Defining Results

PrimeWest (*prim'west) n.*: One of North America's largest conventional oil and gas royalty trusts, positioned to deliver value to unitholders because of its: **1.** natural gas weighting **2.** acquisition and development strategy **3.** low cost operations **4.** monthly distributions and active financial management **5.** access to capital and **6.** caring approach.

PRIMEWEST

ENERGY TRUST

REPORT

TO OUR

UNITHOLDERS

2002

2002 Highlights

¶ 19.5% total return

¶ Production volume 30,189 BOE/day vs. target of 29,000-30,000 BOE/day – targeting 34,500 – 35,500 BOE/day in 2003

¶ 62% natural gas weighting – 68% in 2003

¶ Acquisition and development strategy – added 8.7 million BOE established reserves and increased production/reserves as a result of acquisitions

¶ Low cost operator – operating costs $5.52 per BOE

¶ Monthly distributions and active financial management – distributions $0.40 per unit per month throughout 2002. Debt to cash flow 1.32 times at December 31

¶ Access to capital – internalized management, listed on NYSE

¶ Caring approach – proactive environmental, health and safety program

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Notice of Meeting

The Annual Meeting of the unitholders of PrimeWest Energy Trust will be held on May 6, 2003 at 2:00 pm at the Metropolitan Centre in Calgary, Alberta. All unitholders and interested parties are invited to attend.

This book is the second in a two part set constituting the 2002 annual report for PrimeWest. Adopting this two book approach saves money on printing and design, while increasing PrimeWest's flexibility for using this annual report to tell our story.

PrimeWest's Commitment to Corporate Governance

In 2002, in the wake of several high profile instances of gross mismanagement and malfeasance within the North American business environment, corporate governance received considerable attention.

PrimeWest's corporate governance structure is designed to ensure compliance with the most stringent of standards. In addition, we have consistently disclosed those standards and our compliance.

On the following pages, we profile each of the officers of PrimeWest and each member of PrimeWest's Board of Directors. This is followed by the corporate governance guidelines of the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE), where the NYSE standards differ from the TSX standards. We also assess our compliance with the Saucier Committee's (TSX, CICA) recommendations.

In addition to these standards of governance, PrimeWest has restricted the scope of its auditors to audit and related services, and tax work. PricewaterhouseCoopers LLP have been the Trust's auditors since inception in 1996.

PrimeWest retains Gilbert Laustsen Jung as independent reservoir engineers to estimate its remaining reserves. Substantially all of the Trust's assets are natural gas and crude oil reserves.

Trusts are valued on the basis of these reserves and the cash flow they are expected to generate. We make monthly distributions to unitholders.

The discipline of monthly distributions, the "hard asset" nature of the business, the independence of auditors and reservoir engineers and strong corporate governance provide significant assurance to investors.

A Team That Delivers Results

Senior Officers

Don Garner, P.Eng.

President and Chief Executive Officer

Mr. Garner has over 24 years experience in the oil and gas industry. Before joining PrimeWest, Mr. Garner was President and Chief Operating Officer of Northstar Energy Corporation. Prior to that, he spent a good portion of his career at Imperial Oil Limited in various capacities, including executive responsibility for the Oil Sands Business Unit and as a director of Syncrude Canada Limited. Mr. Garner is an engineering graduate of the University of Saskatchewan.

Tim Granger, P.Eng.

Chief Operating Officer

Mr. Granger is a graduate of Carleton University's engineering program, and has more than 23 years of oil and gas experience in drilling, production operations and property development. Before taking a leadership role at PrimeWest in June 1999, Mr. Granger headed the Canadian operations of a United States-based oil and gas producer.

Ron Ambrozy, P.Eng.

Vice-President, Business Development

Mr. Ambrozy has been active in the oil and gas industry since 1975. Prior to joining PrimeWest in 1997, Mr. Ambrozy held progressively more responsible positions with Gulf Canada. Mr. Ambrozy has led the evaluation of properties and completion of transactions worth more than $3 billion over the past 15 years. For the last five years, Mr. Ambrozy has been actively involved with the Petroleum Acquisition and Divestment Association (PADA) and is current co-chairman of that organization. Mr. Ambrozy is an engineering graduate from the University of Manitoba.

Dennis Feuchuk, CMA

Vice-President, Finance and Chief Financial Officer

Mr. Feuchuk has spent over 27 years in the oil and gas industry in various financial and accounting capacities. Prior to joining PrimeWest in October 2001, Mr. Feuchuk was Vice President and Controller for Gulf Canada Resources Limited and Vice President and Treasurer for Athabasca Oil Sands Trust. Mr. Feuchuk is a graduate of Ryerson University with a Bachelor of Business Management.

Directors

Harold P. Milavsky, FCA

Chairman, Independent Director

Mr. Milavsky is Chairman of Quantico Capital Corp., a privately held company engaged in merchant banking, principal investments and acquisitions. Mr. Milavsky serves as a director of Aspen Properties Ltd., various investment trusts comprising the Citadel Group of Funds, and Torode Realty Limited. Mr. Milavsky was formerly Chief Executive Officer of Trizec Corporation, and a director of TransCanada PipeLines Limited, Telus Corporation Inc., Northrock Resources Ltd., Encal Energy Ltd., Wascana Energy Inc. and past Chair of ENMAX Corporation.

Barry E. Emes, LL.B.

Director

Mr. Emes is a partner in the corporate/commercial group of the Calgary office of Stikeman Elliott and a member of the firm's Partnership Board. In his practice, he has counseled borrowers and lenders in financings; sellers and purchasers of shares and other assets; and independent committees and financial advisors with respect to corporate acquisitions.

Harold N. Kvisle, P. Eng.

Independent Director

Mr. Kvisle is President, Chief Executive Officer and a Director of TransCanada PipeLines Limited, and he acts as a director of several companies and limited partnerships within the TransCanada group. Mr. Kvisle also is a director of Norske Skog Canada Limited. Mr. Kvisle was formerly president of Fletcher Challenge Petroleum.

Kent MacIntyre, P.Eng.

Director

Mr. MacIntyre was Chief Executive Officer of PrimeWest from October 1996 until January 2003. He has over 23 years of oil and gas experience, the last 14 as a principal in the start-up and management of oil and gas ventures. Prior to establishing PrimeWest, he was President and CEO of Triad Energy Inc., and before that, President and CEO of Olympia Energy Ventures Ltd. He is a director of BlackRock Ventures Inc., Beau Venture Resources Inc., Canadian Income Fund Group Inc., Capture Energy Ltd., GLR Solutions Ltd. and various investment trusts comprising the Citadel Group of Funds.

Michael W. O'Brien

Independent Director

Mr. O'Brien is a 35-year veteran of the petroleum business and prior to retirement in 2002, he was the Executive Vice-president, Corporate Development and Chief Financial Officer of Suncor Energy Inc. Mr. O'Brien serves, among other responsibilities, as the current Chair of the Nature Conservancy of Canada, on the Board of Directors for BC Gas Inc. and Suncor Energy Inc. Mr. O'Brien is also past Chair of Canada's Climate Change Voluntary Challenge and Registry Inc.

W. Glen Russell, P. Eng.

Independent Director

Mr. Russell is principal of Glen Russell Consulting, which provides advisory services to energy and technology businesses. As a consultant, Mr. Russell has served as Executive Advisor to CIBC World Markets, providing advisory services on over $4 billion of transactions. Previously, Mr. Russell was President and Chief Operating Officer of Chauvco Resources Ltd. Prior thereto, Senior Vice President and Chief Operating Officer of Gulf Canada Resources Limited. Mr Russell serves as the current Chair of Sonic Mobility Inc.

Statement

Corporate Governance

The Board of Directors and the management team of PrimeWest are committed to a high standard of corporate governance. Effective corporate governance requires specified reporting structures and business processes, a strategic plan, and a commitment to work within this framework. We believe that sound corporate governance contributes to unitholder value and to trust and confidence in PrimeWest.

The Board of Directors of PrimeWest Energy Inc. is ultimately responsible under law for the stewardship of PrimeWest Energy Inc., including the business affairs of PrimeWest Energy Trust. To help execute this mandate, the Board has three standing committees: Audit and Reserves Committee; Compensation Committee; and Corporate Governance and Nominating Committee.

The Toronto Stock Exchange and the New York Stock Exchange have established guidelines for effective corporate governance, guidelines that represent a minimum standard for PrimeWest. These are set out below along with a notation as to PrimeWest's conformity to them.

TSX Corporate Governance Guidelines

Does PrimeWest conform to the guidelines?

1. THE BOARD OF DIRECTORS SHOULD EXPLICITLY ASSUME RESPONSIBILITY FOR THE STEWARDSHIP OF THE COMPANY, SPECIFICALLY:

(a) adopting a strategic planning process;

Yes The Board receives presentations from management with respect to the plans, priorities and performance of the Trust. The Board reviews and analyzes these presentations to ensure that there is congruence among plans, performance and unitholder expectations.

(b) identifying principal risks and ensuring the implementation of systems to manage these risks;

Yes The Board and management are well versed in the principal risks associated with operating PrimeWest. Management updates the Board regularly about the corporate processes for managing risks related to commodity prices and differentials, production levels and trends, and compliance with environment, health and safety legislation and regulations.

(c) planning for succession, including the appointment, training and monitoring of senior management;

Yes The Corporate Governance and Nominating Committee oversees the composition, operation and performance of PrimeWest's senior management.

(d) assuming responsibility for a corporate communications policy; and

Yes The Audit and Reserves Committee reviews all operating and financial results prior to public disclosure. In addition, the Board has adopted written policies governing communications, disclosure and insider trading. These policies are responsive to securities laws and guidelines issued by the Toronto Stock Exchange, the New York Stock Exchange, the Canadian Investor Relations Institute and National Policy 51-201 of the Canadian Securities Administrators.

(e) assuming responsibility for the integrity of internal control and management systems.

Yes The Audit and Reserves Committee oversees PrimeWest's financial reporting processes, the systems for internal control, the audit process, and the management of risk.

2. THE MAJORITY OF THE BOARD SHOULD BE UNRELATED (INDEPENDENT OF MANAGEMENT, FREE FROM CONFLICT OF INTEREST).

Yes PrimeWest's Board of Directors currently consists of six individuals, the majority of whom are unrelated.

3. DISCLOSE WHETHER OR NOT EACH DIRECTOR IS UNRELATED AND EXPLAIN.

Director		Relationship
Barry E. Emes	Related	Partner of firm which provides legal services to PrimeWest
Harold N. Kvisle	Unrelated	
Michael W. O'Brien	Unrelated	
Kent J. MacIntyre	Related	Retired CEO of PrimeWest
Harold P. Milavsky	Unrelated	
W. Glen Russell	Unrelated	

4. THE BOARD SHOULD APPOINT A COMMITTEE OF INDEPENDENT DIRECTORS TO NOMINATE NEW DIRECTORS AND ASSESS ALL DIRECTORS' PERFORMANCE.

Partially The Board's Corporate Governance and Nominating Committee mandate includes this responsibility. Procedures for assessing directors' performance are currently being formulated and will be completed in 2003.

5. THE BOARD SHOULD IMPLEMENT A PROCESS FOR ASSESSING THE EFFECTIVENESS OF THE BOARD AS A WHOLE, THE COMMITTEES OF THE BOARD, AND INDIVIDUAL DIRECTORS.

Partially The Corporate Governance and Nominating Committee has this responsibility and is currently reviewing formal procedures in this respect.

6. EVERY CORPORATION SHOULD PROVIDE AN ORIENTATION AND EDUCATION PROGRAM FOR NEW RECRUITS TO THE BOARD.

Yes Any new director appointed to the Board is briefed thoroughly about PrimeWest and the oil and gas royalty trust sector.

7. EVERY BOARD SHOULD EXAMINE ITS SIZE AND, WITH A VIEW TO EFFECTIVENESS, CONSIDER REDUCING THE SIZE TO IMPROVE DECISION-MAKING.

Yes The Board has examined its size, and has concluded that the Board size should be increased from five to seven with the appointment of two additional independent directors. Mr. Glen Russell, who is independent of and unrelated to PrimeWest, was appointed to the Board on January 8, 2003.

8. THE BOARD SHOULD REVIEW DIRECTORS' COMPENSATION TO ENSURE THAT IT ADEQUATELY REFLECTS RESPONSIBILITIES AND RISKS.

Yes The Compensation Committee, which consists only of independent and unrelated directors, carries out this responsibility annually.

9. COMMITTEES OF THE BOARD GENERALLY SHOULD BE COMPOSED OF INDEPENDENT DIRECTORS WITH THE MAJORITY BEING UNRELATED.

Yes The Audit and Reserves Committee and Compensation Committee of the PrimeWest Board are composed solely of independent and unrelated directors. The Corporate Governance and Nominating Committee has five members, one of whom is related to PrimeWest. Mr. MacIntyre does not sit on any Board Committees.

10. EVERY BOARD SHOULD EXPRESSLY ASSUME RESPONSIBILITY FOR, OR ASSIGN TO A COMMITTEE, THE RESPONSIBILITY FOR DEVELOPING THE COMPANY'S APPROACH TO CORPORATE GOVERNANCE ISSUES.

Yes The Corporate Governance and Nominating Committee focuses on corporate governance and ensures that PrimeWest's corporate governance system is effective.

11. THE BOARD, TOGETHER WITH THE CEO, SHOULD:

(a) develop position descriptions for the Board and for the CEO, setting out limits to management's responsibilities; and

Yes The Board has established clear sets of responsibilities for the Board as a whole and for its committees. It has also done this for the CEO, with defined limits to his responsibilities. The CEO delegates responsibility to the senior officers of PrimeWest, who have written descriptions of their objectives.

(b) approve or develop the corporate objectives for the Board and for the CEO.

Yes The full Board reviews and approves annual operating and financial objectives; management prepares these, and the CEO is accountable for them.

12. EVERY BOARD SHOULD HAVE STRUCTURES AND PROCEDURES TO ENSURE THAT IT CAN FUNCTION INDEPENDENTLY OF MANAGEMENT.

Yes The Chairman of the Board is an unrelated director and independent of management. Any member of the Board may call a meeting to be held without management present. Members of the Audit and Reserves Committee meet directly with the Company's auditors and independent reserves engineering firm, in part without management present. The directors meet in camera for a portion of each Board and committee meeting.

13. ALL BOARDS SHOULD HAVE AN AUDIT COMMITTEE, CONSISTING ONLY OF NON-MANAGEMENT DIRECTORS, WHICH HAS A CLEARLY DEFINED MANDATE AND APPROPRIATE OVERSIGHT.

Yes The Audit and Reserves Committee consists only of unrelated directors and has direct access to external auditors. The Committee reviews financial reporting processes of PrimeWest, its systems of internal controls and the audit process. The Committee also reviews the annual reserves engineering report and all operating and financial results before public disclosure.

14. THE BOARD SHOULD ENABLE AN INDIVIDUAL DIRECTOR TO ENGAGE AN OUTSIDE ADVISOR, IN APPROPRIATE CIRCUMSTANCES, AT THE EXPENSE OF THE COMPANY.

Yes In circumstances considered to be appropriate by the Corporate Governance and Nominating Committee, an individual director may engage an outside advisor at company expense.

The Saucier Report – Beyond Compliance, Building a Governance Culture

The Joint Committee on Corporate Governance (TSX, CICA) delivered its final report in November of 2001. The report contains 15 recommendations for improved corporate governance. Among the recommendations, the following three are most often identified as critical to successful governance practices:

Item	PrimeWest Compliance
Independent board leader.	Board chairman is independent and unrelated.
Board involvement in strategic planning.	See page 4, item 1(a).
Complete disclosure of governance system.	See pages 4-7, items 1 to 14.

New York Stock Exchange – Corporate Accountability and Listing Standards

The New York Stock Exchange submitted its proposed corporate governance listing standards to the United States Securities and Exchange Commission on August 16, 2002. PrimeWest expects these proposals to be effective in 2004.

While it is expected that non-U.S. issuers, such as PrimeWest, will continue to be entitled to waivers from the NYSE corporate governance listing standards, PrimeWest intends to comply with all of the proposals.

Significant Differences Between NYSE and TSX Corporate Governance Standards

NYSE STANDARD	TSX STANDARD	PRIMEWEST COMPLIANCE
Compensation committee composed entirely of independent directors	*No similar standard*	PrimeWest meets NYSE standard.
Various specific requirements for Audit Committees	*No similar standards*	PrimeWest meets NYSE standards.
Each company must have an internal audit function	*No similar standard*	PrimeWest not in compliance in 2002, but plans to comply during 2003.
Listed companies must adopt and disclose a code of business conduct and ethics for directors, officers and employees	*No similar standard*	PrimeWest meets NYSE standard.
CEO must certify compliance to NYSE	*N/A*	PrimeWest meets NYSE standard.

Management's Discussion & Analysis (MD&A)

The following is management's discussion and analysis (MD&A) of PrimeWest's operating and financial results for the year ended December 31, 2002 compared with the prior year as well as information and opinions concerning the Trust's future outlook based on currently available information. This discussion should be read in conjunction with the Trust's audited consolidated financial statements for the years ended December 31, 2002 and 2001, together with accompanying notes. These are included on pages 37 through 60 of this annual report.

CONSOLIDATION OF TRUST UNITS

On August 16, 2002 the Trust Units of PrimeWest began trading on a four to one consolidated basis on the TSX. All per Trust Unit amounts have been restated to conform to the four to one consolidated basis.

CURRENCY

All financial information contained in this MD&A is reported in Canadian dollars, unless otherwise indicated.

NATURAL GAS CONVERSION EQUIVALENT

All calculations required to convert natural gas to a crude oil equivalent (BOE) have been made using a ratio of 6,000 cubic feet of natural gas to 1 barrel of crude oil.

RESERVES AND PRODUCTION INFORMATION

Established reserves include 100% of proved reserves and 50% of probable reserves.
All production information is reported before the deduction of crown and freehold royalties.

Forward-Looking Information

The following discussion, as well as other sections within this annual report, contain forward-looking or outlook information with respect to PrimeWest.

The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe", "outlook" and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in our forward-looking statements. We believe the expectations reflected in those forward-looking statements are reasonable. However, we cannot assure the reader that these expectations will prove to be correct. The reader should not unduly rely on forward-looking statements included in this annual report. These statements speak only as of the date of this annual report.

In particular, this annual report contains forward-looking statements pertaining to the following:

¶ the size of our reserves;

¶ the timing and amount of future production;

¶ prices for oil and natural gas produced;

¶ operating and other costs;

¶ business strategies and plans of management;

¶ supply and demand for oil and natural gas;

¶ expectations regarding our ability to raise capital and to add to our reserves through acquisitions and exploration and development; and

¶ our treatment under governmental regulatory regimes.

Our actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this annual report:

¶ volatility in market prices for oil and natural gas;

¶ risks inherent in our oil and gas operations;

¶ uncertainties associated with estimating reserves;

¶ competition for, among other things; capital, acquisitions of reserves, undeveloped lands and skilled personnel;

¶ incorrect assessments of the value of acquisitions;

¶ geological, technical, drilling and processing problems; and

¶ the other factors discussed under "Operational and Other Business Risks" at pages 34 to 36 of this MD&A.

These factors should not be construed as exhaustive. We undertake no obligation to publicly update or revise any forward-looking statements.

Evaluation of Disclosure Controls and Procedures. The Chief Executive Officer, Don Garner, and Chief Financial Officer, Dennis Feuchuk, evaluated the effectiveness of PrimeWest Energy's disclosure controls and procedures as of a date within 90 days of the filing of this report (Evaluation Date), and concluded that, as of the Evaluation Date, PrimeWest Energy's disclosure controls and procedures were effective to ensure that information PrimeWest is required to disclose in its filings with the Securities and Exchange Commission under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported, within the time periods specified in the Commission's rules and forms, and to ensure that information required to be disclosed by PrimeWest in the reports that it files under the Exchange Act is accumulated and communicated to PrimeWest's management, including its principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Changes to Internal Controls and Procedures for Financial Reporting. There were no significant changes to PrimeWest's internal controls or in other factors that could significantly affect these controls subsequent to the Evaluation Date.

