

# **PRIMEWEST ENERGY TRUST**

## **RENEWAL ANNUAL INFORMATION FORM**

**For the year ended December 31, 2001**

**April 29, 2002**

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SCHEDULE A US GAAP RECONCILIATION

SCHEDULE B FINANCIAL STATEMENTS OF CYPRESS ENERGY INC.

**NOTE TO READER**

Beginning with the 2000 Annual Information Form, the conversion rate to convert natural gas (mcf) to barrels of oil equivalent (boe) was changed to 6:1. For all prior years, a 10:1 conversion rate was used.

## ITEM 1: ORGANIZATION

PrimeWest Energy 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 – 6<sup>th</sup> Avenue S.W., Calgary, Alberta, T2P 3Y7. The appointment of The Trust Company of Bank of Montreal, the predecessor to Computershare as Trustee, was approved at the May 18, 1999 Annual General and Special Meeting of Unitholders. The current term of the Trustee's appointment expires at the conclusion of the sixth annual meeting of the Unitholders, scheduled to be held on May 21, 2002 in Calgary, Canada at The Metropolitan Centre, Grand Lecture Theatre, 333 – 4<sup>th</sup> Avenue S.W.

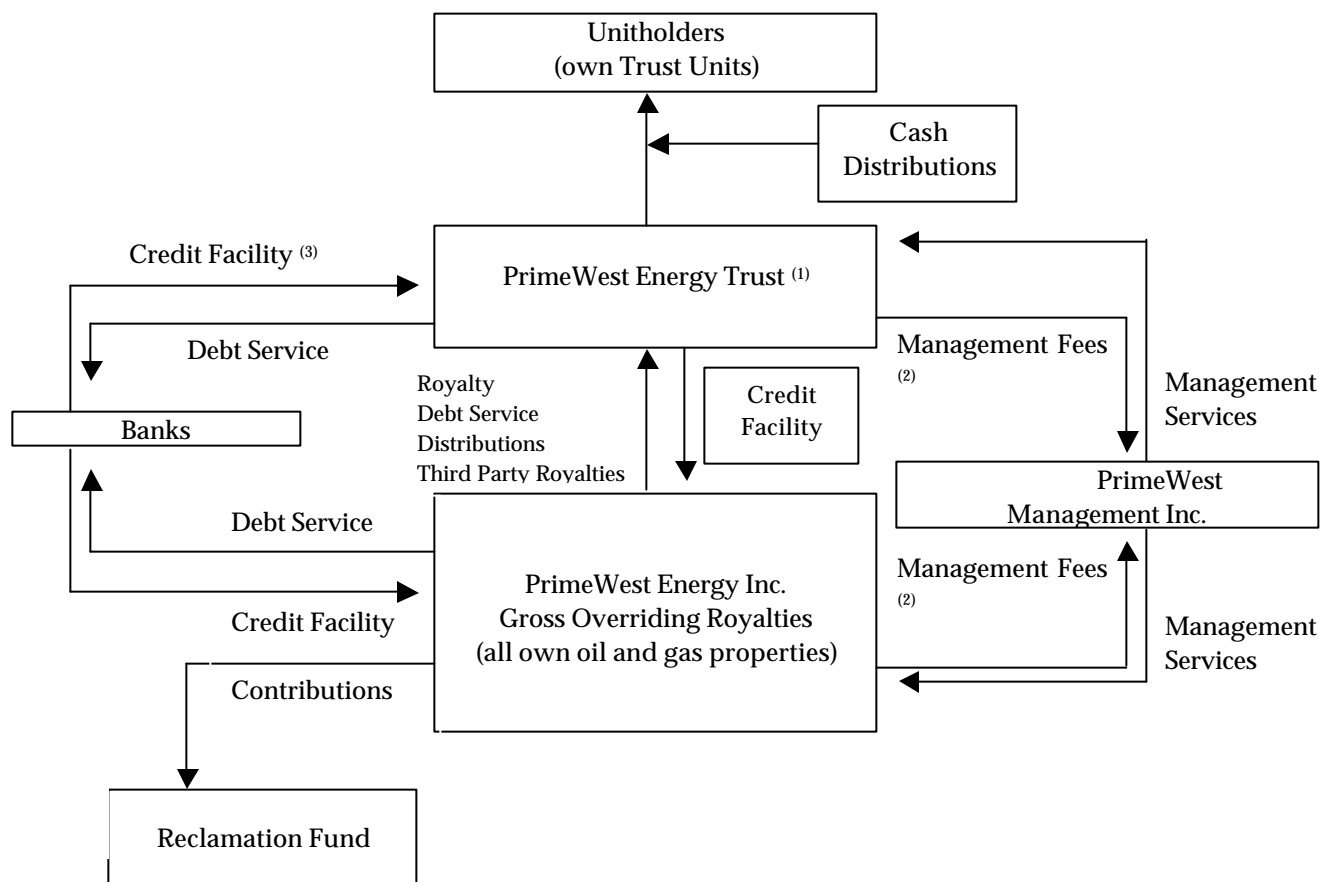
PrimeWest Energy Inc. was incorporated under the *Business Corporations Act* (Alberta) on March 4, 1996 and was amalgamated with PrimeWest Oil and Gas Corp., PrimeWest Royalty Corp. and PrimeWest Resources Ltd. on January 1, 2002 and continued as PrimeWest. PrimeWest is 89% owned by the Trust and 11% owned by PrimeWest Management Inc. PrimeWest's business is the acquisition, development, exploitation, production and marketing of petroleum and natural gas properties and granting the Royalty to the Trust.

PrimeWest Management Inc. was incorporated on March 4, 1996 under the *Business Corporations Act* (Alberta) and is a Canadian controlled private corporation. The business of the Manager is to provide administrative services to the Trust and carry out the management of the business and affairs of PrimeWest.

The head, principal and registered office of PrimeWest and the Manager is 4700, 150 – 6<sup>th</sup> Avenue S.W., Calgary, Alberta T2P 3Y7.

## Trust Structure

The following diagram represents the current structure of the Trust and 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, the Manager, and from the Trust to Unitholders:



### Notes:

- 1) The Declaration of Trust amendments approved by Unitholders at the Special and Annual General Meeting of Unitholders held May 21, 1998 allow the Trust to directly acquire and hold petroleum and natural gas properties, as well as the securities of any issuer holding such assets. The Trust owns Gross Overriding Royalty Interests acquired upon the takeover of Reserve Royalty Corporation in July 2000 (see Item 2: General Development of the Business).
- 2) The Manager is also reimbursed for general and administrative costs.
- 3) PrimeWest provides a guarantee on amounts borrowed by the Trust under the credit facility.

## **Organization and Structure of PrimeWest Energy 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 percent 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 Distributable Income generated by these royalties is then distributed monthly to Unitholders.

## **Re-organization of Operating Structure**

On December 12, 2001, the Unitholders approved a re-organization of PrimeWest's operating structure, which came into effect on January 1, 2002. As a result, PrimeWest Royalty, Resources and Oil & Gas amalgamated with PrimeWest and continued as PrimeWest.

## **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, requires 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 and Class B Exchangeable Shares of PrimeWest***

In connection with the acquisition of Cypress, Oil & Gas issued exchangeable shares to former shareholders of Cypress entitling the holders thereof to acquire a certain number of Trust Units. Similarly, in connection with the acquisition of Venator, Resources issued exchangeable shares to former shareholders of Venator entitling the holders thereof to acquire a certain number of Trust Units.

As a result of the Amalgamation, whereby Oil & Gas and Resources amalgamated with PrimeWest Royalty and PrimeWest, each holder of an exchangeable share of Oil & Gas received one class A exchangeable share of PrimeWest for each exchangeable share previously held and each holder of an exchangeable share of Resources received one class B exchangeable share of PrimeWest for each exchangeable share previously held.

### ***Trustee***

Computershare is the current trustee of the Trust and also acts as the transfer agent for the Trust Units. 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 will expire at the conclusion of the sixth annual meeting of Unitholders, scheduled to be held on May 21, 2002 in Calgary, Canada. 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 *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 percent 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 five percent of the votes attaching to all outstanding Trust Units constitute a quorum for the transaction of business at all 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 *Income Tax Act* (Canada). Accordingly, the Declaration of Trust provides that at no time may non-residents be the beneficial owners of a majority of the Trust Units. If the Trustee becomes aware that the beneficial owners of 49 percent of the Trust Units then outstanding are or may be non-residents or that situation is imminent, the Trustee may make a public announcement in that regard and will not 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 that the person is not a non-resident. Notwithstanding the foregoing, if the Trustee determines that a majority of the Trust Units are beneficially held by non-residents, the Trustee may send a notice to non-resident Unitholders, chosen in inverse order to the order of acquisition or registration or in such other manner as the Trustee may consider equitable and practicable, requiring those non-resident Unitholders to sell their Trust Units or part of them within a specified period of not less than 60 days. If the non-resident Unitholders receiving that notice have not sold the specified number of Trust Units or provided the Trustee with satisfactory evidence that they are not non-residents within that period, the Trustee may on behalf of those Unitholders sell those Trust Units and, in the interim, will suspend the voting and distribution rights attached to those Trust Units. When that sale by the Trustee occurs, the affected Unitholders will cease to be holders of Trust Units and their rights will be limited to receiving the net proceeds of sale on surrender of the certificates representing those Trust Units.

### ***Compulsory Acquisition***

The Declaration of Trust provides that if a person within either 120 days of making an offer to purchase all outstanding Trust Units or the time for acceptance provided in that offer (provided that such offer is open for acceptance for a period of not less than 45 days), whichever period is the shorter, acquires not less than 90 percent 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, 2095. 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.

### **The Manager**

#### ***Business***

The principal business of the Manager is to provide administrative services to the Trust and to carry out the management of the business and affairs of PrimeWest, including managing the operation and administration of the petroleum and natural gas properties owned by PrimeWest.

## ***Manager Compensation***

The Manager is compensated for its services to PrimeWest and the Trust as follows:

- (a) a management fee equal to 2.5 percent of the net production revenue generated by the petroleum and natural gas interests held by PrimeWest or otherwise held directly or indirectly by the Trust, plus ARTC, after certain adjustments for hedging activities, Crown royalties and other Crown charges, third-party processing and other income and certain non-capital operating costs;
- (b) quarterly incentive payments of Trust Units. The first quarterly incentive payment was 12,500 Trust Units and subsequent payments have increased in proportion to the number of additional Trust Units issued by the Trust. The most recent quarterly incentive payment was 65,834 Trust Units for the quarter ended December 31, 2001;
- (c) an acquisition fee equal to 1.5 percent of the purchase price of any properties acquired by PrimeWest or the Trust or of the enterprise value of the Person which owns petroleum and natural gas rights or interests in the event of the acquisition of that Person by PrimeWest or the Trust, and a disposition fee equal to 1.25 percent of the sale price of any properties sold by PrimeWest, the Trust or any Person acquired by PrimeWest or the Trust;
- (d) reimbursement for general and administrative costs and direct costs incurred in providing management and administrative services to PrimeWest and the Trust; and
- (e) one percent of the net cash flow generated by the petroleum and natural gas interests held by PrimeWest, the Trust or any Person acquired by PrimeWest or the Trust (without duplication), after certain costs, expenditures and deductions.

## **Management Policies and Acquisition Strategy**

Activities undertaken by the Manager in overseeing the operations and administration of PrimeWest are directed toward achieving stable long-term growth in Distributable Income paid to the Unitholders and in the value of the properties owned by PrimeWest and the Trust. These two objectives are fundamental to the operation of the Trust and are balanced to enhance benefits to the Unitholders.

Unless PrimeWest is able to acquire additional petroleum and natural gas reserves or increase reserves through development activities, production from the

properties owned by it will eventually decline. Accordingly, the Manager presents proposals to PrimeWest and the Trust to acquire producing properties or to participate in development activities that are considered to be of a low-risk nature in the oil and natural gas industry. When considering the acquisition of any petroleum and natural gas producing property, the Manager focuses on long-life properties with low reservoir risk. The properties may be operated either by PrimeWest or by other acceptable operators and must have the potential to increase Distributable Income and enhance the Trust's value through exploitation of those properties.

The Manager's acquisition strategy uses the following procedures and targets individual properties, or groups of properties, that generally comply with the following guidelines:

- (a) a property, or group of properties, acquired, directly or indirectly, pursuant to an acquisition will provide a forecast internal rate of return that is greater than 400 basis points above the yield of long-term (ten-year) Government of Canada bonds over the life of the reserves associated with that property or group of properties, after deducting general and administrative expenses and management fees and incorporating the impact of debt financing, but before income taxes;
- (b) properties where PrimeWest will become the operator are preferred;
- (c) commodity price and exchange rate assumptions used in acquisition evaluations will be from a major independent petroleum engineering firm;
- (d) each acquisition having a purchase price of \$5,000,000 or more will be based on an independent petroleum engineering report, the results of which report may be modified to incorporate the Manager's view of the engineering analysis contained in that report;
- (e) at no time will more than 25 percent of the total reserve value of the properties owned by PrimeWest or the Trust be attributable to a single property; and
- (f) the expected economic life of a property, or group of properties, acquired in a single transaction will not be less than 20 years.

