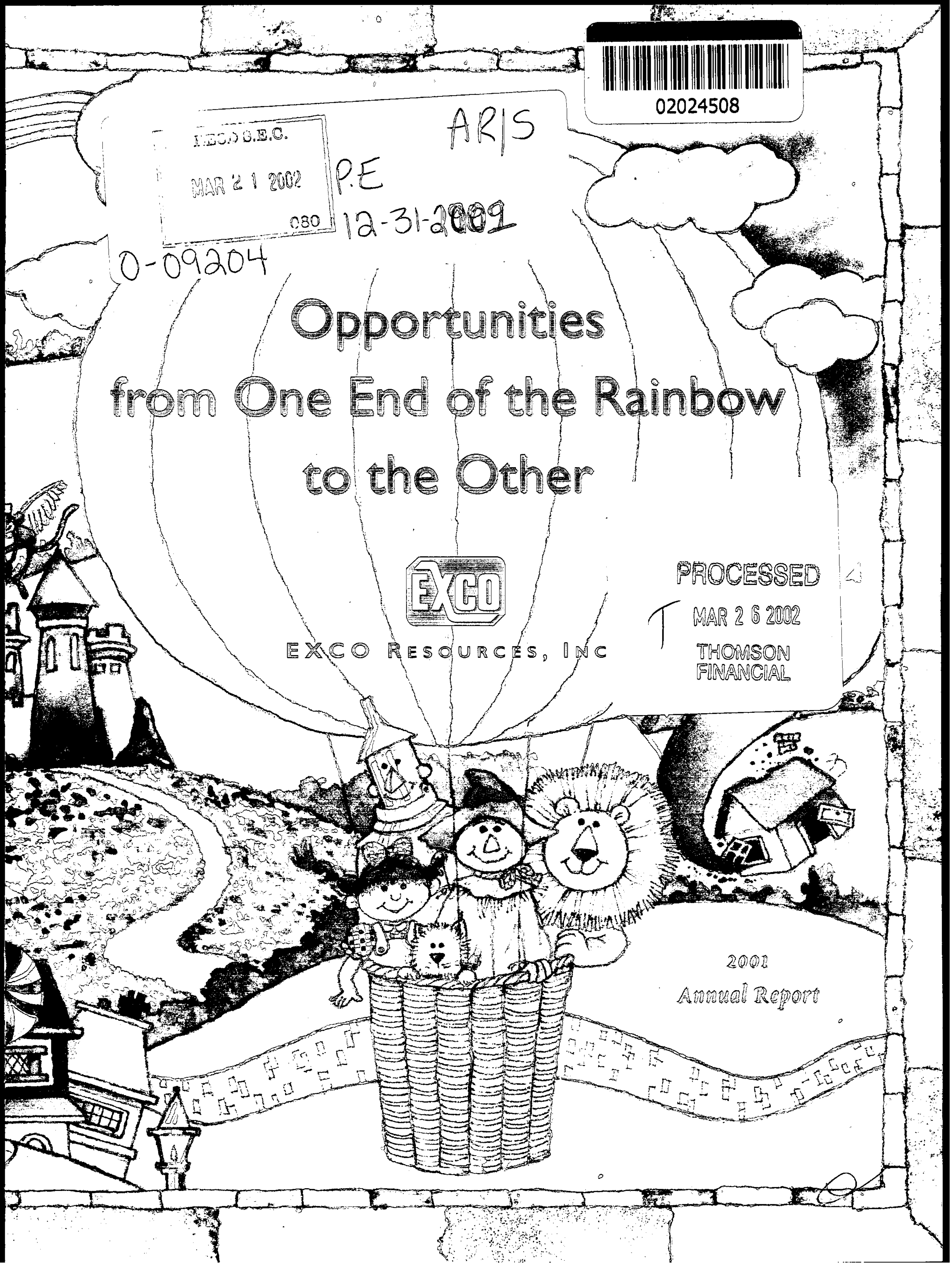
Opportunities from One End of the Rainbow to the Other