How PrimeWest makes money — Business Model

ELEMENT	2002	2001
Production	30,189 BOE/day	29,774 BOE/day
	X	X
Prices[1]	$29.11 per BOE	$34.93 per BOE
	=	=
Revenue	$320.7 million	$379.7 million
	LESS	LESS
Royalty Expense	$56.5 million *(19.3% of revenue before hedging gains)*	$73.2 million *(21.5% of revenue before hedging gains)*
	LESS	LESS
Operating Expense	$60.8 million ($5.52 per BOE)	$59.0 million ($5.42 per BOE)
	=	=
Operating Margin	$203.4 million ($18.46 per BOE)	$247.5 million ($22.78 per BOE)
Other Expenses	LESS	LESS
G&A Costs	$11.3 million	$10.4 million
Interest	$10.8 million	$13.8 million
Taxes	$2.9 million	$2.4 million
Reclamation Fund Contribution	$4.1 million	$3.5 million
Internalization Cost/ Management Fees	$7.4 million	$6.4 million
	=	=
Total Other Expenses	$36.5 million	$36.5 million
Cash Flow Available For Distribution to Unitholders	$166.9 million	$211.0 million

(1) Includes sulphur

DESCRIPTION	CRITICAL SUCCESS FACTORS	2003 OUTLOOK
Produce and sell natural gas, crude oil and natural gas liquids	¶ Strategic acquisitions ¶ Development success ¶ Production success	¶ Growth through accretive acquisitions ¶ $70-$100 million of capital development ¶ Average of 34,500 – 35,500 BOE per day
Commodity prices for natural gas, crude oil and NGL's	¶ Market prices for natural gas, crude oil & NGL's ¶ Commodity price risk management (hedging)	¶ See "Price Outlook" on pages 22 & 23 ¶ See "2003/2004 Hedging Summary" on page 22
Gross cash inflow (including hedging gains)		¶ Dependent upon commodity prices and production
Royalty expense (Percentage of revenue before hedging gains)		¶ Increase related to higher royalties on Caroline/Peace River Arch properties
Operating costs	¶ Continuous benchmarking & process improvement ¶ Acquire low cost operations	¶ $6.00 – $6.50 per BOE
Variable cash flow	¶ High quality production ¶ Low operating costs	¶ Dependent upon variables above
General and administrative costs	¶ Continuous benchmarking & process improvement	¶ $0.90 per BOE of production
Interest	¶ Debt levels managed to no more than 2 times cash flow ¶ Interest rates	¶ expected to be below 2 times cash flow at December 31
Capital Taxes		¶ Modest increases in 2003
Contribution to Reclamation Fund	¶ Prudent reclamation program	¶ $0.50 per BOE of production
Management contract eliminated effective October 1, 2002		¶ no similar costs
Cash Flow Available for Distribution to Unitholders (1)		

(1) Cash flow available for distribution to unitholders is a non-GAAP measurement and therefore is unlikely to be comparable to similar measures presented by other issuers.

Financial And Operating Highlights

(thousands of dollars except per BOE, per trust unit and multiple amounts)	2002	Per BOE	2001	Per BOE
FINANCIAL				
Gross revenues before hedging	**$ 292,623**	**$ 26.56**	$ 340,191	$ 31.30
Hedging revenues	**28,121**	**2.55**	39,480	3.63
Royalty expense	**(56,496)**	**(5.13)**	(73,156)	(6.73)
Operating expense	**(60,773)**	**(5.52)**	(58,951)	(5.42)
Operating margin	**203,475**	**18.46**	247,564	22.78
General and administrative expense	**(11,281)**	**(1.02)**	(10,394)	(0.96)
Cash management fees	**(3,982)**	**(0.36)**	(6,431)	(0.59)
Interest expense	**(10,788)**	**(0.98)**	(13,800)	(1.27)
Capital taxes	**(2,887)**	**(0.26)**	(2,429)	(0.22)
Contribution to reclamation fund	**(4,078)**	**(0.37)**	(3,499)	(0.32)
Cash internalization costs	**(3,598)**	**(0.33)**	–	–
Cash flow available for distribution	**$ 166,861**	**$ 15.14**	$ 211,011	$ 19.42
Per trust unit (1)	**$ 4.89**		$ 8.23	
Cash distributed to unitholders	**$ 157,951**		$ 234,465	
Per trust unit (1)	**$ 4.80**		$ 9.24	
Net debt (2)	**$ 225,436**		$ 224,431	
Net debt to cash flow from operations multiple	**1.32**		1.05	
Trust units and exchangeable shares issued and outstanding				
Year end	**38,944,386**		32,785,085	
Weighted average	**34,134,230**		25,633,250	

	2002	2001
OPERATING		
Daily sales volume		
Natural gas (mmcf/day)	**113.5**	104.8
Crude oil (bbls/day)	**9,239**	10,033
Natural gas liquids (bbls/day)	**2,030**	2,273
Total (BOE/day)	**30,189**	29,774

(1) All unit and per unit figures have been restated to reflect the 4 for 1 unit consolidation effective August 16, 2002.
(2) Net debt is long term debt plus working capital.

Financial And Operating Highlights

¶ Production stable throughout 2002 at approximately 30,000 BOE per day.

¶ Operating margin of $18.46 per BOE for 2002, down 19% from 2001 primarily due to lower prices for natural gas.

¶ Hedging gains of $28.1 million ($2.55 per BOE) in 2002, compared to gains of $39.5 million ($3.63 per BOE) in 2001.

¶ Operating expenses up 2% on a BOE basis from 2001 as higher power and third party processing fees more than offset the benefits from continuing cost containment initiatives.

¶ Royalties per BOE down 24% compared to 2001 primarily due to significantly lower natural gas prices year over year.

¶ General and administrative expenses increased over 2001 reflecting $0.8 million of non-recurring costs in 2002 related to listing the Trust Units on the New York Stock Exchange.

¶ Cash management fees down 39% compared to 2001 primarily due to the internalization of management effective October 1, 2002 and lower net revenues driven by lower natural gas prices in 2002.

¶ Interest expense down 23% from 2001 a result of lower average debt and lower interest rates in 2002 compared to 2001.

¶ Distributions of $4.80 per Trust Unit in 2002 compared to $9.24 in 2001 reflecting reduced cash flow in 2002 due to lower natural gas prices and a 95% payout ratio in 2002 compared to 111% in 2001.

¶ Capital development program of $63.1 million added 8.7 million BOE of established reserves at $7.27 per BOE.

Cash Flow Reconciliation

The following table shows a reconciliation of 2002 cash flow from operations to the prior year.

INCREASE (DECREASE) IN CASH FLOW

(thousands of dollars)			
2001 Cash Flow from Operations		$	214,511
Effect of:	production volumes		3,452
	natural gas price		(55,317)
	hedging gas [1]		(4,100)
	crude oil price		12,414
	hedging crude oil [1]		(7,300)
	natural gas liquids price		(3,253)
	royalty expense		16,660
	other		(6,128)
2002 Cash Flow from Operations		**$**	**170,939**

[1] Reflects change from previous year (ie: reduced hedging gains in 2002 compared to 2001). See 2002 Hedging Results at page 21.

Capital Spending

2002 Development Additions:

¶ 8.7 million BOE of established reserves at $7.27 per BOE

Capital expenditures, including corporate acquisitions, totaled approximately $124.1 million in 2002 as summarized in the following table:

(thousands of dollars)		2002		2001		2000
Land and lease	**$**	**5,663**	$	6,831	$	545
Geological and geophysical		**1,814**		4,048		817
Development drilling		**34,488**		47,766		16,416
Plant and facilities		**21,182**		21,802		5,665
Head office (includes capitalized G&A)		**5,908**		3,457		2,348
Total property, plant and equipment		**69,055**		83,904		25,791
Acquisitions		**59,606**		822,598		118,656
Total additions		**128,661**		906,502		144,447
Property dispositions		**(4,529)**		(78,144)		(855)
Net additions	**$**	**124,132**	$	828,358	$	143,592

In 2002, PrimeWest completed $45.6 million in property acquisitions adding 5.7 million BOE of established reserves and approximately 1,550 BOE per day of production.

Acquisitions includes $13.2 million to acquire the 1% retained royalty as part of the internalization of management plus $0.8 million in capitalized costs to effect the internalization.

For 2002, PrimeWest added 8.7 million BOE of established reserves at a cost of $7.27 per BOE from $63.1 million of development activities (2001 – $80.4 million; 2000 – $23.4 million).

Outlook for Capital Spending

On November 25, 2002, PrimeWest announced its intention to acquire production and reserves at Caroline and Peace River Arch for $206.1 million, including $15 million for certain natural gas processing midstream assets. Established reserves were approximately 17.6 million BOE and production as of January 1, 2003 was approximately 6,800 BOE per day. At December 31, 2002, $14.2 million had been incurred to effect the acquisition. The transaction closed on January 23, 2003.

PrimeWest plans to spend $70 to $100 million in 2003 on capital development programs.

Reserve Reconciliation

TOTAL PROVED RESERVES

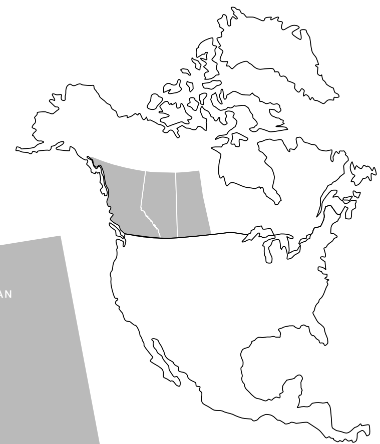
2002	Oil (mbbls)	Natural Gas (Bcf)	NGL (mmbls)	BOE [1] (mBOE)	Net Change (%)
Opening balance	**24,719**	**349.3**	**7,830**	**90,767**	
Additions, extensions, discoveries	182	31.9	796	6,296	(7%)
Acquisitions	373	23.8	862	5,208	(6%)
Divestments	(512)	(6.7)	(158)	(1,789)	(2%)
Revision	26	(7.4)	(138)	(1,350)	(2%)
2002 Production	(3,372)	(41.4)	(741)	(11,020)	(12%)
Closing balance	**21,416**	**349.5**	**8,451**	**88,112**	**(3%)**
Reserve life index	7.1	8.7	11.2	8.4	

[1] Natural gas to crude oil converted on a 6:1 basis

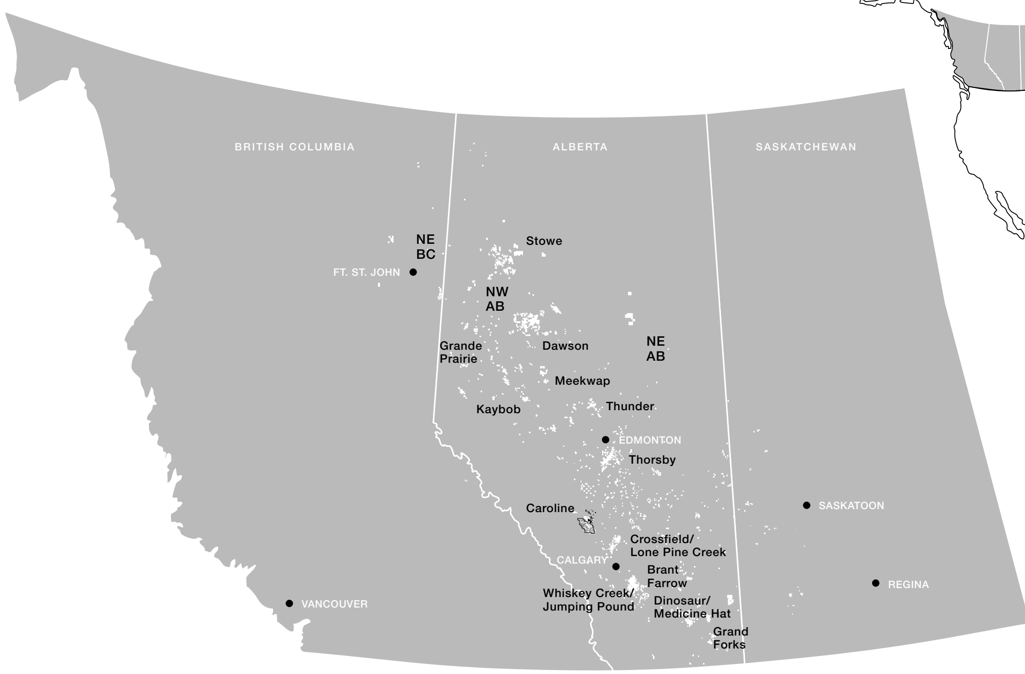
TOTAL ESTABLISHED RESERVES

2002	Oil (mbbls)	Natural Gas (Bcf)	NGL (mmbls)	BOE [1] (mBOE)	Net Change (%)
Opening balance	**28,545**	**413.7**	**9,546**	**107,043**	
Additions, extensions, discoveries	234	43.9	1,133	8,685	8%
Acquisitions	437	26.3	925	5,746	5%
Divestments	(633)	(7.8)	(186)	(2,119)	(2%)
Revision	(751)	(16.2)	(486)	(3,939)	(4%)
2002 Production	(3,372)	(41.4)	(741)	(11,020)	(10%)
Closing balance	**24,460**	**418.5**	**10,191**	**104,396**	**(3%)**
Reserve life index	8.1	10.4	13.5	10.0	

[1] Natural gas to crude oil converted on a 6:1 basis



Core Properties



NORTH BUSINESS UNIT:

NorthWest

- Northwest Alberta
- Northeast Alberta
- Meekwap
- Northeast B.C.
- Kaybob
- Grande Prairie
- North Other

Dawson

- Dawson
- Stowe

SOUTH BUSINESS UNIT

SouthEast

- Brant Farrow
- Dinosaur/Medicine Hat
- Grand Forks
- Whiskey Creek/Jumping Pound
- Saskatchewan
- East Other

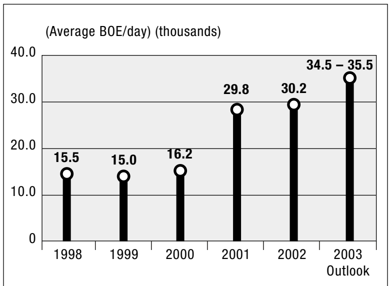
Central

- Crossfield/Lone Pine Creek
- Thunder
- Thorsby
- West Other

Caroline

SUMMARY OF DAILY PRODUCTION VOLUMES

Team	**2002**	2001
Northwest	**4,569**	4,763
Dawson	**6,312**	6,008
Southeast	**7,063**	7,356
Central	**7,797**	8,853
Caroline	**1,463**	1,875
Other Properties	**1,290**	(882)
Royalties	**1,695**	1,801
Total	**30,189**	29,774



Production Growth

Natural Gas:

¶ 62% of 2002 production

¶ 68% estimated for 2003

Natural Gas:

¶ average realized price down 26% from 2001

Production Summary

	2002	%	2001	%	Change
Natural gas (mmcf/day)	**113.5**	**62**	104.8	59	8%
Crude oil (bbls/day)	**9,239**	**31**	10,033	34	(8%)
Natural gas liquids (bbls/day)	**2,030**	**7**	2,273	7	(11%)
Total oil equivalent (BOE/day)	**30,189**	**100**	29,774	100	1%

Development success, particularly at Dawson, contributed to the increase in natural gas production volumes in 2002 compared to 2001. Crude oil volume declined in 2002 compared to 2001 as a significant majority of the 2002 capital development program was focused on the development of natural gas reserves and production.

Outlook For Production Volumes

Our target for 2003 is to produce an average of approximately 34,500 – 35,500 BOE per day, approximately 68% natural gas. Our natural decline rate for production is 15% – 20% per year. Our capital development program of $70 to 100 million for 2003 is expected to significantly offset the impact of natural decline.

Commodity Prices

Average Realized Sales Prices (1)

(Canadian dollars)	2002	2001	Change
Natural gas ($/mcf)	**$ 4.55**	$ 6.16	(26%)
Crude oil ($/bbl)	**33.53**	32.21	4%
Natural gas liquids ($/bbl)	**26.56**	30.96	(14%)
Total oil equivalent (2) ($/BOE)	**$ 29.16**	$ 34.80	(16%)

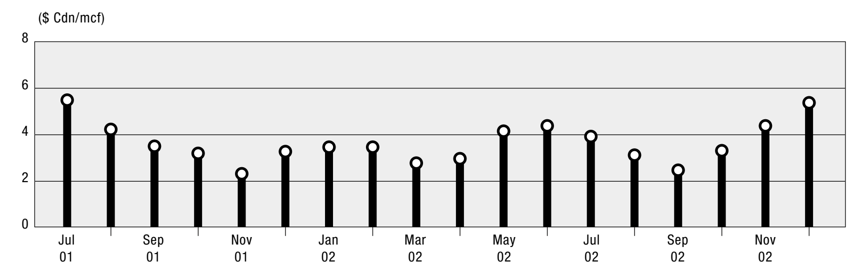
(1) Includes hedging gains/losses

(2) Excludes sulphur

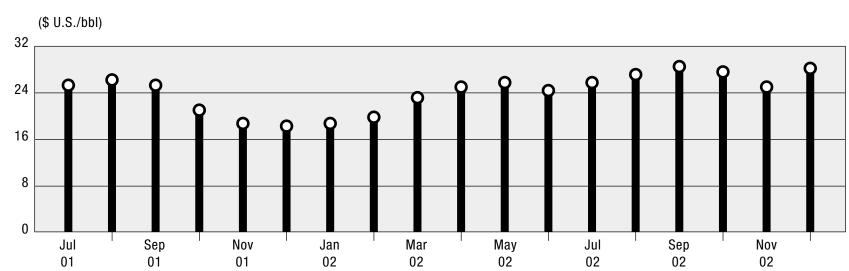
Natural gas, using the AECO daily index as the benchmark, entered 2002 at $3.67 per mcf and exited 2002 at $6.02 per mcf, an increase of 64%. High natural gas storage levels depressed natural gas prices for much of the year, particularly in the first and third quarters with the AECO price averaging $3.30 per mcf. Natural gas prices rose in the second quarter on the prospect for a warmer than normal summer of 2002, and fourth quarter natural gas prices strengthened on the prospect for reduced supply combined with cold weather in the major U.S. natural gas consuming areas.

For 2001, the price for natural gas reached record levels in the first quarter of the year with an average AECO price of $10.91 per mcf. Prices fell through the remainder of 2001 and averaged $6.30 for the year, also a record high.

Crude oil, using West Texas Intermediate (WTI) as the benchmark, entered 2002 at $US 19.84 per barrel, fell to a low of $US 17.97 per barrel on January 17, 2002 then reached a high of $US 32.72 per barrel on December 27, 2002, and exited 2002 at $US 31.20 per barrel. The threat of military action in the Middle East combined with a general strike in Venezuela has driven the market to recent highs.



Monthly Average AECO Prices for 2001 and 2002



Monthly Average WTI Oil Prices for 2001 and 2002

Natural Gas:

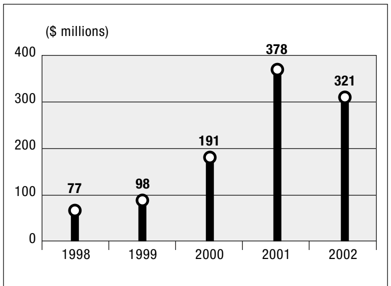
¶ sales revenue down 20% due to lower natural gas prices

Sales Revenue

Gross sales revenues fell by 15% in 2002 compared to 2001. Total sales revenue was influenced both by production volumes, which increased year-over-year, and natural gas prices, which decreased year-over-year as discussed above.

Revenue ($ millions)	2002	%	2001	%	Change
Natural gas [1]	**$ 187.7**	**59**	$ 234.5	62	(20%)
Crude oil	**113.1**	**35**	118.0	31	(4%)
Natural gas liquids	**19.7**	**6**	25.7	7	(23%)
	$ 320.5	**100**	$ 378.2	100	(15%)

(1) Includes sulphur



Sales Revenue

NATURAL GAS REVENUES

The average daily production of natural gas was 8% higher in 2002 than 2001, reflecting the significant weighting to natural gas of the 2002 capital development program. The 26% drop in the average realized natural gas prices in 2002 compared to 2001, significantly outweighed the benefits of the production increase, resulting in a 20% decrease in revenue from natural gas sales in 2002 compared to 2001.

CRUDE OIL REVENUES

Reduced crude oil production was partially offset by higher average crude oil prices comparing 2002 to 2001.

NATURAL GAS LIQUIDS REVENUES

An 11% decrease in production volumes and a 14% decrease in prices, resulted in a 23% decrease in natural gas liquids revenues in 2002 compared to 2001. PrimeWest does not hedge its natural gas liquids prices.

2002 Hedging Results

During 2002, PrimeWest actively protected against the risk of falling prices on a major portion of its production by either fixing the price or protecting the downside risk through put or collar arrangements. In aggregate, total average sales prices were higher by $2.55 per BOE in 2002 (2001 – $3.63 per BOE) than would otherwise have been the case if PrimeWest had not entered into price protection arrangements.

	Crude Oil ($/bbl)		Natural Gas ($/mcf)		BOE [1] ($/BOE)	
	2002	2001	**2002**	2001	**2002**	2001
Unhedged price	**$ 34.25**	$ 30.86	**$ 3.81**	$ 5.26	**$ 26.61**	$ 31.17
Hedging gain (loss)	**(0.72)**	1.35	**0.74**	0.90	**2.55**	3.63
Realized price	**$ 33.53**	$ 32.21	**$ 4.55**	$ 6.16	**$ 29.16**	$ 34.80

(1) Excludes sulphur

	2002		2001	
	Hedging Gain (Loss)		Hedging Gain	
	% Hedged	**$ million**	% Hedged	$ million
Natural gas	**71%**	**$ 30.5**	78%	$ 34.6
Crude oil	**69%**	**(2.4)**	84%	4.9
Total gain		**$ 28.1**		$ 39.5

2003/2004 Hedging Summary

Approximate percentage of future anticipated production volumes hedged as at December 31, 2002, net of anticipated royalties, reflecting full production declines with no offsetting additions:

2003	Q1	Q2	Q3	Q4	Full Year
Crude oil	65%	38%	27%	28%	40%
Natural gas	69%	60%	60%	31%	55%

As at December 31, 2002, the mark-to-market loss for 2003 hedges totaled $13.8 million, $1.9 million for crude oil and $11.9 million for natural gas.