The board of directors of PrimeWest may at its discretion approve acquisitions that do not conform to these guidelines, based on the board's consideration of other qualitative aspects of the subject properties including risk profile, technical upside, reserve life and asset quality.

## **Decision Making**

PrimeWest, the Manager and the Trust are parties to a unanimous shareholder agreement which provides that Unitholders will be entitled to notice of and to attend all meetings of shareholders of PrimeWest and except as set forth below, to direct the manner in which the Manager will vote its shares in PrimeWest at all of those meetings. Accordingly, the Unitholders are entitled to direct the election of directors of PrimeWest (other than the nominees of the Manager), the approval of the financial statements of PrimeWest and the appointment of its auditors. The unanimous shareholder agreement also provides that the board of directors of PrimeWest will, subject to complying with applicable laws regarding the declaration of dividends, declare and pay dividends to the Manager in an amount representing one percent of its net cash flow generated by the petroleum and natural gas interests held by PrimeWest, the Trust or any Person acquired by PrimeWest for the Trust (without duplication), after certain costs, expenditures and deductions.

The board of directors of PrimeWest is responsible for making significant decisions with respect to PrimeWest, including all decisions relating to (a) the acquisition, directly or indirectly, of petroleum and natural gas properties at a cost in excess of \$5,000,000 and the disposition of petroleum and natural gas properties for a sale price or proceeds in excess of \$2,000,000; (b) the approval of capital expenditure budgets; (c) the approval of risk management activities proposed to be undertaken by the Manager; 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, the management agreement, the royalty agreement or the unanimous shareholder agreement respecting the relationships among the Trust, PrimeWest and the Manager, 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 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 in the amount of \$12,071,000 to acquire certain oil and gas properties.

During the year ended December 31, 1997, PrimeWest completed the acquisition of additional petroleum and natural gas reserves having an aggregate acquisition cost of approximately \$35 million.

On February 25, 1998, PrimeWest implemented a Distribution Reinvestment Plan and Optional Trust Unit Purchase Plan of the Trust. The DRIP allows Unitholders to elect to reinvest cash distributions to purchase additional Trust Units from the Trust. The Optional Trust Unit Purchase Plan allows unitholders to make additional investments of between \$100 and \$100,000 per calendar year without incurring brokerage fees.

In March 1998, the Trust completed two acquisitions of petroleum and natural gas reserves in the Grand Forks and Medicine Hat areas of Alberta. Pursuant to those acquisitions, PrimeWest acquired approximately 11.8 million boe of Established Reserves, plus an amount for interests in certain facilities, for an aggregate purchase price of approximately \$60.2 million. Substantially all of the purchase price was financed by an equity offering of 8,000,000 Trust Units at \$7.80 per unit, for net proceeds of \$59,280,000.

On May 21, 1998, the Trust held a special and annual general meeting of Unitholders at which the Unitholders authorized the reorganization of the Trust from a closed-end investment trust to an open-end investment trust. This change was made in order to add flexibility to the investments that the Trust is allowed to make. As a closed-end trust, the Trust was restricted to owning certain types of assets, principally royalty interests. As an open-end trust, the Trust is able to invest in shares of other corporations and in other types of income producing assets.

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.

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 percent of the PrimeWest 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 percent 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 percent 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.

The Rights Plan expires on May 21, 2002, the date of PrimeWest's next annual meeting, unless approval of the Unitholders for the continuation of the Rights Plan is obtained at that meeting.

On October 5, 1999, the Trust closed the issue of 2.75 million Trust Units at a price of \$7.20 per Trust Unit. The issue was done on a bought-deal basis for gross proceeds of \$19.8 million.

On November 3, 1999, Resources completed the acquisition of gas reserves in southeast Alberta. Resources paid \$13.6 million for 16.3 bcf of Established Reserves.

On November 26, 1999, the Trust received approval from The Toronto Stock Exchange to make a normal course issuer bid. The bid commenced November 30, 1999 and terminated on November 29, 2000. From November 30, 1999 to the expiry date of this bid, the Trust purchased 263,100 Trust Units at an average cost of \$6.39 per Trust Unit.

On January 5, 2000, PrimeWest completed the purchase of a 34.6 percent interest in the Crossfield natural gas processing plant and associated gathering system. That transaction increased PrimeWest's stake in the facilities to 54 percent and enabled PrimeWest to become the operator of the facilities. In June 2000, PrimeWest sold a 25.8 percent interest in the facilities to a third party for cash and a life of reserves contract whereby the third party dedicated processing of all of its operated production from three nearby fields to the plant; PrimeWest continued as the operator of the plant.

On April 19, 2000 Resources completed the purchase of all of the issued and outstanding shares of Venator. The purchase price of the transaction, including assumed debt, was \$32.5 million. The transaction added 3.0 million BOE of established reserves and approximately 1,500 BOE per day of daily working interest production. The purchase price consisted of the issuance of 2.4 million Trust Units and 2 million exchangeable shares exchangeable into Trust Units. Subsequent to the Amalgamation, the remaining exchangeable shares of Resources were replaced by an equivalent number of class B exchangeable shares of PrimeWest.

On May 25, 2000, the Trust held its special and annual general meeting of Unitholders. At this meeting, the Unitholders adopted the following resolutions: 1) an enhancement to the DRIP whereby Trust Units issued pursuant to the DRIP would be eligible for a 5 percent discount to the market price; 2) an amendment to the Declaration of the Trust permitting the independent directors to appoint up to two additional independent directors to the board of directors of PrimeWest; 3) an amendment to the Declaration of Trust that modifies borrowing covenants to be based on discounted cash flows at a discount rate equivalent to the then current Government of Canada 10 year bond rate plus 400 basis points (to a maximum of 15 percent); 4) an amendment to the Declaration of Trust permitting the creation of special voting units to allow holders of PrimeWest exchangeable shares to vote at meetings of Unitholders; and 5) an amendment to the Declaration of Trust that gives the board of directors of PrimeWest the sole responsibility for dealing with all matters related to any unsolicited take-over bids.

On May 31, 2000, the Trust announced the appointment of Michael W. O'Brien as an additional independent director of the board of directors of PrimeWest. Mr. O'Brien is Executive VP, Corporate Development and CFO of Suncor Energy Inc. On November 20, 2001, Suncor Energy Inc. issued a news release indicating that Mr. O'Brien had announced plans to retire from those positions effective June 30, 2002.

On July 27, 2000, PrimeWest Royalty completed the purchase of all of the issued and outstanding shares of Reserve Royalty Corp. on a unit for share exchange. The Trust issued 6.67 million Trust Units and assumed debt for total consideration of \$84.0 million. The transaction added approximately 6.1 million BOE of Established Reserves and approximately 1,700 BOE per day of mainly Gross Overriding Royalty production.

On September 28, 2000, the Trust closed the issue of 4.83 million Trust Units at a price of \$8.35 per Trust Unit. The issue was done on a bought-deal basis for gross proceeds of \$40.3 million.

On December 15, 2000, the Trust received approval from The Toronto Stock Exchange to make a normal course issuer bid. The bid commenced December 19, 2000 and terminated on December 18, 2001. The Trust made no purchases under this bid.

The board of directors of PrimeWest has authorized management to apply for a normal course issuer bid if appropriate at a future date.

On March 29, 2001, Oil & Gas completed the purchase of all of the issued and outstanding shares of Cypress. In aggregate, the Trust issued 50.2 million Trust Units at \$9.75, and Oil & Gas issued 5.2 million exchangeable shares, paid \$59.2 million in cash and assumed Cypress' debt totalling \$179 million pursuant to the purchase. The transaction added approximately 57.5 million BOE of Established Reserves (as at December 31, 2000) and approximately 15,000 BOE per day of production. Subsequent to the Amalgamation, the remaining exchangeable shares of Oil & Gas were replaced by an equivalent number of class A exchangeable shares of PrimeWest.

On June 22, 2001, the Trust closed the issue of 9.89 million Trust Units at a price of \$9.60 per Trust Unit. The issue was done on a bought deal basis for gross proceeds of \$94.9 million.

In the second half of 2001, in a number of separate transactions, PrimeWest disposed of several properties for total proceeds of approximately \$78.2 million. These proceeds were applied to reduce outstanding debt.

On November 15, 2001, the Trust closed the issue of 9.9 million Trust Units at a price of \$7.10 per Trust Unit. The issue was done on a bought deal basis for gross proceeds of \$70.3 million.

### **ITEM 3: NARRATIVE DESCRIPTION OF BUSINESS**

#### **The Business of the Trust**

##### **General**

The undertaking of the Trust is to directly and indirectly 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 and the Manager to continue to source and acquire petroleum and natural gas properties both for and on behalf of PrimeWest 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**

The Manager, on behalf of PrimeWest, manages the operation of those properties in respect of which PrimeWest is the operator.

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.

### **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 eventually decline. The Manager, on behalf of PrimeWest and the Trust, continually reviews opportunities for the acquisition of producing oil and natural gas properties. When considering the acquisition of any petroleum and natural gas producing property, the Manager focuses on long-life properties, with low 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 are impacted in varying degrees by factors outside the Trust's control. These include but are not limited to:

- (a) World market forces, most importantly the actions of OPEC, and their implications for the price of crude oil;
- (b) 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;
- (c) North American market forces, most notably shifts in the balance between supply and demand for natural gas and the implications for the price of natural gas; and
- (d) To the extent that crude oil and natural gas prices received by PrimeWest are referenced to WTI oil, which is denominated in U.S. dollars, prices and revenue streams are impacted by changes in value between the Canadian and U.S. dollars.

Fluctuations in commodity prices, quality differentials, foreign exchange and interest rates 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 this risk, 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 2001, 84 percent of full-year crude oil production and 78 percent of full-year natural gas production was hedged, net of royalties. Strategies utilized included both physical and financial instruments with the primary objective of enhancing the stability of cash distributions.

The gas hedging instruments are floors, swaptions and swaps. 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 April 8, 2002, PrimeWest employed hedging structures using swaps and option-based instruments on approximately 65 percent of anticipated crude oil production, net of royalties for 2002 and it also employed hedging structures using swaps and option-based instruments on approximately 26 percent of anticipated crude oil production, net of royalties for 2003.

As at April 8, 2002, PrimeWest employed hedging structures using swaps and option-based instruments on approximately 68 percent of anticipated natural gas production, net of royalties, for 2002 and PrimeWest employed hedging structures using swaps and option-based instruments on approximately 50 percent of anticipated natural gas production, net of royalties, for 2003.

As at March 13, 2002, all 2002 and 2003 hedging contracts mark-to-market represented a net gain of \$31 million.

PrimeWest's marketing portfolio for natural gas is well diversified. Approximately 30 percent of natural gas production is sold to aggregators and approximately 70 percent 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, PrimeWest also works to maintain a relatively balanced production portfolio. Because oil and gas price cycles do not necessarily coincide, such a balance often provides a natural mitigation of price risk.

For 2001, PrimeWest's commodity mix was approximately 41 percent oil and NGLs, and 59 percent natural gas, compared to approximately 50 percent of each in 2000.

### **Reserve Continuity**

Gilbert Laustsen Jung Associates Ltd., independent petroleum consultants, has prepared the Gilbert Report evaluating the crude oil, natural gas, natural gas liquids and sulphur reserves attributable to properties owned by PrimeWest, Resources,

PrimeWest Royalty, Oil & Gas and the Trust as at January 1, 2002. The following table sets forth the reconciliation of the Established Reserves of PrimeWest and the Trust for the year ended December 31, 2001.

<b><u>Reconciliation of Net Company Interest Established Reserves</u></b> <sup>(3)</sup>	<b>Oil &amp; Natural Gas Liquids (mmbbls)</b>	<b>Natural Gas (bcf)</b>	<b>Total</b> <sup>(1)(2)</sup> <b>(mmboe)</b>
As at January 1, 2001	30.79	232.70	69.6
Capital Development Program	2.81	19.7	6.1
Technical Revisions <sup>(5)</sup>	(1.31)	(23.2)	(5.2)
Acquisitions <sup>(4)</sup>	16.95	243.2	57.4
Dispositions	(6.71)	(22.2)	(10.4)
Production	(4.43)	(36.5)	(10.5)
As at January 1, 2002	<u>38.10</u>	<u>413.7</u>	<u>107.0</u>
Net Increase (Decrease)	<u>7.31</u>	<u>181.0</u>	<u>37.40</u>
Percent Increase (Decrease)	<u>24%</u>	<u>78%</u>	<u>54%</u>

Notes:

- 1) May not add due to rounding.
- 2) Natural gas reserves converted to mmboe on the basis of 6:1.
- 3) Established Reserves are the sum of Proved Reserves and 50 percent of Probable Reserves.
- 4) Principally Cypress Energy Inc., acquired as at March 29, 2001.
- 5) All technical revisions on acquired reserves are included in revisions category.

