

PRIMEWEST ENERGY TRUST

RENEWAL ANNUAL INFORMATION FORM

For the year ended December 31, 2003

March 11, 2004

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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 that consolidation.

ITEM 1: ORGANIZATION

PrimeWest Energy Trust (the “**Trust**”) is an open-end investment trust created under the laws of Alberta pursuant to the Declaration of Trust. The undertaking of the Trust is to issue Trust Units to the public and to invest the Trust's funds, directly or indirectly, in 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 is the Trustee of the Trust. The head office and principal place of business of the Trust is 4700, 150 - 6th Avenue S.W., Calgary, Alberta, T2P 3Y7.

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.

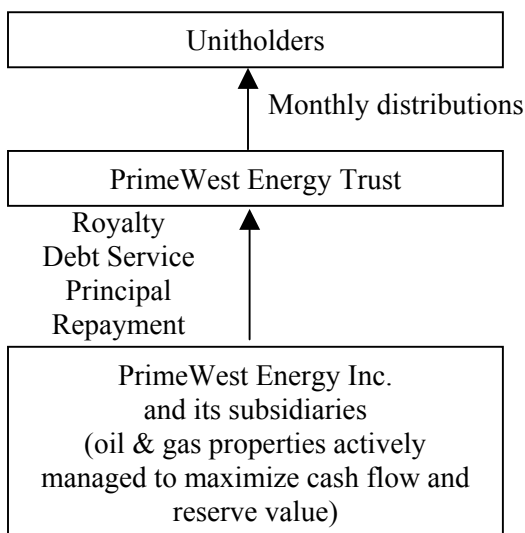
PrimeWest is wholly owned by the Trust. PrimeWest’s business is the acquisition, development, exploitation, production and marketing of petroleum and natural gas and granting the Royalty to the Trust.

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 pursuant to the Royalty Agreement. 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 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:



Note:

1. The Trust also directly owns certain gross overriding royalty interests.

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 other than any instalment payment arrangements that are applicable to an offering of Trust Units in respect of which the Unitholder acquired his 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, 2003, each Class A Exchangeable Share was exchangeable for 0.44302 Trust Units.

PrimeWest issued Class A Exchangeable Shares in connection with the acquisitions of the Manager in November 2002, Cypress Energy Inc. in March 2001 and Venator Petroleum Company Ltd. 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 and reflecting the distributions provided to Unitholders in 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.

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 up to \$100,000. The redemption price payable by the Trust may be satisfied by way of a cash payment, or in certain circumstances, including where such payment 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 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

In order for the Trust to maintain its status as a mutual fund trust under the *Income Tax Act* (Canada), the Trust must not be established or maintained primarily for the benefit of non-residents of Canada within the meaning of the Tax Act, unless pursuant to paragraph 132(7)(a) of the Tax Act, from the date of creation of the Trust to and including the relevant time, all or substantially all of the property of the Trust consisted of property other than "taxable Canadian property", as defined in the Tax Act.

Accordingly, the Declaration of Trust currently provides that at no time may non-residents of Canada be the beneficial owners of a majority of the Trust Units. However, a proposal to amend the Declaration of Trust to provide the board of directors of PrimeWest with a measure of flexibility in determining when to enforce restrictions on ownership of Trust Units by, and transfer of Trust Units to, non-residents of Canada has been put to Unitholders in the Circular. The meeting to approve such amendment is scheduled for May 6, 2004.

If approved by Unitholders, the amended Declaration of Trust would provide that:

- 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.

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. The Rights Plan was approved by Unitholders at the special and annual general meeting of the Unitholders held on May 18, 1999. The Unitholders reconfirmed the Rights Plan at the special and annual general meeting of the Unitholders held on May 21, 2002. The Rights Plan will expire on the date of PrimeWest's Annual general meeting in 2005 unless the Unitholders reconfirm the Rights Plan at that meeting.

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", not requiring the approval of the board of directors of PrimeWest but having terms and conditions designed to provide the board of directors of PrimeWest with sufficient time to properly evaluate a take-over bid and its effects, and to seek alternative bidders or to explore other ways of maximizing Unitholder value in the event of an unsolicited take-over bid.

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, and 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 (i) issuances of Trust Units, (ii) the determination of the amount of distributions to be made by the Trust, (iii) approvals required with regard to any proposed amendment to the Declaration of Trust or the royalty agreement and other aspects respecting the relationship between the Trust and PrimeWest, and (iv) 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 equity financings completed by PrimeWest since January 1, 2001.

Acquisitions

Date	Company/Properties Acquired	Aggregate Purchase Price (currency)	Reserves and Production Acquired
March 2001	Cypress Energy Inc.	\$820.8 million (cash, Trust Units and exchangeable shares)	57.5 mmboe ⁽¹⁾ 15,000 boe/d
December 2002	Caroline/Ells	\$45.6 million (cash)	5.7 mmboe ⁽¹⁾ 1,550 boe/d
January 2003	Caroline/Peace River Arch	\$219.1 million (cash)	15.5 mmboe ⁽²⁾ 6,800 boe/d

⁽¹⁾ Based on evaluations of Established Reserves completed prior to implementation of National Instrument 51-101 in September 2003. See "Statement of Reserves Data and Other Oil and Gas Information" for a discussion of the difference between Established Reserves and Reserves evaluated under National Instrument 51-101.

⁽²⁾ Proved plus Probable Reserves evaluated under National Instrument 51-101.

Public Offerings

Date	No. of Trust Units Issued	Price per Trust Unit	Gross Proceeds
June 2001	2,472,500	\$38.40	\$94.9 million
November 2001	2,475,000	28.40	70.3 million
November 2002	4,200,000	26.20	110.0 million
February 2003	6,000,000	25.75	154.5 million
September 2003	3,100,000	25.90	80.3 million

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 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 May 7, 2003, PrimeWest announced that it had entered into a private placement debt financing for U.S. \$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 \$34.3 million and assumed debt and working capital of \$8.3 million. PrimeWest hedged approximately 70% of the gas production of Seventh at a price of \$6.18 Canadian per mcf for one year. On February 6, 2004, PrimeWest Gas mailed a formal take-over circular to the shareholders of Seventh and anticipates taking up and paying for those shares tendered to the offer on or about March 15, 2004.

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 properties, 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. See "Management Policies and Acquisition Strategy".

Risk Management & Marketing

Prices received for production and associated operating expenses are impacted in varying degrees by factors outside the Trust's control. These include but are not limited to:

- a) World market forces, including the ability of OPEC to set and maintain production levels and prices for crude oil;
- b) Political conditions, including the risk of hostilities in the Middle East and other regions throughout the world;
- c) Increases or decreases in crude oil quality differentials, and their implications for prices received by PrimeWest on the portion of oil production that is medium gravity crude;
- d) To the extent that crude oil prices received by PrimeWest are referenced to benchmarks (such as West Texas Intermediate oil), which are denominated in U.S. dollars, prices and revenue streams are impacted by changes in value between the Canadian and U.S. dollars.
- e) North American market forces, most notably shifts in the balance between supply and demand for crude oil and natural gas and the implications for the price of crude oil and natural gas;
- f) To the extent that natural gas prices received by PrimeWest are established in U.S. dollars, then converted to Canadian dollars, prices and revenue streams are impacted by changes in value between the Canadian and U.S. dollars;
- g) Global and domestic economic and weather conditions;
- h) Price and availability of alternative fuels; and
- i) The effect of energy conservation measures and government regulations.

Fluctuations in commodity prices, quality differentials and foreign exchange and interest rates, among other factors, are outside the control of PrimeWest and yet can have a significant impact on the level of cash available for distribution to Unitholders. To mitigate a portion of these risks, PrimeWest actively initiates, manages and discloses the effects of hedging activities. PrimeWest evaluates these activities against criteria

established under a commodity risk-assessment and management program, which is regularly reviewed by the board of directors of PrimeWest.

As part of PrimeWest's risk-management strategy in 2003, 65% of full-year crude oil production (2002 - 71%) and 61% of full-year natural gas production (2002 - 69%) was hedged, net of royalties. Strategies utilized included both physical and financial instruments with the primary objective of enhancing the stability of cash distributions.

PrimeWest also utilized electrical power hedges during 2003. The electrical power hedges utilized heat rate swaps (8.92 gigajoules per megawatt hour).

The gas hedging instruments are floors, swaps, basis swaps, costless collars, 3-way deals and swaptions. 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. Swaptions give PrimeWest the future right to enter into swap transactions for fixed prices and terms. The oil hedging instruments consist of floors, swaps, costless collars and calls.

As at February 27, 2004:

- (a) PrimeWest employed hedging structures using swaps and option-based instruments on approximately 64% of anticipated crude oil production, net of royalties, for 2004 and on 18% of its anticipated crude oil production, net of royalties, for 2005;
- (b) PrimeWest employed hedging structures using swaps and option-based instruments on approximately 52% of anticipated natural gas production, net of royalties, for 2004 and on approximately 3% of anticipated natural gas production, net of royalties, for 2005;
- (c) PrimeWest employed hedging structures using swaps on approximately 59% of anticipated electrical power requirements for 2004 and on none of the anticipated electrical power requirements for 2005;
- (d) All 2004 and 2005 hedging contracts intrinsic mark-to-market position represented a net loss of \$13.1 million, as compared to a net loss of \$3.5 million as at December 31, 2003. The intrinsic value is the amount of gains or losses that would be realized if all hedge positions were settled over time at the forward prices at December 31, 2003 and February 27, 2004, respectively; and
- (e) All 2004 and 2005 contracts intrinsic plus extrinsic mark-to-market positions represented a net loss of \$14.7 million as compared to a net loss of \$5.4 million as at December 31, 2003. The intrinsic plus extrinsic value is the amount of gains or losses that would be realized if all hedge

positions were closed out at the forward prices at December 31, 2003 and February 27, 2004, 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 one 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 with aggregators vary in length. They have a blend of domestic and U.S. 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 2003, PrimeWest's commodity mix was approximately 33% oil and NGLs and 67% natural gas, compared to approximately 38% oil and NGLs and 62% natural gas in 2002. PrimeWest realized hedge losses of \$30.5 million in 2003 and gains of \$28.1 million in 2002.