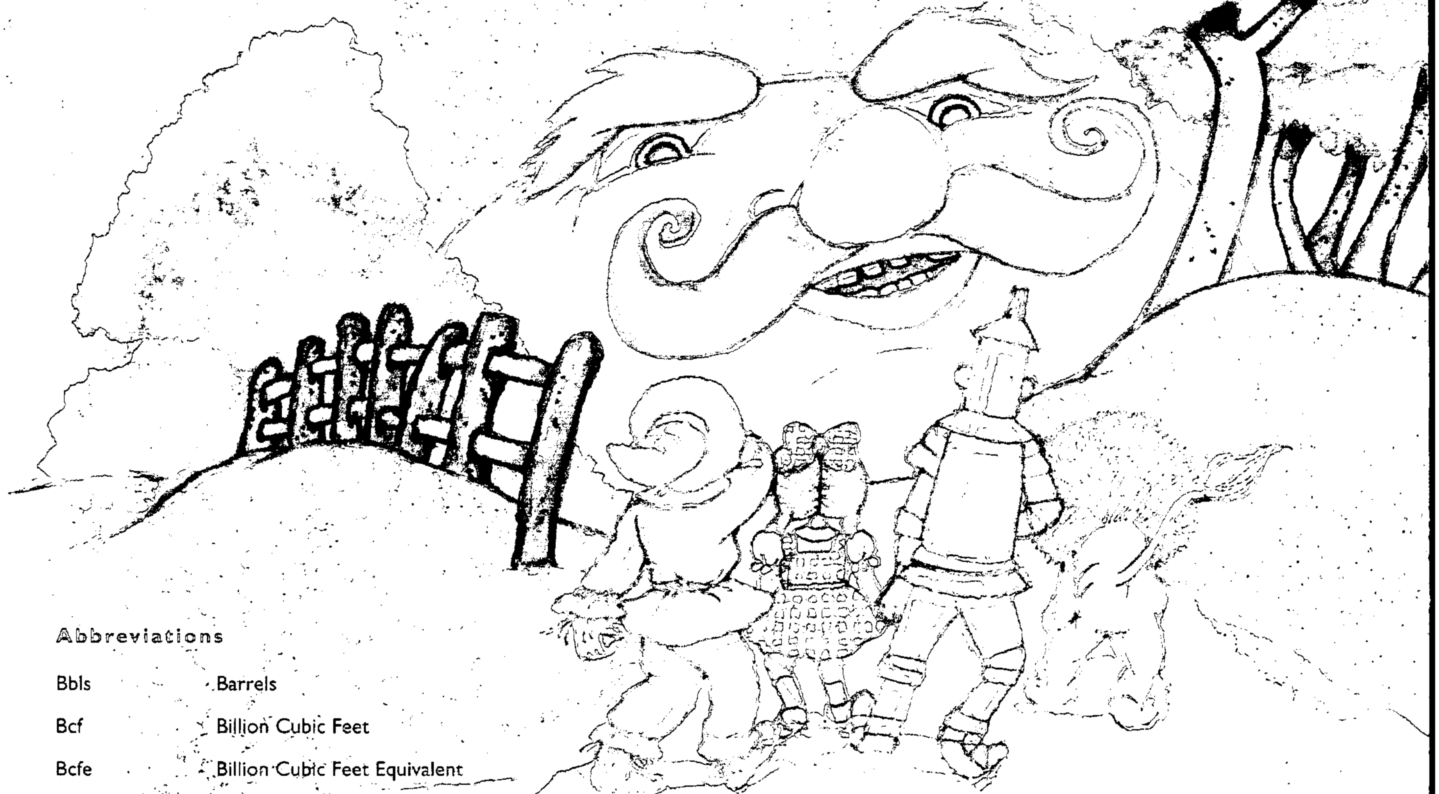
EXCO RESOURCES, INC

2001
Annual Report

EXCO Resources, Inc.

We are an independent energy company principally engaged in the acquisition, exploitation and development of proven oil and natural gas properties. EXCO targets acquisitions principally in the mid-continent region of the U.S. and Canada, where predominant economic value is attributable to proved producing reserves.

The Company's primary goal is to build value for our shareholders by acquiring quality properties and to enhance the value of the assets through control of operations, reduction of costs and property development.



Abbreviations

Bbls	Barrels
Bcf	Billion Cubic Feet
Bcfe	Billion Cubic Feet Equivalent
Boe	Barrels Oil Equivalent 6 Mcf equals 1 Boe
Mbbls	Thousand Barrels
Mcf	Thousand Cubic Feet
Mcfe	Thousand Cubic Feet Equivalent 1 Bbl equals 6 Mcfe
Mmbbls	Million Barrels
Mmcf	Million Cubic Feet
Mmcfe	Million Cubic Feet Equivalent
NGLs	Natural Gas Liquids
PV10	Present Value of Future Net Revenues Discounted at 10% Annually (SEC Case)
Tcf	Trillion Cubic Feet

Contents

FINANCIAL HIGHLIGHTS

(In thousands, except prices, volumes and per share data)