### **Drilling Activity**

During the Trust's last two financial years, PrimeWest drilled or participated in the drilling of the following wells:

	<b>Year Ended December 31, 2001</b>		<b>Year Ended December 31, 2000</b>	
	<b>Gross</b>	<b>Net</b>	<b>Gross</b>	<b>Net</b>
Natural Gas	45	22.49	3	1.59
Crude Oil	30	24.06	59	5.53
Dry	7	4.50	2	1.33
Total	<u>82</u>	<u>51.05</u>	<u>64</u>	<u>8.45</u>

## Capital Expenditures

The following table sets forth the capital expenditures by PrimeWest for the last two financial years:

	<b>Year Ended December 31, 2001 (000's)</b>	<b>Year Ended December 31, 2000 (000's)</b>
Drilling, completion & facilities	\$ 80,447	\$ 23,443
Property acquisitions, net of dispositions (including corporate acquisitions)	744,454	117,801
Head Office	3,457	2,348
	<b>\$ 828,358</b>	<b>\$ 143,592</b>

## 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, as at December 31, 2001, make the properties suitable for a conventional crude oil and natural gas royalty trust structure:

- (a) **Long Life Reserves:** The properties contain long life, low decline rate reserves that have an Established Reserve Life Index of 10 years;
- (b) **Operated Properties:** Approximately 80 percent 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) **Balanced Portfolio:** For the year ended December 31, 2001 production from the properties is approximately 41 percent crude oil and natural gas liquids and 59 percent natural gas, on a barrel-of-oil-equivalent basis. As at January 1, 2002, Established Reserves for the properties are approximately 36 percent crude oil and natural gas liquids and 64 percent natural gas on a barrel-of-oil-equivalent basis. Crude oil reserves are predominantly light-gravity oil, averaging 33 degree API;
- (d) **Concentrated 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 Gilbert Report.

## Oil and Natural Gas Reserves

Gilbert has prepared the Gilbert Report evaluating the properties as at January 1, 2002. **The Gilbert Report evaluates the crude oil, natural gas, natural gas liquids and sulphur reserves attributable to the properties prior to provision for income taxes, interest costs, general and administrative expenses and management fees, but after providing for estimated royalties, operating costs, other income, future capital expenditures and facility site restoration, well abandonment and well-site restoration costs. Probable additional reserves and the present worth of those reserves as set forth in the tables below have been reduced by 50 percent to reflect the degree of risk associated with recovery of those reserves.** It should not be assumed that the discounted future net cash flows estimated by Gilbert 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.

### Petroleum and Natural Gas Reserves and Pre-Tax Net Cash Flows Escalating Cost and Price Case

	Company Interest Reserves						Estimated Present Worth of Future Pre-Tax Net Cash Flows (\$000's)			
	Crude Oil and Natural Gas Liquids (mbbls)		Natural Gas (bcf)		Sulphur (mlt)		Undiscounted	Discounted at		
	Gross	Net	Gross	Net	Gross	Net		10%	15%	20%
Proved										
Producing .....	28,991	24,424	287	225	634	528	1,172,601	658,735	551,485	478,220
Non-Producing..	3,557	2,774	62	48	11	10	206,019	108,303	86,394	71,311
Total Proved .....	32,548	27,198	349	273	645	538	1,378,620	767,038	637,879	549,531
Risked Probable.....	5,542	4,561	65	50	121	101	284,275	105,543	77,674	60,589
Established .....	38,090	31,759	414	323	766	639	1,662,895	872,581	715,553	610,120

### Petroleum and Natural Gas Reserves and Pre-Tax Net Cash Flows Constant Cost and Price Case

	Company Interest Reserves						Estimated Present Worth of Future Pre-Tax Net Cash Flows (\$000's)			
	Crude Oil and Natural Gas Liquids (mbbls)		Natural Gas (bcf)		Sulphur (mlt)		Undiscounted	Discounted at		
	Gross	Net	Gross	Net	Gross	Net		10%	15%	20%
Proved										
Producing .....	28,645	24,124	284	223	546	455	989,311	586,804	497,548	435,402
Non-Producing..	3,501	2,727	62	48	11	10	170,228	92,973	74,762	62,014
Total Proved .....	32,146	26,851	346	271	557	465	1,159,539	679,777	572,310	497,416
Risked Probable.....	5,497	4,521	64	50	107	91	220,631	89,394	66,994	52,860
Established .....	37,643	31,372	410	321	664	556	1,380,170	769,171	639,304	550,276

Notes:

- 1) Columns may not add due to rounding.
- 2) The following definitions have been used in the Gilbert Report:
  - (a) "Proved Reserves" means those reserves estimated as recoverable with a high degree of certainty under current technology and existing economic conditions, in the case of constant price and cost analyses, and anticipated economic conditions in the case of escalated cost and price analyses, from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economic and technically successful in the subject reservoir.
  - (b) "Probable Reserves" means those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved, but where such analysis suggests the likelihood of their existence and future recovery under current technology and existing or anticipated economic conditions. Probable additional reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above that estimated in the proved category, which can be realistically estimated for the pool on the basis of enhanced recovery processes, which can be reasonably expected to be instituted in the future.
  - (c) "Established Reserves" means those reserves estimated as Proved Reserves plus a portion of the Probable additional reserves, reduced to reflect the risks associated with recovery of those reserves. In the Gilbert Report, Established Reserves have been determined as the sum of 50 percent of Probable Reserves and 100 percent of Proved Reserves.
  - (d) "Producing Reserves" means those reserves that are actually on production and could be recovered from existing wells and facilities or, if facilities have not been installed, that would involve a small investment relative to cash flow to install those facilities. In multi-well pools involving a competitive situation, reserves may be subdivided into producing and non-producing reserves in order to reflect allocation of reserves to specific wells and their respective development status.
  - (e) "Non-Producing Reserves" means those reserves that are not classified as producing.
  - (f) "Gross Reserves" means the total remaining recoverable reserves associated with the acreage of interest.
  - (g) "Company Interest Gross Reserves" means the remaining reserves applicable to the properties, before deduction of any royalties.
  - (h) "Company Interest Net Reserves" means the gross remaining reserves applicable to the properties, less all royalties (but not the Royalty to the Trust) and interests owned by others.
- 3) In the Gilbert Report, the present worth values and quantities of Probable Reserves reported in the Established Reserves category have been reduced by 50 percent to reflect the degree of risk associated with the recovery of those reserves.
- 4) All natural gas reserve values are reserves remaining after deducting surface losses due to processing shrinkage and raw gas used as lease fuel.
- 5) The \$US/\$Cdn exchange rate is assumed in the Gilbert Report to be \$0.6363 in 2002 and \$0.6450 in 2003, \$0.6550 in 2004, \$0.6650 in 2005, and 0.6717 in 2006.

- 6) The Gilbert Report estimates total capital expenditures (net to PrimeWest) to achieve the estimated future pre-tax net cash flows from the Established Reserves based on escalating cost and price assumptions to be \$54.2 million (\$42.5 million if discounted by 15 percent per annum) with \$25.0 million, \$15.2 million and \$5.9 million of those capital expenditures estimated for the calendar years 2002, 2003 and 2004 respectively. The corresponding capital expenditures to achieve the estimated future pre-tax net cash flows from the Established Reserves based on constant cost and price assumptions are \$51.4 million (\$41.5 million if discounted by 15 percent per annum) with \$24.8 million, \$14.9 million and \$5.7 million of these capital expenditures estimated for the calendar years 2002, 2003 and 2004 respectively.
- 7) The Gilbert Report estimates total capital expenditures (net to PrimeWest) to achieve the estimated future pre-tax net cash flows from the Total Proved Reserves based on escalating cost and price assumptions to be \$41.3 million (\$32.3 million if discounted by 15 percent per annum) with \$21.5 million, \$8.1 million and \$4.4 million of those capital expenditures estimated for the calendar years 2002, 2003 and 2004, respectively. The corresponding capital expenditures to achieve the estimated future pre-tax net cash flows from the Total Proved Reserves based on constant cost and price assumptions are \$38.8 million (\$31.5 million if discounted by 15 percent per annum) with \$21.4 million, \$7.9 million and \$4.2 million of these capital expenditures estimated for the calendar years 2002, 2003 and 2004, respectively.
- 8) The extent and character of the interests of PrimeWest and the Trust evaluated in the Gilbert Report and all factual data supplied to Gilbert were accepted by Gilbert as represented. The crude oil and natural gas reserve calculations and any projections on which the Gilbert Report is based were determined in accordance with generally accepted petroleum engineering evaluation practices.

- 9) The constant cost and price evaluation was based on wellhead product prices as set forth below:

<u>Average First Year Unit Values</u>	<u>(Cdn.\$)</u>
Crude Oil.....	\$25.44 per bbl
Condensate.....	\$28.31 per bbl
Propane.....	\$17.05 per bbl
Butane.....	\$16.99 per bbl
Ethane.....	\$12.04 per bbl
Natural Gas.....	\$4.03 per mcf
Sulphur.....	\$0.10 per lt

Operating and capital costs were not escalated in the constant cost and price evaluation.

- 10) In respect of the escalated cost and price valuation for the Gilbert Report, average yearly general product prices, which are referred to in these reports as the industry consensus as at January 1, 2002 for natural gas, crude oil, natural gas liquids and sulphur, are outlined in the following table. The figures in the following table were calculated as of that date as the arithmetic average of the then current price forecasts of Gilbert, Sproule Associates Limited, and McDaniel & Associates Consultants Ltd.

	Light Crude Oil		Natural Gas Liquids of Edmonton			Natural Gas			Sulphur \$/lt
	WTI Cushing Oklahoma* \$/bbl	Edmonton Par price 40° API \$/bbl	Propane \$/bbl	Butane \$/bbl	Pentanes Plus \$/bbl	Henry Hub \$/ MMBTU	Alberta Spot AECO-C \$/ MMBTU	BC Direct \$/ MMBTU	
2002.....	19.97	30.30	19.33	19.52	30.88	3.06	4.13	4.08	(4.67)
2003.....	20.85	31.10	20.00	20.07	31.69	3.35	4.52	4.42	2.53
2004.....	21.31	31.39	20.05	20.16	31.98	3.42	4.56	4.40	6.27
2005.....	21.55	31.25	19.80	19.96	31.68	3.45	4.55	4.40	10.06
2006.....	21.87	31.45	19.93	20.06	31.88	3.50	4.58	4.43	12.31
2007.....	22.31	32.01	20.32	20.49	32.45	3.54	4.62	4.47	13.55
2008.....	22.67	32.58	20.65	20.92	33.02	3.59	4.66	4.50	14.97
2009.....	23.03	33.15	20.96	21.32	33.59	3.65	4.72	4.56	16.38
2010.....	23.40	33.73	21.39	21.76	34.17	3.71	4.79	4.64	17.97
2011.....	23.85	34.30	21.74	22.16	34.75	3.77	4.89	4.73	18.38
2012.....	24.21	34.88	22.09	22.60	35.33	3.83	4.96	4.81	18.97
2013.....	24.58	35.46	22.47	22.96	35.92	3.89	5.04	4.89	19.22
2014.....	24.95	36.04	22.76	23.28	36.50	3.95	5.13	4.94	19.48
2015.....	25.33	36.66	23.14	23.68	37.12	4.01	5.23	5.02	19.73
2016.....	25.70	37.25	23.50	24.01	37.72	4.07	5.32	5.09	19.99
2017.....	26.11	37.87	23.92	24.37	38.34	4.14	5.42	5.19	20.25
2018.....	26.52	38.53	24.28	24.77	39.01	4.20	5.51	5.28	20.51

(1) Operating and capital costs have been escalated at 1.67 percent annually for 16 years and 1 percent thereafter.