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 2003, PrimeWest contributed \$0.50 per boe of production, totalling \$6.2 million paid into this fund, while \$2.2 million was paid out for active projects completed. An additional contribution of \$4.2 million was made to fund reclamation liabilities assumed with properties acquired in 2002. The cash balance in the reclamation fund was \$8.2 million at the end of 2003. The 2004 contribution rate remains \$0.50 per boe, which is expected to be sufficient to meet the future funding requirements. In addition, PrimeWest records a provision for site reclamation and abandonment based on cost estimates made by both PrimeWest and external engineers. The provision for 2003 was \$4.2 million compared to \$4.0 million in 2002 and is charged to depletion, depreciation and amortization on a unit of production basis. 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

General

Faced with a number of highly publicized transactions where oil and natural gas Reserve reports were prepared pursuant to National Policy Statement 2-B ("NP 2B") and found to be wanting, the Alberta Securities Commission established an oil and gas taskforce in 1998 to investigate methods of improving the existing legislative regime. The taskforce passed on its findings and recommendations to the Canadian Securities Administrators in 2001, which ultimately initiated its own extensive public consultative process culminating with National Instrument 51-101 ("NI 51-101") which came into force on September 30, 2003. NI 51-101 reflects a dramatic departure from its predecessor 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. While the definition itself is similar to the old definition of Proved Reserves, there was no consideration of probability under NP 2B. 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. With respect to the consideration of certainty, 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.

Proved plus Probable Reserves replace the "Established" Reserves definition that was used historically. Under the old rules, the Established Reserves category was generally calculated on the basis that Proved plus half of Probable Reserves (as those terms were defined in NP 2B) represented the best estimate at the time. PrimeWest believes that its Established Reserves reported under NP 2B were calculated on a reasonable basis as its estimate of Reserves that would ultimately be recovered. As a result, and for comparison purposes, we have included Established Reserves from our December 31, 2002 Reserves Report as our December 31, 2002 opening balances under the Proved plus Probable Reserves category reconciled on a Company Interest basis and on a Net basis (see discussion below). Similarly, we have included 50% of Probable

Reserves from our December 31, 2002 Reserves Report as our opening balances under the Probable Reserves category, again reconciled on a Company Interest basis and on a Net basis. The inclusion of this additional information will assist the reader in comparing historical results to the current results during this period of transition to the new reporting regime dictated by NI 51-101.

Before the implementation of NI 51-101, reporting companies reported and reconciled Reserves on a "Company Interest" basis, which included working interest Reserves plus royalties receivable (with no deduction for royalties payable). Under the new rules, 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 (working interest and royalties receivable, less royalties payable). As required, PrimeWest has reported its Reserves on both a Gross and a Net basis. In addition, we have reconciled our Reserves on a Net basis. Again, for continuity and comparison purposes, we have also reported and reconciled our Reserves using the old Company Interest definition.

The impact of the implementation of NI 51-101 on PrimeWest's Reserves is discussed and reflected further in the tables below under this Item 4. Except as described above, 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 pursue growth opportunities through the development of existing Reserves, the monetization of PrimeWest's exploratory lands and the acquisition of new properties. 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 sales 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 that have an average Reserve Life Index of approximately 9.8 years based on Net Proved plus Probable Reserves calculated in accordance with NI 51-101;

- b) **Operated Properties:** Approximately 80% of the total production from the properties is operated by PrimeWest. 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, 2003 production from the properties is approximately 33% crude oil and natural gas liquids and 67% natural gas, on a barrel-of-oil-equivalent basis. As at December 31, 2003, Proved plus Probable Reserves for the properties are approximately 32% crude oil and natural gas liquids and 68% natural gas on a barrel-of-oil-equivalent basis;
- d) **Diversified Portfolio:** While the properties are diversified from a geological and geographic perspective, PrimeWest generally has the largest working interest in these 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, GLJ has prepared the GLJ Report dated January 1, 2004 evaluating, as at December 31, 2003, 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 the undiscounted or 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.

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

**Summary of Oil and Natural Gas Reserves
and Net Present Values of Future Net Revenue
as of December 31, 2003**

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	16,324	14,622	14,764	4,135	4,123	3,798
Developed Non-Producing	11	11	9	0	0	0
Undeveloped	591	376	553	122	122	105
TOTAL PROVED	16,926	15,009	15,326	4,257	4,245	3,903
PROBABLE	2,969	2,656	2,602	640	639	585
TOTAL PROVED PLUS PROBABLE	19,895	17,665	17,928	4,897	4,884	4,488

RESERVES CATEGORY	RESERVES					
	Natural Gas (Bcf)			Natural Gas Liquids (mdbl)		
	Company Interest	Gross	Net	Company Interest	Gross	Net
PROVED						
Developed Producing	308.6	301.1	243.7	7,872	7,724	5,606
Developed Non-Producing	17.8	17.8	14.0	463	463	342
Undeveloped	20.5	19.5	15.2	710	690	465
TOTAL PROVED	346.9	338.3	272.9	9,046	8,877	6,414
PROBABLE	89.8	88.2	70.8	2,898	2,867	2,055
TOTAL PROVED PLUS PROBABLE	436.7	426.6	343.7	11,944	11,744	8,469

RESERVES CATEGORY	RESERVES		
	Total (mboe)		
	Company Interest	Gross	Net
PROVED			
Developed Producing	79,760	76,645	64,788
Developed Non-Producing	3,442	3,442	2,677
Undeveloped	4,838	4,431	3,661
TOTAL PROVED	88,040	84,518	71,126
PROBABLE	21,475	20,869	17,044
TOTAL PROVED PLUS PROBABLE	109,515	105,387	88,169

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	1,565.9	923.5	1,565.9	923.5
Developed Non-Producing	64.8	28.2	64.8	28.2
Undeveloped	84.0	41.4	84.0	41.4
TOTAL PROVED	1,714.7	993.1	1,714.7	993.1
PROBABLE	438.9	168.6	438.9	168.6
TOTAL PROVED PLUS PROBABLE	2,153.6	1,161.7	2,153.6	1,161.7

**Total Future Net Revenue
(Undiscounted)
as of December 31, 2003**

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	3,196.89	565.74	804.93	69.45	42.10	1,714.67	0	1,714.67
Proved Plus Probable Reserves	3,978.60	716.23	955.35	110.88	42.57	2,153.57	0	2,153.57

**Future Net Revenue
By Production Group
as of December 31, 2003**

Constant Prices and Costs

Reserves Category	Production Group	Future Net Revenue Before Future Income Tax Expenses (discounted at 10%/year) (MM\$)
Proved Reserves	Light and Medium Crude Oil ⁽¹⁾	198.88
	Heavy Oil ⁽¹⁾	63.30
	Natural Gas ⁽²⁾	748.35
Proved Plus Probable Reserves	Light and Medium Crude Oil ⁽¹⁾	219.19
	Heavy Oil ⁽¹⁾	72.14
	Natural Gas ⁽²⁾	885.35

Notes:

1. Including solution gas and other by-products.
2. Including by-products but excluding solution gas from oil wells.

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

**Summary of Oil and Natural Gas Reserves
and Net Present Values of Future Net Revenue
as of December 31, 2003**

Forecast Prices and Costs

RESERVES CATEGORY	RESERVES					
	Light And Medium Crude Oil (mbl)			Heavy Oil (mbl)		
	Company Interest	Gross	Net	Company Interest	Gross	Net
PROVED						
Developed Producing	15,744	14,084	14,284	3,110	3,102	2,856
Developed Non-Producing	11	11	9	0	0	0
Undeveloped	572	363	535	118	118	103
TOTAL PROVED	16,327	14,459	14,829	3,228	3,220	2,959
PROBABLE	2,847	2,541	2,504	477	476	435
TOTAL PROVED PLUS PROBABLE	19,174	17,000	17,333	3,706	3,696	3,394

RESERVES CATEGORY	RESERVES					
	Natural Gas (Bcf)			Natural Gas Liquids (mbl)		
	Company Interest	Gross	Net	Company Interest	Gross	Net
PROVED						
Developed Producing	304.9	297.4	240.7	7,798	7,650	5,570
Developed Non-Producing	18.0	18.0	14.1	469	469	346
Undeveloped	20.3	19.3	15.1	708	688	466
TOTAL PROVED	343.2	334.7	269.9	8,975	8,807	6,381
PROBABLE	89.0	87.4	70.1	2,888	2,857	2,051
TOTAL PROVED PLUS PROBABLE	432.2	422.1	339.9	11,863	11,664	8,433

RESERVES CATEGORY	RESERVES		
	Total (mboe)		
	Company Interest	Gross	Net
PROVED			
Developed Producing	77,474	74,405	62,827
Developed Non-Producing	3,472	3,472	2,700
Undeveloped	4,785	4,385	3,618
TOTAL PROVED	85,732	82,263	69,145
PROBABLE	21,037	20,440	16,670
TOTAL PROVED PLUS PROBABLE	106,769	102,703	85,815

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	1,194.7	890.6	725.7	621.3	548.5	1,194.7	890.6	725.7	621.3	548.5
Developed Non- Producing	51.8	30.1	21.4	16.7	13.7	51.8	30.1	21.4	16.7	13.7
Undeveloped	59.8	40.2	28.6	21.4	16.5	59.8	40.2	28.6	21.4	16.5
TOTAL PROVED	1,306.3	960.9	775.8	659.4	578.7	1,306.3	960.9	775.8	659.4	578.7
PROBABLE	348.9	195.2	128.8	93.5	72.1	348.9	195.2	128.8	93.5	72.1
TOTAL PROVED PLUS PROBABLE	1,655.2	1,156.0	904.6	752.9	650.8	1,655.2	1,156.0	904.6	752.9	650.8

**Total Future Net Revenue
(Undiscounted)
as of December 31, 2003**

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	2,782.73	481.57	872.25	72.27	50.33	1,306.31	0	1,306.31
Proved Plus Probable Reserves	3,487.97	612.62	1,053.83	113.73	52.55	1,655.24	0	1,655.24

**Future Net Revenue
By Production Group
as of December 31, 2003**

Forecast Prices and Costs

Reserves Category	Production Group	Future Net Revenue Before Future Income Tax Expenses (discounted at 10%/year) (MM\$)
Proved Reserves	Light and Medium Crude Oil ⁽¹⁾	154.71
	Heavy Oil ⁽¹⁾	41.24
	Natural Gas ⁽²⁾	599.14
Proved Plus Probable Reserves	Light and Medium Crude Oil ⁽¹⁾	170.06
	Heavy Oil ⁽¹⁾	46.81
	Natural Gas ⁽²⁾	704.48

Notes:

1. Including solution gas and other by-products.
2. Including by-products but excluding solution gas from oil wells.

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, 2003

Constant Prices and Costs

Historical (Year End)	OIL				Natural Gas	EDMONTON LIQUIDS PRICES			Inflation Rates % / year	Exchange Rate \$U.S / Cdn
	WTI Cushing Oklahoma \$US/bbl	Edmonton Par Price 40° API \$Cdn/ bbl	Hardisty Heavy 12° API \$Cdn/bbl	Cromer Medium 29.3° API \$Cdn/bbl	AECO Gas Price \$CDN/ mmbtu	Propane \$Cdn./bbl	Butane \$Cdn/bbl	Pentanes Plus \$Cdn/bbl		
2000	30.22	44.56	27.34	39.91	5.08	32.18	35.60	46.31	2.7	0.6740
2001	25.97	39.40	16.94	31.56	6.21	31.85	31.17	42.48	2.6	0.6448
2002	26.08	40.33	26.57	35.48	4.04	21.39	27.08	40.73	2.2	0.6376
2003 (Year End)	32.52	40.81	23.31	34.81	6.09	29.81	31.81	41.31		0.7738
2003 (Average)	30.96	43.51	26.01	37.26	6.66	32.01	34.01	44.01	2.8	0.7213