Results of Operations

	Years Ended December 31,					2000 - 2001
	1997	1998	1999	2000	**2001**	Change
Oil and natural gas sales, including results of hedging	$ 670	$ 1,385	$ 5,294	$ 28,869	**$ 61,237**	112%
Total revenues	$ 698	$ 2,075	$ 12,404	$ 30,659	**$ 66,940**	118%
Earnings before interest, taxes, depreciation, depletion and amortization and other non-operating items *(a)*	$ (110)	$ 58	$ 8,267	$ 19,172	**$ 34,074**	78%
Income (loss) from operations before income taxes *(b)*	$ (205)	$ (511)	$ 1,530	$ 12,316	**$ 16,561**	34%
Earnings (loss) on common stock from operations before income taxes *(b)*	$ (205)	$ (511)	$ 1,530	$ 12,316	**$ 13,908**	11%
Net income (loss)	$ (205)	$ (511)	$ 4,665	$ 8,454	**$ (39,347)**	-565%
Earnings (loss) on common stock	$ (205)	$ (511)	$ 4,665	$ 8,454	**$ (42,000)**	-597%
Cash flow from operations *(c)*	$ (111)	$ (46)	$ 2,918	$ 14,148	**$ 30,041**	112%
Per basic share						
Earnings (loss) on common stock	$ (0.51)	$ (0.18)	$ 0.69	$ 1.23	**$ (5.96)**	-585%
Cash flow from operations	$ (0.28)	$ (0.02)	$ 0.44	$ 2.07	**$ 4.26**	107%
Per diluted share						
Net income (loss)	$ (0.51)	$ (0.18)	$ 0.69	$ 1.18	**$ (5.96)**	-605%
Cash flow from operations	$ (0.28)	$ (0.02)	$ 0.43	$ 1.98	**$ 2.98**	51%
Oil production (Mbbls)	14	53	208	433	**967**	123%
Natural gas production (Mmcf)	181	412	765	3,982	**8,329**	109%
NGL Production (Mbbls)	-	-	-	89	**164**	84%
Total production (Mmcfe) *(d)*	265	730	2,013	7,114	**15,115**	112%
Average realized price, including hedge results						
Oil (per Bbl)	$ 19.56	$ 12.01	$ 17.83	$ 27.39	**$ 24.17**	-12%
Natural gas (per Mcf)	$ 2.14	$ 1.82	$ 2.07	$ 3.72	**$ 4.20**	13%
NGL (per Bbl)	$ -	$ -	$ -	$ 24.60	**$ 17.70**	-28%

Financial Position

	December 31,					2000 - 2001
	1997	1998	1999	2000	**2001**	Change
Total assets	$ 1,270	$ 36,888	$ 50,932	$ 102,372	**$ 191,056**	87%
Total debt and long-term liabilities	$ 15	$ -	$ -	$ 43,926	**$ 57,355**	31%
Stockholders' equity	$ 927	$ 36,240	$ 40,880	$ 49,791	**$ 120,379**	142%
Book value per basic share	$ 2.30	$ 12.62	$ 6.10	$ 7.28	**$ 17.08**	135%
Book value per diluted share	$ 2.30	$ 12.61	$ 6.09	$ 6.99	**$ 11.98**	71%
Closing common stock price	$ 6.25	$ 7.25	$ 7.25	$ 15.63	**$ 16.80**	7%
Closing 5% convertible preferred stock price	$ -	$ -	$ -	$ -	**$ 17.51**	
Reserve information - SEC Case *(e)*						
Proved oil reserves (Mbbls)	58	963	2,744	12,378	**14,853**	20%
Proved natural gas reserves (Bcf)	4.3	7.7	16.5	94.4	**183.7**	95%
Proved NGL reserves (Mbbls)	-	-	370	465	**3,616**	678%
Total reserves (Bcfe) *(d)*	4.6	13.5	35.2	171.5	**294.5**	72%
Future net cash flow	$ 6,985	$ 14,379	$ 60,138	$ 848,692	**$ 385,935**	-55%
Present value at 10%	$ 4,028	$ 7,964	$ 36,977	$ 396,400	**$ 189,155**	-52%
Year-end NYMEX prices:						
Oil (per Bbl)	$ 17.64	$ 12.05	$ 25.60	$ 26.80	**$ 19.84**	-26%
Natural gas (per Mcf)	$ 2.26	$ 1.95	$ 2.33	$ 9.78	**$ 2.57**	-74%

At the end of 1997 and the beginning of 1998, new management bought a controlling interest in EXCO and redirected its focus.