**Estimated Pre-Tax Net Cash Flows  
Established Reserves of the Properties  
Escalating Cost and Price Case  
(Smillions except for production)**

	Company Annual Production	Interest Revenue <sup>(1)</sup>	Royalty Burdens <sup>(2)</sup>	Net Revenue After Royalty Burdens	Alberta Royalty Tax Credit	Net Operating Expenses <sup>(3)</sup>	Net Production Revenue <sup>(4)</sup>	Abandonment Costs	Net Capital Investment	Net Cash Flow Before Income Taxes <sup>(5)(6)</sup>
	(mboe)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)
2002.....	11,951	291.7	59.0	232.7	0.5	60.6	164.0	2.7	25.0	145.0
2003.....	11,456	302.9	61.5	241.4	0.5	59.0	174.8	2.7	15.2	165.0
2004.....	9,943	267.8	52.5	215.2	0.5	54.4	154.1	3.1	5.9	152.3
2005.....	8,446	228.3	43.1	185.2	0.5	49.3	129.9	3.1	1.9	131.3
2006.....	7,206	196.6	35.8	160.9	0.5	45.8	109.6	2.9	0.4	112.4
2007.....	6,241	172.8	30.4	142.4	0.5	42.0	95.4	1.3	0.6	98.9
2008.....	5,413	152.0	26.1	125.9	0.5	39.1	82.4	1.4	0.5	85.4
2009.....	4,702	134.1	22.5	111.6	0.5	36.3	71.1	1.5	0.4	73.8
2010.....	4,149	120.6	19.8	100.8	0.5	34.2	62.7	1.3	0.3	65.3
2011.....	3,687	109.4	17.8	91.6	0.5	32.0	56.1	2.0	0.6	57.6
2012.....	3,248	98.0	15.7	82.3	0.5	28.7	50.2	1.2	0.4	52.4
2013.....	2,904	89.1	14.1	75.0	0.5	26.9	45.0	1.4	0.3	46.8
Remainder	27,696	971.4	145.8	825.6	5.5	330.7	469.2	21.6	2.9	476.7
TOTAL.....	107,042	3,134.7	544.3	2,590.4	11.5	838.5	1,664.6	46.3	54.2	1,662.9

Total net cash flow before income taxes discounted at:

10 percent: \$872.6 million

15 percent: \$715.6 million

20 percent: \$610.1 million

Notes:

- 1) Includes working-interest revenue and royalty-interest revenue.
- 2) Includes royalties net of gas processing allowances.
- 3) Includes other expenses, net-profits interest payments, capital and mineral taxes less third party processing and other income.
- 4) Company-interest revenue less Company interest royalty burdens and operating expenses.
- 5) Undiscounted.
- 6) Net cash flow before income taxes is stated prior to interest, general and administrative expenses and management fees.
- 7) Columns may not add due to rounding.

**Estimated Pre-Tax Net Cash Flows  
Established Reserves of the Properties  
Constant Cost and Price Case  
(Smillions except for production)**

	<b>Annual Production n</b>	<b>Company Interest Revenue<sup>(1)</sup></b>	<b>Royalty Burdens<sup>(2)</sup></b>	<b>Net Revenue After Royalty Burdens</b>	<b>Alberta Royalty Tax Credit</b>	<b>Operating Expenses<sup>(3)</sup></b>	<b>Net Production Revenue<sup>(4)</sup></b>	<b>Abandonment Costs</b>	<b>Net Capital Investment</b>	<b>Net Cash Flow Before Income Taxes<sup>(5)(6)</sup></b>
	(mboe)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)
2002.....	11,948	291.6	59.0	232.7	0.5	60.4	164.2	3.0	24.8	145.0
2003.....	11,436	279.7	56.5	223.2	0.5	57.2	158.5	2.6	14.9	149.1
2004.....	9,928	242.3	47.3	195.0	0.5	51.8	136.6	3.0	5.7	135.1
2005.....	8,438	205.4	38.6	166.8	0.5	46.3	114.6	2.8	1.8	116.4
2006.....	7,201	175.3	31.7	143.6	0.5	42.1	95.9	2.8	0.3	98.8
2007.....	6,237	151.7	26.5	125.2	0.5	38.1	82.3	1.2	0.6	85.9
2008.....	5,402	131.4	22.5	108.9	0.5	34.6	69.9	1.3	0.4	73.2
2009.....	4,692	114.1	19.0	95.1	0.5	31.6	59.4	1.4	0.3	62.4
2010.....	4,128	100.5	16.4	84.1	0.5	29.0	51.3	1.1	0.3	54.2
2011.....	3,671	89.5	14.4	75.1	0.5	26.6	45.0	2.0	0.5	46.5
2012.....	3,193	78.0	12.4	65.6	0.5	22.7	39.6	1.1	0.3	42.0
2013.....	2,856	69.8	10.9	58.8	0.4	20.9	34.9	1.6	0.3	36.5
Remainder	26,823	658.0	99.0	559.1	4.0	212.5	320.9	14.3	1.2	335.1
<b>TOTAL.....</b>	<b>105,953</b>	<b>2,587.4</b>	<b>454.1</b>	<b>2,133.2</b>	<b>9.9</b>	<b>673.6</b>	<b>1,373.1</b>	<b>37.9</b>	<b>51.4</b>	<b>1,380.2</b>

Total net cash flow before income taxes discounted at:

10 percent: \$769.2 million

15 percent: \$639.3 million

20 percent: \$550.3 million

Notes:

- 1) Includes working-interest revenue and royalty-interest revenue.
- 2) Includes royalties net of gas processing allowances.
- 3) Includes other expenses, net-profits interest payments, capital and mineral taxes, less third party processing and other income.
- 4) Company-interest revenue less Company interest royalty burdens and operating expenses.
- 5) Undiscounted.
- 6) Net cash flow before income taxes is stated prior to interest, general and administrative expenses and management fees.
- 7) Columns may not add due to rounding.

### **Principal Properties**

The following is a description of the significant properties owned by PrimeWest as of January 1, 2002. Remaining established reserves, ultimate recovery estimates and working interests contained in the following property descriptions are derived from the Gilbert Report. The term "net" used in the following property descriptions refers to the working interest of PrimeWest in the properties.

#### **Boundary Lake Area**

The Boundary Lake Area is located approximately 25 miles east of Fort St. John, British Columbia on the British Columbia/Alberta border. The Boundary Lake Field was discovered in 1955. The productive horizon is the Boundary Lake member of the Triassic Charlie Lake Formation at a depth of approximately 4,200 feet, which produces a 35-degree API light-gravity crude oil and solution gas. PrimeWest operates and PrimeWest has a 100 percent working interest in both Boundary Lake Project No. 1, and Boundary Lake Project No. 2, (both projects are located in British Columbia), varying working interests averaging 4.2 percent in three producing oil wells operated by Imperial Oil Limited in the British Columbia portion of the field and a 25 percent working interest in a producing oil well operated by PrimeWest in the Alberta portion of the field. PrimeWest also has a 2.1 percent working interest in the Boundary Lake Unit No. 1. The Gilbert Report assigns remaining established reserves of 6,487 mbbbl of oil, 672 mmcf of natural gas and 46 mbbbl of natural gas liquids for a total of 6,646 mboe, before deduction of royalties, to the Boundary Lake Area properties. The average net production from the Boundary Lake Area properties for the year ended December 31, 2001 was approximately 1,132 bbls/d of oil and natural gas liquids and 25 mcf/d of natural gas for a total of 1,137 boe/d, in each case before deduction of royalties.

## **Brant/Farrow**

The Brant/Farrow property is located in Twps. 18 to 21, Ranges 23 to 26 W4M, approximately 40 miles southeast of Calgary. The lands are located in the Brant, Farrow, Mossleigh and Herronton fields. Gas is the major product constituting approximately 95 percent of the total production volumes. The Brant/Farrow area is characterised by shallow to medium depth natural gas and oil reservoirs. The area produces oil and natural gas from the Mississippian, Basal Quartz, Glauconite, Belly River, and Medicine Hat formations.

The average net production for 2001 was 6,654 mcf/d natural gas and 192 bbls/d of oil and NGLs', for a total of 1,301 BOE/d, before the deduction of royalties. Net remaining Established Reserves at January 1, 2002 total 4,823 mboe, consisting of 25,403 mmcf of natural gas and 589 mbbl of oil and NGLs, before the deduction of royalties.

PrimeWest operates two gas-processing plants in the area, which have 15 mmcf/d of capacity.

For the year ended December 31, 2001 PrimeWest drilled 14 gross (11 net) wells in the area. Further drilling activity is planned for 2002.

## **Crossfield/Lone Pine Creek Area**

The Crossfield/Lone Pine Creek Area is located approximately 20 miles north of Calgary, Alberta, and was discovered in 1960. Production of natural gas and natural gas liquids occurs from the Elkton, Wabamun (Crossfield), Leduc and Nisku Formations. Oil production occurs from the Cardium, Basal Quartz, Elkton and Nisku Formations. The Gilbert Report assigns net remaining Established Reserves of 328 mbbl of oil, 49,028 mmcf of natural gas and 607 mbbl of natural gas liquids for a total of 9,107 mboe, before deduction of royalties, and 706 mlt of sulphur to the East Crossfield/Lone Pine Creek Area properties. The aggregate average net daily sales volumes from this area for the year ended December 31, 2001 was approximately 10,163 mcf/d of natural gas and 305 bbls/d of oil and natural gas liquids for a total of 1,999 boe/d, in each case before royalties.

PrimeWest operates and PrimeWest has a net working interest in the following: 54.6 percent in the East Crossfield Unit - Crossfield Formation, 68.4 percent in the Lone Pine Creek Gas Unit No. 1, 75 percent in the Lone Pine Creek Gas Unit No. 3, 76.6 percent in the Lone Pine Creek Gas Unit No. 5, 65.9 percent in the Lone Pine Creek D-3 Gas Unit No. 1, 100 percent in the East Crossfield Elkton "F" Pool, five (4.3 net) non-unit gas wells and a 100 percent working interest in one non-unit oil well. In addition, PrimeWest have varying working interests averaging 25 percent in two non-operated oil wells, and a 100 percent working interest in two PrimeWest-operated, producing natural gas wells.

All operated natural gas production is processed at the East Crossfield Sour Gas Processing Facility. The East Crossfield gas processing facility has a throughput capacity of 74 mmcf/d. Originally, PrimeWest had a 20 percent interest in the facility. Effective January 5, 2000, PrimeWest acquired Amoco's 34.6 percent interest and became operator of the facility. In May 2000, PrimeWest sold a 25.8 percent interest to a third party for cash and a dedication of the third party gas reserves and adjacent levels to the plant on a life reserves basis. After this sale, PrimeWest's ownership in the facility is 28.8 percent. All of PrimeWest's natural gas produced from this area is processed on a plant operating-cost basis. During 2001, plant utilization was approximately 55 percent. Other major facilities owned by PrimeWest in respect of this property include the Lone Pine Creek Central Gathering and Compression Facility (42.8 percent interest), the Lone Pine Creek Waukesha Compressors (50.1 percent interest), the Lone Pine Creek D-1 Unit Booster Compressor (68.4 percent interest) and the Lone Pine Creek to East Crossfield Amalgamation Pipeline (40.2 percent interest).

PrimeWest has no ownership interest in the Sulphur Block or any liability related to future clean-up costs.

### **Laprise Creek Area**

The Laprise Creek Area is located in northeast British Columbia, approximately 110 miles northwest of Fort St. John, British Columbia. Gas is produced from the Baldonnel Formation at a depth of approximately 4,200 feet. The Laprise Creek Baldonnel "A" Pool is one of British Columbia's largest natural gas pools, having original gas-in-place of 880 bcf. PrimeWest has a 75.6 percent working interest in the Laprise Creek Baldonnel Unit No. 1, which is operated by PrimeWest. The Unit consists of 20 (15.1 net) producing natural gas wells and one (0.76 net) suspended well. In addition, PrimeWest have a 100 percent interest in one producing non-unit gas well. The Gilbert Report assigns net remaining Established Reserves of 41,588 mmcf of natural gas and 1,065 mbbl of natural gas liquids for a total of 7,996 mboe, before deduction of royalties, to the Laprise Creek Area properties. The average net production from the Laprise Creek Area properties for the year ended December 31, 2001 was approximately 9,028 mcf/d of natural gas and 208 bbls/d of crude oil and natural gas liquids for a total of 1,714 boe/d, before deduction of royalties.

### **Northwest Alberta Area**

PrimeWest's significant holdings in the Northwest Alberta area are located in Twps. 90 to 97, Range 21W5 to Range 3W6M, approximately 100 miles southeast of Rainbow Lake, Alberta. The lands are located in the Stowe, Hotchkiss, Naylor, Sutton and Keg River Post fields. The Northwest Alberta area is characterized by prolific, high deliverability oil and natural gas reservoirs located in multiple, shallow to medium depth horizons. The area produces oil and natural gas from the Gilwood formation, as well as natural gas from the Bluesky, Gething, Debolt, Shunda and Slave Point formations. PrimeWest's current focus in this area is on the development of natural gas

reserves in the shallow Cretaceous and Mississippian formations as well as oil and gas from the deeper Devonian formations.

PrimeWest's average net production from this area for the year ended December 31, 2001 was 1,906 boe/d consisting of 9,258 mcf/d natural gas and 351 bbl/d oil and NGL's, all before the deduction of royalties. The Gilbert Report assigns net remaining Established Reserves of 6,541 mboe, consisting of 32,142 mmcf of natural gas and, 1,184 mmbbls of oil and NGL's, before the deduction of royalties.