Summary of Pricing and Inflation Rate Assumptions as of December 31, 2003

Forecast Prices and Costs

Year	OIL				Natural Gas ⁽¹⁾	EDMONTON LIQUIDS PRICES			Inflation Rates % / year	Exchange Rate \$U.S / Cdn
	WTI Cushing Oklahoma \$US/bbl	Edmonton Par Price 40° API \$Cdn/ bbl	Hardisty Medium 25.7° API \$Cdn/bbl	Cromer Medium 29.3° API \$Cdn/bbl	AECO Gas Price \$Cdn/ mmbtu	Propane \$Cdn./bbl	Butane \$Cdn/bbl	Pentanes Plus \$Cdn/bbl		
Forecast										
2004	29.21	37.81	28.05	32.31	5.90	26.80	28.27	38.54	0.0	0.75
2005	26.43	34.10	26.35	29.30	5.33	22.64	23.96	34.80	1.67	0.75
2006	25.42	32.79	25.99	28.60	4.98	21.16	22.53	33.48	1.67	0.75
2007	25.38	32.72	25.89	28.54	4.95	21.03	22.48	33.42	1.67	0.75
2008	25.51	32.89	26.00	28.67	4.92	21.03	22.59	33.60	1.67	0.75
2009	25.81	33.26	26.31	29.00	4.96	21.24	22.85	33.98	1.67	0.75
2010	26.11	33.63	26.68	29.37	5.00	21.42	23.10	34.36	1.67	0.75
2011	26.42	34.04	27.09	29.78	5.06	21.69	23.36	34.78	1.67	0.75
2012	26.72	34.42	27.47	30.16	5.12	21.94	23.62	35.17	1.67	0.75
2013	27.03	34.83	27.88	30.57	5.19	22.22	23.92	35.59	1.67	0.75
2014	27.37	35.25	28.30	30.99	5.25	22.50	24.21	36.02	1.67	0.75
2015	27.88	35.87	28.92	31.61	5.36	22.87	24.59	36.65	1.67	0.75
2016	28.40	36.49	29.54	32.23	5.46	23.23	24.98	37.28	1.67	0.75
2017	28.91	37.12	30.17	32.86	5.56	23.60	25.39	37.92	1.67	0.75
2018	29.43	37.71	30.76	33.45	5.66	23.94	25.75	38.52	1.67	0.75
Thereafter	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00	0.75

Weighted Average Realized Sales Prices

(\$Cdn)	2003
Natural Gas (\$/mcf)	6.05
Crude Oil (\$/bbl)	33.94
Natural Gas Liquids (\$/bbl)	35.34

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 3.6 mmboe. PrimeWest’s Net Probable Reserves were 16.7 mmboe as at January 1, 2004. PrimeWest invests capital into development work which moves its PUD Reserves and Probable Reserves into the Proved Developed Producing category. In 2003, \$104.5 million was spent on capital development, and between \$65 and \$90 million has been budgeted for development capital in 2004. A portion of the development capital will be used to convert PUD Reserves and Probable Reserves into Proved Developed Producing Reserves. Allocating capital to properties and timing of development is based on economics and performance of the asset. PrimeWest’s focus for 2004 development continues to be in the core areas of Caroline, Brant/Farrow, Valhalla and Princess/Hays.

Of PrimeWest’s Net PUD Reserves, 49% 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 2004 development in this area, see “Other Oil and Gas Information”). Other areas with notable Net PUD Reserves include Dinosaur/Medicine Hat (11%) and Crossfield/Lone Pine Creek (10%). Of PrimeWest’s total Net Probable Reserves, 32% are in Caroline. Other areas with notable Net Probable Reserves include Thorsby (12%) and Crossfield/Lone Pine Creek (11%).

For properties other than Caroline, Brant/Farrow, Valhalla and Princess/Hays, which have PUD or Probable 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 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 Reserves becoming Proved Developed Producing Reserves.

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)
2004	15.04	24.74	15.04	24.74
2005	12.51	19.29	12.72	19.61
2006	11.65	20.01	12.04	20.68
2007	3.95	16.29	4.15	17.12
2008	3.65	3.77	3.90	4.03
Total: Undiscounted	69.45	110.88	72.27	113.73
Total: Discounted at 10%/year	49.21	79.86	50.91	82.57

The Future Development Costs are capital expenditures required in the future for PrimeWest to convert Proved Undeveloped Reserves and Probable Reserves into Proved Developed Producing Reserves. Over the estimated life of the Reserves, it is anticipated that \$72.3 million would be incurred for the Proved Reserves and \$113.7 million for the Proved plus Probable Reserves categories, based on Forecast Prices and Costs. PrimeWest anticipates using a combination of internally-generated cash flow, debt and equity financing to fund these future Development Costs. Based on the commodity price and cost assumptions adopted for both the Constant Prices and Costs case and the Forecast Prices and Costs case, all of the expenditures included in the future Development Costs are economic as they enhance the net present values of the Proved Developed Reserves.

Reconciliations 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, 2003 using Forecast Price and Cost estimates derived from the GLJ Report as required under NI 51-101 guidelines and format, reconciled to December 31, 2002 Proved plus 50% of Probable Reserves (Established Reserves). Net Reserves include working interest Reserves plus royalties receivable less royalties payable, as stipulated by NI 51-101. See notes following table and 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, 2002	14,641.0	15,355.0	2,252.0 ^(a)	17,607.0 ^(b)	3,320.0	3,723.0	405.0 ^(a)	4,128.0 ^(b)
Extensions	11.9	49.2	40.8	90.0	37.6	37.6	24.9	62.5
Improved								
Recovery	451.6	443.0	(26.1)	416.9	265.1	0.0	0.0	0.0
Technical								
Revisions ^(d)	672.3	470.6	199.1	669.7	(441.0)	(406.9)	(52.5)	(459.4)
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Acquisitions	219.1	219.1	36.5	255.6	156.5	156.5	24.6	181.1
Dispositions	(21.4)	(21.4)	(4.3)	(25.7)	(2.7)	(2.7)	0.0	(2.7)
Economic Factors	(104.0)	(100.0)	6.0	(94.0)	290.0	221.0	33.0	254.0
Production	(1,586.5)	(1,586.5)	0.0	(1,586.5)	(769.5)	(769.5)	0.0	(769.5)
December 31, 2003	14,284.0	14,829.0	2,504.0	17,333.0^(c)	2,856.0	2,959.0	435.0	3,394.0^(c)

	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, 2002	228.0	277.5	54.5 ^(a)	331.9 ^(b)	4,927.0	6,140.0	1,259.0 ^(a)	7,399.0 ^(b)
Extensions	10.0	9.8	2.0	11.8	69.6	70.8	8.4	79.2
Improved								
Recovery	5.8	4.8	0.1	4.9	278.5	342.2	82.4	425.0
Technical								
Revisions ^(d)	(7.6)	(30.8)	3.3	(27.4)	(25.8)	(613.0)	360.5	(252.9)
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Acquisitions	41.8	46.7	11.8	58.5	1,095.7	1,223.4	342.8	1,566.2
Dispositions	(0.2)	(0.8)	(1.6)	(2.3)	(0.8)	(2.2)	(1.1)	(3.3)
Economic Factors	(0.3)	(0.5)	(0.1)	(0.5)	(6.0)	(12.0)	(1.0)	(13.0)
Production	(36.9)	(36.9)	0.0	(36.9)	(768.2)	(768.2)	0.0	(768.2)
December 31, 2003	240.7	269.9	70.1	339.9^(c)	5,570.0	6,381.0	2,051.0	8,432.0^(c)

	Total (mmboe)			
	Proved Producing	Proved	Probable	Proved Plus Probable
December 31, 2002	60.9	71.5	13.0 ^(a)	84.5 ^(b)
Extensions	1.8	1.8	0.4	2.2
Improved				
Recovery	2.0	1.6	0.1	1.7
Technical				
Revisions ^(d)	(1.1)	(5.7)	1.1	(4.6)
Discoveries	0.0	0.0	0.0	0.0
Acquisitions	8.4	9.4	2.4	11.8
Dispositions	(0.1)	(0.2)	(0.3)	(0.4)
Economic				
Factors	0.1	0.0	0.0	0.1
Production	(9.3)	(9.3)	0.0	(9.3)
December 31, 2003	62.8	69.1	16.7	85.8^(c)

Columns may not add due to rounding

Notes:

- (a) Amount equals 50% of Probable Reserves reported in PrimeWest's December 31, 2002 Reserves report.
- (b) Proved plus Probable figures for December 31, 2002 represent Established Reserves from PrimeWest's December 31, 2002 Reserves Report. Proved plus Probable illustrates the reconciliation between Established Reserves as at December 31, 2002 under NP 2B to Proved plus Probable Reserves as at December 31, 2003 under NI 51-101. See initial discussion above under "Statement of Reserves Data and Other Oil and Gas Information – General".
- (c) Proved plus Probable Reserves reflect at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved plus Probable Reserves.
- (d) Includes infill drilling.

The following table sets forth a reconciliation of light, medium and heavy crude oil, natural gas, natural gas liquids and barrels of oil equivalent of the Company Interest Reserves of PrimeWest for the year ended December 31, 2003 derived from the GLJ report using Forecast Price and Cost estimates, and reconciled to December 31, 2002 Proved plus 50% of Probable Reserves (Established Reserves). PrimeWest's Company Interest Reserves include working interest and royalties receivable. This definition is consistent with the basis on which Reserves were reported in prior years. See notes following table and initial discussion above under "Statement of Reserves Data and Other Oil and Gas Information – General".