For 2004, PrimeWest has none of its crude oil production and 12% of its natural gas hedged with a combination of swaps, and option based instruments. As at December 31, 2002, there is no material gain or loss on a mark-to-market valuation of these hedges.

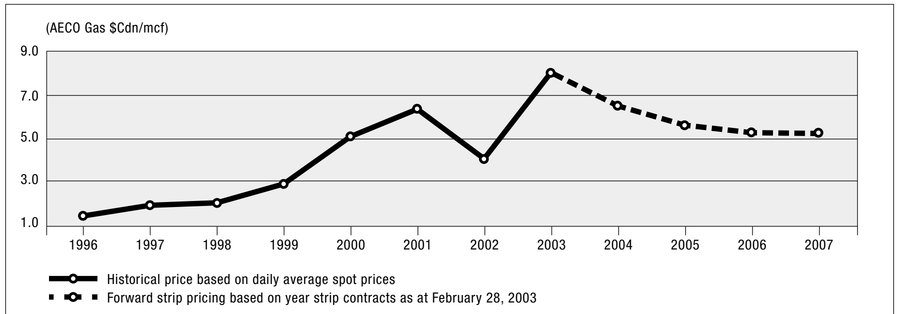
Price Outlook

natural gas

Natural gas is a commodity that moves through pipelines within North America and as such is affected by supply and demand forces within North America. New gas supply is added primarily by drilling, re-working of existing wells, and additions to capital infrastructure. Disruptions to supply can come from extreme weather conditions such as extreme cold hindering operations, extreme heat reducing pipeline and compression efficiencies, and hurricane activity affecting offshore operations. Demand comes from use of natural gas for central heating, to generate electricity, and as a feedstock for commercial or industrial use. Gas is currently stored in the summer months when heating demand is low and gas is withdrawn in winter when heating demand is high.

After a year of robust pricing in 2001 (AECO gas averaged $6.30/mcf), the year 2002 started off with much more modest pricing ($3.67/mcf for the first nine months). This led to a significant drop in industry drilling activity through the year that has resulted in a reduction of North American supply capability in the near term. In addition, hurricane activity in the Gulf of Mexico through the summer and into early fall caused significant supply disruptions. On the demand side, economic activity has not rebounded, but hot weather in North America over the summer resulted in additional gas fired electricity demand and very cold weather in the central and northeast parts of the continent this winter have resulted in significant year-over-year demand increases.

Early in 2003, natural gas in storage is at historically low levels and concerns are being raised about the ability to re-fill storage to adequate levels by the end of the summer in time for the next winter heating season due to supply declines. Pricing year-to-date has been exceptionally strong and is expected to remain so for the next several years.



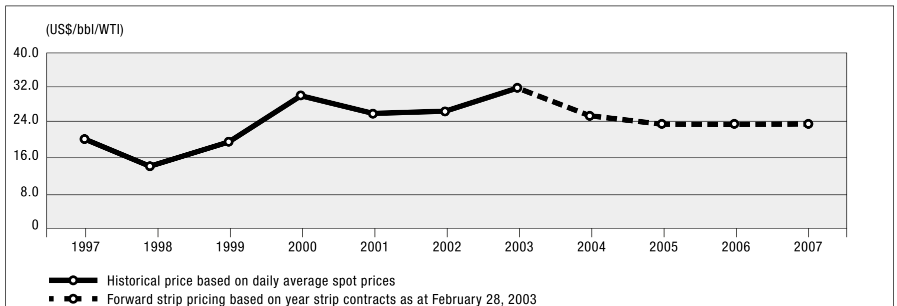
Significant Step Change in Natural Gas Prices

CRUDE OIL

Crude oil can be transported by pipeline, tank truck, and ocean tanker. As such, oil is truly a world commodity and is influenced by global supply and demand fundamentals. World supply is dominated by the OPEC cartel and by production changes within a few key non-OPEC exporting countries (e.g. Russia and other Former Soviet Union nations, Norway). World demand fluctuates with the global economies.

Oil entered 2002 with comfortable inventories and the prospect of global oversupply. As the year progressed, overall tightening of OPEC quotas and supply, combined with several global supply disruptions (a delay in renewing the Iraq oil for food program, hurricane activity in the Gulf of Mexico, a general strike in Venezuela) significantly reduced inventories.

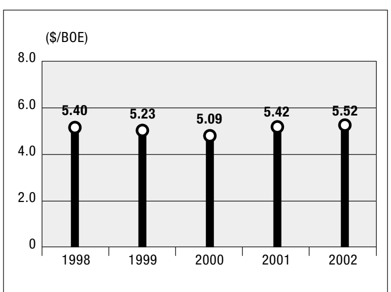
Early in 2003, crude oil inventories have been reduced further and the potential for hostilities in the Middle East remains high. Crude oil prices have increased to levels not seen since the 1990 Gulf War.



Crude Oil Historical and Forward Strip Prices

Low Cost Operations:

¶ target $6.00 – $6.50 per BOE of operating expenses for 2003



PrimeWest is a low cost operator among the seven largest conventional oil and gas royalty trusts.

Royalties (Net of ARTC)

	2002	2001	% Change
Royalty expense (net of ARTC) ($ millions)	**$ 56.5**	$ 73.2	(23%)
Per BOE	**$ 5.13**	$ 6.73	(24%)
Royalties as % of sales revenues			
– with hedging revenue	**18%**	19%	(9%)
– excluding hedging revenue	**19%**	22%	(10%)

Lower royalties are the direct result of lower revenues. The overall decrease in the royalty rate is due to lower natural gas prices year-over-year. Hedging gains, that do not attract royalties and result in lower royalty expense as a percentage of sales, were substantial for both 2002 and 2001 as previously discussed.

Operating Expenses

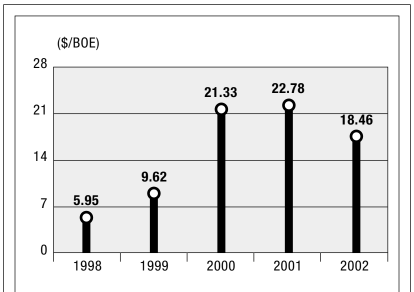
	2002	2001	% Change
Operating expenses ($ millions)	**$ 60.8**	$ 59.0	3%
Per BOE	**$ 5.52**	$ 5.42	2%

The year-over-year increase of $1.8 million is due, in part, to the 1% increase in production volumes. On a BOE basis, operating expenses increased 2% over the 2001 level. PrimeWest continues as a low cost producer among the seven largest oil and gas royalty trusts.

Operating Margin

($/BOE)	2002	2001	% Change
Sales price and other revenue (1)	**$ 29.11**	$ 34.93	(17%)
Royalties	**(5.13)**	(6.73)	(24%)
Operating expenses	**(5.52)**	(5.42)	2%
Operating margin	**$ 18.46**	$ 22.78	(19%)

(1) Includes hedging and sulphur



Lower gas prices and 62% natural gas weighting resulted in a lower operating margin in 2002.

The decrease in operating margin reflects lower natural gas prices in 2002 compared to 2001 and PrimeWest's 62% natural gas production weighting in 2002, partially offset by lower royalty expense. In 2001, record high prices for natural gas benefited natural gas weighted producers including PrimeWest.

General & Administrative Expenses

	2002	2001	% Change
General & administrative expense ($ millions)	**$ 11.3**	$ 10.4	9%
Per BOE	**$ 1.02**	$ 0.96	6%

Excluding $0.8 million of 2002 expenses related to the NYSE listing, the full year 2002 result would have been $10.5 million or $0.95 per BOE.

Unit Appreciation Rights Expense

Unit Appreciation Rights (UAR) expense of $6.1 million (2001 – $4.2 million) relates to PrimeWest's long-term incentive program for employees, directors and officers. The program rewards employees based on total unitholder return, which is comprised of cumulative distributions on a reinvested basis plus growth in unit price. Total unitholder return was 19.5% in 2002 (2001 – a loss of 6%). No benefit accrues to employees with respect to the first 5% of total unitholder return. Expenses related to the UAR plan are recorded on a mark-to-market basis, whereby increases or decreases in the valuation of the UAR liability are reported quarterly, as a charge to the income statement, over the six year life of the unit appreciation rights.

Unit appreciation rights in a trust are similar to stock options in a corporation. The intent is to align employee and unitholder interests. The outcome is expected to be a modest dilution to unitholders' positions over time.

Effective January 1, 2002 the method of accounting for the long-term incentive plan was changed to comply with new CICA accounting standard 3870. The calculation of the long-term incentive liability now includes vested and unvested UARs. Previously, only vested UARs were included. The Trust has the option of paying cash to settle the long-term incentive liability. The long-term incentive liability has been reclassified as equity on the balance sheet as the Trust intends to settle the liability in the form of Trust Units.

Costs Outlook

PrimeWest's operating costs in 2002 and 2001 were among the lowest of the seven largest conventional oil and gas royalty trusts. The acquisition of low cost production at Caroline and Peace River Arch effective January 1, 2003, is expected to reinforce our low cost leadership position. We are targeting stabilization in our cost structure in 2003 as follows:

Low Cost Operations:

¶ cash G&A targeted at $0.90 per BOE for 2003

We Care:

¶ eliminated management fees effective October 1, 2002

OPERATIONS:

¶ Per BOE costs of approximately $6.00 – $6.50 reflecting:
  ¶ lower costs associated with the Caroline and Peace River Arch properties,
  ¶ continued rationalization of operations, particularly at Caroline,
  ¶ offsetting the above, we expect to have higher power costs, and third party processing fees for 2003.

GENERAL AND ADMINISTRATIVE:

¶ per BOE costs of $0.90. Increases in the cost of employee benefits and corporate governance are expected to be offset by continued process improvements.

At PrimeWest, we are committed to contain costs during all phases of the commodity price cycle.

Management Fees/Internalization Costs

($ millions)	2002	2001
Cash management fees	**$ 4.0**	$ 6.4
Non-cash management fees	**1.4**	1.8
Non-cash internalization costs	**13.1**	–
Acquisition/disposition fees	**0.4**	13.0
1% retained royalty	**1.3**	3.4
Purchase of 1% retained royalty	**13.2**	–
	$ 33.4	$ 24.6

On November 4, 2002, unitholders voted, by a 92% majority, to internalize management at a cost of $26.3 million. Approximately $13.2 million of cash consideration related to the acquisition of the 1% retained royalty and was recorded as an acquisition. The balance of the consideration was paid in the form of Class A Exchangeable Shares of PrimeWest Energy Inc., exchangeable for approximately 491,000 Trust Units as at the effective date, and was charged to expense. In addition, the internalization transaction included retention provisions for senior management of $3.5 million payable in the form of Class A Exchangeable Shares over a five year vesting period, and payment of $1.5 million to terminate a management incentive program

From inception in 1996 through September 30, 2002, PrimeWest Management Inc. received a management fee of 2.5% of net production revenue as well as a quarterly allocation of Trust Units and a 1% retained royalty. The 1% retained royalty was based on the net cash flow from operations and the proceeds from property dispositions.

In addition, PrimeWest Management Inc. was also entitled to an acquisition fee representing 1.5% of capital spent on asset or corporate acquisitions and a disposition fee representing 1.25% of proceeds received from asset dispositions.

The $13.0 million of acquisition/disposition fees in 2001 related primarily to the Cypress acquisition.

Interest Expense

Interest expense decreased to $10.8 million in 2002 compared to $13.8 million in 2001. Lower year-over-year average debt levels and lower interest rates contributed to the decrease.

	2002	2001
Interest expense (millions)	**$ 10.8**	$ 13.8
Year end net debt level (millions)	**$ 225.4**	$ 224.4
Year end debt level per Trust Unit	**$ 5.79**	$ 6.84
Average cost of debt	**4.6%**	5.4%

Depletion, Depreciation And Amortization

The 2002 depletion, depreciation and amortization (DD&A) rate was $16.51 per BOE compared to $14.66 per BOE for 2001. The 2002 rate reflects a full year of production from the Cypress properties acquired on March 29, 2001.

The 2002 and 2001 DD&A rates are inflated relative to the acquisition cost of reserves due to the requirement to account for future income tax liabilities associated with these reserves. Absent this tax adjustment, the 2002 DD&A rate would have been lower by approximately $5.00 per BOE. (See also Income Taxes – Trust.)

Ceiling Test

PrimeWest performs a ceiling test at each balance sheet date, which compares the net book value of capital assets (i.e. the value of capital assets reflected on the balance sheet, net of DD&A) with an estimate of the future net revenue from proved reserves (as determined by independent engineers) less estimated future general and administrative costs, debt servicing costs, and applicable income taxes.

Performing this test at December 31, 2002, using commodity prices of AECO $5.59 per mcf for natural gas and $US 29.39 per barrel WTI for crude oil, a ceiling test surplus of $900 million results.

Site Reclamation And Restoration Reserve

Since the inception of the Trust, PrimeWest has maintained an environmental fund to pay for future costs related to well abandonment and site clean-up. In 2002, PrimeWest contributed $0.37 per BOE, totaling $4.1 million for 2002, to this fund. The fund is used to pay for reclamation and abandonment costs as they are incurred. In 2002, a total of $3.9 million was paid out of the reserve, leaving a balance of $0.01 million in the fund at year end.

A provision of $4.0 million was made for site reclamation and abandonment during 2002, compared to $3.5 million for 2001. The provision is based on site reclamation and abandonment cost estimates made by both PrimeWest and external engineers and is charged to depletion, depreciation and amortization expense on a unit of production basis.

The 2003 contribution rate has been set at $0.50 per BOE which is expected to be sufficient to meet the funding requirements for the future.

Income Taxes – Trust

Current income tax expense of $2.9 million for 2002 (2001 – $2.4 million) is comprised of the Federal Large Corporations Tax and other capital taxes payable by PrimeWest Energy Inc.

PrimeWest Energy Inc. manages its operating and financing activities such that it is not subject to current tax payable, other than the capital taxes noted above.

Future income taxes are recorded on corporate acquisitions to the extent that the book value of capital assets acquired exceeds the tax pools acquired. These future taxes increase the cost basis of the capital assets acquired and are recovered over time as royalties are paid to the Trust. The income statement for the year ended December 31, 2002 reflects a future income tax recovery of $32.3 million (2001 – $30.3 million) due primarily to the drawdown of future income tax liability of $376.3 million recorded as part of the Cypress acquisition. The future income tax liability was $339.9 million at December 31, 2002 ($362.6 million at December 31, 2001).

The unitholders of the Trust are allocated taxable income based on the amount of royalty revenue, interest and revenue from direct investments earned (essentially distributions before crown royalty charges), less certain tax deductions such as Canadian Oil and Gas Property Expense (COGPE), resource allowance, unit issue expenses and other direct costs.

Income Taxes – Unitholders

For the 2002 taxation year, unitholders of the Trust were paid $4.80 per Trust Unit in distributions. Of these distributions, 45%, or $2.16 per Trust Unit is a tax deferred return of capital and 55%, or $2.64 per Trust Unit, is taxable to unitholders as other income (taxed at the same rate as interest income). The tax deferred return of capital reduces the unitholder's adjusted cost base for purposes of calculating a capital gain or loss upon ultimate disposition of their Trust Units. It should be noted that this represents the tax treatment for Canadian residents.

For unitholders resident in the United States, taxability of distributions is calculated using U.S. tax rules which allow for the deduction of crown royalties and accounting based depletion. As a result, none of the 2002 distribution is taxable as dividends, 100% of the 2002 distributions are a tax deferred reduction to the cost of units for tax purposes.

Unitholders contemplating a disposition may wish to consult the "Unitholder Information" section on PrimeWest's website and use the adjusted cost base calculator.

Unitholders should always seek independent competent tax advice.

Income Taxes – Unitholders – Outlook

Based on current expectations for cash flow for 2003, it is anticipated that approximately 55% of 2003 distributions will be taxable and 45% will be tax deferred, for unitholders resident in Canada. For residents of the United States, Canadian withholding tax applies to 55% of the distribution.

Net Asset Value

Net asset value (NAV) is a measure of the worth of PrimeWest's underlying assets – primarily crude oil, natural gas and natural gas liquids reserves. The value placed on these reserves is the pre-tax present value of future net cash flows, discounted at 10% from these reserves, as independently assessed by Gilbert Laustsen Jung Associates Ltd. (GLJ) as at January 1, 2003. The commodity price forecast used in this assessment is based on the arithmetic average of three independent consultants' price forecasts. The present value of reserves reflects provisions for royalties, operating costs, future capital costs and site reclamation and abandonment costs, but is prior to deductions for income taxes, interest costs and general and administrative costs.

This calculation is a "snapshot" in time and is heavily dependent upon future commodity price expectations at the point in time the "snapshot" is taken. Accordingly, the NAV as at January 1, 2003 may not reflect fairly the equity market trading value of PrimeWest.

It is also significant to note that NAV reduces as reserves are produced and net operating cash flow is distributed. Value is delivered to unitholders through such monthly distributions.

The following table sets forth the calculation of NAV:

As at December 31 ($ million except per Trust Unit amounts)		2002	2001
ASSETS			
Present value of net cash flow from established reserves discounted at 10%		**$ 923.0**	$ 872.6
Hedging mark-to-market		**(13.6)**	50.5
Unproved lands		**44.2**	55.7
Reclamation fund		**–**	0.8
		$ 953.6	$ 979.6
LIABILITIES			
Working capital deficiency		**$ (0.4)**	$ (29.4)
Long-term debt		**(225.0)**	(195.0)
		(225.4)	(224.4)
Total net asset value		**$ 728.2**	$ 755.2
Net asset value pre-tax per Trust Unit		**$ 18.71**	$ 23.03
Reference prices	– Oil ($US WTI/bbl)	**$ 25.83**	$ 19.68
	– Exchange rate ($US/$Cdn)	**0.64**	0.63
	– Natural gas ($Cdn/mcf)	**$ 5.85**	$ 4.03

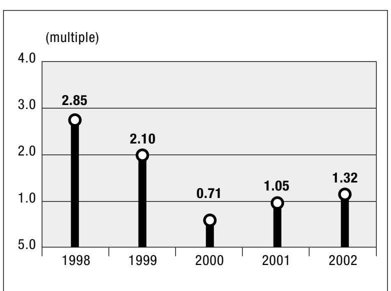
The NAV calculation is based on the above reference prices as of January 1, 2003 and 2002 and is highly sensitive to changes in price forecasts over time. Also, the NAV calculation assumes a "blow down" scenario whereby existing reserves are produced without being replaced by acquisitions. A major cornerstone of PrimeWest's strategy is to replace reserves through accretive acquisitions and capital development.

NET INCOME

($ million)	2002	2001
Net income	**$ 0.6**	$ 79.5

Net income declined by $78.9 million as a result of significantly lower natural gas prices, increased DD&A reflecting a full year of Cypress volumes and costs of $16.7 million associated with the internalization of management.

Monthly Distributions and Active Financial Management:
¶ conservative balance sheet with net debt to cash flow ratio of 1.32 times



Net Debt to Cash Flow

Liquidity And Capital Resources

LONG-TERM DEBT

At December 31, 2002, long-term debt, net of working capital was $225.4 million or $5.79 per Trust Unit, compared to $224.4 million, or $6.84 per Trust Unit at the end of 2001.

(thousands of dollars)	2002	2001
Long-term debt	**$ 225,000**	$ 195,000
Working capital deficit	**436**	29,431
Net debt	**225,436**	224,431
Market value of Trust Units and exchangeable shares outstanding (1)	**989,187**	834,053
Total capitalization	**$ 1,214,623**	$ 1,058,484
Net debt as a percentage of total capitalization	**19%**	21%

(1) Based on December 31 closing price

OUTLOOK – LONG-TERM DEBT

Long-term debt net of working capital in 2003 is expected to increase as a result of the 2003 capital development program, and the Caroline/Peace River Arch acquisition which closed on January 23, 2003, partially offset by the net proceeds of the equity issue which closed on February 13, 2003.

UNITHOLDERS' EQUITY

On August 16, 2002, Trust Units were consolidated on a 4 to 1 basis in anticipation of the November 19, 2002 listing on the New York Stock Exchange.

The Trust had 37,004,522 Trust Units outstanding at December 31, 2002 compared to 31,491,402 Trust Units at the end of 2001. In addition, there are 5,179,278 exchangeable shares (see below) outstanding at year end, exchangeable into a total of 1,939,864 Trust Units. The weighted average number of Trust Units, including those issuable by the exchange of exchangeable shares, was 34,134,230 Trust Units for 2002 compared to 25,633,250 for 2001.

During 2002, PrimeWest issued 979,209 Trust Units for $24.1 million pursuant to the Distribution Reinvestment and Optional Trust Unit Purchase Plans (441,424 Trust Units, $14.1 million in 2001), 153,749 pursuant to the Long-Term Incentive Plan for employees and 66,853 to PrimeWest Management Inc. pursuant to the Management Agreement.