PrimeWest operates a gas processing plant in the area that has 22 mmcf/d of capacity.

### ***Dawson***

The Dawson area consists of extensive land holdings from Twps. 75 to 81 and Ranges 14 to 23W5M, approximately 80 miles northeast of Grande Prairie, Alberta. PrimeWest generally holds a 50 percent working interest in the majority of lands. The lands are located in the Normandville, Dawson, Roxana, Lalby and Kimiwan fields. The Dawson area is characterised by prolific, high deliverability natural gas reservoirs located in multiple shallow depth horizons and deep oil production from the Beaverhill Lake and Slave Point formations.

PrimeWest operates the majority of its activities in this area. The Gilbert Report assigns net remaining Established Reserves of 4,437 mboe, consisting of 13,074 mmcf of natural gas and 2,259 mmbbls of oil and NGL's, before the deduction of royalties. The average net production for 2001 was 1,867 BOE/d consisting of 7,674 mcf/d of natural gas and 588 bbls/d of oil and NGL's, before the deduction of royalties. PrimeWest operates three gas processing plants, which have 17 mmcf/d of capacity, net to PrimeWest.

### ***Thorsby***

The Thorsby property is located in Twps. 47 to 50, Ranges 27 W4 to Range 2 W5M, approximately 35 miles southwest of Edmonton, Alberta. The lands are located in the Pembina, Thorsby, Holburn, Wizard Lake and Bonnie Glen fields. PrimeWest holds an average 83 percent working interest in the area.

PrimeWest has various working interests in four property groupings – Thorsby Operated, Thorsby Non-Operated, Pembina Non-Operated, and Bonnie Glen Non-Operated. The Gilbert Report assigns net remaining Established Reserves at January 1, 2002 of 19,637 mboe, consisting of 92,019 mmcf of natural gas, and 4,301 mmbbl of oil and NGL's, before the deduction of royalties.

The average net production for 2001 was 3,945 BOE/d, consisting of 18,936 mcf/d natural gas and 166 bbls/d of oil and NGL's, all before deduction of royalties.

## **SouthEastern Alberta Area**

### ***Grand Forks***

The Grand Forks property is located 45 miles west of Medicine Hat, Alberta. Crude oil reserves are found predominantly in the Sawtooth and Arcs (Nisku) formations at an average depth of 3,100 feet. PrimeWest has an average 73 percent working interest in 190 (138.7 net) producing oil wells and a 94 percent working interest in 10 (9.4 net) producing gas wells.

The Gilbert Report assigns net remaining Established Reserves of 7,238 mbbbl of oil and natural gas liquids and 3,930 mmcf of natural gas for a total of 7,893 net mboe, before deduction of royalties to the Grand Forks property. The average net production from the Grand Forks property for the year ended December 31, 2001 was approximately 3,225 bbls/d of crude oil and natural gas liquids and 1,420 mcf/d of natural gas for a total of 3,462 boe/d, before deduction of royalties.

### ***Medicine Hat***

The Medicine Hat property covers a 25 mile radius around Medicine Hat, Alberta. The Gilbert Report assigns net remaining Established Reserves of 16,536 mmcf of natural gas for a total of 2,756 net mboe, before deduction of royalties to the Medicine Hat properties. The average net production from the Medicine Hat properties for the year ended December 31, 2001 was approximately 76 bbls/d of crude oil and natural gas liquids and 2,323 mcf/d of natural gas for a total of 464 boe/d, before deduction of royalties. PrimeWest has a 49.44 percent working interest in the PrimeWest operated Medicine Hat Consolidated Unit #2 which is located 25 miles northeast of Medicine Hat. Gas is produced from the Medicine Hat "A", "C", "D", Lower Colorado and Milk River zones.

### ***Dinosaur/Patricia***

The Dinosaur/Patricia area is located approximately 110 miles east of Calgary. PrimeWest owns a 51 percent operated interest in both the Patricia Gas Unit #1 and the Dinosaur Gas Unit #1. There are currently 69 producing gross (35.2 net) wells in the Patricia Unit and 25 producing gross (12.75 net) wells in the Dinosaur Unit. The Gilbert Report assigns net remaining Established Reserves of 13,123 mmcf of gas (2,187 mboe), before deduction of royalties. The average net production from the Dinosaur/Patricia property for the year ended December 31, 2001 was approximately 2,345 mcf/d of gas, before deduction of royalties.

## **Sundre Area**

### **1) *Caroline***

The Caroline properties are located approximately 60 miles northwest of Calgary, Alberta. PrimeWest have a working interest in five separate contiguous properties comprising the Caroline Area - North Caroline Gas, South Leg, East Caroline, SW Caroline/Northridge and West Caroline. The Gilbert Report assigns remaining Established Reserves of 194 mbbbl of oil, 32,048 mmcf of natural gas and 1,645 mbbbl of natural gas liquids for a total of 7,181 mboe, before deduction of royalties. The average net production from the Caroline Area properties for the year ended December 31, 2001 was approximately 210 bbls/d of oil and natural gas liquids and 2,673 mcf/d of natural gas for a total of 656 boe/d, before royalties. Effective December 18, 2001, the East Caroline portion of the Caroline properties were sold.

### **2) *Ricinus***

The Ricinus Cardium Unit #2 is located approximately 85 miles northwest of Calgary. PrimeWest own a 53.5 percent operated working interest in the Unit and a 1.8 percent interest in the Amoco operated Ricinus gas plant. The Gilbert Report assigns net remaining established reserves of 111 mbbbls of oil, 5,751 mmcf of natural gas and 158 mbbbls of natural gas liquids for a total of 1,227 mboe, before deduction of royalties. Average net production for the Ricinus property for the year ended December 31, 2001 was 68 bbls/d of oil; 4,560 mcf/d of natural gas and 123 bbls/d of natural gas liquids for a total of 952 boe/d, before deduction of royalties.

## **Other Properties**

The following is a description of PrimeWest's and the Trust's minor properties.

### ***Kaybob South Area***

The Kaybob South Area is located approximately 150 miles northwest of Edmonton, Alberta and consists of oil and solution gas production from the Kaybob South Triassic "A" Pool at a depth of approximately 7,000 feet. PrimeWest has a 42.5 percent working interest in the Kaybob South Triassic Unit No. 1 and a 20.1 percent working interest in the Kaybob South Triassic Unit No. 2, both of which are operated by PrimeWest. The Gilbert Report assigns net remaining Established Reserves of 1,354 mbbbl of oil, 706 mmcf of natural gas and 89 mbbbl of natural gas liquids for a total of 1,561 mboe, before deduction of royalties, to the Kaybob South Area properties. The average net production from the Kaybob South Area properties for the year ended December 31, 2001 was 480 bbls/d of oil and natural gas liquids and 200 mcf/d for a total of 514 boe/d, before deduction of royalties.

### ***Jumping Pound West***

PrimeWest has a 14.6 percent interest in the Jumping Pound West Unit No. 2 operated by Shell Canada Limited and located 30 miles west of Calgary. The unitized zone is the Rundle Formation. Production from the unit commenced in 1972 and is currently coming from 12 natural gas wells. Production is processed at the adjacent Jumping Pound Unit No. 1 plant facilities on a custom-processing-fee basis. The production is slightly sour and liquid rich, yielding 40 bbls of liquids per mmcf of natural gas. The Gilbert Report assigns net remaining Established Reserves of 11,101 mmcf of natural gas and 463 mbbls of natural gas liquids for a total of 2,313 net mboe, before deduction of royalties, to the Jumping Pound West property. Average net production for the year ended December 31, 2001 was 2,425 mcf/d of natural gas and 91 bbls/d of natural gas liquids for a total of 495 boe/d, before deduction of royalties.

### ***Eagle Lake Viking Voluntary Unit***

PrimeWest has a 9.4 percent working interest in the Eagle Lake Viking Voluntary Unit operated by Viking Holdings Management Ltd. The Unit was formed in 1966, and is located approximately 90 miles southwest of Saskatoon, Saskatchewan. The unitized zone consists of the Viking Formation, and 38 degree API light-gravity crude oil is recovered by waterflood, which was implemented in 1967. The Gilbert Report assigns net remaining Established Reserves of 770 mboe, before deduction of royalties, to the Eagle Lake Viking Voluntary Unit. Net oil production for the unit for the year ended December 31, 2001 averaged 108 bbls/d before deduction of royalties.

### ***Willesden Green***

The Willesden Green properties are located approximately 10 miles northeast of Rocky Mountain House, Alberta. PrimeWest has a 13.4 percent working interest and a 0.29 percent royalty interest in the Petro-Canada operated Willesden Green Cardium Unit No. 6, as well as varying minor royalty interests in units 1, 2, 4, 7 and 8. The Unit produces a 40-degree API light-gravity crude oil from the Willesden Green Cardium "A" Pool at a depth of approximately 6,230 feet. The Pool was discovered in 1959 and Unit No. 6 was formed in 1966 when a field wide waterflood scheme was implemented. The Gilbert Report assigns net remaining Established Reserves of 904 mboe, before deduction of royalties, to the Willesden Green properties. Average net production for the Willesden Green area for the year ended December 31, 2001 was 141 bbls/d of oil and natural gas liquids and 180 mcf/d of natural gas, for a total of 172 boe/d, before deduction of royalties. Drilling and completion of three infill wells was in progress as at year-end.

## Gross Overriding Royalty (GORR) Interests

These interests, principally acquired from Reserve Royalty Corp. in July 2000, entitle PrimeWest to a share of the gross sales price on production from the underlying properties generally without deduction for royalties and operating expenses. As well, as the owner of the GORR interest, PrimeWest is not generally responsible for any capital costs or abandonment and restoration costs associated with any exploration or development activities undertaken by the underlying working interest owner of the lands subject to the GORR. The Gilbert Report assigned remaining Established Reserves of 4,212 mboe at January 1, 2002. The 2001 average production from these GORR interests was 1,574 boe/d consisting of 1,030 bbls/d of crude oil and NGL's and 3.2 mmcf/d of gas.

## Unproved Lands

PrimeWest has an interest in approximately 1,269,596 (953,427 net) acres of unproved lands at December 31, 2001. PrimeWest is currently reviewing available seismic and other data, and developing an exploitation plan for these properties. Capital expenditures, farmouts and/or dispositions may result in future revenues from these undeveloped lands. The province and value of the unproved lands is as follows:

### Unproved Lands

	<b>Gross Acres</b>	<b>Net Acres</b>	<b>Gross Royalty Acres</b>	<b>Total Net Acres</b>	<b>Value of Net Acres</b>
Alberta	987,701	693,963	223,660	917,623	\$54,327,646
BC	18,416	7,334	0	7,334	513,400
Sask	18,518	7,149	21,301	28,470	819,957
<b>TOTAL</b>	<b>1,024,635</b>	<b>708,446</b>	<b>244,961</b>	<b>953,427</b>	<b>\$55,661,003</b>

## 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 or the Trust 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 the Manager 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 per day). Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the 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, and not exceeding two years in the case of heavy crude, 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 planning 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. The Manager believes that PrimeWest is in material compliance with applicable environmental laws and regulations properties.

## **Risk Factors**

### **Volatility of Oil and Natural Gas Prices**

The results of operations and financial condition of each of PrimeWest, and therefore the amounts paid to the Trust, will be dependent on the prices received oil and natural gas production. Crude oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil producing regions, which are beyond the control of PrimeWest or the Trust. Any decline in crude oil or natural gas prices could have a material adverse effect on the operations, financial condition, proved reserves and the level of expenditures for the development of the oil and natural gas reserves of PrimeWest. The Manager may manage the risk associated with changes in commodity prices and foreign exchange rates by causing PrimeWest to, from time to time, enter into one or more of crude oil, natural gas and foreign currency risk management contracts and forward foreign-exchange contracts.

### **Reserves Replacement (Sustainability)**

The Trust has certain unique attributes, which differentiate it from other oil and natural gas industry participants. Distributions of Distributable Income in respect of properties, absent commodity price increases or cost-effective acquisition and development activities, will decline over time in a manner consistent with declining production from typical oil, natural gas and natural gas liquids reserves. PrimeWest will not be reinvesting cash flow in the same manner as other oil and natural gas exploration and production company industry participants. PrimeWest's future oil and natural gas reserves and production, and therefore its cash flows, will be highly dependent on the Manager's success in exploiting existing reserve bases and acquiring additional reserves. Without reserve additions through acquisition and/or development activities, the reserves and production of PrimeWest and the Trust will decline over time as reserves are produced.