	Light, Medium and Heavy Crude Oil (mmbbls)				Natural Gas (Bcf)			
	Proved Producing	Total Proved	Probable	Proved Plus Probable	Proved Producing	Total Proved	Probable	Proved Plus Probable
December 31, 2002	20,136.2	21,416.2	3,043.9 ^(a)	24,460.1 ^(b)	286.6	349.5	69.0 ^(a)	418.5 ^(b)
Capital additions ^(d)	832.8	575.9	43.0	618.9	20.4	18.8	2.6	21.4
Technical Revisions ^(c)	263.4	10.3	99.2	109.5	(6.9)	(35.5)	4.4	(31.1)
Acquisitions	436.9	436.9	71.9	508.8	57.3	64.0	16.2	80.2
Dispositions	(28.0)	(28.0)	(5.0)	(33.0)	(0.2)	(1.0)	(2.0)	(3.0)
Economic Factors	197.0	128.0	71.0	199.0	(3.4)	(3.7)	(1.2)	(4.9)
Production	(2,984.3)	(2,984.3)	0.0	(2,984.3)	(48.9)	(48.9)	0.0	(48.9)
December 31, 2003	18,854.0	19,555.0	3,324.0	22,879.0^(e)	304.9	343.2	89.0	432.2^(e)

	Natural Gas Liquids (mmbbls)				Barrel of oil equivalent (mmboe)			
	Proved Producing	Total Proved	Probable	Proved Plus Probable	Proved Producing	Total Proved	Probable	Proved Plus Probable
December 31, 2002	6,795.3	8,448.3	1,740.7 ^(a)	10,189.0 ^(b)	74.7	88.1	16.3 ^(a)	104.4 ^(b)
Capital additions ^(d)	497.3	590.0	130.3	720.3	4.7	4.3	0.6	4.9
Technical Revisions ^(c)	(8.9)	(749.9)	534.8	(215.1)	(0.8)	(6.7)	1.4	(5.3)
Acquisitions	1,565.3	1,747.7	489.7	2,237.4	11.6	12.9	3.2	16.1
Dispositions	(1.1)	(3.2)	(1.5)	(4.7)	(0.1)	(0.2)	(0.3)	(0.5)
Economic Factors	(8.0)	(16.0)	(6.0)	(22.0)	(0.4)	(0.5)	(0.1)	(0.6)
Production	(1,041.9)	(1,041.9)	0.0	(1,041.9)	(12.2)	(12.2)	0.0	(12.2)
December 31, 2003	7,798.0	8,975.0	2,888.0	11,863.0^(e)	77.5	85.7	21.0	106.8^(e)

Columns may not add due to rounding

Notes:

- (a) Amount equals 50% of Probable Reserves reported in PrimeWest's December 31, 2002 Reserves report.
- (b) Proved plus Probable figures for December 31, 2002 represent Established Reserves from PrimeWest's December 31, 2002 Reserves Report. Proved plus Probable illustrates the reconciliation between Established Reserves as at December 31, 2002 under NP 2B to Proved plus Probable Reserves as at December 31, 2003 under NI 51-101. See initial discussion above under "Statement of Reserves Data and Other Oil and Gas Information – General".
- (c) Proved plus Probable Reserves reflect at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved plus Probable Reserves.
- (d) Includes Discoveries, Extensions, and Improved Recoveries.
- (e) Includes infill drilling.

Future Net Revenue Reconciliation

The following table sets forth the reconciliation of estimated Future Net Revenues attributable to the Net Proved Reserves of PrimeWest and the Trust for the

year ended December 31, 2003, 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%**

**Proved Reserves
Constant Prices and Costs**

Period and Factor	Before Tax 2003 (MM\$)	Before Tax 2002 (MM\$)
Estimated Net Present Value at December 31, 2002	1,155.3	598.3
Oil and Gas Sales During the Period Net of Production Costs and Royalties ⁽¹⁾	(255.0)	(203.5)
Changes due to Prices, Production Costs and Royalties Related to Forecast Production ⁽²⁾	(106.2)	672.6
Development Costs During the Period ⁽³⁾	103.6	63.1
Changes In Forecast Development Costs ⁽⁴⁾	(95.3)	(79.2)
Changes Resulting from Extensions and Improved Recovery ⁽⁵⁾	48.5	41.8
Changes Resulting from Discoveries ⁽⁵⁾	-	10.5
Changes Resulting from Acquisitions of Reserves ⁽⁵⁾	156.4	40.6
Changes Resulting from Dispositions of Reserves ⁽⁵⁾	(2.3)	(4.5)
Changes Resulting from Technical Reserves Revisions	(58.5)	28.3
Accretion of Discount ⁽⁶⁾	115.5	59.8
Net Change in Income Taxes ⁽⁷⁾	0	0
All Other Changes	(68.9)	(72.5)
Estimated Net Present Value at End of Period	993.1	1,155.3

⁽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.

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 in respect of 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.

North

Boundary Lake

Boundary Lake, discovered in 1955, is located on the B.C.-Alberta border about 40km east of Fort St. John, B.C. PrimeWest operates and has 100% working interest in Boundary Lake Project No. 1 and No. 2, plus smaller adjoining working interests in several wells and a production unit, for an overall average working interest of 91%. Infrastructure consists of three oil batteries. During 2003 PrimeWest produced an average of 1,110 boe/d, 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 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 2003 continued development work on managing a waterflood. In 2003 PrimeWest drilled one well on the western edge of the pool. Future work in Boundary Lake will focus on additional drilling, waterflood enhancement, facilities optimization, and gas conservation to maximize recovery of oil in place and extend the economic life of the reservoir.

Laprise

Laprise is a natural gas asset that during 2003 produced an average of 1,643 boe/d 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 separator and dehydrator. Two wells were drilled and one wellbore was acquired at Laprise in 2003 and for 2004 PrimeWest has budgeted \$2.2 million and plans to upgrade facilities and shoot seismic to delineate additional drilling opportunities.

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 85%, and production averaged 2,159 boe/d during 2003. PrimeWest has 100% ownership in a natural gas processing facility which consists of two sour gas compressors and one sweet gas compressor. Capital expenditures in 2003 totalled \$12.2 million and included the shooting of new 3-D seismic, drilling of 5 wells, and the commencement of a significant upgrade to the facility. The seismic program earned an interest in 9 sections of land to add to PrimeWest's opportunity base. The \$3.5 million facility upgrade involved the implementation of leading edge microbial processing sulphur technology to make the

sour plant emission-free. The upgrade, expected to be complete in 2004, will increase sour gas processing capacity, both for PrimeWest and third party volumes.

Due to the high netback gas and multizone development, PrimeWest sees significant upside opportunities at Valhalla. A \$12 million capital program has been budgeted for 2004, the majority of which will be used for drilling (10 wells planned) and associated infrastructure.

Dawson

PrimeWest holds a 63% average working interest in Dawson, located about 130 km northeast of Grande Prairie, Alberta. During 2003, average daily production at Dawson was 2,467 boe /d, consisting predominantly of natural gas from the shallow Bluesky, Falher, Notikewin, and Paddy formations, and light oil from the deeper Slave Point formation.

This winter-access region contains extensive field infrastructure, including 5 compressor sites and offers high netback gas. Capital expenditures in 2003 totalled \$6 million and included investments in facility infrastructure of \$1 million and \$0.7 million in seismic. For 2004, PrimeWest has budgeted \$5.2 million in capital development in this area.

Stowe

PrimeWest holds an average 97% working interest at Stowe, which includes lands in the Hotchkiss, Naylor and Sutton areas, grouped about 120 km northwest of Peace River in the northwestern 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 1,548 boe/d during 2003. Field facilities at this winter-access area include a refridge site with 2 compressors, an oil battery and 1 additional field compressor. Budgeted capital expenditures of \$2.8 million in 2004 will fund new seismic and a modest drilling program in this area offering high netback gas and infrastructure.

North - Other

During 2003, production from all North properties not discussed above totalled approximately 1,487 boe/d. Included in PrimeWest's "North - Other" area are non-operated interests in the long-life units at Rycroft, Spirit River and Progress. The Rycroft, Spirit River and Progress assets produced a combined average 2003 production of 578 boe/d 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 maintains no infrastructure in the fields. For 2004, PrimeWest has budgeted \$3.7 million to upgrade facilities and drill four new wells within the Spirit River and Rycroft oil units.

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 highly 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 \$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/d.

At year-end 2003, following the acquisition activity, 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 2003 totalled approximately 5,154 boe/d, primarily natural gas. This was an increase of 233% from year-end 2002. PrimeWest derived further revenues through gas processing for third parties.

Caroline is now a well-organized, foundational asset for PrimeWest. It offers significant potential for incremental production and Reserves through low-risk development drilling and acquisitions. Capital expenditures are budgeted at \$11 million for 2004 and will include up to 12 new development wells identified on 3-D seismic targeting natural gas. Included in this figure is \$0.5 million budgeted for facility infrastructure.

Crossfield/Lone Pine Creek

The Crossfield/Lone Pine Creek area produces both natural gas and light to medium crude oil and is located approximately 30km northwest of Calgary, Alberta. Production net to PrimeWest averaged 2,158 boe/d in 2003, 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 and has a 28.8% interest in the facility.

Gaining operatorship of the 142 mmcf/d plant enabled PrimeWest to implement efficiency measures and modernization, significantly reducing unit operating costs of the PrimeWest's production, improving operating netbacks, generating third-party

processing fees and extending the plant's economic life by at least 10 years. PrimeWest has no ownership interest in the plant's sulphur block.

For 2004, PrimeWest has budgeted \$4 million of capital for Crossfield/Lone Pine Creek, including potential development in a Nisku waterflood and upgrades to the sour processing facility.

Thorsby

PrimeWest has a high working interest in Thorsby, located about 30 km southwest of Edmonton, Alberta. Production averaged approximately 4,000 boe/d for 2003 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 2004, PrimeWest has budgeted \$4 million in capital investments in this area, including drilling of 2 new wells, purchase of seismic data, and debottlenecking gathering systems to capitalize on production optimization opportunities. A review of waterflood potential in the Glauconite oil pool will be conducted. The opportunity to consolidate processing with other operators in the area to reduce operating costs is being pursued.

Thunder

PrimeWest operates a high working interest in Thunder, a natural gas prone area, located 50 km northwest of Edmonton, Alberta. Production from the Ellerslie and Glauconite formations at Thunder averaged 428 boe/d during 2003. PrimeWest has two compressor stations in the area.

PrimeWest's 2004 capital budget for Thunder of \$4 million includes plans to run seismic and to drill 2 new wells. Opportunities to process third party gas volumes at the two compression stations are also being pursued. The Thunder area offers coal bed methane potential in addition to conventional shallow gas targets.

South

Brant/Farrow

Located about 65 km southeast of Calgary, Brant Farrow is PrimeWest's most active shallow gas property. PrimeWest has an average 78% working interest over lands in the Brant, Farrow, Mossleigh and Herronton fields. 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. There is additional deeper gas potential in the Mississippian, Basal Quartz and Glauconite formations that PrimeWest is revisiting.

Major infrastructure at Brant Farrow includes 65% ownership of two processing plants with combined capacity of 15 mmcf/d.

Following a successful program of 9 net new wells in 2002, capital investment in 2003 totalled \$16 million and included 26 new operated wells. During 2003, production at Brant/Farrow averaged approximately 1,813 boe/d of sweet, dry natural gas. Exploiting its extensive undeveloped lands and the low exploration risk, PrimeWest has budgeted \$10 million for 2004, which will fund drilling of 18-25 new gas wells as well as an seismic program to help identify new prospects.

