation (i.e. income tax, capital tax, goods and services tax, and value added tax) up to a pre-determined maximum annual limit of \$50,000. The Audit and Finance Committee will be informed routinely as to the non-audit services actually provided by the auditor pursuant to this pre-approved 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 financial statements.

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:

	<u>2004</u>	<u>2003</u>
Audit fees ⁽¹⁾	\$394,000	\$327,000
Tax fees ⁽²⁾	66,858	80,850
	<u>\$460,858</u>	<u>\$407,850</u>

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 statutory and regulatory filings or engagements.
- (2) 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.