Trust Units will have no value when reserves from the properties or additional properties can no longer be economically marketed and, as a result, subscribers for Trust Units will have to obtain the return of capital invested out of cash flow derived from their investment in Trust Units during the period when reserves can be economically recovered.

To the extent that external sources of capital, including the issuance of additional Trust Units, become limited or unavailable, the ability of PrimeWest and the Trust to make the necessary capital investments to maintain or expand their 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 Distributable Income will be reduced.

There is strong competition relating to all aspects of the oil and natural gas industry. The Manager actively competes for reserve acquisitions and skilled industry personnel with a substantial number of other oil and natural gas companies, many of which have significantly greater financial resources than the Manager. There can be no assurance that PrimeWest will be successful in developing additional reserves or acquiring additional reserves on terms that meet the acquisition guidelines.

### **Changes in Legislation**

There can be no assurance that income tax laws or government incentive programs relating to the oil and natural gas industry, such as the status of mutual fund trusts and the resource allowance, will not be changed in a manner which adversely affects Unitholders.

### **Investment Eligibility**

If the Trust ceases to qualify as a mutual fund trust, the Trust Units will cease to be qualified investments for RRSPs, RRIFs and DPSPs and RESPs that acquired the Trust Units after October 27, 1998 ("Exempt Plans"). Where at the end of any month an Exempt Plan holds Trust Units that are not qualified investments, the Exempt Plan must, in respect of that month, pay a tax under Part XI.1 of the Tax Act equal to 1 percent of the fair market value of the Trust Units at the time those Trust Units were acquired by the Exempt Plan. In addition, where a trust governed by an RRSP holds Trust Units that are not qualified investments; the trust will become taxable on its income attributable to the Trust Units while they are not qualified investments.

### **Operational Matters**

The operation of oil and natural gas wells and processing facilities involves a number of operating and natural hazards, which may result in blowouts, environmental damage and other unexpected or dangerous conditions, resulting in damage to the property of PrimeWest and possible liability to third parties. PrimeWest, on behalf of itself and the Trust, maintains liability insurance, where available, in amounts consistent with industry standards. Business interruption insurance may also be purchased for selected facilities, to the extent that kind of insurance is available. PrimeWest may become liable for damages arising from those events against which it cannot insure or against which it may elect not to insure because of high premium costs or other reasons. In particular, insurance against environmental risks is not generally available to PrimeWest or to other companies in the oil and natural gas industry. Costs incurred to repair that damage or pay those liabilities will reduce amounts paid to the Trust.

Continuing production from a property, and to some extent the marketing of production therefrom, are largely dependent upon the capability of the operator of the property. To the extent the operator fails to perform these functions properly, revenue

may be reduced. Payments from production generally flow through the operator, and there is a risk of delay and additional expense in receiving those revenues if the operator becomes insolvent.

Although satisfactory title reviews of the properties will be conducted in accordance with industry standards, those title reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat the claim of PrimeWest to a property. A reduction of amounts paid to the Trust could result in those circumstances.

### **Environmental Concerns**

The oil and natural gas industry is subject to environmental regulation pursuant to municipal, provincial and federal legislation. A breach of that legislation may result in the imposition of fines or the issuance of clean up orders. That legislation may be changed to impose higher standards and potentially more costly obligations on PrimeWest. See "Industry Conditions – Environmental Regulation". Although PrimeWest has established a reclamation fund for the purpose of funding the currently estimated future environmental and reclamation obligations of PrimeWest and the Trust based on its current knowledge, there can be no assurance that PrimeWest will be able to satisfy actual future environmental and reclamation obligations. Ongoing environmental obligations will be funded out of cash flow and will therefore reduce Distributable Income payable 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.

### **Debt Service**

Amounts paid in respect of interest and principal, and other costs, expenses and disbursements ("Debt Service Charges") relating to debt incurred in respect of the properties will reduce amounts paid to the Trust. Variations in interest rates and other credit charges and scheduled principal repayments could result in significant changes in the amount required to be applied to Debt Service Charges before payment of amounts paid to the Trust and Distributable Income. Certain covenants of the agreements with the bank providing the Credit Facility may also limit distributions to and by the Trust. Although the Manager and PrimeWest believe the Credit Facility will be sufficient for all immediate requirements, there can be no assurance that the amount will be adequate for the future financial obligations of PrimeWest and the Trust or that additional funds will be able to be obtained.

The bank syndicate providing the Credit Facility will be provided with security over substantially all of the assets of each of PrimeWest and the Trust. If PrimeWest becomes unable to pay its Debt Service Charges in respect of the Credit Facility, or

otherwise commits an event of default such as bankruptcy, the syndicate may foreclose on or sell the properties free from the rights of the Trust to the revenue therefrom.

### **Delay in Cash Distributions**

In addition to the usual delays in payment by purchasers of Petroleum Substances produced from the properties to the operator of the properties, from the operator to PrimeWest (where PrimeWest is not the operator), from PrimeWest to the Trust and from the Trust to Unitholders, payments between any of those parties may also be affected or 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 properties, or the establishment by the operator of reserves for those expenses.

### **Reliance on the Manager**

Unitholders will be dependent on the management of the Manager in respect of the administration and management of all matters relating to the properties, PrimeWest, the Trust and Trust Units. Investors who are not willing to rely on the management of the Manager should not invest in the Trust Units.

### **Potential Conflicts of Interest**

There may be circumstances in which the interests of the Manager will conflict with those of Unitholders.

The Manager will use all reasonable efforts to resolve such conflicts of interest in a manner that will treat the Trust and PrimeWest, as the case may be, and the other interested party fairly, taking into account all of the circumstances of the Trust and PrimeWest, as the case may be, and such interested party, and to act honestly and in good faith in resolving those matters.

Circumstances may arise where members of the board of directors of PrimeWest are directors or officers of corporations, which are in competition to the interests of PrimeWest and the Trust. No assurances can be given that opportunities identified by those board members will be provided to PrimeWest and the Trust.

### **Nature of Trust Units**

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 PrimeWest. The Trust Units represent a fractional interest in the Trust. As holders of Trust Units, Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring oppression or derivative actions.

The Trust's sole assets will be permitted short-term investments, direct and indirect interests in petroleum and natural gas properties and related contractual rights and shares in PrimeWest. The market price of the Trust Units will be a function of anticipated Distributable Income, the value of the properties owned by PrimeWest and the Trust, and the Manager's ability to effect long-term growth in the value of the Trust.

The market price of the Trust Units will be sensitive to a variety of market conditions including, but not limited to, interest rates and the ability of the Trust to acquire suitable oil and natural gas properties. Changes in market conditions may adversely affect the trading price of the Trust Units.

### **Unitholder Limited Liability**

The Declaration of Trust provides that no Unitholder will be subject to any liability in connection with the Trust or its obligations and affairs and, in the event that a court determines Unitholders are subject to any of those liabilities, those liabilities will be enforceable only against, and will be satisfied only out of the Trust's assets. Pursuant to the Declaration of Trust, the Trust will indemnify and hold harmless each Unitholder from any costs, damages, liabilities, expenses, charges and losses suffered by a Unitholder resulting from or arising out of that Unitholder not having that limited liability.

The Declaration of Trust provides that all written instruments signed by or on behalf of the Trust must contain a provision to the effect that the obligations in those instruments will not be binding on Unitholders personally. Where however the Trust holds direct interests in oil and gas properties, such as in the case of third party gross overriding royalties, the terms of contracts assigned to the Trust may not contain such provisions. In such cases the assignments to the Trust of such interests specifically reserve out the assumption by the Trust of any liability to the Unitholders personally. Personal liability may also arise in respect of claims against the Trust that do not arise under contracts, including claims in tort, claims for taxes, and possibly certain other statutory liabilities. The possibility of any personal liability of this nature arising is considered unlikely.

The operations of the Trust will be conducted, on the advice of counsel, in such a way and in such jurisdictions as to avoid as far as possible any material risk of liability on the Unitholders for claims against the Trust.

## ITEM 4: 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

	For the Year Ended December 31				
	2001	2000	1999	1998	1997
(\$000's except per Trust Unit)					
<b>Earnings Information</b>					
Total Revenue, net of royalties .....	306,515	156,561	83,063	66,057	59,593
Expenses, including D, D & A and taxes .....	226,979	100,949	77,078	79,604	56,423
Net Income (Loss) .....	79,536	55,612	5,985	(13,547)	3,170
Net Income (Loss) per Trust Unit (\$)					
Basic .....	0.78	1.25	0.18	(0.43)	0.13
Diluted .....	0.77	1.21	0.18	(0.43)	0.13
<b>Distributable Income Information</b>					
Cash Available for Distribution .....	236,834	79,832	37,728	26,030	33,746
Cash Available for Distribution to Trust Unitholders .....	234,465	79,033	37,351	25,769	33,409
Cash Available for Distribution per Trust Unit (\$)....	2.31	1.77	1.10	0.82	1.34
<b>Balance Sheet Information</b>					
Total Assets .....	1,516,081	434,238	320,210	316,140	285,765
Long Term Debt, including current portion .....	195,067	79,046	92,286	73,112	66,829
Average Trust Units Outstanding .....	102,533	44,652	33,965	31,426	24,931

### Selected Quarterly Information

	For the Quarters Ended - 2001			
	March 31	June 30	September 30	December 31
(\$000's except per Trust Unit)				
Total Revenue, net of royalties .....	56,990	87,974	83,105	78,446
Expenses including D, D & A and taxes .....	32,800	53,742	59,255	81,182
Net Income (Loss).....	24,190	34,232	23,850	(2,736)
Net Income (Loss) per Trust Unit				
Basic .....	0.45	0.33	0.20	(0.02)
Diluted .....	0.44	0.33	0.20	(0.02)
<b>For the Quarters Ended - 2000</b>				
	March 31	June 30	September 30	December 31
Total Revenue, net of royalties .....	27,829	34,641	41,091	53,000
Expenses including D, D & A and taxes .....	19,748	24,609	26,431	30,161
Net Income .....	8,081	10,032	14,660	22,839
Net Income per Unit				
Basic .....	0.23	0.26	0.31	0.45
Diluted .....	0.23	0.25	0.30	0.43

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.

### **Selected Financial and Operational Information**

The information in the tables below sets forth certain quarterly comparative financial and operations data which is intended to supplement the financial and operations results otherwise set forth herein and in the documents incorporated by reference herein.

#### **Average Daily Production Volume (before royalties)**

	<b>For the Quarters Ended - 2001</b>			
	<b>March 31</b>	<b>June 30</b>	<b>September 30</b>	<b>December 31</b>
Crude Oil (bbls/d) .....	6,988	11,453	11,216	10,425
Natural Gas Liquids (bbls/d).....	1,613	2,614	2,414	2,441
Natural Gas (mmcf/d) .....	49.58	127.72	121.32	119.65

	<b>For the Quarters Ended - 2000</b>			
	<b>March 31</b>	<b>June 30</b>	<b>September 30</b>	<b>December 31</b>
Crude Oil (bbls/d) .....	5,763	6,038	7,087	7,422
Natural Gas Liquids (bbls/d).....	1,264	1,537	1,521	1,610
Natural Gas (mmcf/d) .....	48.13	48.39	52.10	47.49

#### **Average Netbacks - Crude Oil and NGLs (per bbl)**

	<b>For the Quarters Ended - 2001</b>			
	<b>March 31</b>	<b>June 30</b>	<b>September 30</b>	<b>December 31</b>
Average net product price.....	33.05	35.35	32.37	28.98
Royalties.....	5.78	6.42	6.24	4.32
Operating expenses <sup>(1)</sup> .....	5.49	4.80	6.08	5.69
Netback received.....	21.78	24.13	20.05	18.97

	<b>For the Quarters Ended - 2000</b>			
	<b>March 31</b>	<b>June 30</b>	<b>September 30</b>	<b>December 31</b>
Average net product price.....	32.84	34.17	38.56	38.43
Royalties.....	6.86	6.20	6.58	6.95
Operating expenses <sup>(1)</sup> .....	4.96	5.00	5.13	5.20
Netback received.....	21.02	22.97	26.85	26.28

Note:

- 1) Operating expenses have been allocated to crude oil and NGLs produced based on the relative production of crude oil and NGLs as compared to production of natural gas.

## Average Netbacks – Natural Gas (per mcf)

	For the Quarters Ended – 2001			
	March 31	June 30	September 30	December 31
Average net product price.....	10.38	6.21	5.32	5.16
Royalties.....	2.50	1.70	0.75	0.67
Operating expenses <sup>(1)</sup> .....	0.92	0.81	0.91	0.95
Netback received.....	6.96	3.70	3.66	3.54

	For the Quarters Ended – 2000			
	March 31	June 30	September 30	December 31
Average net product price.....	3.01	3.99	4.20	7.43
Royalties.....	0.53	0.74	1.03	1.26
Operating expenses <sup>(1)</sup> .....	0.83	0.83	0.85	0.87
Netback received.....	1.65	2.42	3.32	5.30

Note:

- 1) Operating expenses have been allocated to natural gas produced based on the relative production of natural gas as compared to production of crude oil and NGLs.