Dividends declared were $1.3 million in 2002, compared to $4.1 million in 2001. Dividends were paid to PrimeWest Management Inc. in conjunction with the Management Agreement (see discussion under Management Fees).

PrimeWest completed a bought deal financing which closed on November 13, 2002 raising net proceeds of $104.5 million on the issuance of 4.2 million Trust Units at $26.20 per Trust Unit. Proceeds were used to fund the Caroline/Ells acquisitions announced in October of 2002 and to reduce outstanding indebtedness.

EXCHANGEABLE SHARES

Exchangeable shares were issued in connection with both the Venator acquisition in April 2000 and the Cypress acquisition in March 2001. These shares were issued to provide a tax-deferred rollover of the adjusted cost base from the shares being exchanged to the exchangeable shares of PrimeWest. A tax deferral is not permitted by Canadian tax law when shares are exchanged for Trust Units.

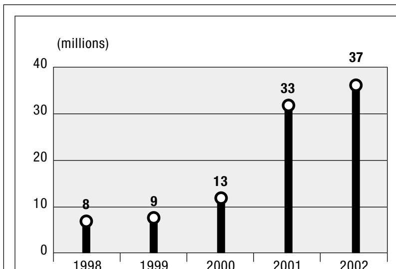
Access to Capital:
¶ equity financing for acquisitions and development

A further 1,363,714 exchangeable shares were issued in 2002 in connection with the management internalization transaction previously discussed.

The exchangeable shares do not receive cash distributions. In lieu of receiving cash distributions, the number of Trust Units that the exchangeable shareholder will receive upon exchange increases each month based on the distribution amount divided by the market price of the Trust Units on the 15th day of each month.

At December 31, 2002, there were 5.2 million exchangeable shares outstanding. The exchange ratio on these shares was 0.37454 Trust Units for each exchangeable share as at year-end.

For purposes of calculating basic per Trust Unit amounts, these exchangeable shares have been assumed to be exchanged into Trust Units at the current exchange ratio.



Units Outstanding at Year End

CASH DISTRIBUTIONS

Cash distributions in 2002 totaled $158.0 million, or $4.80 per Trust Unit, compared to $234.5 million, or $9.24 per Trust Unit in 2001. Commencing in 2003, PrimeWest pays distributions to registered U.S. unitholders in U.S. funds upon request. Payments to U.S. unitholders are subject to 15% Canadian withholding tax, which applies to the taxable portion of the distribution under Canadian tax law, estimated at 55% for 2003.

Since inception in October of 1996 to December 31, 2002, PrimeWest has distributed $35.92 per Trust Unit (through December 31, 2001 – $31.12 per Trust Unit).

PrimeWest has committed to distribute 40 cents per unit through the first quarter of 2003.

Natural Gas:

¶ a $0.10/mcf change in natural gas prices results in a $0.09 change in cash flow before hedging

OUTLOOK FOR CASH DISTRIBUTIONS

PrimeWest distributed $0.40 per unit per month for January and February of 2003 and has committed to distributing $0.40 per Trust Unit per month for March and April of 2003, subject to revision should there be a material change to expected cash flows during this period. Beyond this time frame, the Board of Directors will establish a distribution level commensurate with cash flow expectations and any foreseen internal requirements.

CASH FLOW SENSITIVITIES

Impact on 2003 annual cash available for distribution per unit (increase/decrease):

Crude oil price ($US 1.00/bbl WTI increase)	0.10 [(1)]
Natural gas price ($0.10/mcf increase)	0.09 [(1)]
Interest rate (1% increase)	(0.04)
Exchange rate ($US 0.01 increase)	(0.14)
Production (1,000 BOE/day increase)	0.20

(1) Without the effect of price protection

Business Risks

PrimeWest's operations are affected by a number of underlying risks, both internal and external to the Trust. These risks are similar to those affecting others in both the conventional oil and gas royalty trust sector and the conventional oil and gas producers sector. The Trust's financial position, results of operations, and cash available for distribution to unitholders are directly impacted by these factors. These factors are discussed under two broad categories – Commodity Price, Foreign Exchange and Interest Rate Risk; and Operational and Other Business Risks.

Commodity Price, Foreign Exchange And Interest Rate Risk

The two most important factors affecting the level of cash distributions available to unitholders are the level of production achieved by PrimeWest, and the price received for its products. These prices are influenced in varying degrees by factors outside the Trust's control. Some of these factors include:

¶ world market forces, specifically the actions of OPEC and other large crude oil producing countries including Russia, and their implications on the supply of crude oil;

¶ world and North American economic conditions which influence the demand for both crude oil and natural gas and the level of interest rates set by the governments of Canada and the U.S.;

¶ weather conditions that influence the demand for natural gas and heating oil;

¶ the Canadian/U.S. exchange rate that affects the price received for crude oil as the price of crude oil is referenced in U.S. dollars;

¶ transportation availability and costs; and

¶ price differentials among world and North American markets based on transportation costs to major markets and quality of production.

To mitigate these risks, PrimeWest has an active hedging program in place based on an established set of criteria that has been approved by the Board of Directors. The results of the hedging program are reviewed against these criteria and the results actively monitored by the Board.

Beyond our hedging strategy, PrimeWest also mitigates risk by having a well-diversified marketing portfolio and by transacting with a number of counter-parties and limiting exposure to each counter-party. In 2002, approximately 30% of natural gas production was sold to aggregators and 70% into the Alberta short-term or export long-term markets.

The contracts that PrimeWest has with aggregators vary in length. They represent a blend of domestic and U.S. markets and fixed and floating prices designed to provide price diversification to our revenue stream.

The primary objective of our commodity risk management program is to reduce the volatility of our cash distributions, to lock in the economics on major acquisitions and to protect our capital structure when commodity prices cycle downwards. In 2002, PrimeWest added $28.1 million ($0.82 per Trust Unit) to our cash flow through various physical and financial hedging transactions. In total, PrimeWest hedged 69% of full year crude oil production and 71% of full year natural gas production net of royalties.

Operational And Other Business Risks

PrimeWest is also exposed to a number of risks related to its activities within the oil and gas industry that also have an impact on the amount of cash available to unitholders. These risks, and the ways in which PrimeWest seeks to mitigate these risks include, but are not limited to:

RISK:

Production

Risk associated with the production of oil and gas – includes well operations, processing and the physical delivery of commodities to market.

We mitigate by:

Performing regular and proactive protective well, facility and pipeline maintenance supported by telemetry, physical inspection and diagnostic tools.

Commodity Price

Fluctuations in natural gas, crude oil and natural gas liquid prices

We mitigate by:

Hedging. See page 21 of this MD&A.

Transportation

Market risk related to the availability of transportation to market and potential disruption in delivery systems.

We mitigate by:

Diversifying the transportation systems on which we rely to get our product to market.

Natural decline

Development risk associated with capital enhancement activities undertaken – the risk that capital spending on activities such as drilling, well completions, well workovers and other capital activities will not result in reserve additions or in quantities sufficient to replace annual production declines.

We mitigate by:

Diversifying our capital spending program over a large number of projects so that too much capital is not risked on any one activity. We also have a highly skilled technical team of geologists, geophysicists and engineers working to apply the latest technology in planning and executing capital programs. Capital is spent only after strict economic criteria for production and reserve additions are assessed.

Acquisitions

Acquisition risk associated with acquiring producing properties at low cost to renew our inventory of assets.

We mitigate by:

Continually scanning the marketplace for opportunities to acquire assets. Our technical acquisition specialists evaluate potential corporate or property acquisitions and identify areas for value enhancement through operational efficiencies or capital investment. All prospects are subjected to rigorous economic review against established acquisition and economic hurdle rates.

Reserves

Reserve risk in respect of the quantity and quality of recoverable reserves.

We mitigate by:

Contracting our reserves evaluation to a reputable third party consultant, Gilbert Laustsen Jung Associates Ltd. (GLJ). The work and independence of GLJ is reviewed by the Audit and Reserves Committee of the Board of Directors of PrimeWest. Our strategy is to invest in mature, longer life properties having a higher proved producing component where the reserve risk is generally lower and cash flows are more stable and predictable.

Environmental Health and Safety (EH&S)

Environmental, health and safety risks associated with oil and gas properties and facilities.

We mitigate by:

Establishing and adhering to strict guidelines for EH&S including training, proper reporting of incidents, supervision and awareness. PrimeWest has active community involvement in field locations including regular meetings with stakeholders in the area. PrimeWest carries adequate insurance to cover property losses, liability and business interruption.

These risks are reviewed regularly by the Corporate Governance and Nominating Committee of the Board, which acts as PrimeWest's Environmental, Health and Safety Committee.

Regulation, Tax, Royalties

Changes in government regulations including reporting requirements, income tax laws, operating practices and environmental protection requirements and royalty rates.

We mitigate by:

Keeping informed of proposed changes in regulations and laws to properly respond to and plan for the effects that these changes may have on our operations.

Liability to unitholders

There is no statutory protection for unitholders from liabilities of the Trust.

We mitigate by:

Limiting the business of the Trust to the right to receive the net cash flow of PrimeWest Energy Inc. All of the oil and gas business operations of PrimeWest are conducted by PrimeWest Energy Inc. PrimeWest Energy Inc. has a vigorous EH&S program as well as significant insurance protection.

Management Responsibility for Financial Statements and Management's Discussion and Analysis

The consolidated financial statements of PrimeWest Energy Trust and Management's Discussion and Analysis (MD&A) were prepared by, and are the responsibility of, the management of PrimeWest Energy Inc. The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in Canada. The financial and operating information presented in this annual report is consistent with that shown in the consolidated financial statements.

Management has designed and maintains a system of internal controls to safeguard assets and ensure that transactions are properly authorized and recorded and form part of these financial statements. Where estimates are used in the preparation of these financial statements, management has ensured that careful judgement has been made and that these estimates are reasonable, based on all information known at the time the estimates are made.

The Board of Directors of PrimeWest is responsible for ensuring that management fulfills its responsibilities for financial reporting, and it has reviewed and approved these financial statements and MD&A. The Board carries out this responsibility through the audit and reserves committee, which consists of the independent directors of the Board.

Unitholders have appointed the external audit firm of PricewaterhouseCoopers LLP to express their opinion on the consolidated financial statements. The auditors have full and unrestricted access to the audit and reserves committee to discuss their findings.

Don Garner
President and Chief Executive Officer
February 7, 2003

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

Auditors' Report

To the unitholders of PrimeWest Energy Trust:

We have audited the consolidated balance sheets of PrimeWest Energy Trust as at December 31, 2002, 2001 and 2000 and the consolidated statements of income, cash distributions, unitholders' equity, and cash flows for the years then ended. These financial statements are the responsibility of the management of the Trust. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free from 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 Trust as at December 31, 2002, 2001 and 2000, and the results of its operations and cash flows for the years then ended, in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP, *Chartered Accountants*
Calgary, Alberta
February 7, 2003

Consolidated Balance Sheets

As at December 31 (thousands of Canadian dollars)	**2002**	2001	2000
ASSETS			
Current Assets			
Accounts Receivable	**$ 71,635**	$ 60,609	$ 40,561
Prepaid Expenses	**9,759**	9,112	4,398
Inventory	**2,204**	3,173	840
	83,598	72,894	45,799
Cash Reserved for Site Restoration			
and Reclamation *(Note 7)*	**12**	755	398
Property, Plant and Equipment *(Note 4)*	**1,404,463**	1,448,661	395,376
Other Assets *(Note 5)*	**14,179**	–	–
	$ 1,502,252	$ 1,522,310	$ 441,573
LIABILITIES AND UNITHOLDERS' EQUITY			
Current Liabilities			
Bank Overdraft	**$ 3,057**	$ 14,613	$ 834
Accounts Payable	**43,109**	26,207	19,057
Accrued Liabilities	**23,950**	39,350	13,440
Accrued Distributions to Unitholders	**13,918**	11,980	9,961
Due to Related Company *(Note 10)*	**–**	10,108	2,057
Current Portion of Long-term Debt *(Note 6)*	**–**	67	106
	84,034	102,325	45,455
Long-term Debt *(Note 6)*	**225,000**	195,000	78,940
Future Income Taxes *(Note 11)*	**339,888**	362,595	16,596
Site Restoration and			
Reclamation Provision *(Note 7)*	**6,232**	6,113	1,958
	655,154	666,033	142,949
Unitholders' Equity			
Net Capital Contributions *(Note 8)*	**1,299,968**	1,152,551	435,342
Capital Issued but Not Distributed	**884**	1,035	614
Long-Term Incentive Plan Equity *(Note 9)*	**10,068**	7,932	8,930
Accumulated Income	**123,170**	122,550	43,014
Accumulated Cash Distributions	**(578,934)**	(420,983)	(186,518)
Accumulated Dividends	**(8,058)**	(6,808)	(2,758)
	847,098	856,277	298,624
	$ 1,502,252	$ 1,522,310	$ 441,573

Commitments and Contingencies *(Note 13)*

The accompanying notes form an integral part of these financial statements.

Harold P. Milavsky
Chairman of the Board of Directors

Don Garner
President and Chief Executive Officer

Consolidated Statements of Unitholders' Equity

For the Years Ended December 31 (thousands of Canadian dollars)	2002	2001	2000
Unitholders' Equity – Beginning of Year,			
as previously reported	**$ 856,277**	$ 298,624	$ 200,039
Future Income Tax			
Accounting Change *(Note 11)*	**–**	–	(10,219)
Net Income for the Year	**620**	79,536	55,612
Capital Contributions, Net of Costs	**147,417**	717,209	124,293
Cash Distributions	**(157,951)**	(234,465)	(79,033)
Dividends	**(1,250)**	(4,050)	(1,612)
Long-Term Incentive Plan Equity	**2,136**	(998)	8,930
Capital Issued but Not Distributed	**(151)**	421	614
Unitholders' Equity – End of Year	**$ 847,098**	$ 856,277	$ 298,624

The accompanying notes form an integral part of these financial statements.

Consolidated Statements of Income

For the Years Ended December 31 (thousands of Canadian dollars, except per Trust Unit amounts)	**2002**	2001	2000
REVENUES			
Sales of Crude Oil, Natural Gas & Natural Gas Liquids	**$ 320,517**	$ 378,155	$ 191,339
Crown & Other Royalties, Net of ARTC	**(56,496)**	(73,156)	(35,157)
Other Income	**227**	1,516	379
	264,248	306,515	156,561
EXPENSES			
Depletion, Depreciation & Amortization	**181,956**	159,332	42,865
Operating	**60,773**	58,951	30,174
General & Administrative	**11,281**	10,394	4,140
Unit Appreciation Rights	**6,125**	4,158	10,296
Interest	**10,788**	13,800	6,359
Cash Management Fees *(Note 10)*	**3,982**	6,431	3,277
Non-Cash Management Fees *(Note 10)*	**1,414**	1,819	731
Cash Internalization Costs	**3,598**	–	–
Non-Cash Internalization Costs *(Note 10)*	**13,124**	–	–
	293,041	254,885	97,842
Income/(Loss) Before Taxes for the Year	**(28,793)**	51,630	58,719
Income and Capital Taxes	**2,887**	2,428	549
Future Taxes (Recovery) *(Note 11)*	**(32,300)**	(30,334)	2,558
	(29,413)	(27,906)	3,107
Net Income	**$ 620**	$ 79,536	$ 55,612
Net Income per Trust Unit			
Basic	**$ 0.02**	$ 3.12	$ 5.00
Diluted	**$ 0.02**	$ 3.08	$ 4.84

The accompanying notes form an integral part of these financial statements.

Consolidated Statements of Cash Distributions

For the Years Ended December 31 (thousands of Canadian dollars, except per Trust Unit amounts)	2002	2001	2000
Net Income for the Year	**$ 620**	$ 79,536	$ 55,612
Add Back (Deduct)			
Depletion, Depreciation & Amortization	**181,956**	159,332	42,865
Cash (Retained)/Paid from Cash Available for Distribution	**(7,315)**	25,822	(29,266)
Contribution to Reclamation Fund	**(4,078)**	(3,499)	(2,964)
Management Fees Paid in Trust Units	**1,414**	1,819	731
Internalization Costs Paid in Trust Units	**13,124**	–	–
Unit Appreciation Rights Expense	**6,125**	4,158	10,296
Future Income Taxes (Recovery)	**(32,300)**	(30,334)	2,558
	$ 159,546	$ 236,834	$ 79,832
Cash Distributions to Trust Unitholders (99%)	**$ 157,951**	$ 234,465	$ 79,033
Cash Distributions per Trust Unit [1]	**$ 4.80**	$ 9.24	$ 7.08

[1] After giving effect to 4 for 1 Trust Unit consolidation on August 16, 2002.

The accompanying notes form an integral part of these financial statements.

Consolidated Statements of Cash Flow

For the Years Ended December 31 (thousands of Canadian dollars)	2002	2001	2000
OPERATING ACTIVITIES			
Net Income for the Year	**$ 620**	$ 79,536	$ 55,612
Add: (Deduct) Items Not Involving Cash Flow from Operations			
Depletion, Depreciation & Amortization	**181,956**	159,332	42,865
Non-Cash Internalization Costs	**13,124**	–	–
Unit Appreciation Rights Expense	**6,125**	4,158	10,296
Non-Cash Management Fees	**1,414**	1,819	731
Future Income Taxes	**(32,300)**	(30,334)	2,558
Cash Flow from Operations	**170,939**	214,511	112,062
Expenditures on Site Restoration & Reclamation *(Note 7)*	**(3,909)**	(3,769)	(3,561)
Change in Non-Cash Working Capital	**(10,729)**	(20,487)	(15,570)
	156,301	190,255	92,931
FINANCING ACTIVITIES			
Proceeds from Issue of Trust Units, Net of Costs	**118,333**	159,542	38,036
Acquisition of Trust Units pursuant to Normal Course Issuer Bid	**–**	–	(926)
Cash Distributions to Unitholders	**(145,887)**	(223,658)	(77,173)
Dividends Paid	**(1,250)**	(602)	(1,612)
Increase (Decrease) in Long-Term Debt	**29,933**	(62,980)	(41,449)
Change in Non-Cash Working Capital	**1,797**	2,019	6,291
	2,926	(125,679)	(76,833)
INVESTING ACTIVITIES			
Expenditures on Property, Plant and Equipment	**(69,055)**	(84,206)	(25,791)
Acquisition of Capital/ Corporate Assets *(Notes 3 and 10)*	**(59,606)**	(84,054)	(6,306)
Proceeds on Disposition of Property, Plant and Equipment	**4,529**	78,144	855
Expenditures for Future Acquisition *(Note 5)*	**(14,179)**	–	–
Cash Reserved for Future Site Restoration & Reclamation	**743**	(357)	661
Proceeds on Disposition of Short-Term Investments	**–**	–	174
Change in Non-Cash Working Capital	**(10,103)**	12,118	7,971
	(147,671)	(78,355)	(22,436)
Increase (Decrease) in Cash for the Year	**11,556**	(13,779)	(6,338)
Cash (Bank Overdraft), Beginning of Year	**(14,613)**	(834)	5,504
(Bank Overdraft), End of Year	**$ (3,057)**	$ (14,613)	$ (834)
Cash Interest Paid	**$ 10,275**	$ 13,159	$ 6,872
Cash Taxes Paid	**$ 3,960**	$ 460	$ 453

The accompanying notes form an integral part of these financial statements.

Notes to Consolidated Financial Statements

(all amounts are expressed in thousands of Canadian dollars unless otherwise indicated)

1. Structure Of The Trust

PrimeWest Energy Trust (the Trust) is an open-ended investment trust formed under the laws of Alberta in accordance with a declaration of trust dated August 2, 1996. The beneficiaries of the Trust are the holders of Trust Units (the unitholders).

The common shares of PrimeWest Energy Inc. (PrimeWest) are 100% owned by the Trust.

The principal undertaking of the Trust's operating company, PrimeWest, is to acquire and hold, directly and indirectly, interests in oil and gas properties. One of the Trust's primary assets is a royalty entitling it to receive 99% of the net cash flow generated by the oil and gas interests owned by PrimeWest. The royalty acquired by the Trust effectively transfers substantially all of the economic interest in the properties to the Trust.

On November 4, 2002, unitholders voted, by a 92% majority, to internalize management. PrimeWest Management Inc. received a total of $26.3 million. Approximately $13.2 million related to the acquisition of the 1% retained royalty and was recorded as an acquisition in property, plant and equipment. The balance was charged to non-cash internalization expense. In addition, retention provisions for senior management totaling $3.5 million were agreed to and $1.5 million was accrued relating to the termination of the management incentive program (see Note 10).

2. Accounting Policies

Consolidation

These consolidated financial statements include the accounts of the Trust and its wholly-owned subsidiaries, PrimeWest, PrimeWest Management Inc., and PrimeWest Gas Inc. The Trust, through the royalty, obtains substantially all of the economic benefits of the operations of PrimeWest. In addition, the unitholders of the Trust elect the Board of Directors of PrimeWest.

Cash And Short Term Investments

Short term investments, with maturities less than three months at date of acquisition, are considered to be cash equivalents and are recorded at cost, which approximates market value.

Inventory

Inventory is measured at lower of cost and net realizable value.