Dinosaur/Medicine Hat

These 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, Alberta, 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 50% working interest owner and operator of the Medicine Hat Consolidated Unit No. 2. Combined average production from Dinosaur/Medicine Hat during 2003 was 767 boe/d of sweet, dry natural gas. Field infrastructure at the three units includes compression and gas processing facilities. Downspacing capital is included in the 2004 budget in the Medicine Hat Consolidated Unit #2. This capital will be deferred if partners do not wish to drill in 2004.

Grand Forks

During 2003, production at Grand Forks averaged 2,927boe/d of crude oil (approximately 25 degrees API), primarily from the Sawtooth and Arcs formations. This property, 70 km west of Medicine Hat, Alberta, is PrimeWest's fourth largest producer. This property has an approximate 80% average working interest and is mainly operated. 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 2004 is limited to gas conservation initiatives and some potential pool delineation in the Arcs.

Jumping Pound West/Whiskey Creek

PrimeWest has a 14.6% working interest in the non-operated, low decline area of 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 2003 averaged 395 boe/d 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 property of Whiskey Creek, PrimeWest's average working interest is approximately 35%. Following tie-in of a well drilled in 2002 and the drilling and tie-in of an additional well in 2003, a total of 2 wells were on production and produced a combined 1.2 mmcf/d net sales at year-end. Both properties have deep-thrusted Mississippian reservoirs characterized by stable, long-life production. In 2003, one well was drilled in Whiskey Creek and will be brought on stream in the fourth quarter of 2004. However, at the date hereof, PrimeWest's natural gas production was shut-in at Whiskey Creek as a result of the operator increasing the amount of production that other producers direct to the 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 be near the end of 2004.

Saskatchewan

PrimeWest's Saskatchewan area is comprised mainly of the Java and Premier properties and consists primarily of heavy oil production from the Cantaur and Roseay formations. In 2003, 545 boe/d was produced from Java and Premier combined. A seismic shoot in February of 2003 identified some drilling opportunities that are in the 2004 budget of \$1.8 million.

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 acquire a working interest in successful exploration results, including development drilling.

Oil and Natural Gas Properties and Wells

The following table summarizes, as at December 31, 2003, PrimeWest's interests in Producing and non-Producing wells.

	Producing Wells				Non-Producing Wells			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	894	462	2,801	1,814	400	207	209	135
British Columbia	248	128	49	32	22	11	11	7
Saskatchewan	436	225	33	21	97	50	0	0
Total	1,578	815	2,883	1,867	519	268	220	142

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
<i>North</i>			
Boundary Lake	18,301	15,038	0
Laprise	6,448	3,919	1,215
Valhalla	26,813	18,955	2,725
North Other	68,761	21,466	2,285
Dawson	211,768	123,871	59,074
Stowe	174,962	143,289	35,040
<i>Central</i>			
Thunder	55,360	22,070	10,713
Caroline	51,053	35,711	160
Crossfield/Lone Pine			
Creek	4,393	3,234	2,976
Thorsby	53,768	31,991	9,280
<i>South</i>			
Jumping			
Pound/Whiskey Creek	5,278	1,087	831
Grand Forks	34,972	17,413	625
East Other	26,046	19,639	1,951
Brant Farrow	113,939	83,404	13,745
Dinosaur/Medicine Hat	7,198	4,181	191
Saskatchewan	8,849	6,078	322
<i>Non-Core</i>			
Kaybob	4,200	1,420	0
Meekwap	7,040	3,124	2,305
Seal	12,640	8,106	1,344
Other	33,494	14,254	1,728
GORR	176,791		14,560
Total:	1,102,074	578,250	161,071

Additional Information Concerning Abandonment and Reclamation Costs

The following table discloses the abandonment and reclamation costs PrimeWest anticipated incurring as at December 31, 2003, 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 and reclamation costs in respect of 2,976 Net wells.

PrimeWest has established an abandonment and reclamation fund to finance any future environmental expenditure. 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 spending profile. In 2003, PrimeWest provided \$0.50/boe of production into this fund and will continue with the same funding level for 2004. As of December 31, 2003, there is an unused cash balance of \$8.2 million in the fund.

Period	Abandonment and Reclamation Costs Net of Salvage Value Undiscounted (\$M)	Abandonment and Reclamation Costs Net of Salvage Value Discounted at 7% (\$M)
Total as at December 31, 2003	118,950	19,794
Anticipated to be paid in 2004	5,492	5,307
Anticipated to be paid in 2005	5,260	4,752
Anticipated to be paid in 2006	4,700	3,969

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 deduction of the royalties on underlying oil and gas properties held by its operating subsidiaries. Therefore, it can be expected that no income tax liability would be incurred by PrimeWest 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, 2003.

	Property Acquisition Costs		Exploration Costs	Development Costs
	Proved Properties	Unproved Properties		
Total (\$M)	200.5	34.0	5.7	92.9

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,

2003 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
Oil	-	-	16	4.4
Natural Gas	-	-	79	51.4
Service Wells	-	-	-	-
Dry Holes	-	-	10	7.1
Total	-	-	105	62.9

PrimeWest does not engage in high risk exploration and therefore drilled no Exploratory Wells in 2003. PrimeWest engages in development drilling along with acquisitions to try and offset natural production decline and add to Reserves. Specific details on development plans and 2004 capital budgets for each of PrimeWest's important properties is 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 2004 using Forecast Prices and Costs. At December 31, 2003, PrimeWest estimated its 2004 production would average approximately 30,000 boe/d.

	Light and Medium Crude Oil (mbbl)	Heavy Oil (mbbl)	Natural Gas (mmcf)	Natural Gas Liquids (mbbl)
2004 Estimated Total Production	1,998	733	43,492	1,008

Production History

The following table discloses, on a quarterly basis for the year ended December 31, 2003, 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, etc.)			
		Price Received	Royalties Paid	Production Costs	Netbacks
Light/medium/heavy Oil (bbls/day)					
1 st Quarter	8,142	\$ 38.32	\$ 8.36	\$ 6.43	\$ 28.86
2 nd Quarter	8,222	33.60	5.85	6.66	22.31
3 rd Quarter	7,913	32.95	5.86	6.58	21.95
4 th Quarter	8,189	\$ 31.27	\$ 5.63	\$ 6.58	\$ 21.20
Natural Gas (mmcf/day)					
1 st Quarter	140.3	\$ 7.07	\$ 1.79	\$ 1.14	\$ 4.91
2 nd Quarter	137.9	6.17	1.46	1.08	4.14
3 rd Quarter	131.4	5.65	1.35	0.90	3.68
4 th Quarter	126.9	\$ 5.54	\$ 1.21	\$ 1.26	\$ 3.03
Natural Gas Liquids (bbls/day)					
1 st Quarter	3,030	\$ 40.77	\$ 10.83	\$ 6.65	\$ 23.29
2 nd Quarter	2,800	32.71	7.97	6.58	18.16
3 rd Quarter	2,811	33.04	8.55	6.51	17.98
4 th Quarter	2,779	\$ 34.49	\$ 9.52	\$ 6.51	\$ 18.46

Note:

1. Before deduction of royalties.

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, 2003.

Field	Light, Medium & Heavy Crude Oil (mbbls)	Natural Gas (mmcf)	Natural Gas Liquids (mbbls)	Average Daily Production (boe/d)
NORTH	899	16,484	156	10,415
Boundary Lake	378	153	2	1,110
Laprise	7	3,069	79	1,643
Valhalla	22	4,225	62	2,159
North Other	132	2,390	13	1,488
Dawson	292	3,652	0	2,467
Stowe	66	2,995	0	1,548
SOUTH	1,161	7,324	72	6,719
Jumping				
Pound/Whiskey Creek	-	1,170	49	667
Grand Forks	942	662	15	2,927
Brant Farrow	39	3,695	7	1,813
Dinosaur / Med Hat	1	1,683	-	767
Saskatchewan	179	114	1	545
CENTRAL	251	19,775	730	11,729
Thunder	10	827	8	428
Caroline	81	8,512	382	5,154
Crossfield/LPC	25	4,018	93	2,151
Thorsby	135	6,418	247	3,996
NON-CORE	417	3,427	48	2,849
Kaybob	125	88	8	404
Meekwap	138	93	7	441
Seal	2	1,281	-	591
Other	151	1,965	33	1,413
GORR	235	1,886	36	1,604
TOTAL	2,962	48,896	1,042	33,316

It is anticipated that production from PrimeWest's non-operated Ells property in Northeast Alberta (included in the "Non-Core - Other" row of the foregoing table) will be subject to shut-in by the Alberta Energy and Utilities Board in April 2004, upon spring break-up taking place, 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 Northeastern Alberta. The process outlined by the EUB is expected to result in the shut-in of production as outlined above. PrimeWest is seeking compensation for the loss of revenue that will result from the shut-in of this production.

An additional shut-in at PrimeWest's non-operated Whiskey Creek area is as a result of the operator increasing the amount of production that other producers direct to the 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 be through 2004.

PrimeWest's estimates for 2004 production volumes take into account the approximately 1,000 boe/d that will be lost due to these shut-ins.

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 /d). 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 issue of such a licence requires the approval of the Governor in Council.

The governments of Alberta, British Columbia and Saskatchewan also regulate the volume 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 issue 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 U.S. and Mexico became effective. The NAFTA carries forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the U.S. 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 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 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. It is generally believed that the oil and gas industry, as a major producer of carbon dioxide (as a necessary by-product and emission of hydrocarbon production), will bear a disproportionately large share of the anticipated cost of implementation.

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 oil and natural gas Reserves. Any resulting decline in PrimeWest's cash flow could reduce distributions.

PrimeWest uses financial derivative instruments and other hedging mechanisms to try 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 experience if commodity prices were to increase. In addition, its commodity hedging activities could expose PrimeWest to losses. Such losses could occur under various circumstances, including where the other party to a hedge does not perform its obligations under the hedge 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 as well as affect the market price of the Trust Units.

Higher operating costs for the underlying properties of PrimeWest will directly decrease the amount of cash flow received by the Trust and, therefore, may reduce distributions to our Unitholders. Electricity, chemicals, supplies, reclamation and abandonment and labour costs are a few of the 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. Hence, the timing and amount of capital expenditures may affect the amount of net cash flow received by the Trust and, as a consequence, the amount of cash available to distribute to Unitholders. Therefore, 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 under the credit facility. Funds used for such purposes will not be payable to the Trust. As a consequence, 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 that it received for production which, in turn, could reduce distributions to Unitholders as well as 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 be subject to unfavourable price changes to the extent that PrimeWest 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 oil and natural gas 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 Reserves. 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 affect the market price of the Trust Units and distributions to Unitholders.

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

- historical production in the area compared with 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 the relevant evaluations were prepared. Many of these factors are subject to change and are beyond PrimeWest's control. If these factors, assumptions and prices 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 reserve acquisitions 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.