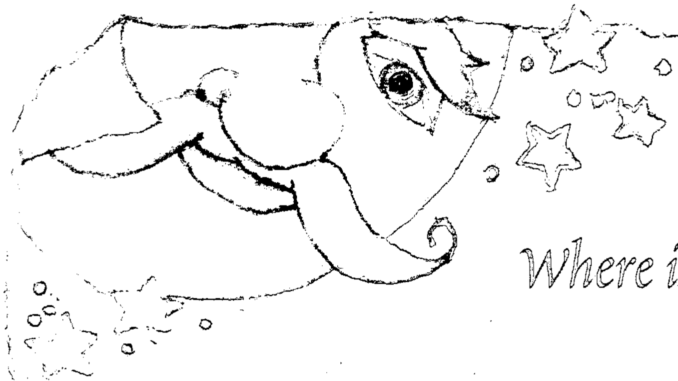
(a) Adjusted for non-operating items in 2001 of $60.2 million for impairments of oil and natural gas properties and the uncollectible value of Enron hedges offset by $4.1 million of other income from hedge ineffectiveness and from derivatives for which hedge accounting was terminated.

(b) Adjusted for gains of $5.1 million, $538,000 and $136,000 from the sale of oil and natural gas properties and other assets in 1999, 2000, and 2001 respectively, and in 2001, for non-cash items of $60.2 million for impairments of oil and natural gas properties and the uncollectible value of Enron hedges offset by $4.1 million of other income from hedge ineffectiveness and from derivatives for which hedge accounting was terminated.

(c) Cash flow from operations before changes in working capital.

(d) Oil and NGLs converted to natural gas on the basis of one Bbl per six Mcf.

(e) Reserve information is based upon data contained in the reports of independent consulting petroleum engineers under SEC reporting parameters using prices and costs at the dates indicated before future income taxes.



Where is the Industry Now?

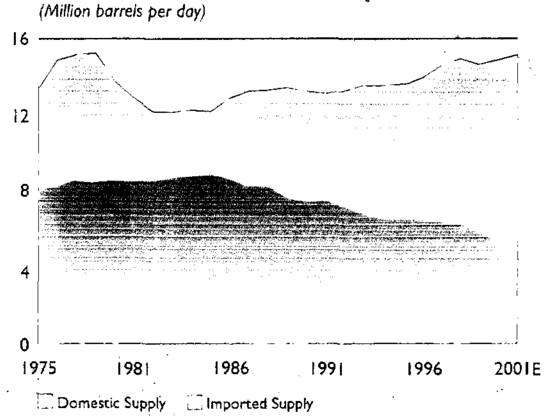
The oil and gas industry has done an about face since the end of 2000. Compare the following:

	2000	2001
NYMEX oil price per Bbl at 12/31	$ 26.80	$ 19.84
NYMEX natural gas price per Mcf at 12/31	$ 9.87	$ 2.57
Number of gas drilling rigs in use at 12/31	879	748
Average number of rigs drilling per day	720	939
Annual domestic gas production (Tcf)	19.0	19.3
Annual domestic gas demand (Tcf)	22.5	21.4
Finding and development costs per Mcfe	$ .90	$ 1.50
Natural gas in storage at 12/31 (Tcf)	1.7	2.9
EXCO common stock price at 12/31	$ 15.63	$ 16.80

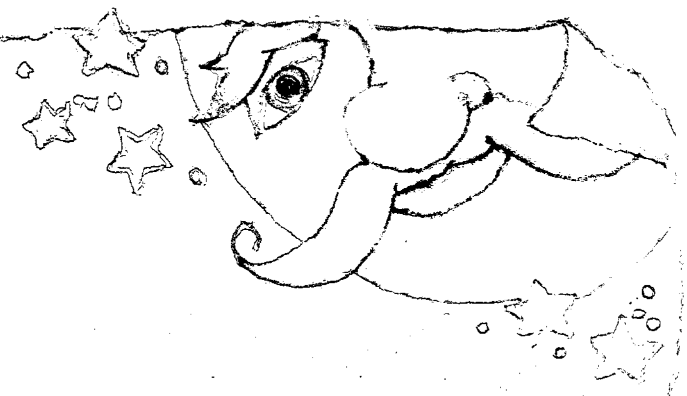
At the beginning of the year 2001, commodity prices were very high and so was exploration and development activity. Yet with all the drilling activity last year, U.S. domestic natural gas production was only increased by 1.7%. Now drilling activity has slowed with only 650 rigs drilling for gas in the U.S. at the end of February 2001. A weak economy and a mild winter have left gas storage at or near historically high levels and as a result, gas prices have fallen sharply. Crude oil prices have likewise fallen with reduced world demand caused by decreased economic activity.

Many oil and gas independents spent significant resources in 2001 and found very little with the drill bit. Now some of these companies are in financial trouble with too much debt, low commodity prices and declining production. They are being forced to liquidate assets to clean up their balance sheets or, in some cases, to survive. (It's hard to find new equity for a bad strategy). Some of these companies will not be able to escape bankruptcy.