## Capital Expenditures (in thousands)

	For the Quarters Ended – 2001			
	March 31	June 30	September 30	December 31
Property acquisitions.....	\$ 767,549	\$ 58,800	\$ 7,422	\$ 12,927
Exploration, including drilling.....	-	-	-	-
Development, including facilities.....	6,014	14,740	29,749	29,944
Other <sup>(1)</sup> .....	666	575	609	1,607

	For the Quarters Ended – 2000			
	March 31	June 30	September 30	December 31
Property acquisitions.....	\$ 1,053	\$ 32,659	\$ 84,349	\$ 595
Exploration, including drilling.....	-	-	-	-
Development, including facilities.....	3,162	4,467	6,162	9,262
Other <sup>(1)</sup> .....	276	389	362	1,321

Note:

- 1) Other capital expenditures include capitalized general and administrative expenses and other corporate expenditures.

## ITEM 5: 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 6: MARKET FOR SECURITIES

The outstanding Trust Units of the Trust are listed for trading on The Toronto Stock Exchange under the symbol PWI.UN. The outstanding exchangeable shares of PrimeWest are listed for trading on The Toronto Stock Exchange under the symbol PWX.

## ITEM 7: 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 and the Manager.

### Directors

The Trust has the right to nominate and elect a majority of the board of directors of PrimeWest. 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 March 31, 2002, are as follows:

<b><u>Name and Present Principal Occupation or Employment</u></b>	<b><u>Director of PrimeWest Since</u></b>	<b><u>Municipality of Residence</u></b>	<b><u>Trust Units Beneficially Owned or over which Control or Discretion is Exercised as at March 31, 2002</u></b>
HAROLD P. MILAVSKY Chairman Quantico Capital Corp.	1996	Calgary, Alberta	65,608
BARRY E. EMES Partner Stikeman Elliott	1996	Calgary, Alberta	9,000
HAROLD N. KVISLE President TransCanada PipeLines Limited	1996	Calgary, Alberta	17,900
MICHAEL W. O'BRIEN Executive Vice President, Corporate Development and Chief Financial Officer Suncor Energy Inc.	2000	Canmore, Alberta	5,000
KENT J. MACINTYRE Chief Executive Officer PrimeWest Energy Inc.	1996	Calgary, Alberta	1,143,354

Each of the foregoing persons has been engaged in the occupation set forth above or similar occupations with the same employer for the last five years, other than 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. Mr. O'Brien was Executive Vice-President of Sunoco Inc., a wholly-owned subsidiary of Suncor Energy Inc. On November 20, 2001, Suncor Energy Inc. issued a news release indicating that Mr. O'Brien had announced plans to retire from Suncor Energy Inc. effective June 30, 2002.

PrimeWest does not have an executive committee, but is required to, and does have, an audit committee. The audit committee consists of those directors of PrimeWest who are nominees of the Trust. Barry E. Emes, Harold N. Kvisle, Michael W. O'Brien and Harold P. Milavsky, who are Independent Directors, are members of the Audit Committee and the Audit Committee also serves as PrimeWest's Reserves Committee. The Independent Directors also act as the Corporate Governance and Compensation Committees of PrimeWest. The Corporate Governance and Compensation Committee also serves as PrimeWest's Environmental, Health and Safety Committee.

Computershare is currently the Trustee of the Trust.

## **Officers**

Each person who is an officer of the Manager also holds the same office with PrimeWest. The name, municipality of residence, position held and principal occupation of each officer of each of PrimeWest and the Manager on the date hereof are set out below:

<b><u>Name and Municipality</u></b>	<b><u>Position with the Manager</u></b>	<b><u>Principal Occupation</u></b>
Kent J. MacIntyre Calgary, Alberta	Director, Vice-Chairman and Chief Executive Officer Since October 1996	Vice-Chairman and Chief Executive Officer of the Manager and PrimeWest
Donald A. Garner Calgary, Alberta	President and Chief Operating Officer Since June 2001	President and Chief Operating Officer of the Manager and PrimeWest
Ronald J. Ambrozy Calgary, Alberta	Vice-President, Business Development Since October 1997	Vice-President, Business Development of the Manager and PrimeWest
Dennis G. Feuchuk Calgary, Alberta	Vice-President, Finance and Chief Financial Officer Since October 2001	Vice-President, Finance and Chief Financial Officer of the Manager and PrimeWest
Timothy S. Granger Calgary, Alberta	Vice-President, Operations and Development Since June 1999	Vice-President, Operations and Development of the Manager and PrimeWest
William N. Rowe	Vice-President, Planning and	Vice-President, Planning and

Calgary, Alberta	Investor Relations Since December 2001	Investor Relations of the Manager and PrimeWest
James T. Bruvall Calgary, Alberta	Secretary Since October 1996	Partner, Stikeman Elliott

Prior to June 2001, Mr. Garner was President and Chief Operating Officer of Northstar Energy Corporation and prior to that an executive at Imperial Oil. Prior to September 1997, Mr. Ambrozy held several positions of progressive responsibility at Gulf Canada Resources Limited over the previous 22 years. For 26 years prior to October 2001, Mr. Feuchuk held various financial positions with Gulf Canada Resources, most recently as Vice President and Controller and also as Vice President and Treasurer for Athabasca Oil Sands Trust. For the five years prior to June, 1999, Mr. Granger held various managerial positions at Pogo Canada Ltd., Petro-Canada and prior to that at Amerada-Hess. Prior to December 2001, Mr. Rowe was Vice President, Investor Relations for NOVA Chemicals Corporation and its predecessor NOVA Corporation (NOVA) (April 1997 – November 2001) and Director of Investor Relations prior to April 1997.

### **Management of the Manager**

#### ***Kent J. MacIntyre, Director, Vice-Chairman and Chief Executive Officer***

Mr. MacIntyre has overall responsibility for leading and overseeing the business direction of the Manager. He has over 20 years of experience in the oil and natural gas industry, the last eleven years as principal in the start-up and management of several energy ventures including Olympia Energy Ventures Ltd. (1989-1993) and Triad Energy Inc. (1994-1996). Through these ventures, Mr. MacIntyre has been directly involved in and responsible for the acquisition of various petroleum and natural gas properties and the enhancement of the value of those properties through selective operating, marketing, development and exploration strategies. In each of those acquisitions Mr. MacIntyre's companies became the operator of the acquired properties and developed a record of acquiring properties at costs substantially below industry averages.

Prior to 1989, Mr. MacIntyre held executive or engineering operating positions with Sabre Energy Ltd., Vikor Resources Ltd., and Hudson's Bay Oil and Gas Company Ltd. Mr. MacIntyre has a B.Sc. (Eng.) from the University of Manitoba and an MBA from the University of Calgary.

#### ***Donald A. Garner, President and Chief Operating Officer***

Mr. Garner joined the Manager in June 2001 and has overall responsibility for the day-to-day business and operations of the Manager. He has more than 20 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 University of Calgary.

***Ronald J. Ambrozy, Vice-President, Business Development***

Mr. Ambrozy has over 26 years of experience in the petroleum and natural gas industry. Prior to joining the Manager 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.

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

Mr. Feuchuk joined the Manager in October 2001 and is responsible for the general financial operations of the Manager and for providing advice to the Manager on tax and accounting matters. Mr. Feuchuk has over 26 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.

***Timothy S. Granger, Vice President, Operations and Development***

Mr. Granger joined the Manager in June 1999 and is responsible for field operations and the capital development program. Mr. Granger has more than 20 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.

***William N. Rowe, Vice-President, Planning and Investor Relations***

Mr. Rowe joined the Manager in December 2001 and is responsible for corporate communications with all PrimeWest stakeholders including the investment

community. In addition Mr. Rowe, is responsible for strategic planning. Prior to joining the Manager, Mr. Rowe was Vice President, Investor Relations for NOVA Chemicals Corporation. Mr. Rowe has 29 years of experience in commodity based industries, public accounting and management consulting.

A Bachelor of Commerce (1973, McMaster University) and Chartered Accountant (1975), Mr. Rowe is a Past President of the Canadian Investor Relations Institute and winner of its 2000 Award of Excellence. Mr. Rowe is also a past director of the Vienna, Virginia based National Investor Relations Institute.

## **Employees**

As of December 31, 2001, the Trust had no employees. The activities of PrimeWest and the Trust are carried out by the Manager pursuant to the terms of the Management Agreement. The Manager had 154 employees (including field staff) as of December 31, 2001, all of which devoted substantially all of their working time to the business of the Trust and PrimeWest.

## **Potential Conflicts of Interest**

Mr. Milavsky, a director of PrimeWest, is also the Chairman of five publicly listed mutual fund trusts (collectively, the "Citadel Funds") and receives remuneration for acting in such capacity. Mr. MacIntyre, the Chief Executive Officer of PrimeWest and an officer of the Manager, owns a controlling interest in each of the corporate administrators of the Citadel Funds. Mr. Emes, a director of PrimeWest, and Mr. Bruvall, the Secretary of PrimeWest, are partners in a law firm which provides services to PrimeWest.

The Board of Directors of PrimeWest does not believe that any of the activities set forth above and undertaken by such individuals interferes in any way with their ability to act in their respective capacities for PrimeWest and with a view to the best interests of PrimeWest.

## **ITEM 8: ADDITIONAL INFORMATION**

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Trust's securities, interests of insiders in material transactions and the compensation of the Manager, 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, 2001, 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, 2001 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, 2001 and a copy of the Circular dated April 23, 2002.

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 measurements are given in standard Imperial or metric units only. The following table sets forth certain standard conversions:

<b>bbls</b>	Barrels	<b>mcf/d</b>	1,000 cubic feet per day
<b>mbbls</b>	1,000 barrels	<b>bcf</b>	1,000,000,000 cubic feet
<b>mmbbls</b>	1,000,000 barrels	<b>m</b>	1000 cubic metres
<b>bbls/d</b>	Barrels per day	<b>boe</b>	barrels of oil equivalent
<b>mcf</b>	1,000 cubic feet	<b>mboe</b>	1,000 barrels of oil equivalent
<b>mmcf</b>	1,000,000 cubic feet	<b>boe/d</b>	barrels of oil equivalent per day
<b>mlt</b>	1,000 long tons	<b>mmboe</b>	millions of barrels of oil equivalent

For purposes of this document, 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:

**Amoco** means, collectively, Amoco Canada Petroleum Company Ltd. and its affiliates.

**Amalgamation** means the amalgamation of PrimeWest Oil and Gas Corp., PrimeWest Resources Ltd. and PrimeWest Royalty Corp. on January 1, 2002 pursuant to the provisions of the *Business Corporations Act* (Alberta).

**Annual Report** means the 2001 Annual Report of PrimeWest Energy Trust filed on SEDAR at [www.sedar.com](http://www.sedar.com).

**ARTC** means Alberta royalty tax credit.

**Cash Distribution Date** means the date Distributable Income is paid to Unitholders, currently being the 15th day following any Record Date.

**Circular** means the Management Proxy Circular of PrimeWest Energy Trust, to be dated on or about April 23, 2002.

**Computershare** means Computershare Trust Company of Canada.

**Credit Facility** means a bank syndication of Canadian chartered banks offering a maximum borrowing capability of \$350 million.

**Cypress** means Cypress Energy Inc.

**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 October 26, 2001, as amended from time to time.

**Distributable Income** means 99 percent of the Royalty Income together with any income earned by the Trust from permitted short term investments plus any ARTC, less Crown royalties and other Crown charges that are not deductible by PrimeWest for income tax purposes and that are reimbursed by the Trust to PrimeWest less general and administrative expenses of the Trust.

**DRIP** means the Distribution Reinvestment Plan of the Trust.

**Established Reserves, Proved Reserves** and **Probable Reserves** have the meanings given to those terms in this Annual Information Form under the heading "Oil and Natural Gas Reserves".

**General and Administrative Costs** means the amount in aggregate representing all expenditures and costs incurred under the Management Agreement in respect of PrimeWest, the Trust or the Royalty or in the management and administration of PrimeWest, the Trust or the Royalty, other than Management Fees.

**Gilbert** means Gilbert Laustsen Jung Associates Ltd.

**Gilbert Report** means the reserve report prepared by Gilbert evaluating the crude oil, natural gas, natural gas liquids and sulphur reserves attributable to properties owned by PrimeWest, Resources, PrimeWest Royalty, Oil & Gas and the Trust as at January 1, 2002.

**Management Agreement** means the amended and restated management agreement dated January 1, 2002 among the Manager, PrimeWest and the Trustee for and on behalf of the Trust, as amended from time to time, pursuant to which the Manager provides management services to PrimeWest and the Trust.