Some of PrimeWest's properties are not operated by PrimeWest 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, 2003, approximately 20% of PrimeWest's daily production was from properties operated by third parties. To the extent a third-party operator fails to perform its functions efficiently or becomes insolvent, PrimeWest's revenue may be reduced. Third party operators also make estimates of future capital expenditures more difficult.

Further, the operating agreements which 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, such as Unitholders, 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 the operators of PrimeWest's 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 to the providers of the Trust and PrimeWest's Credit Facility reduces 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 required to be applied to the debt before payment of any amounts to the Unitholders. 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 restricted.

The lenders under the Credit Facility have been provided with a security interest in substantially all of the Trust's 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 not only 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. PrimeWest may become liable for damages arising from these 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 1997 Kyoto Protocol to the United Nation's Framework Convention on Climate Change, known as 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 PrimeWest's 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 the net capitalized costs exceed this limit, PrimeWest must charge the amount of the excess against earnings. 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 PrimeWest 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 occur, PrimeWest's entitlement to the production from such purchased 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.
- The Trust would cease to be eligible for the capital gains refund mechanism available under Canadian tax laws if it ceased to be a mutual fund trust.
- 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. If an RESP holds non-qualified Trust Units, it may have its registration revoked by the Canada Customs and Revenue Agency.

In addition, the Trust may take certain measures in the future to the extent the Trust believes them necessary to ensure that the Trust 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.

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

The market price of the Trust's 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's 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 these offerings if, for example, the cash flow, production or Reserves from the acquired assets do not reflect the additional number of trust units issued to acquire those assets. Unitholders may also suffer dilution in connection with future issuances of Trust Units to effect acquisitions.

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 the United States or Canada.

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.

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 a potential bidder 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 rights 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 a redemption is subject to limitations. Any securities which may be distributed *in specie* to Unitholders in connection with a redemption may not be listed on any stock exchange and a market may not develop for such securities. In addition, there may be resale restrictions imposed by law upon the recipients of the securities pursuant to the redemption right.

ITEM 7: SELECTED CONSOLIDATED FINANCIAL INFORMATION

Reference is made to the consolidated financial statements of the Trust contained in the Annual Report, which financial statements are hereby incorporated into this Annual Information Form by reference.

Selected Annual Information

(\$000's except per Trust Unit)	For the Year Ended December 31				
	2003	2002	2001	2000	1999
Earnings Information					
Total Revenue, net of royalties	239,636	264,309	306,515	156,561	83,063
Expenses, including D, D & A and taxes	242,707	263,690	226,979	100,949	77,078
Net Income	90,342	619	79,536	55,612	5,985
Net Income per Trust Unit (\$)					
Basic	1.96	0.02	3.12	5.00	0.72
Diluted	1.95	0.02	3.08	4.84	0.72
Cash Distribution Information					
Cash Available for Distribution	192,613	159,546	236,834	79,832	37,728
Cash Distribution to Trust Unitholders	192,613	157,951	234,465	79,033	37,351
Cash Distribution per Trust Unit (\$)	4.32	4.80	9.24	7.08	4.40
Balance Sheet Information					
Total Assets	1,679,996	1,502,522	1,522,310	441,573	320,210
Long Term Debt, including current portion	250,063	225,000	195,067	79,046	92,286
Average Trust Units Outstanding (000's)	46,016	34,135	25,633	11,162	8,491

Selected Quarterly Information

(\$000's except per Trust Unit)

	For the Quarters Ended - 2003			
	March 31	June 30	September 30	December 31
Total Revenue, net of royalties	94,005	85,642	77,307	73,024
Expenses including D, D & A and taxes	71,982	24,024	69,876	73,754
Net Income (Loss).....	22,023	61,618	7,431	(730)
Net Income (Loss) per Trust Unit				
Basic	0.52	1.35	0.16	(0.01)
Diluted	0.52	1.34	0.16	(0.01)
	For the Quarters Ended - 2002			
	March 31	June 30	September 30	December 31
Total Revenue, net of royalties	69,464	62,265	63,791	68,789
Expenses including D, D & A and taxes	63,492	68,454	55,613	76,131
Net Income	5,972	(6,189)	8,178	(7,342)
Net Income per Unit				
Basic	0.20	(0.20)	0.24	(0.20)
Diluted	0.16	(0.20)	0.24	(0.20)

In addition, applicable securities laws require the Trust to provide certain historical financial statements of Cypress in connection with any offering of Trust Units. Those financial statements are attached to this Annual Information Form as Schedule A.

ITEM 8: MANAGEMENT'S DISCUSSION AND ANALYSIS

Reference is made to the information under the heading "Management's Discussion and Analysis" in the Annual Report, which information is hereby incorporated into this Annual Information Form by reference.

ITEM 9: 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.

ITEM 10: 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, 2003, are as follows:

Name and Present Principal Occupation or Employment	Director of PrimeWest Since	Municipality of Residence	Trust Units Beneficially Owned or over which Control or Discretion is Exercised as at December 31, 2003
HAROLD P. MILAVSKY ⁽¹⁾⁽²⁾⁽³⁾ Chairman Quantico Capital Corp.	1996	Calgary, Alberta	17,850
BARRY E. EMES ⁽³⁾ Partner Stikeman Elliott LLP	1996	Calgary, Alberta	5,370
HAROLD N. KVISLE ⁽¹⁾⁽²⁾⁽³⁾ President TransCanada PipeLines Limited	1996	Calgary, Alberta	14,007
KENT J. MACINTYRE Independent Businessman	1996	Calgary, Alberta	44,302 ⁽⁴⁾
MICHAEL W. O'BRIEN ⁽¹⁾⁽²⁾⁽³⁾ Corporate Director	2000	Canmore, Alberta	6,895
JAMES W. PATEK ⁽¹⁾⁽²⁾⁽³⁾ President Patek Energy Consultants	2003	Fripp Island, South Carolina, U.S.A.	Nil
W. GLEN RUSSELL ⁽¹⁾⁽²⁾⁽³⁾ Management Consultant	2003	Calgary, Alberta	Nil

Notes:

1. Member of the Audit and Reserves Committee.
2. Member of the Compensation Committee.
3. Member of the Corporate Governance and Nominating Committee.
4. Consists of 100,000 Class A Exchangeable Shares (which, at December 31, 2003, were exchangeable into 44,302 Trust Units), all of which were held by Canadian Income Fund Group Inc., a corporation wholly-owned by Mr. MacIntyre.

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 Pipelines Limited (October 1999 to May 2001) and prior to October 1999 was President of Fletcher Challenge Energy Canada Inc.; (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) and prior to December 1999 was Executive Vice-President of Sunoco Inc., a wholly-owned subsidiary of Suncor Energy Inc.; and (d) Mr. Patek who prior to June 2000 was President of Fletcher Challenge Energy Canada.

Officers

The name, municipality of residence, position held and holdings of Trust Units by each officer of PrimeWest on December 31, 2003 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, 2003⁽¹⁾
Donald A. Garner Calgary, Alberta	President and Chief Executive Officer Since January 2003	39,473
Timothy S. Granger Calgary, Alberta	Chief Operating Officer Since January 2003	5,677
Ronald J. Ambrozy Calgary, Alberta	Vice-President, Business Development Since October 1997	13,690
Dennis G. Feuchuk Calgary, Alberta	Vice-President, Finance and Chief Financial Officer Since October 2001	9,652

Note:

1. Includes holdings of Class A Exchangeable Shares exchanged into Trust Units at a ratio of 0.44302:1.

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.

An engineering graduate of the University of Saskatchewan, Mr. Garner has undertaken postgraduate studies through the Wharton School, The American Graduate School of International Management and the University of Calgary.

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 and corporate 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 and has completed the Richard Ivey School of Business Executive Development Program and is a Certified Management Accountant.

Employees

As of December 31, 2003, PrimeWest had 148 permanent, full time employees 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 which 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.

ITEM 11: 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, 2003, contained in the Annual Report.

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, 2003 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, 2003 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.

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/d</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/d</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/d</i>	barrels of oil equivalent /day
<i>mmcf/d</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.

Definitions

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

Annual Report means the 2003 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 18, 2004.

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;

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, 2003, 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 \$390 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 Agreement.

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 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, 2003.

Gross means:

- (a) in relation to PrimeWest's interest in production or Reserves, its "company gross Reserves", which are PrimeWest's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of PrimeWest; or
- (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 National Energy Board.

Net means:

- (a) in relation to PrimeWest's interest in Production or Reserves, PrimeWest's working interest (operating or non-operating) share after deduction of royalty obligations, plus PrimeWest's royalty interests 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 those 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 reporting company must believe that there is 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 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 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, 2003.

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 by PrimeWest to the Trust pursuant to the Royalty Agreement, which royalty equals 99% of Royalty Income.

Royalty Agreement 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, 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 Charges, 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 Agreement, 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 Charges.

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.

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
FINANCIAL STATEMENTS OF CYPRESS ENERGY INC.
AUDITORS' REPORT

TO: The Shareholders of Cypress Energy Inc.

We have audited the consolidated balance sheets of Cypress Energy Inc. as at December 31, 2000, 1999 and 1998 and the consolidated statements of income and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in Canada. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2000, 1999 and 1998 and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in Canada.

Calgary, Canada
April 16, 2001

(signed) Ernst & Young LLP
Chartered Accountants

CYPRESS ENERGY INC.
CONSOLIDATED BALANCE SHEETS

As at December 31
(in thousands of dollars)

	2000		1999		1998
Assets					
Current assets (note 6)					
Accounts receivable	\$ 31,813	\$	17,112	\$	9,531
Deposits, prepaids and other	2,531		2,452		542
Assets held for resale (note 3)	-		5,395		-
	34,344		24,949		10,073
Property and equipment (note 4)	368,479		270,572		136,489
	\$ 402,823	\$	295,531	\$	146,562
Liabilities and Shareholders' Equity					
Current Liabilities					
Accounts payable and accrued liabilities	\$ 47,870	\$	25,511	\$	10,392
Long-term debt (note 6)	113,889		92,760		34,559
Deferred rental obligation	532		772		-
Future income taxes (note 8)	61,743		8,017		518
Provision for future site restoration	3,972		2,043		618
	180,136		103,592		35,695
Shareholders' Equity					
Share capital (note 7)	149,747		155,478		96,921
Retained earnings	25,070		10,950		3,554
	174,817		166,428		100,475
	\$ 402,823	\$	295,531	\$	146,562

Commitments and contingencies (notes 6 and 10)
See accompanying notes

CYPRESS ENERGY INC.