Property, Plant And Equipment

PrimeWest follows the full cost method of accounting. All costs of acquiring oil and gas properties and related development costs are capitalized and accumulated in one cost centre. Maintenance and repairs are charged against earnings. Renewals and enhancements that extend the economic life of the capital asset are capitalized.

Gains and losses are not recognized on disposition of oil and gas properties unless that disposition would alter the rate of depletion by 20% or more.

i) Ceiling test

PrimeWest places a limit on the aggregate cost of capital assets which may be carried forward for depletion against net revenues of future periods (the ceiling test). The ceiling test is a cost recovery test whereby; capitalized costs, less accumulated depletion and site restoration, the lower of cost and market value of unproved land and future income taxes, are limited to an amount equal to estimated undiscounted future net revenues from proved reserves, less general and administrative expenses, site restoration, future financing costs and applicable income taxes. Costs and prices at the balance sheet date are used. Any costs carried on the balance sheet in excess of the ceiling test limitation are charged to income.

ii) Site restoration and reclamation provision

PrimeWest provides for the cost of future site restoration and reclamation, based on estimates by management, using the unit-of-production method. Actual site-restoration costs are charged against the accumulated liability. PrimeWest places cash in reserve to fund actual expenditures as they are incurred.

iii) Depletion, depreciation and amortization

Provision for depletion and depreciation is calculated on the unit-of-production method, based on proved reserves before royalties. Reserves are estimated by independent petroleum engineers. Reserves are converted to equivalent units on the basis of approximate relative energy content.

Depreciation and amortization of head office furniture and equipment is provided for at rates ranging from 10% to 30%.

Joint Venture Accounting

PrimeWest conducts substantially all of its oil and gas production activities through joint ventures, and the accounts reflect only PrimeWest's proportionate interest in such activities.

Long-Term Incentive Plan

Liabilities under the Trust's Long-term Incentive Plan are estimated at each balance sheet date, based on the amount of Unit Appreciation Rights that are in the money using the unit price as at that date. Expenses are recorded through non-cash general and administrative costs, with an offsetting amount in long-term incentive plan equity. As Trust Units are issued under the plan, the exercise value is recorded in net capital contributions.

Income Taxes

The Trust is considered an inter-vivos trust for income tax purposes. As such, the Trust is subject to tax on any taxable income that is not allocated to the unitholders.

Periodically, current taxes may be payable by PrimeWest, depending upon the timing of income tax deductions. Should these taxes prove to be unrecoverable, they will be deducted from royalty income in accordance with the royalty agreement.

Future income taxes are recorded for PrimeWest using the liability method of accounting. Future income taxes are recorded to the extent that the carrying value of PrimeWest's capital assets exceeds the available tax pools.

Financial Instruments

PrimeWest uses financial instruments to manage its exposure to fluctuations in commodity prices and interest rates. PrimeWest does not use financial instruments for speculative trading purposes and, accordingly, they are accounted for as hedges. Gains and losses on hedging activity are reflected in revenue, or in the case of interest rate hedges, in interest expense, at the time of sale of the related hedged production, or when the monthly exchange contracts expire.

Measurement Uncertainty

Certain items recognized in the financial statements are subject to measurement uncertainty. The recognized amounts of such items are based on PrimeWest's best information and judgement. Such amounts are not expected to change materially in the near term. They include:

¶ the amounts recorded for depletion, depreciation and future site restoration costs which depend on estimates of oil and gas reserves or the economic lives and future cash flows from related assets; and

¶ the amounts recorded for assets and liabilities of acquired companies which depend on estimates of their fair values on the acquisition date.

3. Corporate Acquisitions

a) On March 29, 2001, PrimeWest Oil & Gas Corp. (Oil & Gas) completed the acquisition of all of the issued and outstanding shares of Cypress Energy Inc. (Cypress) pursuant to a takeover bid. In aggregate, PrimeWest issued 50.2 million Trust Units and PrimeWest issued 5.2 million exchangeable shares of Oil & Gas and paid $59.2 million in exchange for the shares of Cypress. Subsequent to the transaction, Cypress and Oil & Gas were amalgamated. The acquisition was accounted for using the purchase method of accounting with net assets acquired and consideration paid as follows:

Net Assets Acquired At Assigned Values		Consideration Paid	
Petroleum and natural gas assets	$ 1,201,485		
Working capital (deficit) assumed	(19,174)	Cash	$ 59,235
Long-term debt assumed	(179,000)	Trust Units issued	489,815
Site restoration provision	(4,307)	Exchangeable shares issued	50,254
Future income taxes	(376,334)	Costs associated with acquisition	23,366
	$ 622,670		$ 622,670

b) On April 19, 2000, PrimeWest Resources Ltd. (Resources) completed the acquisition of all of the issued and outstanding shares of Venator Petroleum Company Limited (Venator) on a unit/share for share exchange. Resources issued 0.657 Trust Units or 0.657 exchangeable shares for each Venator share. In aggregate, 2.4 million Trust Units and 2.0 million exchangeable shares were issued for total consideration, including debt assumed, of $32.5 million. Subsequent to the transaction, the assets of Venator were transferred to Resources and Venator was dissolved. The acquisition was accounted for using the purchase method of accounting with the purchase price allocated as follows:

Net Assets Acquired At Assigned Values		Consideration Paid	
Petroleum and natural gas assets	$ 34,392	Trust Units issued	$ 15,637
Working capital (deficit) assumed	(2,323)	Exchangeable shares issued	13,282
Future income taxes	(1,898)	Costs associated with acquisition	1,252
	$ 30,171		$ 30,171

c) On July 27, 2000, PrimeWest Royalty Corp. (Royalty Corp.) completed the acquisition of all of the issued and outstanding shares of Reserve Royalty Corporation on a unit for share exchange. Royalty Corp. issued 0.65 Trust Units for each Reserve Royalty share. In aggregate, 6.67 million Trust Units were issued for total consideration, including debt assumed, of $84.0 million. Subsequent to the transaction, Reserve Royalty was amalgamated into Royalty Corp. and the majority of its assets transferred to the Trust. The acquisition was accounted for using the purchase method of accounting with the purchase price allocated as follows:

Net Assets Acquired At Assigned Values		Consideration Paid	
Petroleum and natural gas assets	$ 85,860		
Working capital assumed	1,049		
Long-term debt assumed	(28,210)	Trust Units issued	$ 53,947
Future income taxes	(1,921)	Costs associated with acquisition	2,831
	$ 56,778		$ 56,778

As of January 1, 2002, Oil & Gas, Resources and Royalty Corp. were amalgamated with PrimeWest.

4. Property, Plant and Equipment

		2002	
	Cost	**Accumulated depletion, depreciation and amortization**	**Net book value**
Property acquisition oil and gas rights	**$ 1,682,592**	**$ (430,636)**	**$ 1,251,956**
Drilling and completion	**139,885**	**(34,684)**	**105,201**
Production facilities and equipment	**60,497**	**(15,395)**	**45,102**
Head office furniture and equipment	**5,209**	**(3,005)**	**2,204**
	$ 1,888,183	**$ (483,720)**	**$ 1,404,463**

		2001	
	Cost	Accumulated depletion, depreciation and amortization	Net book value
Property acquisition oil and gas rights	$ 1,608,435	$ (268,137)	$ 1,340,298
Drilling and completion	103,583	(24,074)	79,509
Production facilities and equipment	38,198	(11,537)	26,661
Head office furniture and equipment	4,238	(2,045)	2,193
	$ 1,754,454	$ (305,793)	$ 1,448,661

		2000	
	Cost	Accumulated depletion, depreciation and amortization	Net book value
Property acquisition oil and gas rights	$ 474,091	$ (135,256)	$ 338,835
Drilling and completion	51,769	(10,216)	41,553
Production facilities and equipment	16,397	(3,249)	13,148
Head office furniture and equipment	3,199	(1,359)	1,840
	$ 545,456	$ (150,080)	$ 395,376

Unproved land costs of $ 44.2 million (2001 – $55.7 million, 2000 – $17.2 million) are excluded from costs subject to depletion and depreciation.

PrimeWest capitalized $3.8 million of general and administrative costs in 2002 ($2.2 million in 2001; $0.9 million in 2000).

In accordance with stated accounting policies, PrimeWest has performed a ceiling test using commodity prices as at the measurement date of December 31, 2002. Using December 31, 2002 commodity prices of AECO $5.59 per mcf for natural gas and WTI $US 29.39 per barrel for crude oil, results in a ceiling test surplus of $900 million.

At December 31, 2001, PrimeWest performed its ceiling test using commodity prices as at that measurement date of AECO $3.67 per mcf for natural gas and WTI $US 19.84 per barrel for crude oil. The ceiling test resulted in a deficiency of $150 million. PrimeWest did not record a writedown at this time as the writedown occurred within the first two years of the acquisition of Cypress.

5. Other Assets

	2002	2001	2000
Deposit on acquisition	**$ 10,850**	$ –	$ –
Expenditures incurred on acquisition	**3,329**	–	–
	$ 14,179	$ –	$ –

Other assets include expenditures required to effect the acquisition of all of the issued and outstanding shares of two private Canadian companies on January 23, 2003 (see Note 14).

6. Long-Term Debt

	2002	2001	2000
Revolving credit facility	**$ 225,000**	$ 195,000	$ 78,879
Capital lease obligation	**–**	–	61
	225,000	195,000	78,940
Current portion	**–**	67	106
	$ 225,000	$ 195,067	$ 79,046

PrimeWest and the Trust (as co-borrowers) have a combined revolving credit facility in the amount of $335 million (2001 – $350 million; 2000 – $150 million), with a borrowing base at December 31, 2002 of $335 million (2001 – $350 million; 2000 – $150 million). The facility consists of a revolving term loan of $310 million and an operating facility of $25 million. The facility and borrowing base increased to $390 million on January 23, 2003 upon the completion of the acquisition of two private Canadian companies. In addition, PrimeWest had $100 million of bridge financing which was drawn on January 23, 2003 and was repaid in February 2003 upon completion of the equity offering (see Note 14). In addition to amounts outstanding under the facility as indicated in the table above, PrimeWest has outstanding letters of credit in the amount of $3.8 million (2001 – $2.8 million; 2000 – $4.3 million). Collateral for the credit facility is provided by a floating-charge debenture covering all existing and after acquired property in the principal amount of $750 million. Each borrower under the facility has also provided an unconditional full liability guarantee in respect of amounts borrowed under the facility.

Advances under the facility are made in the form of Banker's Acceptances (BA), prime rate loans or letters of credit. In the case of BA, interest is a function of the BA rate plus a stamping fee based on the Trust's current ratio of debt to cash flow. In the case of prime rate loans, interest is charged at the bank's prime rate. While any amounts are outstanding under the bridge facility the interest rates and stamping fees increase by 50 basis points. For 2002, the effective interest rate was 4.6% (2001 – 5.6%, 2000 – 7.5%)

The credit facility revolves until April 30, 2003, by which time the lender will have conducted its annual borrowing base review. The lender also has the right to re-determine the borrowing base at one other time during the year. During the revolving phase, the facility has no specific terms of repayment. At the end of the revolving period, the lender has the right to extend the revolving period for a further 364-day period or to convert the facility to a term facility. If the lender converts to a non-revolving facility 60% of the aggregate principal amount of the loan shall be repayable on the date which is 366 days after such conversion date and the remaining 40% of the aggregate principal amount outstanding shall be repayable on the date which is 365 days after the initial term repayment date.

7. Cash Reserve For Site Restoration And Reclamation

Commencing in 1998, funding for the reserve was provided for by reducing distributions otherwise payable based on an amount per BOE produced ($0.15 per BOE produced for 1998 and 1999, $0.24 per BOE produced in 2000, $0.32 per BOE produced in 2001 and $0.37 per BOE produced in 2002). The cash amount contributed, including interest earned, was $4.1 million in 2002 (2001 – $4.2 million; 2000 – $3.0 million). Actual costs of site restoration and abandonment totaling $3.9 million were paid out of this cash reserve for the year ended December 31, 2002 (2001 – $3.8 million; 2000 – $3.6 million).

8. Unitholders' Equity

PrimeWest Energy Trust

The authorized capital of the Trust consists of an unlimited number of Trust Units.

Trust Units	Number of Units	Amounts ($000's)
Balance, December 31, 1999	35,768,801	$ 311,049
Issued for cash	4,830,000	40,331
Issue expenses	–	(2,741)
Retired pursuant to Normal Course Issuer Bid	(141,900)	(926)
Issued to acquire Venator Petroleum Company Ltd.	2,368,936	15,637
Issued to acquire Reserve Royalty Corporation	6,660,082	53,947
Issued for payment of management fees	82,203	616
Issued on exchange of exchangeable shares	922,073	5,940
Issued pursuant to Distribution Reinvestment Plan	215,035	1,860
Issued pursuant to Long-Term Incentive Plan	226,423	1,841
Issued pursuant to Optional Trust Unit Purchase Plan	50,440	447
Balance, December 31, 2000	50,982,093	$ 428,001
Issued for cash	19,790,000	165,234
Issue expenses	–	(9,013)
Issued to acquire Cypress Energy Inc.	50,234,771	489,815
Issued for payment of management fees	199,841	1,635
Issued on exchange of exchangeable shares	2,415,363	20,298
Issued pursuant to Distribution Reinvestment Plan	1,623,171	10,807
Issued pursuant to Long-Term Incentive Plan	577,840	5,155
Issued pursuant to Optional Trust Unit Purchase Plan	142,528	3,321
Balance, December 31, 2001	125,965,607	$ 1,115,253
Restated giving effect for 4 to 1 Trust Unit consolidation on August 16, 2002	31,491,402	
Issued for cash	4,200,000	110,040
Issue expenses	–	(5,641)
Issued for payment of management fees	66,853	1,832
Issued on exchange of exchangeable shares	106,934	2,698
Issued pursuant to Distribution Reinvestment Plan	476,106	10,126
Issued pursuant to Long-Term Incentive Plan	153,749	4,000
Issue of units due to odd lot program	111	–
Issue of fractional units due to 4 to 1 consolidation	6,264	–
Issued pursuant to Optional Trust Unit Purchase Plan	503,103	13,936
Balance, December 31, 2002	**37,004,522**	**$ 1,252,244**

The number of units was restated giving effect of four for one Trust Unit consolidation effective August 16, 2002.

The weighted average number of Trust Units and exchangeable shares outstanding in 2002 was 34,134,230 (2001 – 25,633,250; 2000 – 11,162,900). For purposes of calculating diluted net income per Trust Unit, 341,315 Trust Units (2001 – 311,789; 2000 – 249,516) issuable pursuant to the long-term incentive plan were added to the weighted average number. The per unit cash distribution amounts paid or declared reflects distributions paid or declared to Trust Units outstanding on the record dates.

PrimeWest Exchangeable Class A Shares

In connection with the Cypress transaction (see Note 3a), PrimeWest Oil & Gas Corp. (now amalgamated with PrimeWest Energy Inc.) amended its articles to create an unlimited number of exchangeable shares. The exchangeable shares are exchangeable into PrimeWest Trust Units at any time up to March 29, 2010, based on an exchange ratio that adjusts each time the Trust makes distribution to its unitholders. The exchange ratio, which was 1:1 on the date that the transaction closed, is based on the total monthly distribution, divided by the closing unit price on the distribution payment date. The exchange ratio on December 31, 2002 was 0.37454 (2001 – 0.3126:1) (restated effecting 4 to 1 Trust Unit consolidation).

Exchangeable Shares	# of shares		Amounts ($000's)
Balance, December 31, 2000	–	$	–
Issued to acquire Cypress Energy Inc.	5,154,225		50,254
Exchanged for Trust Units	(1,837,483)		(17,916)
Balance, December 31, 2001	3,316,742		32,338
Issued for internalization	1,363,714		13,124
Conversion of Class B shares	710,795		4,287
Exchanged for Trust Units	(211,973)		(2,025)
Balance, December 31, 2002	**5,179,278**	**$**	**47,724**

PrimeWest Exchangeable Class B Shares

In connection with the Venator transaction (see Note 3b), PrimeWest Resources Ltd. (now amalgamated with PrimeWest Energy Inc.) amended its articles to create an unlimited number of exchangeable shares. At special meetings held in May and June of 2002, holders of Class B Exchangeable Shares and Class A Exchangeable shares voted to approve a special resolution amending the articles of the Corporation to convert all Class B Exchangeable shares to Class A Exchangeable Shares. As at June 14, 2002, 649,561 Class B Exchangeable shares were converted to Class A Exchangeable Shares using an exchange ratio of 1.09427:1.

Exchangeable Shares	# of shares		Amounts ($000's)
Balance, December 31, 1999	–	$	–
Issued to acquire Venator Petroleum Company Ltd.	2,012,422		13,282
Exchanged for Trust Units	(900,052)		(5,940)
Balance, December 31, 2000	1,112,370		7,342
Exchanged for Trust Units	(360,838)		(2,382)
Balance, December 31, 2001	751,532		4,960
Exchanged for Trust Units	(101,971)		(673)
Converted to Class A Exchangeable Shares	(649,561)		(4,287)
Balance, December 31, 2002	**–**	**$**	**–**

Normal Course Issuer Bid

On November 29, 1999, the Trust received approval from the Toronto Stock Exchange to make a normal course issuer bid. During 2000, the Trust acquired 141,900 Trust Units pursuant to the bid at an average cost of $6.53 per Trust Unit. This bid expired on November 29, 2000. On December 15, 2000, the Trust received approval from the Toronto Stock Exchange to renew its bid for a further one year period. During 2001, no purchases were made under the renewed bid. This bid expired on December 15, 2001 and was not renewed in 2002.

Trust Units and Exchangeable Shares Issued & Outstanding (1)

	2002	2001	2000
Trust Units issued & outstanding	**37,004,522**	31,491,402	12,745,523
Exchangeable shares			
PrimeWest Resources Ltd. (2)			
(2001 – 751,532 shares exchangeable at 0.34201 2000 – 1,112,370 shares exchangeable at 0.2733)	**–**	257,035	304,039
PrimeWest Oil and Gas Corp. (2)			
(5,179,278 shares exchangeable at 0.37454; 2001 – 3,316,742 shares exchangeable at 0.3126)	**1,939,864**	1,036,648	–
Total units and exchangeable shares issued & outstanding	**38,944,386**	32,785,085	13,049,562
Unit Appreciation Rights	**341,315**	311,788	249,516
Total units and exchangeable shares issued & outstanding – diluted	**39,285,701**	33,096,873	13,299,078

(1) Restated Trust Units to give effect to 4 for 1 unit consolidation effective August 16, 2002.

(2) Amalgamated with PrimeWest Energy Inc. effective January 1, 2002

9. Trust Unit Incentive Plan

Under the terms of the Trust Unit Incentive Plan, a maximum of 622,500 Trust Units are reserved for issuance pursuant to the exercise of Unit Appreciation Rights (UARs) granted to employees of PrimeWest. Payouts under the plan are based on total unitholder return, calculated using both the change in the Trust Unit price as well as cumulative distributions paid. The plan requires that a hurdle return of 5% per annum be achieved before payouts accrue. UARs have a term of 6 years and vest equally over a 3-year period, except for the independent members of the Board, whose UARs vest immediately. The Board of Directors has the option of settling payouts under the plan in PrimeWest Trust Units or in cash. To date, all payouts under the plan have been in the form of Trust Units.

Effective January 1, 2002, the method of accounting for the long-term incentive plan was changed to comply with new CICA accounting standard 3870. The calculation of the long-term incentive liability now includes vested and unvested UARs. Previously, only vested UARs were included. In addition, the long-term incentive liability has been reclassified as equity on the balance sheet as the Trust intends to settle the liability in the form of Trust Units.

As at December 31, 2002 Year of Grant	UARs issued & outstanding	UARs vested	Current return per "in the money" UARs	Total equity 000s	Trust Unit dilution
1997	**52,927**	**52,927**	**$ 22.98**	**$ 1,216**	**47,883**
1998	**105,798**	**105,798**	**33.99**	**3,596**	**141,563**
1999	**115,215**	**114,667**	**22.38**	**2,578**	**101,076**
2000	**187,984**	**125,661**	**8.22**	**1,546**	**37,831**
2001	**515,634**	**185,780**	**2.12**	**635**	**12,861**
2002	**1,120,142**	**82,097**	**1.97**	**497**	**101**
Total	**2,097,700**	**666,930**		**$ 10,068**	**341,315**

As at December 31, 2001 Year of Grant					
1996	131,719	131,719	$ 15.84	$ 2,086	82,010
1997	79,839	79,839	13.76	1,098	43,165
1998	127,956	127,957	24.80	3,171	124,654
1999	148,416	89,566	14.76	1,323	52,025
2000	240,914	86,951	2.92	254	9,935
2001	629,343	25,211	–	–	–
Total	1,358,187	541,243		$ 7,932	311,789

As at December 31, 2000 Year of Grant					
1996	135,969	135,969	$ 20.96	$ 2,849	79,607
1997	94,452	94,452	18.20	1,718	48,011
1998	161,887	100,903	17.32	2,785	77,794
1999	253,605	74,024	21.20	1,482	41,409
2000	342,372	23,679	7.96	96	2,695
Total	988,285	429,027		$ 8,930	249,516

Cumulative to December 31, 2002, 640,503 (2001 – 399,199; 2000 – 184,836) UARs have been exercised, resulting in the issuance of 358,369 Trust Units from treasury (2001 – 205,003; 2000 – 60,543).