**Management Fees** means the fees payable to the Manager pursuant to the Management Agreement.

**Manager** means PrimeWest Management Inc.

**NEB** means National Energy Board.

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

- 1) the amount received or receivable by PrimeWest in respect of the sale of its interest in all Petroleum Substances produced from the properties;
- 2) 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 1);
- 3) 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
- 4) ARTC applicable to the properties;  
less
- 5) 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.

**Oil & Gas** means PrimeWest Oil and Gas Corp.

**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.

**PrimeWest** means PrimeWest Energy Inc., 89% owned by the Trust and 11% owned by the Manager.

**PrimeWest Royalty** means PrimeWest Royalty Corp.

**Record Date** means the last day in each 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, 2001.

**Resources** means PrimeWest Resources Ltd.

**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 percent 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, Management Fees, 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 percent 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.

**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.

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

**Venator** means Venator Petroleum Company Ltd.

**SCHEDULE A**  
**US GAAP RECONCILIATION**  
**AUDITORS' REPORT**

**TO:** The Board of Directors of PrimeWest Energy Trust

Our audits of the consolidated financial statements referred to in our report dated March 1, 2002 appearing in the Annual Report to Shareholders of PrimeWest Energy Trust, which report and financial statements are incorporated by reference into this Annual Information Form also included audits of the Reconciliation to US GAAP. In our opinion, this Reconciliation to US GAAP is presented fairly, in all material respects, when read in conjunction with the related consolidated financial statements.

PricewaterhouseCoopers LLP  
Chartered Accountants

Calgary, Alberta  
March 1, 2002

## **Reconciliation to accounting principles generally accepted in the United States**

PrimeWest's financial statements are prepared in accordance with accounting principles generally accepted (GAAP) in Canada which, in some respects differ from those generally accepted in the United States (U.S.). The following are those policies that result in significant measurement differences.

### **Property, plant and equipment**

PrimeWest follows the full cost accounting guideline as established by the Canadian Institute of Chartered Accountants. Under this guideline, the net carrying value of the company's oil and gas properties is limited to an estimated recoverable amount calculated as aggregate undiscounted future net revenues, after deducting future general and administrative costs, financing costs, and income taxes. In accordance with the full cost method of accounting as set out by the U.S. Securities and Exchange Commission, the net carrying value is limited to a standardized measure of discounted future cash flows, before financing and general administrative costs. Where the amount of a ceiling test write down under Canadian GAAP differs from the amount of a write down under U.S. GAAP, the charge for depreciation and depletion under U.S. and Canadian GAAP will differ in subsequent years.

### **Income taxes**

Effective January 1, 2000, the company adopted, retroactively without restating prior years, the liability method of accounting for income taxes as recommended by the Canadian Institute of Chartered Accountants. In prior years, the company computed deferred income taxes using the deferral method.

The new Canadian accounting standard is similar to the United States Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes (FAS 109), which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been recognized in the company's financial statements or tax returns. In estimating future tax consequences, both the new Canadian standard and FAS 109 generally consider all expected events, including enacted changes in laws or rates.

### **Derivative financial instruments**

Effective January 1, 2001, the company adopted United States Statement of Financial Accounting Standards No. 133 Accounting for Derivative Instruments and Hedging Activities, as amended by SFAS 138, which establishes accounting and reporting

standards for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities. All derivatives, whether designated in hedging relationships or not, and excluding normal purchase and sales are required to be recorded on the balance sheet at fair value. If the derivative is designated as a fair value hedge, the changes in the fair value of the derivative and of the hedged item attributable to the hedged risk are recognized in earnings. If the derivative is designated as a cash flow hedge, the effective portions of the changes in fair value of the derivative are recorded in other comprehensive income (OCI) and are recognized in the income statement when the hedged item is realized. Ineffective portions of changes in the fair value and the cash flow hedges are recognized in earnings, immediately.

The adoption of FAS 133 resulted in Other Comprehensive Income of \$44.3 million. Assets increased by \$44.3 million as a result of recording derivative instruments on the consolidated balance sheet at fair value. The increase in U.S. GAAP comprehensive earnings is attributable to the mark to market derivative gain at the balance sheet date.

Implementation of this accounting standard did not affect the company's cash flow or liquidity.

### **Recent Accounting Pronouncements**

During 2001 the following new or amended standards and guidelines were issued:

#### ***Business Combinations and Goodwill and Other Intangible Assets***

The Canadian Institute of Chartered Accountants (CICA) issued CICA 1581 "Business Combinations" and CICA 3062 "Goodwill and Other Intangible Assets". In addition, the Financial Accounting Standards Board (FASB) in the United State issued SFAS No. 141 "Business Combinations" and SFAS No. 142 "Goodwill and Other Intangible Assets". Under the new standards, all business combinations initiated after June 30, 2001 must be accounted for using the purchase method, which could result in additional amounts of goodwill being recorded.

Goodwill and intangible assets with indefinite lives will no longer be amortized but rather subject to a periodic impairment test. This requires prospective application effective January 1, 2002. The impact on the Trust's earnings is immaterial.

#### ***Accounting for Asset Retirement Obligations***

FASB issued SFAS No. 143 "Accounting for Asset Retirement Obligations", effective for years beginning after June 15, 2002. The standard requires legal obligations associated with the retirement of long-lived tangible assets to be recognized at fair value. The

Trust has not yet determined the effect this new standard will have on its consolidated financial statements.

### ***Accounting for the Impairment or Disposal of Long-Lived Assets***

FASB issued SFAS No. 144 “Accounting for the Impairment or Disposal of Long-Lived Assets”, which is effective for fiscal years beginning after December 15, 2001 and interim periods within those fiscal years. The standard supersedes SFAS No. 121 “Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed Of” and APB Opinion No. 30 “Reporting Results of Operations – Reporting the Effects of Disposal of a Segment of A Business”. The standard requires an impairment to be recognized on long-lived assets when the expected undiscounted cash flows are less than the carrying amount. Impairment would be calculated as the carrying amount less the fair value of the assets. The value of long-lived assets to be disposed of by sale is measured at the lower of the carrying amount or the fair value less selling costs. In addition, earnings from discontinued operations between the measurement date and the disposal date are excluded from the net gain/loss on disposal. The Trust anticipates that adoption of SFAS No. 144 will not have a material effect on its consolidated financial statements.

### ***Stock-based Compensation and Other Stock-based Payments***

The CICA issued CICA 3870 “Stock-based Compensation and Other Stock-based Payments”. The new standard requires that stock-based payments to non-employees be accounted for using the fair value based method and requires compensation costs to be recognized for stock appreciation rights, awards to be settled in cash or other assets and direct awards of stock to employees. The standard is effective for fiscal years beginning on or after January 1, 2002. The Trust anticipates that adoption of CICA 3870 will not have a material effect on its consolidated financial statements.

### ***Foreign Currency Translation***

The CICA approved amendments to CICA 1650 “Foreign Currency Translation”. The amendment eliminates the deferral and amortization of translation gains and losses on long-term monetary assets and liabilities. The amendment is effective for fiscal years beginning on or after January 1, 2002. The Trust anticipates that adoption of CICA 1650 will not have a material effect on its consolidated financial statements.

### ***Hedging Relationships***

The CICA issued Accounting Guideline 13 “Hedging Relationships” which deals with the identification, designation, documentation and effectiveness of hedging relationships for the purpose of applying hedge accounting. The guideline establishes

conditions for applying hedge accounting, but does not specify hedge accounting methods. The guideline is effective for fiscal years beginning on or after June 1, 2002. The Trust anticipates that adoption of Accounting Guideline 13 will not have a material effect on its consolidated financial statements.

The following tables set out the significant differences in the consolidated financial statements using U.S. GAAP.

**a) Consolidated net income**

	<b>2001</b> <b>\$000's</b>	<b>2000</b> <b>\$000's</b>
Net income as reported	79,536	55,612
Adjustments		
Depletion and depreciation	(539,288)	6,523
FAS 133 adjustment	43,300	-
Future income tax recovery/(expense)	184,291	(780)
Adjusted net (loss)/income	(232,161)	61,355
Other comprehensive income		
Cumulative effect type adjustment – fair value of cash flow hedging instruments	(970)	-
Change during the year	970	-
Accumulated other comprehensive income	-	-
Adjusted net and comprehensive (loss)/income	(232,161)	61,355
Net (loss)/income per Trust Unit		
Canadian GAAP	0.78	1.25
U.S. GAAP	(2.25)	1.37

**b) Consolidated balance sheets**

	<b>2001</b>		<b>2000</b>	
	<b>Cdn GAAP</b> <b>\$</b>	<b>U.S. GAAP</b> <b>\$</b>	<b>Cdn GAAP</b> <b>\$</b>	<b>U.S. GAAP</b> <b>\$</b>
Other assets	-	44,270	-	-
Property, plant and equipment – net	1,448,661	850,526	395,376	336,529
Future income tax liability	(362,595)	(172,963)	(16,596)	(11,255)
Retained earnings (deficit)	122,550	(241,683)	43,014	(10,492)
Accumulated other comprehensive income	-	-	-	-

**c) Consolidated cash flows**

The consolidated statements of cash flows prepared in accordance with Canadian GAAP conform in all material respects with U.S. GAAP except that Canadian GAAP allows for the presentation of operating cash flow before changes in non-cash working capital items in the consolidated statement of cash flows. This total cannot be presented under U.S. GAAP.

**SCHEDULE B**

**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)**

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

	<b>2000</b>	<b>1999</b>	<b>1998</b>
Revenue			
Petroleum and natural gas sales	\$ 186,763	\$ 78,168	\$ 34,124
Royalties, net of ARTC	(45,180)	(17,270)	(7,098)
	<b>141,583</b>	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
	<b>72,544</b>	45,666	23,742
Income before income taxes	<b>69,039</b>	15,232	3,284
Income taxes			
Capital taxes	1,178	746	165
Future income taxes (note 8)	29,363	7,049	1,527
	<b>30,541</b>	7,795	1,692
Net income for the year	<b>38,498</b>	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)**

	<b>2000</b>	<b>1999</b>	<b>1998</b>
Cash provided by (used in):			
<b>Operating Activities</b>			
Net income for the year	\$ <b>38,498</b>	\$ 7,437	\$ 1,592
Non-cash items			
Depletion, depreciation and site restoration	<b>41,912</b>	26,417	14,332
Future income taxes	<b>29,363</b>	7,049	1,527
Cash flow from operations	<b>109,773</b>	40,903	17,451
Net change in non-cash working capital items	<b>12,734</b>	1,561	2,525
	<b>122,507</b>	42,464	19,976
<b>Funding Activities</b>			
Increase in long-term debt	<b>21,129</b>	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	<b>1,378</b>	991	688
Repurchase of Class A shares	<b>(9,577)</b>	(129)	(3)
Share issue and repurchase costs (note 7)	<b>(47)</b>	(1,724)	(1,157)
	<b>12,883</b>	34,242	29,166
<b>Investing Activities</b>			
Additions to property and equipment	<b>(135,096)</b>	(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	<b>(294)</b>	(197)	(225)
	<b>(135,390)</b>	(76,706)	(49,142)
Change in cash and cash, beginning and end of year	-	-	-
<b>Cash flow from operations per common share (note 9)</b>			
Basic Class A and Class B shares	\$ <b>2.56</b>	\$ 1.09	\$ 0.68
Fully diluted	\$ <b>2.39</b>	\$ 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 percent 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 percent and 20 percent.

### **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
	<b>451,065</b>	313,469	153,889
Accumulated depletion and depreciation	<b>(82,586)</b>	(42,897)	(17,400)
Net property and equipment	\$ <b>368,479</b>	\$ 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)
<b>Total Consideration</b>	<b>\$</b>	<b>46,584</b>
Consideration was comprised of		
Cash	\$	3,619
Issue of 10,479,200 Class A shares at \$4.10 per share		42,965
<b>Total Consideration</b>	<b>\$</b>	<b>46,584</b>

## 6) 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
<b>Total Consideration</b>	<b>\$</b>	<b>15,808</b>
Consideration was comprised of		
Cash	\$	63
Issue of 2,581,200 Class A shares at \$6.10 per share		15,745
<b>Total Consideration</b>	<b>\$</b>	<b>15,808</b>

## 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 percent (1999 - 5.7 percent; 1998 - 5.9 percent).

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 percent 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.

- 7) 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.
- 8) 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.
- 9) 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 percent immediately and 20 percent 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:

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

<b>Sales Volume (GJ/day)</b>	<b>Terms</b>	<b>Contract Expiry Dates</b>
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 change 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 Rancho Energy Inc. ("Rancho") its Offer to Purchase ("Offer") all of the outstanding Class A shares of Rancho ("Rancho shares") on the basis of, for each Rancho 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-rata. 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.