**CONSOLIDATED STATEMENTS OF INCOME
AND RETAINED EARNINGS**

**Years ended December 31
(in thousands of dollars except per share amounts)**

	2000	1999	1998
Revenue			
Petroleum and natural gas sales	\$ 186,763	\$ 78,168	\$ 34,124
Royalties, net of ARTC	(45,180)	(17,270)	(7,098)
	141,583	60,898	27,026
Expenses			
Production	18,394	11,983	6,235
General and administrative	4,453	3,508	1,894
Interest	7,785	3,758	1,281
Depletion, depreciation and site restoration	41,912	26,417	14,332
	72,544	45,666	23,742
Income before income taxes	69,039	15,232	3,284
Income taxes			
Capital taxes	1,178	746	165
Future income taxes (note 8)	29,363	7,049	1,527
	30,541	7,795	1,692
Net income for the year	38,498	7,437	1,592
Retained earnings, beginning of year	10,950	3,554	1,962
Adjustment to reflect adoption of new income tax accounting policy (note 11)	(20,195)	-	-
Acquisition of shares in excess of carrying value	(4,183)	(41)	-
Retained earnings, end of year	\$ 25,070	\$ 10,950	\$ 3,554
Earnings per common share (note 9)			
Basic Class A and Class B shares	\$ 0.90	\$ 0.20	\$ 0.06
Fully diluted	\$ 0.84	\$ 0.20	\$ 0.06

See accompanying notes

CYPRESS ENERGY INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years ended December 31
(in thousands of dollars except per share amounts)

	2000	1999	1998
Cash provided by (used in):			
Operating Activities			
Net income for the year	\$ 38,498	\$ 7,437	\$ 1,592
Non-cash items			
Depletion, depreciation and site restoration	41,912	26,417	14,332
Future income taxes	29,363	7,049	1,527
Cash flow from operations	109,773	40,903	17,451
Net change in non-cash working capital items	12,734	1,561	2,525
	122,507	42,464	19,976
Funding Activities			
Increase in long-term debt	21,129	31,373	7,043
Issue of Class A flow-through shares	-	3,731	1,995
Issue of Special Warrants	-	-	20,600
Issue of Class A shares on exercise of stock options	1,378	991	688
Repurchase of Class A shares	(9,577)	(129)	(3)
Share issue and repurchase costs (note 7)	(47)	(1,724)	(1,157)
	12,883	34,242	29,166
Investing Activities			
Additions to property and equipment	(135,096)	(79,732)	(48,917)
Cash expenditures on acquisitions (note 5)	-	(3,682)	-
Cash acquired on acquisition (note 5)	-	6,905	-
Site restoration and abandonment expenditures	(294)	(197)	(225)
	(135,390)	(76,706)	(49,142)
Change in cash and cash, beginning and end of year	-	-	-
Cash flow from operations per common share (note 9)			
Basic Class A and Class B shares	\$ 2.56	\$ 1.09	\$ 0.68
Fully diluted	\$ 2.39	\$ 1.04	\$ 0.60

See accompanying notes

CYPRESS ENERGY INC

Notes to the Consolidated Financial Statements

December 31, 2000, 1999 and 1998
(thousands of dollars except per share amounts)

1. DESCRIPTION OF THE BUSINESS

Cypress Energy Inc. ("Cypress" or the "Company") was incorporated under the laws of the Province of Alberta on November 16, 1995. The Company's business is related to the acquisition of petroleum and natural gas rights and the exploration for, and the development, exploitation and production of, petroleum and natural gas in Canada.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles which, in management's opinion, have been properly prepared within reasonable limits of materiality and within the framework of the accounting policies summarized below.

Property and Equipment

Capitalized Costs

The Company follows the full cost method of accounting in accordance with the guidelines issued by the Canadian Institute of Chartered Accountants whereby all costs associated with the exploration for and development of petroleum and natural gas reserves, whether productive or unproductive, are capitalized and charged to income as set out below. Such costs include lease acquisition, drilling, geological and geophysical, equipment costs, staff costs and certain overhead expenses directly related to exploration and development activities. Costs of acquiring and evaluating unproved properties are excluded from depletion calculations until it is determined whether or not proved reserves are attributable to the properties or when impairment occurs.

Gains or losses are not recognized upon disposition of petroleum and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the rate of depletion of 20% or more.

Depletion and Depreciation

Depletion of petroleum and natural gas properties and depreciation of production equipment is provided on accumulated costs using the unit of production method based on estimated proven petroleum and natural gas reserves, before royalties, as determined by independent engineers. For purposes of the depletion calculation natural

gas reserves and production are converted to equivalent barrels of oil using the relative energy content of six thousand cubic feet of natural gas to one barrel of oil. Depreciation of gas plants and related equipment is provided for on a straight-line basis over fifteen years.

The depletion and depreciation cost base includes total capitalized costs, less costs of unproved properties, plus a provision for future development costs of proven undeveloped reserves.

Ceiling Test

The Company applies a ceiling test to capitalized costs to ensure that such costs do not exceed the aggregate of estimated future net revenues from production of proven reserves and the costs of unproved properties, net of impairment allowances, less estimated future production costs, general and administrative costs, financing costs, site restoration and abandonment costs, and income taxes. Future net revenues are estimated using year-end prices and costs without escalation or discounting, and the income tax and Alberta Royalty Tax Credit legislation in effect at the year end.

Office furniture and equipment

Office furniture and equipment are carried at cost and are depreciated on a straight-line basis over the estimated useful lives of the assets at rates varying between 15% and 20%.

Future site restoration and abandonment costs

The estimated cost of future site restoration and abandonment is based on the current cost and the anticipated method and extent of site restoration and abandonment in accordance with existing legislation and industry practice. The annual charge, provided for on a unit of production basis, is accounted for as part of depletion, depreciation and site restoration expense. Site restoration expenditures are charged to the accumulated provision account as incurred.

Measurement uncertainty

The amounts recorded for depletion and depreciation of property and equipment and the provision for future site restoration and abandonment costs are based on estimates. The ceiling test calculation is based on estimates of proven reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the consolidated financial statements of changes in such estimates in future years could be significant.

Joint operations

Substantially all of the Company's exploration and development activities are conducted jointly with others, and accordingly the consolidated financial statements reflect only the Company's proportionate interest in such activities.

Future Income Taxes

The Company follows the liability method in accounting for income taxes. Under this method future tax assets and liabilities are determined based on differences between financial reporting and income tax bases of assets and liabilities, and are measured using enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in net income in the period in which the change occurs.

Flow-through shares

A portion of the Company's exploration and development activities is financed through proceeds received from the issue of flow-through shares. Under the terms of the flow-through share issues, the tax attributes of the related expenditures are renounced to the share subscribers. To recognize the foregone tax benefits to Cypress, the flow-through shares issued are recorded net of the tax benefits renounced as the expenditures are incurred and renounced with a corresponding future tax liability recorded.

Financial Instruments

Financial instruments of the Company consist mainly of accounts receivable, accounts payable and accrued liabilities and long-term debt. As at December 31, 2000, 1999 and 1998 there are no significant differences between the carrying amounts reported on the balance sheet and the estimated fair values of the financial instruments.

The Company also from time to time employs financial instruments to manage exposures related to interest rates, Canada/U.S. exchange rates and commodity prices. These instruments are not used for speculative trading purposes.

Gains and losses on exchange rate and commodity price hedges are included in revenues upon the sale of the related production provided there is reasonable assurance that the hedge is and will continue to be effective. Amounts received or paid under interest rate swaps are recognized in interest expense on an accrual basis.

Stock Based Compensation Plan

The Company follows the intrinsic value method of accounting for stock-based compensation plans. Consideration paid by employees, consultants or directors on the

exercise of stock options is credited to share capital. Options are issued at current market value, consequently no compensation expense is recorded.

3. ASSETS HELD FOR RESALE

On November 1, 1999 the Company acquired assets in the Thorsby area for \$5.5 million. The Company has granted a third party an irrevocable option, exercisable through May 14, 2000, to purchase these assets for a purchase price equal to the original acquisition cost of \$5.5 million subject to adjustments relating to operations from November 1, 1999 to the option exercise date. Assets held for resale has been shown net of revenue attributable to the property during the option period to date of \$0.1 million. On March 3, 2000 the option was exercised and the properties were sold to the option holder.

4. PROPERTY AND EQUIPMENT

	2000	1999	1998
Petroleum and natural gas properties	\$ 449,895	\$ 312,624	\$ 153,392
Office furniture and equipment	1,170	845	497
	451,065	313,469	153,889
Accumulated depletion and depreciation	(82,586)	(42,897)	(17,400)
Net property and equipment	\$ 368,479	\$ 270,572	\$ 136,489

At December 31, 2000 the Company estimates its liability for future site restoration and abandonment to be \$12.6 million (net of the year-end accumulated provision) (1999 - \$7.8 million; 1998 - \$3.3 million).

At December 31, 2000 \$34.5 million (1999 - \$31.4 million; 1998 - \$9.5 million) of costs associated with unproved properties have been excluded from costs subject to depletion.

5. ACQUISITIONS

a) Acquisition of Canadian Conquest Exploration Inc.

In May, 1999, the Company acquired all of the common shares of Canadian Conquest Exploration Inc. ("Canadian Conquest"). Canadian Conquest was amalgamated with Cypress effective September 1, 1999. The acquisition was accounted for by the purchase method and the purchase price was allocated as follows:

Net working capital	\$	1,140
Property and equipment		75,396
Long-term debt		(26,828)
Rent obligation		(1,207)
Provision for deferred taxes		(1,215)
Provision for future site restoration		(702)
Total Consideration	\$	46,584
Consideration was comprised of		
Cash	\$	3,619
Issue of 10,479,200 Class A shares at \$4.10 per share		42,965
Total Consideration	\$	46,584

1) Acquisition of Gardiner Exploration Limited

In July, 1999, the Company acquired all of the common shares of Gardiner Exploration Limited ("Gardiner"). Gardiner was amalgamated with Cypress effective September 1, 1999. The acquisition was accounted for by the purchase method and the purchase price was allocated as follows:

Cash	\$	6,905
Net non-cash working capital		623
Property and equipment		8,280
Total Consideration	\$	15,808
Consideration was comprised of		
Cash	\$	63
Issue of 2,581,200 Class A shares at \$6.10 per share		15,745
Total Consideration	\$	15,808

6. LONG-TERM DEBT

At December 31, 2000, the Company had a \$180.0 million syndicated revolving term credit facility, which was subsequently increased to \$200.0 million. The loan facility provides that advances may be made by way of direct advances, bankers acceptances or U.S. dollar LIBOR advances which bear interest at the applicable bankers' acceptances or LIBOR rates plus an applicable bank fee per annum or the bank's prime lending rate depending on the nature of the advance. The authorized limit is subject to an annual review and redetermination of the Company's borrowing base by the bank.

The effective interest rate on the amounts outstanding under the facility at December 31, 2000 was 6.8% (1999 - 5.7%; 1998 - 5.9%).

Cash interest paid for the years ended December 31, 2000, 1999 and 1998 approximated interest expense.