10. Related-Party Transactions

On September 26, 2002, the Trust announced the planned elimination, effective October 1, 2002, of its external management structure and all related management, acquisition and disposition fees, as well as the acquisition of the right to mandatory quarterly dividends commonly referred to as the "1% retained royalty". The transaction was approved by the Unitholders and the holders of Exchangeable Shares on November 4, 2002 and closed November 6, 2002. The transaction resulted in the elimination of the 2.5% management fee on net production revenue, quarterly incentive payments payable in the form of Trust Units, the 1.5% acquisition fee and the 1.25% disposition fee, which resulted in payments to PrimeWest Management Inc. in 2002 totaling $5.8 million (2001 – $21.3 million; 2000 – $5.7 million). In addition, the amount of the 1% retained royalty paid in 2002 was $1.3 million (2001 – $3.4 million; 2000 – $0.8 million).

As at December 31, 2002, the Trust and PrimeWest owed $nil (2001 – $10.1 million; 2000 – $2.1 million) to PrimeWest Management Inc. for unpaid management and other fees and reimbursement of general and administrative costs.

The internalization transaction was achieved through the purchase by PrimeWest of all of the issued and outstanding shares of PrimeWest Management Inc. for a total consideration of approximately $26.3 million comprised of a cash payment of $13.2 million and the issuance of Exchangeable Shares exchangeable, based on an agreed exchange ratio, for approximately 491,000 Trust Units and valued at approximately $13.1 million based on the closing price of the Trust Units on the TSX on September 26, 2002. The $13.2 million that related to the acquisition of the 1% retained royalty was capitalized; an additional $9.5 million was capitalized with an offset to future tax liability as a result of the property, plant and equipment having no tax basis. In addition, PrimeWest agreed to issue Exchangeable Shares valued at $1.5 million to certain senior managers to terminate a management incentive program of PrimeWest Management Inc. and to create a special executive retention plan for those senior managers which provides for long term incentive bonuses in the form of Exchangeable Shares valued, in the aggregate, at $3.5 million. Exchangeable Shares will be issued pursuant to the retention plan on each of the second, third, fourth and fifth anniversaries of the completion of the internalization transaction.

11. Income Taxes

The Trust, and consequently the unitholders of the Trust, had taxable income totaling $86.9 million for 2002 representing approximately 55% of distributions paid in the year (2001 – $155.8 million representing 67%; 2000 – $38.3 million representing 53%).

PrimeWest and its subsidiaries had no taxable income for 2002, 2001, and 2000, as tax-pool deductions and the royalty payable were sufficient to reduce taxable income in these entities to nil.

Effective January 1, 2000, the Company changed the method of accounting for income taxes from the deferral method to the liability method. The new method was applied retroactively without restatement of prior periods. The effect of the change in accounting policy on the financial statements was to decrease unitholders' equity by $10.2 million with a corresponding increase in the provision for future income tax liabilities on the balance sheet. The effect on the provision for income taxes for 2000, as a result of this change in accounting policy, was to decrease future income tax liability by $2.6 million. The future income tax liability results from the carrying value of the capital assets exceeding the available tax pools.

The future tax provision results from temporary differences in the recognition of revenues and expenses for income taxes and accounting purposes as follows:

	2002	2001	2000
Loss carry forwards	**$ (4,977)**	$ (10,601)	$ –
Capital assets	**350,014**	378,015	21,455
Site restoration provision	**(1,969)**	(2,283)	(874)
Long-term incentive liability	**(3,180)**	(2,536)	(3,985)
	$ 339,888	$ 362,595	$ 16,596

The provisions for income taxes varies from the amounts that would be computed by applying the combined Canadian federal and provincial income tax rates for the following reasons:

	2002	2001	2000
Net income (loss) before taxes	**$ (28,793)**	$ 51,630	$ 58,719
Computed income tax expense (recovery) at the Canadian statutory rate of 42.12% (2001 – 43.12%; 2000 – 44.62%)	**(12,128)**	22,263	26,200
Increase (decrease) resulting from:			
Non-deductible crown royalties and other payments, net of ARTC	**5,725**	273	157
Federal resource allowance	**(3,466)**	(9,729)	(1,447)
Amounts included in trust income and other	**(22,431)**	(43,141)	(22,352)
Future income taxes	**$ (32,300)**	$ (30,334)	$ 2,558

12. Financial Instruments

a) Commodity Price Risk Management

PrimeWest generally sells its oil and gas under short-term market-based contracts. Derivative financial instruments, options and swaps may be used to hedge the impact of oil and gas price fluctuations.

A summary of these contracts in place at December 31, 2002 follows:

CRUDE OIL

Period	Volume (bbls/d)	Type	WTI Price (U.S.$/bbl)
Jan – Jan 2003	500	Swap	$ 30.50
Jan – Jan 2003	500	Swap	28.95
Jan – Mar 2003	1,000	Costless Collar	21.00 / 27.70
Jan – Mar 2003	1,000	Costless Collar	20.50 / 25.50
Jan – Mar 2003	500	Costless Collar	22.00 / 30.01
Jan – Mar 2003	500	Swap	27.28
Jan – Mar 2003	500	3 Way	19.50 / 24.50 / 29.90
Jan – Mar 2003	1000	Purchase Call	34.00
Jan – Jun 2003	1,000	3 Way	18.50 / 22.50 / 27.70
Feb – Feb 2003	500	Swap	28.75
Feb – Feb 2003	500	Swap	30.60
Mar – Mar 2003	500	Swap	29.00
Apr – Apr 2003	500	Swap	27.20
Apr – Jun 2003	500	Costless Collar	22.00 / 30.10
Apr – Dec 2003	1,000	3 Way	17.00 / 20.50 / 25.50
May – May 2003	500	Swap	27.05
Jun – Jun 2003	500	Swap	27.10
July – Dec 2003	1,000	3 Way	18.50 / 22.50 / 27.20

NATURAL GAS (AECO)

Period	Volume (mmcf/day)	Type	AECO Price (Cdn$/mcf)
Jan 2002 – Oct 2003	4.7	Swap	$ 3.98
Jan 2002 – Oct 2003	4.7	Swap	4.17
Nov 2002 – Mar 2003	4.7	Costless Collar	4.22 by 5.96
Nov 2002 – Mar 2003	4.7	3 Way	3.17 / 4.48 / 6.59
Nov 2002 – Mar 2003	4.7	3 Way	3.17 / 3.96 / 5.46
Nov 2002 – Mar 2003	4.7	3 Way	4.22 / 5.28 / 7.04
Nov 2002 – Mar 2003	4.7	Swap	5.43
Nov 2002 – Oct 2004	9.5	3 Way	3.17 / 4.22 / 6.09
Jan 2003 – Mar 2003	4.7	Costless Collar	5.28 / 6.35
Jan 2003 – Mar 2003	23.7	Put	5.28
Feb – Feb 2003	4.7	Swap	7.02
Apr – Jun 2003	4.7	Put Swaption	5.28
Apr – Oct 2003	4.7	Fixed Price	4.75
Apr – Oct 2003	4.7	Swap	5.05
Apr – Oct 2003	4.7	3 Way	3.17 / 4.48 / 6.26
Apr – Oct 2003	4.7	3 Way	3.17 / 3.96 / 5.39
Apr – Oct 2003	4.7	3 Way	3.69 / 4.75 / 6.65
Apr – Oct 2003	9.5	Put Swaption	5.28
Nov 2003 – Mar 2004	4.7	3 Way	4.22 / 5.28 / 8.23

NATURAL GAS (BASIS DIFFERENTIAL $US / MCF)

Period	Volume (mmcf/day)	Type	WTI Price (US$/mcf)
Nov 2002 – March 2003	5.0	Basis Swap	0.425
Apr 2003 – October 2003	5.0	Basis Swap	0.450

In 2002, the financial impact of contracts settling in the year was an increase in sales revenues of $28.1 million (2001 – $39.5 million increase in sales revenues; 2000 – $2.2 million decrease in sales revenues).

The mark-to-market value of the hedges in place as at December 31, 2002 is a $13.6 million loss of which $11.7 million is attributable to natural gas and $1.9 million is attributable to crude oil.

b) Interest Rate Risk Management

PrimeWest has the following interest rate swaps outstanding at December 31, 2002.

Term	Notional amount ($ millions)	Fixed BA rate (%)	Mark-to-market value ($ millions)
Dec 18/02 – May 05/03	$ 20	4.50	(0.3)
Dec 04/01 – Dec 04/03	$ 25	3.21	(0.1)
May 24/98 – May 25/04	$ 25	6.48	(1.3)
Nov 26/01 – May 26/04	$ 25	3.85	(0.3)

The effect of these swaps was to increase interest paid in 2002 by $1.5 million (2001 – $0.4 million, 2000 – $0.7 million).

c) Fair Value Of Financial Instruments

Financial instruments include cash, accounts receivable, accounts payable and accrued liabilities, accrued distributions to unitholders, long-term debt and financial hedges. As at December 31, 2002, 2001, and 2000, the fair market value of the financial instruments, other than long-term debt and financial hedges, approximate their carrying value, due to the short-term maturity of these instruments. The fair value of long-term debt approximates its carrying value, because the cost of borrowing approximates the market rate for similar borrowings.

13. Commitments And Contingencies

a) PrimeWest has lease commitments relating to office buildings. The estimated annual minimum operating lease rental payments for the buildings, after deducting sublease income will be $1.5 million in 2003, $1.2 million in 2004, $1.1 million in 2005, $1.1 million in 2006 and $2.4 million in 2007 – 2009, the remaining term of the leases.

b) As part of PrimeWest's internalization transaction (see Note 10), PrimeWest agreed to pay $3.5 million in exchangeable shares as a special executive retention plan. One quarter of the exchangeable shares will be issuable to the Senior Managers of PrimeWest on each of the second, third, fourth and fifth anniversary of transaction closing, November 6, 2002.

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

14. Subsequent Event

On November 25, 2002, PrimeWest and PrimeWest Gas Inc. (PrimeWest Gas), a wholly-owned subsidiary of PrimeWest, entered into an acquisition agreement with two private Canadian companies for an aggregate purchase price of $206.1 million, net of adjustments (including working capital) in cash. Of the purchase price, $191.1 million is attributed by PrimeWest Gas to oil and gas reserves and $15 million is attributed to certain natural gas processing midstream assets. The acquisition closed on January 23, 2003.

15. Prior Years' Comparative Numbers

Certain prior years' comparative numbers have been restated to conform with the current year's presentation.

16. Differences Between Canadian And United States Generally Accepted Accounting Principles

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.

1. Property, Plant And Equipment

PrimeWest follows the full cost accounting guideline as established by the Canadian Institute of Chartered Accountants (CICA). 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.

2. 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 CICA. In prior years, the company computed deferred income taxes using the deferral method.

The Canadian accounting standard is similar to the United States Statement of Financial Accounting Standards (FAS) No. 109, Accounting for Income Taxes, 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. Under U.S. GAAP, enacted tax rates are used to calculate future taxes, whereas Canadian GAAP uses substantively enacted rates. In Canada adjustments resulting from implementation of the new standard are recorded in retained earnings. In the United States these adjustments are booked to income.

3. Derivative Financial Instruments

Effective January 1, 2001, the company adopted FAS 133 Accounting for Derivative Instruments and Hedging Activities, as amended by FAS 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 OCI of $1.0 million. Assets increased by $1.0 million as a result of recording derivative instruments on the consolidated balance sheet at fair value.

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

Recent Accounting Pronouncements Issued But Not Implemented

During 2002 and year to date 2003, the following new or amended standards and guidelines were issued:

Accounting for Guarantees

In February, 2003, the CICA issued an accounting guideline on the financial statement disclosures to be made by a guarantor relative to its obligations under guarantees. Effective for the fiscal year beginning January 1, 2003, the accounting guideline requires the disclosure of the nature of the guarantee, the approximate term of the guarantee, how it arose, the events or circumstances that would trigger performance under the guarantee, the maximum potential amount of future payments, the current carrying amount of the liability if any, the nature of any recourse provision and any assets held as collateral.

In November 2002, the Financial Accounting Standards Board (FASB) issued an interpretation FIN No. 45, "Gurantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others," which requires that a guarantor disclose and recognize in its financial statements its obligations relating to guarantees that it has issued. Liability recognition is required at the inception of the guarantee, whether or not payment is probable. The Trust is currently assessing the impact on its financial statements of this guidance.

Accounting for Gains and Losses on Settlement of Debt

In April 2002, FAS 145 was issued rescinding the requirement to include gains and losses on the settlement of debt as extraordinary items. FAS 145 is applicable for fiscal years beginning on or after May 15, 2002. The standard has been no impact on the Trust.

Accounting for Costs Associated with Exit or Disposal Activities

In June 2002, FAS 146 was issued. The standard requires that liabilities for exit or disposal activity costs be recognized and measured at fair value when the liability is incurred. This standard is effective for disposal activities initiated after December 31, 2002.

Accounting for Stock-Based Compensation – Transition and Disclosure

In December 2002, FAS 148 "Accounting for Stock-Based Compensation – Transition and Disclosure" was issued as an amendment to FAS 123 "Accounting for Stock-Based Compensation", to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. FAS 148 is applicable for fiscal years beginning after December 15, 2003. The Trust does not expect that the adoption of this pronouncement will have an impact on its 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 July 1, 2003. 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

	2002	2001 (restated)	2000
Net income as reported	**$ 620**	$ 79,536	$ 55,612
Adjustments			
Depletion and depreciation	**67,255**	(539,288)	6,523
FAS 133 adjustment	**(55,813)**	43,300	–
Future income tax recovery/(expense)	**(1,405)**	165,202	(780)
Effect of change in accounting policy	–	–	(10,219)
Adjusted net (loss)/income	**10,657**	(251,250)	51,136
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	**$ 10,657**	$ (251,250)	$ 51,136
Net (loss)/income per Trust Unit			
U.S. GAAP – basic	**$ 0.31**	$ (9.80)	$ 4.58
– diluted	**$ 0.31**	$ (9.80)	$ 4.58

b) Consolidated Unitholders' Equity

(thousands of Canadian dollars)	2002	2001 (restated)
Unitholders' Equity as reported	**$ 847,098**	$ 856,277
Adjustments		
Depletion and depreciation	**(530,880)**	(598,135)
FAS 133 adjustment	**(11,543)**	44,270
Future income tax recovery	**169,138**	170,543
	$ 473,813	$ 472,955

c) Consolidated Balance Sheets

(thousands of Canadian dollars)	2002		2001	
	Cdn GAAP	**U.S. GAAP**	Cdn GAAP	U.S.GAAP (restated)
Other assets	**$ 14,179**	**$ 14,179**	$ –	$ 44,270
Property, plant and equipment, net	**1,404,463**	**873,583**	1,448,661	850,526
Other liabilities	**–**	**11,543**	–	–
Future income tax liability	**339,888**	**170,750**	362,595	192,052
Accumulated Income (deficit)	**123,170**	**(250,115)**	122,550	(260,772)

d) 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.

e) Restatement

2001 numbers have been restated to tax effect the FAS 133 adjustment. The effect is to increase future tax expense and future income tax liability by $19,089 in 2001.

SFAS No. 69 Supplemental Reserve Information (Unaudited)

The following data supplements oil and gas disclosure in the Trust's Annual Report, and is provided in accordance with the provision of the United States Financial Accounting Standards Board's Statement No. 69.

Oil and Gas Reserves

Users of this information should be aware that the process of estimating quantities of "proved" and "proved developed" crude oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of the numerous factors including, but not limited to, additional development activity, evolving production history, and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Canadian provincial royalties are determined based on a graduated percentage scale which varies with prices and production volumes. Canadian reserves, as presented on a net basis, assume prices and royalty rates in existence at the time the estimates were made, and the Trust's estimate of future production volumes. Future fluctuations in prices, production rates, or changes in political or regulatory environments could cause the Trust's share of future production from Canadian reserves to be materially different from that presented.

Subsequent to December 31, 2002, no major discovery or other favorable or adverse event is believed to have caused a material change in the estimates of proved or proved developed reserves as of that date.

RESULTS OF OIL AND GAS OPERATIONS

(thousands of Canadian dollars)	**2002**	2001	2000
Revenues	**$ 264,248**	$ 306,515	$ 156,561
Expenses			
Production costs	**60,773**	58,951	30,174
Depreciation, depletion and amortization	**113,498**	697,934	35,891
Tax (recovery)/expense	**(25,956)**	(217,053)	3,887
	148,315	539,832	69,952
Results of operations from oil and gas operations	**$ 115,933**	$ (233,317)	$ 86,609

COSTS INCURRED

(thousands of Canadian dollars)	2002	2001	2000
Property acquisition costs			
Proved properties	**$ 57,709**	$ 820,844	$ 116,433
Unproved properties	**5,662**	6,831	545
Exploration costs	**1,814**	4,048	817
Development costs	**56,786**	71,322	24,304
	$ 121,971	$ 903,045	$ 142,099

Acquisition costs include costs incurred to purchase, lease, or otherwise acquire oil and gas properties.

Development costs include the costs of drilling and equipping development wells and facilities to extract, treat and gather and store oil and gas, along with an allocation of overhead.

There were no oil and gas property costs not being amortized in any of the years presented.

CAPITALIZED COSTS

(thousands of Canadian dollars)	2002	2001	2000
Proved properties	**$ 1,838,739**	$ 1,694,555	$ 525,019
Unproved properties	**44,235**	55,661	17,238
	1, 882,974	1,750,216	542,257
Less related accumulated depreciation, depletion and amortization	**(1,011,595)**	(901,883)	(208,018)
	$ 871,379	$ 848,333	$ 334,239

PROVED OIL AND GAS RESERVE QUANTITIES

	2002	2002	2001	2001	2000	2000
	Crude Oil & Natural Gas Liquids (mbbls)	**Natural Gas (mmcf)**	Crude Oil & Natural Gas Liquids (mbbls)	Natural Gas (mmcf)	Crude Oil & Natural Gas Liquids (mbbls)	Natural Gas (mmcf)
Opening balance	**26,657**	**267,371**	21,540	153,217	17,437	144,155
Revision of previous estimates	**1,737**	**5,700**	(1,264)	(20,442)	2,608	3,342
Purchase of reserves in place	**954**	**18,929**	11,536	160,184	3,556	24,047
Sales of reserves in place	**(568)**	**(5,328)**	(3,845)	(13,146)	–	(4,510)
Discoveries and extensions	**736**	**25,337**	2,360	15,449	463	406
Production	**(3,527)**	**(32,903)**	(3,670)	(27,891)	(2,524)	(14,223)
Closing balance	**25,989**	**279,106**	26,657	267,371	21,540	153,217

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves

The standardized measure for calculating the present value of future net cash flows from proved oil and gas reserves is based on current costs and prices and a ten percent discount factor as prescribed by FASB 69.

Accordingly, the estimated future net cash inflows were computed by applying selling prices prevailing during the month of December to the estimated future production of proved reserves. Estimated future expenditures to be incurred in developing and producing proved reserves are based on average costs incurred in each year presented and assume the continuation of economic conditions existing at the end of each year presented.

Although these calculations have been prepared according to the standards described above, it should be emphasized that due to the number of assumptions and estimates required in the calculation, the amounts are not indicative of the amount of net revenue that the Trust expects to receive in future years. They are also not indicative of the current value or future earnings that may be realized from the production of proved reserves, nor should it be assumed that they represent the fair market value of the reserves or of the oil and gas properties.

Although the calculations are based on existing economic conditions at each year-end, such economic conditions have changed and may continue to change significantly due to events such as the continuing changes in the natural gas market and changes in government policies and regulations. While the calculations are based on the Trust's understanding of the established FASB guidelines, there are numerous other equally valid assumptions under which these estimates could be made that would produce significantly different results.

STANDARDIZED MEASURE

(millions of Canadian dollars)	**2002**	2001	2000
Future cash inflows	**$ 2,890.5**	$ 1,732.5	$ 2,182.1
Future production costs	**(699.0)**	(642.5)	(400.8)
Future development costs	**(73.4)**	(38.7)	(31.1)
Other related future costs	**(43.4)**	(37.1)	(25.2)
Future net cash flows	**2,074.7**	1,014.2	1,725.0
Discount at 10%	**(919.4)**	(415.9)	(754.5)
Standardized measure of discounted future net cash flow related to proved reserves	**$ 1,155.3**	$ 598.3	$ 970.5

SUMMARY OF CHANGES IN THE STANDARDIZED MEASURE DURING THE YEAR

(millions of Canadian dollars)	**2002**	2001	2000
Sales of oil and gas produced, net of production costs	**$ (203.5)**	$ (247.3)	$ (126.3)
Net change in sales and transfer prices, net of development and production costs	**672.6**	(586.6)	513.4
Sales of reserves in place	**(4.5)**	(78.1)	(0.9)
Purchases of reserves in place	**45.6**	826.6	118.6
Extensions, discoveries and improved recovery, less related costs	**52.3**	101.7	4.7
Changes in timing of future net cash flows and other	**(93.6)**	(389.3)	32.4
Revisions of previous quantity estimates	**28.3**	(96.3)	27.8
Accretion of discount	**59.8**	97.1	36.4
Net change	**557.0**	(372.2)	606.1
Balance at beginning of year	**598.3**	970.5	364.4
Balance at end of year	**$ 1,155.3**	$ 598.3	$ 970.5

Supplemental Information

Operating Highlights

	2002	2001	2000	1999	1998	1997
DAILY SALES VOLUMES						
Crude oil (bbls/day)	**9,239**	10,033	6,582	5,958	5,868	3,737
Natural gas liquids (bbls/day)	**2,030**	2,273	1,483	1,293	1,226	1,137
Natural gas (mmcf/day)	**113.5**	104.8	49.0	46.5	50.4	42.2
Total (BOE/day)	**30,189**	29,774	16,237	14,995	15,497	11,913
AVERAGE SELLING PRICES						
Crude oil ($/bbl)	**$ 33.53**	$ 32.21	$ 36.67	$ 21.69	$ 16.92	$ 25.93
Natural gas liquids ($/bbl) (1)	**$ 26.57**	$ 30.96	$ 34.42	$ 19.09	$ 14.55	$ 22.65
Natural gas ($/mcf)	**$ 4.55**	$ 6.16	$ 4.65	$ 2.51	$ 1.83	$ 1.85
Total ($/BOE)	**$ 29.16**	$ 34.80	$ 32.19	$ 17.95	$ 13.58	$ 16.94
OPERATING MARGIN *($/BOE)*						
Revenue (2)	**$ 29.09**	$ 34.80	$ 32.19	$ 17.95	$ 13.58	$ 16.94
Other revenue	**0.02**	0.13	0.08	0.04	0.05	0.04
Royalties	**(5.13)**	(6.73)	(5.92)	(3.14)	(2.28)	(3.27)
Operating expenses	**(5.52)**	(5.42)	(5.08)	(5.23)	(5.40)	(4.89)
Operating margin	**$ 18.46**	$ 22.78	$ 21.27	$ 9.62	$ 5.95	$ 8.82

	2002	2001	2000	1999	1998	1997
ESTABLISHED RESERVES						
Crude oil (mmbbls)	**24.5**	28.5	24.4	20.0	21.7	15.3
Natural gas liquids (mmbbls)	**10.2**	9.5	6.4	6.1	6.5	6.7
Natural gas (Bcf)	**418.5**	413.7	232.7	224.0	243.5	227.3
Total (mmBOE)	**104.4**	107.0	69.6	63.7	68.8	59.9
NET ASSET VALUE						
(millions of dollars, except per Trust Unit)						
Established reserves (discounted at 10 percent)	**$ 923.0**	$ 872.6	$ 623.0	$ 328.0	$ 313.0	$ 298.0
Hedging mark-to-market	**(13.6)**	50.5	(1.0)	–	–	–
Unproved lands and reclamation fund	**44.2**	56.5	17.2	10.2	10.6	8.4
Other assets and working capital	**(0.4)**	(29.4)	0.1	6.9	4.2	3.5
Long-term debt	**(225.0)**	(195.0)	(78.9)	(92.2)	(73.0)	(66.7)
Total net asset value	**$ 728.2**	$ 755.2	$ 560.4	$ 252.9	$ 254.8	$ 243.2
Per Trust Unit	**$ 18.71**	$ 23.03	$ 42.92	$ 28.28	$ 30.88	$ 39.00

(1) Excludes Sulphur

(2) Includes Sulphur

Supplemental Information

Daily Production Volumes By Commodity And Major Property

	2002	2001	2000	1999	1998
NATURAL GAS *(mcf/day)*					
Dawson					
Dawson	**17,841**	15,456	–	–	–
Stowe	**11,813**	12,877	–		–
Northwest					
NW Alberta	**661**	553	–	–	–
NE Alberta	**847**	–	–	–	–
NE BC	**8,576**	9,032	9,270	9,915	10,643
Kaybob	**477**	184	258	469	393
Meekwap	**304**	393	–	–	–
Grande Prairie	**1,979**	2,614	2,611	–	–
Caroline	**5,878**	7,866	5,220	6,817	3,935
Central					
Thorsby	**21,865**	28,433	1,453	966	(217)
Crossfield/Line Pine Creek	**10,336**	10,131	12,064	12,750	14,364
Thunder	**4,945**	4,490	–	–	–
Southeast					
Brant Farrow	**8,764**	9,399	–	–	–
Dinosaur/Medicine Hat	**4,944**	4,935	4,553	1,734	843
Grand Forks	**2,206**	1,436	356	180	103
Whiskey Creek/Jumping Pound	**2,691**	2,660	2,630	3,088	3,537
Saskatchewan	**468**	526	35	44	59
Others	**4,162**	(10,937)	8,065	9,608	15,857
Royalties	**4,743**	4,752	2,485	929	883
Total	**113,500**	104,800	49,000	46,500	50,400

	2002	2001	2000	1999	1998
CRUDE OIL *(bbls/day)*					
Dawson					
Dawson	**1,082**	770	–	–	–
Stowe	**287**	490	–	–	–
Northwest					
NE BC	**1,202**	1,158	840	773	790
Kaybob	**374**	434	609	775	898
Meekwap	**455**	577	–	–	–
Grande Prairie	**75**	61	30	–	–
Caroline	**208**	255	314	370	343
Central					
Thorsby	**384**	422	81	49	(45)
Crossfield/Line Pine Creek	**82**	79	100	94	80
Thunder	**46**	(72)	–	–	–
Southeast					
Brant Farrow	**163**	237	–	–	–
Dinosaur/Medicine Hat	**1**	2	–	–	15
Grand Forks	**2,999**	3,168	2,900	2,612	2,072
Saskatchewan	**562**	616	117	134	156
Others	**513**	937	1,113	1,104	1,526
Royalties	**806**	899	478	47	33
Total	**9,239**	10,033	6,582	5,958	5,868

Supplemental Information

Daily Production Volumes By Commodity And Major Property (continued)

	2002	2001	2000	1999	1998
NATURAL GAS LIQUIDS *(bbls/day)*					
Dawson					
Stowe	**–**	26	–	–	–
Northwest					
NE BC	**199**	187	173	165	159
Kaybob	**17**	53	66	73	137
Meekwap	**15**	24	–	–	–
Grande Prairie	**96**	133	165	–	–
Caroline	**275**	309	305	365	212
Central					
Thorsby	**794**	913	48	50	–
Crossfield/Lone Pine Creek	**202**	237	221	191	161
Thunder	**98**	98	–	–	–
Southeast					
Brant Farrow	**13**	38	–	–	–
Grand Forks	**38**	29	30	13	–
Whiskey Creek/Jumping Pound	**107**	104	83	71	96
Saskatchewan	**3**	2	2	3	5
Others	**74**	10	–	334	440
Royalties	**99**	110	390	28	16
Total	**2,030**	2,273	1,483	1,293	1,226

	2002	2001	2000	1999	1998
BOE EQUIVALENT *(BOE/day)*					
Dawson					
Dawson	**4,056**	3,346	–	–	–
Stowe	**2,256**	2,662	–	–	–
Northwest					
NW Alberta	**105**	99	–	–	–
NE Alberta	**141**	–	–	–	–
NE BC	**2,830**	2,850	2,558	2,590	2,723
Kaybob	**471**	517	719	926	1,100
Meekwap	**521**	667	–	–	–
Grande Prairie	**501**	630	630	–	–
Caroline	**1,463**	1,875	1,490	1,871	1,211
Central					
Thorsby	**4,822**	6,074	371	260	101
Crossfield/Lone Pine Creek	**2,007**	2,005	2,332	2,410	2,635
Thunder	**968**	774	–	(114)	101
Southeast					
Brant Farrow	**1,636**	1,842	–	–	–
Dinosaur/Medicine Hat	**825**	824	759	289	115
Grand Forks	**3,404**	3,437	2,989	2,655	–
Whiskey Creek/Jumping Pound	**555**	547	521	585	685
Saskatchewan	**643**	706	125	144	171
Major Property Totals	**27,204**	28,855	12,494	11,616	8,842
Other Properties	**1,290**	(882)	2,801	3,149	6,459
Royalties	**1,695**	1,801	942	230	196
Total	**30,189**	29,774	16,237	14,995	15,497

Supplemental Information

Reserves Summary

As at January 1, 2003	Crude oil (mmbbls)	Natural gas (mmcf)	Natural gas liquids (mmbbls)	January 1, 2003 total reserves (mmBOE)	January 1, 2002 total reserves (mmBOE)	January 1, 2001 total reserves (mmBOE)	January 1, 2000 total reserves (mmBOE)	January 1, 1999 total reserves (mmBOE)
Proved producing	20.1	287	6.8	**74.7**	76.8	48.9	45.3	45.9
Total proved	21.4	349	8.4	**88.1**	90.8	57.1	51.0	54.1
Probable	6.1	139	3.5	**32.6**	32.6	24.9	25.3	29.6
Total proved and probable	27.5	487	11.9	**120.7**	123.3	82.0	76.3	83.7
Established	24.5	418	10.2	**104.4**	107.0	69.6	63.6	68.9
% of total established reserves	23	67	10					

Reserves Reconciliation (Established)

as at January 1, 1999	Natural Gas (Bcf)	Oil (mbbls)	Natural Gas Liquids (mbbls)	Sulphur (MLT)	Oil Equivalent (mmBOE)
Opening Reserves	227.3	15,240.3	6,728.6	832.0	59.8
Capital additions	19.5	2,863.2	253.7	112.6	6.4
Technical revisions	1.2	325.1	65.3	(31.4)	0.6
Acquisitions	23.3	6,422.0	76.1	13.8	10.4
Dispositions	(9.2)	(892.3)	(137.0)	(0.1)	(2.6)
Production	(18.5)	(2215.9)	(443.0)	(94.4)	(5.7)
Ending Reserves	243.6	21,742.4	6,543.6	832.5	68.9

as at January 1, 2000	Natural Gas (Bcf)	Oil (mbbls)	Natural Gas Liquids (mbbls)	Sulphur (MLT)	Oil Equivalent (mmBOE)
Opening Reserves	243.5	21,744.5	6,544.0	833.0	68.9
Capital additions	1.3	558.1	61.3	–	0.7
Technical revisions	(19.5)	(1,150.8)	(188.3)	–	(4.7)
Acquisitions	26.8	1,659.1	445.8	(17.8)	6.6
Dispositions	(10.6)	(609.6)	(238.7)	0.3	(2.6)
Production	(17.1)	(2,139.6)	(464.5)	(71.6)	(5.3)
Ending Reserves	224.5	20,061.7	6,159.6	743.9	63.6

as at January 1, 2001	Natural Gas (Bcf)	Oil (mbbls)	Natural Gas Liquids (mbbls)	Sulphur (MLT)	Oil Equivalent (mmBOE)
Opening Reserves	224.5	20,061.4	6,160.0	744.5	63.6
Capital additions	0.5	491.5	20.6	–	0.6
Technical revisions	(2.0)	1,617.7	194.2	188.0	1.5
Acquisitions	34.2	4,591.7	580.9	57.6	10.9
Dispositions	(6.6)	–	–	–	(1.1)
Production	(17.9)	(2,393.6)	(535.1)	(104.5)	(5.9)
Ending Reserves	232.7	24,368.7	6,420.6	885.6	69.6

Note: Columns may not add due to rounding.

Supplemental Information

Reserves Reconciliation (Established) continued

as at January 1, 2002	Natural Gas (Bcf)	Oil (mbbls)	Natural Gas Liquids (mbbls)	Sulphur (MLT)	Oil Equivalent (mmBOE)
Opening Reserves	232.7	24,368	6,420	885.6	69.6
Capital additions	19.7	2,671	142	–	6.1
Technical revisions	(23.2)	(1,005)	(312)	(52.0)	(5.2)
Acquisitions	243.2	11,695	5,250	–	57.4
Dispositions	(22.2)	(5,533)	(1,177)	0.4	(10.4)
Production	(36.5)	(3,651)	(778)	(83.2)	(10.5)
Ending Reserves	413.7	28,545	9,545	750.8	107.0

as at January 1, 2003	Natural Gas (Bcf)	Oil (mbbls)	Natural Gas Liquids (mbbls)	Sulphur (MLT)	Oil Equivalent (mmBOE)
Opening Reserves	413.7	28,545	9,546	765.5	107.0
Capital additions	43.9	234	1,133	–	8.7
Technical revisions	(16.2)	(751)	(486)	60.9	(3.9)
Acquisitions	26.3	437	925	50.5	5.7
Dispositions	(7.8)	(633)	(186)	(8.0)	(2.1)
Production	(41.4)	(3,372)	(741)	(57.0)	(11.0)
Ending Reserves	418.5	24,460	10,191	811.9	104.4

January 1, 2002 – Oil equivalency changed to 6:1 on gas

Reserves reconciliation as per Gilbert Laustsen Jung

Note: Columns may not add due to rounding.

Established Reserves

	2002 Proved Producing Oil Equivalent (mmBOE)	**2002 Established Oil Equivalent (mmBOE)**	2001 Oil Equivalent (mmBOE)	2000 Oil Equivalent (mmBOE)	1999 Oil Equivalent (mmBOE)	1998 Oil Equivalent (mmBOE)
RESERVE RECONCILIATION						
Opening reserves	**76.9**	**107.0**	69.6	63.6	68.9	59.8
Capital additions	**4.4**	**8.7**	6.1	0.6	0.7	6.4
Technical revisions	**0.8**	**(3.9)**	(5.2)	1.5	(4.7)	0.6
Acquisitions	**4.9**	**5.7**	57.4	10.9	6.6	10.4
Dispositions	**(1.3)**	**(2.1)**	(10.4)	(1.1)	(2.6)	(2.6)
Production	**(11.0)**	**(11.0)**	(10.5)	(5.9)	(5.3)	(5.7)
Ending reserves	**74.7**	**104.4**	107.0	69.6	63.6	68.9

Supplemental Information

Unproved Lands

	2002			2001		
	Acres		Net Value	Acres		Net Value
	Gross	Net	($)	Gross	Net	($)
Dawson						
Dawson	**236,488**	**144,647**	**$ 11,571,760**	247,608	156,229	$ 14,129,465
Stowe	**218,571**	**201,885**	**9,084,825**	158,467	144,842	8,884,822
Other	**6,880**	**4,160**	**270,400**	8,256	4,992	697,859
NorthWest						
NW Alberta	**28,000**	**19,554**	**586,620**	32,699	22,835	685,050
NE BC	**13,482**	**4,202**	**350,820**	14,830	4,622	323,540
Kaybob	**7,200**	**1,420**	**78,100**	7,920	1,562	109,340
Meekwap	**7,040**	**3,166**	**221,620**	8,096	3,640	254,800
Grande Prairie	**20,347**	**15,840**	**633,600**	23,399	18,216	1,275,120
Other	**81,574**	**41,249**	**2,580,545**	71,731	35,065	3,895,369
Caroline						
Caroline	**49,362**	**35,802**	**2,506,140**	47,489	35,063	1,402,550
Central						
Thorsby	**62,048**	**48,775**	**2,194,875**	56,931	49,011	3,430,770
Crossfield/LPC	**45,178**	**23,866**	**2,413,575**	46,468	35,781	2,504,670
Thunder	**53,920**	**24,987**	**1,124,415**	67,680	33,813	2,366,910
Other	**36,168**	**11,854**	**766,000**	44,439	21,224	2,307,444
SouthEast						
Brant Farrow	**116,888**	**88,090**	**5,285,400**	78,609	60,414	4,228,980
Dinosaur/MHCU2	**13,907**	**9,618**	**376,950**	15,530	13,779	543,127
Grand Forks	**43,732**	**20,328**	**813,120**	48,835	29,122	1,971,582
Whiskey Creek/Jumping Pound	**5,438**	**4,095**	**163,800**	6,073	5,867	236,011
Saskatchewan	**6,463**	**5,123**	**237,425**	7,109	5,635	394,450
Other	**29,406**	**25,231**	**926,840**	32,466	26,754	2,344,729
Total Working Interest Acres	**1,082,092**	**733,892**	**42,186,830**	1,024,635	708,466	51,986,588
Gross Royalty Acres	**204,791**	**204,791**	**2,047,910**	244,961	244,961	3,674,415
Total	**1,286,883**	**938,683**	**$ 44,234,740**	1,269,596	953,427	$ 55,661,003

Supplemental Information

Crude Oil Reserves By Major Property *(mbbls)*

As at January 1, 2003	Established	Proved	Probable
Dawson			
Dawson	971	808	326
Stowe	876	717	318
Northwest			
Meekwap	1,055	703	704
NE B.C.	6,055	5,671	768
Kaybob	1,176	1,015	322
Grande Prairie	363	274	178
North Other	647	582	130
Caroline	1,287	1,168	238
Central			
Thorsby	1,200	1,021	358
Crossfield/Lone Pine Creek	282	224	116
Thunder	179	161	36
Southeast			
Brant Farrow	189	146	86
Grand Forks	6,436	5,512	1,848
Saskatchewan	1,758	1,580	356
Reserve Royalty	1,699	1,573	252
Other	287	261	51
Total	24,460	21,416	6,087

Natural Gas Reserves By Major Property *(Bcf)*

As at January 1, 2003	Established	Proved	Probable
Dawson			
Dawson	20.9	17.8	6.3
Stowe	25.1	21.8	6.7
Northwest			
NW Alberta	2.2	1.9	0.5
NE Alberta	11.2	10.5	1.6
NE B.C.	41.5	36.4	10.1
Grande Prairie	3.3	2.8	0.9
North Other	3.0	1.9	2.2
Caroline	51.1	37.1	27.9
Central			
Thorsby	81.3	73.7	15.3
Crossfield/Lone Pine Creek	53.6	41.7	23.8
Thunder	10.4	8.4	4.0
Other	5.0	4.3	1.3
Southeast			
Brant Farrow	25.1	17.5	15.2
Dinosaur/Medicine Hat	32.9	29.2	7.3
Grand Forks	4.1	3.4	1.3
Whiskey Creek/Jumping Pound	30.2	25.4	9.5
Saskatchewan	2.9	2.1	1.5
Reserve Royalty	13.3	12.4	1.9
Other	1.4	1.2	0.7
Total	418.5	349.5	138.0

Supplemental Information

Natural Gas Liquids Reserves By Major Property *(mbbls)*

As at January 1, 2003	Established	Proved	Probable
Northwest			
NE B.C.	987	868	238
Grande Prairie	194	162	64
Caroline	3,119	2,306	1,626
Central			
Thorsby	2,865	2,595	540
Crossfield/Lone Pine Creek	718	580	276
Thunder	201	161	80
Other	104	89	30
Southeast			
Whiskey Creek/Jumping Pound	1,466	1,220	492
Reserve Royalty	215	195	40
Other	322	275	95
Total	10,191	8,451	3,481

Present Worth Of Reserves

As at January 1, 2003 (millions of dollars)	Discounted @ 0%	Discounted @ 10%	Discounted @ 12%	Discounted @ 15%
Proved producing	1,254	705	655	595
Total proved	1,478	816	756	683
Probable	594	214	187	157
Total proved and probable	2,072	1,030	943	840
Established value January 1, 2003	1,775	923	849	762
Established value January 1, 2002	1,663	873	801	716
Established value January 1, 2001	1,108	624	577	520
Established value January 1, 2000	624	328	299	265
Established value January 1, 1999	606	313	284	250
Established value January 1, 1998	627	298	268	233

Crude Oil Pricing Assumptions

As at January 1, 2003	WTI ($US/bbl)	Edmonton Par ($Cdn/bbl)	Exchange Rate ($US/$Cdn)
2003	25.83	38.84	0.6410
2004	23.20	34.41	0.6467
2005	21.84	32.14	0.6500
2006	21.92	32.09	0.6533
2007	22.28	32.53	0.6567
Next 12 years average	24.83	36.57	0.6536
Thereafter escalated at	1%	1%	1%

Supplemental Information

Natural Gas Pricing Assumptions

As at January 1, 2003	Henry Hub ($US/mmbtu)	Alberta Government Reference Price ($Cdn/mmbtu)	AECO Spot ($Cdn/mmbtu)
2003	4.22	5.39	5.61
2004	3.89	4.93	5.13
2005	3.61	4.57	4.76
2006	3.54	4.52	4.70
2007	3.60	4.57	4.76
Next 12 years average	4.00	5.09	5.08
Thereafter escalated at	1%	1%	1%

Established Reserve Life Index *(years)*

	2002	2001	2000	1999	1998	1997
Established Reserve Life Index	**10.0**	10.0	10.2	10.9	11.1	12.2