Collateral pledged for the facility consists of a fixed and floating charge demand debenture in the principal amount of \$300.0 million conveying a floating charge on all of the property and assets of the Company.

While the credit facility is demand in nature, the bank has stated that it is not its intention to call for repayment before December 31, 2001 provided that there is no adverse change in the Company's financial position. Accordingly, the loan advances are classified as long-term.

At December 31, 2000, the Company was party to a contract to fix the interest rate on \$9.0 million of its loan advances at approximately 6.8% until March 11, 2002. In addition, the counterpart to the contract has an option to extend the contract at its expiry to March 11, 2004 at the same rate and for the same notional amount. If the Company were required to settle this contract at December 31, 2000, a cash payment of approximately \$0.2 million would be required.

7. SHARE CAPITAL

Authorized:

Unlimited number of Class A and Class B common voting shares

Issued:

	2000		1999		1998	
	Number of Shares (000s)	Amount	Number of Shares (000s)	Amount	Number of Shares (000s)	Amount
Class A Shares						
Outstanding, beginning of year	42,521	\$ 161,211	28,256	\$ 97,867	23,408	\$ 74,587
On acquisition of Canadian Conquest (see note 5)	-	-	10,479	42,965	-	-
On acquisition of Gardiner (see note 5)	-	-	2,581	15,745	-	-
Private Placement (a)	-	-	746	3,731	547	1,995
Adjustment to reflect adoption of new income tax accounting policy (see note 11)	-	(1,668)	-	-	-	-
Special Warrants financings (b)	-	-	-	-	4,000	20,600
Repurchase of Class A Shares	(1,438)	(5,394)	(24)	(88)	(1)	(3)
Exercised stock options	410	1,378	483	991	302	688
Class A Shares						
Outstanding, end of year	41,493	155,527	42,521	161,211	28,256	97,867
Class B Shares (c)						
Outstanding, beginning and end of year	558	5,580	558	5,580	558	5,580
		161,107		166,791		103,447
Share issue costs (d)		(4,179)		(4,132)		(3,173)
Tax benefits renounced (a)		(7,181)		(7,181)		(3,353)
Total Share Capital		\$ 149,747		\$ 155,478		\$ 96,921

- a) On December 31, 1999 Cypress issued 746,263 (1998 - 546,574) flow-through shares at \$5.00 (1998 - \$3.65) per share resulting in gross proceeds of \$3.7 million (1998 - \$2.0 million).

During 2000, in accordance with the terms of the flow-through share offering and pursuant to certain provisions of the Income Tax Act (Canada), Cypress incurred aggregate exploration expenditures of \$3.7 million and renounced the tax benefits to the purchasers of its flow-through shares.

- b) On March 30, 1998, Cypress completed a Special Warrants financing consisting of 4,000,000 Special Warrants at \$5.15 per Special Warrant for gross proceeds of \$20.5 million. The Special Warrants were converted in April, 1998 into 4,000,000 Class A shares for no additional consideration.
- c) The Class B shares are convertible at the option of Cypress into Class A shares at any time after March 1, 2000 and before March 1, 2002. After March 1, 2002 the Class B shares are convertible at the option of the shareholder until June 30, 2002 when all remaining Class B shares will be deemed to be converted. The number of Class A shares to be issued on conversion of each Class B share will be equal to \$10.00 divided by the greater of \$1.00 or the current market price of the Class A shares at the conversion date.
- d) The total share issue costs incurred related to the 2000, 1999 and 1998 share issues were \$0.05 million, \$1.7 million and \$1.2 million respectively. A charge to share capital of \$0.05 million (1999 - \$1.0 million; 1998 - \$0.6 million) was recorded to reflect these costs, with no associated estimated future tax benefit in 2000 (1999 - estimated deferred tax benefit of \$0.7 million; 1998 - \$0.6 million).

Stock options

The Company has established a stock option plan whereby options may be granted to its directors, officers and employees. The exercise price of each option equals the market price of the Company's stock on the date of the grant and an option's maximum term is five years. The stock options are exercisable over a five-year period from the date of grant. The options are exercisable on a cumulative basis of 20% immediately and 20% per year for each of the first four years of the plan. No compensation expense is recognized for the plan when stock options are issued or exercised. The following is a continuity of stock options outstanding for which shares have been reserved:

	2000		1999		1998	
	Shares (000s)	Weighted Average Exercise Price (\$)	Shares (000s)	Weighted Average Exercise Price (\$)	Shares (000s)	Weighted Average Exercise Price
Balance, beginning of year	3,582	\$ 3.96	2,181	\$ 3.06	1,456	\$ 2.51
Granted	1,009	\$ 6.82	1,925	\$ 4.48	1,119	\$ 3.55
Exercised	(410)	\$ 3.39	(483)	\$ 2.05	(302)	\$ 2.05
Cancelled	(43)	\$ 3.53	(41)	\$ 3.37	(92)	\$ 2.99
Balance, end of year	4,138	\$ 4.71	3,582	\$ 3.96	2,181	\$ 3.06

The following summarizes information about stock options outstanding at December 31, 2000:

Range of Exercise Prices	Number Outstanding at 12/31/00 (000s)	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Number Exercisable at 12/31/00 (000s)	Weighted Average Exercise Price
\$ 1.78 to \$ 2.75	212	1.1	\$ 2.21	181	\$ 2.12
\$ 3.15 to \$ 3.75	1,065	2.6	\$ 3.48	492	\$ 3.52
\$ 4.10 to \$ 4.95	1,805	3.5	\$ 4.53	709	\$ 4.52
\$ 5.45 to \$ 6.00	397	4.3	5.94	81	5.96
\$ 6.85 to \$ 7.30	659	4.9	\$ 7.29	132	\$ 7.29
	4,138	3.4	\$ 4.71	1,595	\$ 4.24

8. FUTURE INCOME TAXES

The liability for future income taxes is primarily due to the excess carrying value of property plant and equipment over the associated tax basis.

The effective tax rate used in the financial statements differs from the statutory income tax rate due to the following:

	2000	1999	1998
Statutory tax rate	44.7%	45.0%	45.0%
Calculated income tax expense	\$ 30,840	\$ 6,796	\$ 1,478
Increase (decrease) in income tax resulting from:			
Non-deductible Crown payments (net of ARTC)	15,007	4,757	1,174
Resource allowance	(16,103)	(6,321)	(2,445)
Other	(381)	1,817	1,320
Total future income tax	29,363	7,049	1,527
Large corporation and capital tax	1,178	746	165
Income tax provision	\$ 30,541	\$ 7,795	\$ 1,692

As at December 31, 2000, the Company has exploration and development costs, undepreciated capital costs and unamortized share issue costs and loss carryforwards available for deduction against future taxable income in aggregate of approximately \$209.2 million (1999 - \$185.5 million; 1998 - \$106.5 million).

Cash tax paid for the years ended December 31, 2000, 1999 and 1998 approximated the amounts reported above for large corporation and capital taxes for each of the years.

9. PER SHARE AMOUNTS

The calculations of "earnings per common share-basic" and "cash flow from operations per common share - basic" are based on the weighted average number of Class A shares

outstanding during the year ended December 31, 2000 of 42.9 million (1999 - 36.5 million; 1998 - \$24.3 million). The "fully diluted" weighted average number of shares outstanding during the year ended December 31, 2000 is 46.5 million (1999 - 39.9 million; 1998 - \$29.7 million). The number of shares for the calculation of "Class A and Class B" and "fully diluted" assumes that the Class B shares were deemed to be converted into Class A shares based on the conversion formula described in note 7(c) using the trading price of the Class A shares as at December 31, 2000 which was \$9.75 (1999 - \$6.10; 1998 - \$3.85). The fully diluted number of shares also includes the effects of exercising outstanding stock options.

Cash flow from operations per share is based on cash flow from operations before changes in non-cash working capital items.

10. COMMODITY MARKETING ARRANGEMENTS

As at December 31, 2000, physical delivery contracts were in effect to deliver a total of 5,201 gigajoules ("GJ") per day at prices as set out in the following table:

Sales Volume (GJ/day)	Terms	Contract Expiry Dates
2,740	AECO Daily Spot less \$0.075/GJ	October 31, 2002
2,461	AECO Monthly plus variable premium, less 3% marketing fee	September 30, 2003

The balance of 2000 gas sales was split between aggregator sales (approximately 13.5 mmcf/d) and spot gas sales. All liquids are sold on a spot basis.

At December 31, 2000, the Company had no financial natural gas contracts or swaps outstanding.

11. CHANGE IN ACCOUNTING POLICY - FUTURE INCOME TAX

Effective January 1, 2000, Cypress adopted the Canadian Institute of Chartered Accountants' new accounting recommendations with respect to income taxes. The new recommendations were applied retroactively without restatement of prior year financial statements. The application of the new liability method for income taxes resulted in a charge against retained earnings of \$20.2 million (largely as a result of prior years' corporate acquisitions). There was a corresponding increase to the Company's liability for future income taxes of \$24.4 million, an increase to property plant and equipment of \$2.5 million and a reduction to share capital of \$1.7 million.

Prior to the adoption of the new recommendation, the Company followed the deferral method of accounting for income taxes. Under this method, the Company provided for deferred income taxes to the extent that income taxes otherwise payable were reduced

by exploration and development costs and capital cost allowances in excess of the depletion and depreciation provisions recorded in the accounts.

12. SUBSEQUENT EVENTS

On February 28, 2001 the Company announced that it had mailed to the registered shareholders of Ranchero Energy Inc. ("Ranchero") its Offer to Purchase ("Offer") all of the outstanding Class A shares of Ranchero ("Ranchero shares") on the basis of, for each Ranchero share, \$1.68 in cash or 0.1723 of a Class A share of Cypress, subject to an aggregate maximum of 1,076,900 Class A shares of Cypress and subject to pro-ration. On March 23, 2001 the Company announced that all of the conditions to the Offer were satisfied.

On February 16, 2001 PrimeWest Energy Trust ("PrimeWest") and Cypress jointly announced that they had entered into an agreement whereby PrimeWest offered to purchase all of the issued and outstanding common shares of Cypress. The offer consisted of cash of \$14.00 per Cypress share up to a maximum of \$60.0 million, or, at the option of the Cypress shareholder, 1.45 PrimeWest Trust Units or 1.45 exchangeable shares of a subsidiary of PrimeWest (subject to a maximum of 5.44 million exchangeable shares). On March 29, 2001, PrimeWest announced that all of the conditions to the Offer were satisfied.

SCHEDULE B

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, 2003. The reserves data consists of the following:
 - (a)
 - (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2003 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, 2003 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, 2003, 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
February 2, 2004	Canada	\$60,724	\$843,857	\$0	\$904,581

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

Dated February 2, 2004

SCHEDULE C

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, 2003 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, 2003 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, 2003.

The Audit 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 Audit 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