Quarterly Production Volumes By Commodity

	2002	2001	2000	1999	1998	1997
NATURAL GAS *(mmcf/day)*						
First quarter	**113.3**	49.6	48.1	48.9	49.2	40.3
Second quarter	**111.1**	127.7	48.4	47.3	54.0	36.2
Third quarter	**115.5**	121.3	52.1	41.3	50.0	43.3
Fourth quarter	**114.2**	119.7	47.5	48.4	48.5	49.0
Total average	**113.5**	104.8	49.0	46.5	50.4	42.2
CRUDE OIL *(bbls/day)*						
First quarter	**10,244**	6,988	5,763	6,154	4,780	3,680
Second quarter	**8,990**	11,453	6,038	5,805	6,206	3,843
Third quarter	**8,975**	11,216	7,087	5,957	6,264	3,646
Fourth quarter	**8,766**	10,425	7,422	5,919	6,201	3,778
Total average	**9,239**	10,033	6,582	5,958	5,868	3,737
NATURAL GAS LIQUIDS *(bbls/day)*						
First quarter	**2,240**	1,613	1,264	1,342	1,278	1,045
Second quarter	**2,055**	2,614	1,537	1,277	1,254	948
Third quarter	**1,950**	2,414	1,521	1,193	1,185	1,416
Fourth quarter	**1,878**	2,441	1,610	1,360	1,188	1,134
Total average	**2,030**	2,273	1,483	1,293	1,226	1,137
TOTAL OIL EQUIVALENT *(BOE/day)*						
First quarter	**31,370**	16,864	15,044	15,648	14,255	11,433
Second quarter	**29,559**	35,353	15,642	14,972	16,460	10,831
Third quarter	**30,362**	33,849	17,291	14,028	15,774	12,280
Fourth quarter	**29,678**	32,807	16,949	15,346	15,474	13,073
Total average	**30,189**	29,774	16,237	14,995	15,497	11,913
Natural gas as a percentage of production	**62%**	59%	50%	52%	54%	59%

Supplemental Information

Financial Highlights

(thousands of dollars, except per BOE and per Trust Unit amounts)	**2002**	2001	2000	1999	1998	1997
Cash flow from operations	**170,939**	214,511	112,062	41,081	24,806	32,086
per BOE	**15.51**	19.74	18.91	7.51	4.39	7.38
per Trust Unit	**5.01**	8.36	10.04	4.84	3.16	5.16
Operating revenues, net of royalties	**264,248**	306,515	156,561	81,282	64,257	59,592
per BOE	**23.98**	28.20	26.42	14.85	11.36	13.71
per Trust Unit	**7.74**	11.96	14.04	9.56	8.16	9.56
Operating expenses	**60,773**	58,951	30,175	28,609	30,550	21,270
per BOE	**5.52**	5.42	5.09	5.23	5.40	4.89
per Trust Unit	**1.78**	2.28	2.72	3.36	3.88	3.40
Operating margin	**203,475**	247,564	126,386	52,673	33,707	38,322
per BOE	**18.46**	22.78	21.33	9.62	5.95	8.82
per Trust Unit	**5.96**	9.64	11.32	6.20	4.28	6.16
Cash general & administrative expenses	**11,281**	10,394	4,140	5,321	5,108	3,708
per BOE	**1.02**	0.96	0.70	0.97	0.90	0.85
per Trust Unit	**0.33**	0.40	0.36	0.64	0.64	0.60
Cash management fees	**3,982**	6,431	3,277	1,386	882	923
per BOE	**0.36**	0.59	0.55	0.25	0.16	0.21
per Trust Unit	**0.12**	0.24	0.28	0.16	0.12	0.12
Interest expense	**10,788**	13,800	6,359	4,885	4,711	2,140
per BOE	**0.98**	1.27	1.07	0.89	0.83	0.49
per Trust Unit	**0.32**	0.52	0.56	0.56	0.60	0.36
Cash distributed to unitholders	**157,951**	234,465	79,033	37,351	25,769	33,409
per Trust Unit	**4.80**	9.24	7.08	4.40	3.28	5.36

Supplemental Information

Financial Highlights

(thousands of dollars, except unit and per Trust Unit)	**2002**	2001	2000	1999	1998	1997
Cumulative cash distributions	**578,934**	420,983	186,518	107,485	70,134	44,365
Per Trust Unit	**35.92**	31.12	21.88	14.80	10.40	7.12
Units outstanding at year-end (thousands)	**37,005**	31,492	12,746	8,942	8,256	6,238
Exchangeable shares outstanding	**5,179**	4,068	1,112	–	–	–
Capital expenditures	**69,055**	83,904	25,791	14,172	17,416	15,771
Acquisitions net of dispositions	**55,077**	744,454	117,801	18,738	4,776	33,953
Working capital (deficit)	**(436)**	(29,431)	(344)	5,850	2,369	1,845
Total assets	**1,502,252**	1,522,310	441,573	320,210	316,140	285,765
Net asset value	**728,200**	755,200	561,400	252,900	254,800	243,200
Net asset value per Trust Unit	**18.71**	23.03	42.20	28.28	30.88	39.00
Total capitalization (including debt)	**1,072,534**	1,080,708	377,220	323,718	237,403	276,953
DEBT ANALYSIS						
Long-term debt, including working capital	**225,436**	224,431	78,596	85,854	70,637	64,878
Debt-to-annual-cash flow ratio	**1.32**	1.05	0.71	2.10	2.85	2.02
Debt-to-equity ratio	**26.6**	26.3	26.6	46.1	34.2	34.5
Interest-coverage ratio	**16.9**	16.5	18.6	8.5	6.0	15.5
Average cost of debt	**4.6%**	5.4%	7.4%	5.9%	6.3%	4.8%
Net debt per Trust Unit	**5.79**	6.85	6.02	9.64	8.56	10.40
TAX POOLS *(Consolidated)*						
Canadian oil and gas property expense (COGPE)	**425,000**	424,000	299,000	255,000	263,400	225,600
Canadian exploration expense (CEE)	**–**	23,700	5,700	–	1,850	300
Canadian development expense (CDE)	**41,200**	11,100	9,000	–	–	7,200
Capital cost allowance (CCA)	**108,000**	101,200	35,850	24,425	32,330	25,000
Losses available for carry forward	**11,800**	24,800	–	–	–	–
Unit issue expenses	**12,500**	12,171	6,245	8,300	14,600	11,900

Income Tax Considerations

For Canadian Unitholders

For purposes of the Canadian Income Tax Act, PrimeWest is treated as a mutual fund trust, and each year an income tax return is filed by the Trust with the taxable income allocated to, and taxable in the hands of unitholders. Distributions paid to the Trust are both a return of capital (i.e. a repayment of a portion of your investment) and a return on capital. (i.e. income) The allocation between these two streams is dependent upon the tax deductions that the Trust is entitled to claim against the income it earns from royalty income received from PrimeWest Energy Inc. (the operating company) and income the Trust earns directly. The level of these tax deductions is primarily driven by COGPE (Canadian Oil and Gas Property Expense) representing the cost of acquiring the royalty from the operating company or the Trust's direct investment in revenue producing property.

Each year the return on capital, or taxable income portion, is calculated and reported in the Trust's T3 return and allocated to each unitholder who received distributions in that taxation year on the T3 supplementary forms, which are mailed out in late February or early March. The T3 slip will report only the other income component in box 26. This income is taxed in the same manner as interest revenue. The non-taxable portion impacts the unitholder's adjusted cost base (ACB) and should be reported as a capital gain at time of disposition.

For fiscal 2003, the tax consideration on distributions is estimated to be 55% taxable and 45% return of capital.

For U.S. and Other Non-Resident Unitholders

Unitholders who are not residents of Canada for Income Tax purposes are encouraged to seek advice from a qualified tax advisor in your country of residence for the tax treatment of distributions. Monthly distributions payable to non-residents of Canada are normally subject to a withholding tax of 25% as prescribed by the Income Tax Act of Canada. This withholding tax may however be reduced in accordance with reciprocal tax treaties, and in the case of the Tax Treaty between Canada and the United States, the withholding tax for residents of the United States is prescribed at 15%. U.S. taxpayers may be eligible for a foreign tax credit with respect to the Canadian withholding taxes paid.

In the instance of a U.S. unitholder, the taxable portion of the monthly distribution is determined by PrimeWest based upon current and accumulated earnings in accordance with U.S. tax law. The taxable portion is considered a dividend for tax reporting purposes and U.S. unitholders should receive a Form 1099 or facsimile form detailing the total distribution received, the amount withheld, and the taxable portion.

The non-taxable portion of the cash distribution is treated as a return of the cost base. This cost base is reduced by this accumulated amount when computing gains or losses at time of disposition. Once the full amount of the cost base has been recovered, any additional non-taxable distributions should be reported as capital gains.

For unitholders resident in the United States, taxability of distributions is calculated using U.S. tax rules which allow for the deduction of crown royalties and accounting based depletion. As a result, none of the 2002 distribution is taxable as dividends, rather 100% of the 2002 distributions are tax deferred as a reduction to the cost of the units for tax purposes. For U.S. residents, the income tax laws of the United States apply and certain deductions not available in Canada are available in the United States.

Distribution Reinvestment and Optional Trust Unit Purchase Plans

The Distribution Reinvestment Plan (commonly referred to as the DRIP) and our Optional Trust Unit Purchase Plan provide our Canadian unitholders with an economical, convenient way to maximize their investment in PrimeWest. Participants do not pay any costs associated with these plans, including brokerage commissions.

These plans enable unitholders to reinvest their monthly distributions automatically and make additional annual investments of between $100 and $100,000 – without incurring brokerage fees and with a 5% discount off the 20-day weighted average market price at the time. To view the 5% discounted unit prices by month, please refer to our DRIP section of the PrimeWest Web site at www.primewestenergy.com.

Some banks, trust companies or brokerage firms will allow participation in PrimeWest's DRIP and others will not. You will need to make enquiries directly with your account holder. If you cannot participate as a non-registered holder, you must either transfer your units to hold them directly or transfer them to an account that allows participation.

If you are a Canadian resident and a registered unitholder (you have a Trust Unit certificate), you may fill out forms 'Part A' and 'Part B' located in the DRIP section of the PrimeWest Web site at www.primewestenergy.com.

For further information, contact Computershare Trust Company of Canada – by phone toll-free phone (1-800-332-0095) or fax (514-982-7895). You may also contact PrimeWest Investor Relations – by phone (403-234-6600), toll-free phone in Canada and the continental United States (1-877-968-7878), fax (403-699-7269) or e-mail (investor@primewestenergy.com).

Environmental, Health And Safety

ENVIRONMENT

PrimeWest believes that attaining a high standard of environmental stewardship is a key component of our business objectives. To achieve these high standards, PrimeWest focuses on the following components:

EH&S Strategy

Our vision for the future is to work with our employees, our stakeholders and our partners to:

¶ Set standards for operator and service provider competency;

¶ Provide hands on training and mentoring in both the field and head office, through training presentations from regulatory agencies, and other subject matter experts; and

¶ Provide access to state of the art tools and systems to improve the speed and accuracy of reporting, to facilitate the implementation of corporate and site specific standards, and to ensure a program of regular audit.

Environmental Compliance

¶ In the fall of 2002 we began an extensive independent environmental audit process of all of our heritage and acquisition properties. All non-compliance items of a greater than minor nature were required to have action plans in place within five days of identification.

¶ Two independent Partnerships in Safety Program audits were completed in order to provide a baseline for the 2003 goal of achieving a passing grade within the program.

¶ We partnered with the Alberta Energy and Utilities Board (AEUB) and sponsored several in-house educational information sessions on environmental and operational regulations and guidelines that are integral to day-to-day operations.

Environmental Liability

¶ Our average contribution rate for abandonment and reclamation is one of the highest in the royalty trust sector compared to our peers. As a result, we have a very proactive abandonment and reclamation program which is indicative of our high level of commitment to responsible care of the environment.

¶ Of the approximately 850 leases identified within the company portfolio as reclamation candidates, work was conducted on approximately 300 leases during the 2002 season.

¶ Reclamation certificates were achieved for 21 sites in 2002. Key areas of activity include Grand Forks, Brant Farrow, Caroline, Thorsby and Dawson. Along with our farming and ranching stakeholders, our hope is that 2003 will see the end of the drought in Western Canada and more amenable conditions for re-vegetating reclamation sites.

¶ A total of approximately 363 inactive wells have been identified for abandonment, with 40 abandonments completed during 2002. A similar level of effort is expected on both the abandonment and reclamation programs in 2003.

¶ The AEUB Licensee Liability Rating Report (LLR) is a measure of the risk that a company will be unable to address its abandonment and reclamation liabilities. Companies are required to maintain an LLR of greater than 1.0 or a bond may be required prior to the board issuing new licenses. Our current rating of 6.62 is well within the AEUB requirements.

Emissions And Waste Reduction

¶ During 2002, decision tree analyses were completed for all of our solution gas flare and venting sources as part of compliance with Guide 60 – "Upstream Petroleum Industry Flaring Guide".

¶ We achieved a Gold Level Award for participation in the Canadian Association of Petroleum Producers (CAPP) EH&S Stewardship Program for our 2001 company commitment to public consultation and industry benchmarked operating practices. We expect to receive a Gold Level Award for our 2002 participation.

¶ We maintained a Gold Champion Level status for our 2001 participation in the Voluntary Challenge Registry, an organization dedicated to the reduction of greenhouse gas emissions and flaring. In addition, we have submitted our data with respect to receiving a Gold Champion Level status for our 2002 participation.

Stakeholder Relationships

¶ We have been active participants in community organizations that advocate for responsible corporate care of the environment including the Sundre Petroleum Operators Group, the Vulcan County Mutli-Stakeholders Group, APPA (the Airdrie and Area Public and Petroleum Producers Awareness Alliance), and the Parkland Airshed Management Zone Association (PAMZ).

¶ During 2002 we continued to amend our Emergency Response Plans and conducted several emergency response exercises to address our responsibilities for the health and safety of the communities in which we operate.

HEALTH AND SAFETY

¶ Operator competency is intrinsic to safe operations. Development of a new in-house operator certification program commenced in the summer and was ready for trial implementation in December of 2002. All field operators will be certified over the next 24 months. Yearly re-certification for health and safety sensitive tasks will be the norm.

¶ Targets for 2002 were met when all field operators attended an intensive, one week off-site health and safety training program, resulting in Certification in Transportation of Dangerous Goods (TDG), Workplace Hazardous Materials Information Systems (WHMIS), Gas Testing, Industrial Fire Fighting, Defensive Driving, Respiratory Protection, Accident /Incident Reporting, and Standard First Aid/CPR. The re-certification of field operators will work off a three-year staggered schedule in the future and training/certification compliance will be carefully monitored.

Trading Performance

		First Quarter 2002	Second Quarter 2002	Third Quarter 2002	Fourth Quarter 2002	NYSE Fourth Quarter 2002
Trust Unit price:	High	**$ 29.00**	**$ 29.48**	**$ 29.56**	**$ 27.68**	**U.S.$16.69**
	Low	**$ 23.60**	**$ 25.60**	**$ 24.48**	**$ 24.23**	**U.S.$15.62**
	Close	**$ 28.80**	**$ 28.92**	**$ 26.45**	**$ 25.40**	**U.S.$16.16**
Average daily volume traded		**139,039**	**121,599**	**109,216**	**123,964**	**39,276**

		2002	2001	2000	1999	1998	1997
Trust Unit price:	High	**$ 29.56**	$ 42.16	$ 37.20	$ 30.80	$ 35.00	$ 45.80
	Low	**$ 23.60**	$ 23.80	$ 25.20	$ 19.00	$ 19.00	$ 30.00
	Close	**$ 25.40**	$ 25.44	$ 35.80	$ 26.60	$ 20.20	$ 34.00
Average daily volume traded		**123,455**	156,122	30,314	12,442	13,830	10,581

	First quarter 2002	Second quarter 2002	Third quarter 2002	Fourth quarter 2002	**2002**	2001	2000	1999	1998	1997
WTI ($US/bbl)	**21.64**	**26.25**	**28.27**	**28.15**	**26.08**	25.97	30.20	19.24	14.43	20.61
Monthly AECO Spot ($Cdn/mcf)	**3.34**	**4.42**	**3.25**	**5.26**	**4.07**	6.30	5.02	2.96	2.07	1.88
Exchange rate ($US/$Cdn)	**0.63**	**0.64**	**0.64**	**0.64**	**0.64**	0.65	0.67	0.67	0.67	0.72
Closing										
Government of Canada 10-year bond yield	**5.51%**	**5.50%**	**5.10%**	**5.07%**	**5.07%**	5.35%	5.40%	6.26%	4.91%	5.62%
TSE 300 Index	**7,851**	**7,146**	**6,180**	**6,615**	**6,615**	7,688	8,934	8,414	6,472	6,699
TSE Oil and Gas Producers Index	**8,725**	**8,805**	**8,658**	**8,606**	**8,606**	7,468	7,271	4,976	3,907	5,869
S&P 500 Index	**1,147**	**990**	**815**	**880**	**880**	1,148	1,320	1,469	1,242	970

DISTRIBUTION HISTORY

(dollars/Trust Unit)	**2002**	2001	2000	1999	1998	1997
First quarter	**$ 1.20**	$ 2.40	$ 1.20	$ 0.72	$ 0.96	$ 1.40
Second quarter	**1.20**	2.64	1.56	0.92	0.88	1.20
Third quarter	**1.20**	2.44	1.92	1.36	0.72	1.20
Fourth quarter	**1.20**	1.76	2.40	1.40	0.72	1.56
Total	**$ 4.80**	$ 9.24	$ 7.08	$ 4.40	$ 3.28	$ 5.36
% Tax deferred	**45%**	33%	47%	100%	100%	100%

Glossary

ABBREVIATIONS

bbls	barrels
mbbls	one thousand barrels
mmbbls	one million barrels
bbls/day	barrels per day
mcf	one thousand cubic feet
mmcf	one million cubic feet
mcf/day	one thousand cubic feet per day
Bcf	one billion cubic feet
m^3	one thousand cubic meters
BOE	barrels of oil equivalent
BOE/day	barrels of oil equivalent per day
mmBOE	millions of barrels of oil equivalent

CONVERSION FACTORS:

1 cubic meter (liquids) = 6.29 barrels

1 cubic meter (natural gas) = 35.49 cubic feet

1 litre = 0.22 imperial gallon

1 hectare = 2.47 acres

1 cubic meter = 1000 litres

1 mcf of natural gas = 1.055 gigajoules of natural gas = 1 mmbtu

AECO

Refers to a pricing point for gas produced in Western Canada located at a gas storage facility adjacent to the TransCanada mainline near the Alberta-Saskatchewan border.

BARREL OF OIL EQUIVALENT (BOE)

Natural gas production is converted using six thousand cubic feet of gas for one barrel of oil, with this number added to the actual number of barrels of crude oil and natural gas liquids on an average day to derive the barrels of oil equivalent produced per day.

CASH DISTRIBUTION DATE

The date Distributable Income is paid to Unitholders, currently being the 15th of each month, or the earlier business day if applicable, following any record date.

DECLARATION OF TRUST

Refers to the declaration of trust dated August 2, 1996 among the Trustee, PrimeWest, and the Initial Unitholder (as therein defined), as amended from time to time and administered.

DEVELOPMENT DRILLING

Drilling activity conducted in an area where production is already in place and where there is a high probability of finding additional oil and gas deposits.

ESTABLISHED RESERVES

Indicates all proved and one half of probable reserves.

EX-DISTRIBUTION DATE

The holder of units purchased prior to the ex-distribution date is entitled to the declared distribution paid on the 15th of the next month. Ex-distribution date is 2 business days prior to the record date.

PROBABLE RESERVES

Those reserves which analysis data does not demonstrate to be proved, but where the analysis suggests the likelihood of their existence and future recovery under current technology and existing or anticipated economic conditions. Probable reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above estimated Proved Reserves 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.

PROVED RESERVES

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 analysis, and anticipated economic conditions, in the case of escalated cost and price analysis, 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.

RECORD DATE

Means the last business day in each month.

RESERVE LIFE INDEX

Is calculated by dividing the quantity of reserves by the total production of oil, natural gas, and natural gas liquids during the year.

TRUSTEE

Refers to ComputerShare Trust Company of Canada, or its successor as trustee of the Trust.

WEST TEXAS INTERMEDIATE (WTI)

A high quality grade of crude oil produced in West Texas whose price is most commonly used as a benchmark for crude oil pricing internationally.

Corporate Information

Board of Directors

Harold P. Milavsky[1, 2]

Kent J. MacIntyre

Barry E. Emes[2]

Harold N. Kvisle[1, 2]

Michael W. O'Brien[1, 2]

W. Glen Russell[1, 2]

1 Member of the Audit and Reserves Committee and Compensation Committee

2 Member of the Corporate Governance and Nominating Committee

Officers

Harold P. Milavsky
Chairman

Donald A. Garner
President and Chief Executive Officer

Timothy S. Granger
Chief Operating Officer

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

Ronald J. Ambrozy
Vice-president, Business Development

James T. Bruvall
Secretary

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(PWI.UN; PWX)

The New York Stock Exchange,
(PWI)

Registrar and Transfer Agent

Computershare Trust
Company of Canada
Toll-free in Canada:
1-800-332-0095

Auditor

PricewaterhouseCoopers LLP,
Calgary, Alberta

Engineering Consultants

Gilbert Laustsen Jung Associates Ltd.,
Calgary, Alberta

Legal Counsel

Stikeman Elliott, LLP
Calgary, Alberta

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