Total U.S. Crude Oil Consumption
(Million barrels per day)



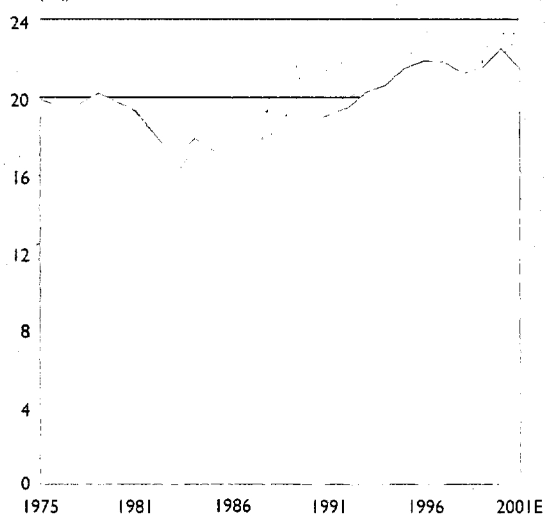
Source: Department of Energy



So What's Ahead?

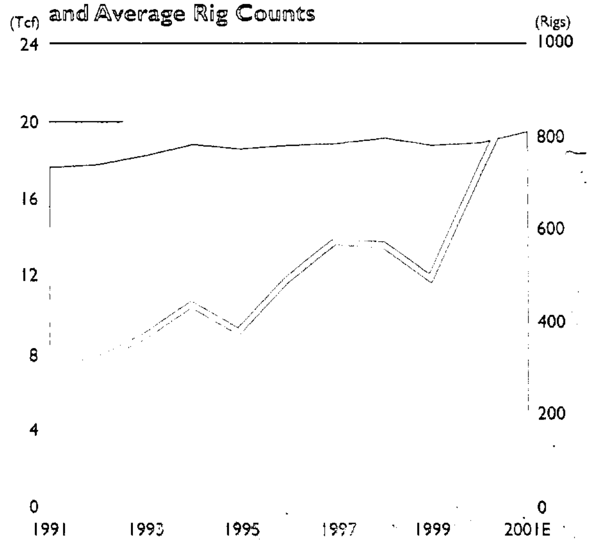
- The consolidation of the independent energy sector in both the U.S. and Canada will continue at a faster pace. Companies with access to capital will be the acquirors and many of the others will be acquired.
- Major energy companies will resume sales of onshore domestic reserves and continue their search for larger fields offshore and in foreign countries.
- Absent some world crisis such as a Middle East war, commodity prices will stay relatively weak until a significant upswing in world economic activity begins.
- North American natural gas production will decline and excess gas in storage will moderate.
- Economic recovery will begin and consumption of both crude oil and natural gas will increase.
- Natural gas will continue to be the clean burning fuel of choice for new power generation.
- The price of natural gas and possibly crude oil will increase.
- There will be some continuing fallout from Enron's financial collapse.

Total U.S. Natural Gas Consumption
(Tcf)



Domestic Supply   Imported Supply
Source: Department of Energy

Total U.S. Natural Gas Consumption and Average Rig Counts



Domestic Supply   Imported Supply   Rig Count
Source: Department of Energy and Baker Hughes, Inc.

Letter to the Shareholders

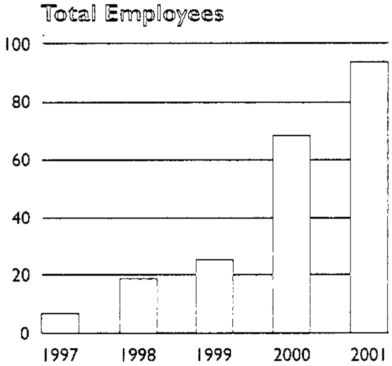
Dear Shareholders,

Have you ever stopped to wonder what it is about the stories of our childhood that have such allure? Let us suggest that it is our willingness to be swept up in a dream and that childlike ability to recognize and embrace adventure at every turn. Haven't we all sat in our own version of Kansas with dreams of the magic and hope in the land of Oz?

When we become adults, we come to realize that magic lies in that mysterious thing called opportunity, the chance to do something unique, special, and beyond the ordinary.

Doing something beyond the ordinary — for us, that is the magic of building a successful energy company. It is the promise and excitement of EXCO Resources. At times (not unlike the journey toward the Emerald City) seizing the opportunity demands unique heart and courage and maybe an element of good luck. Heart and courage are in abundance in our story, and evident in the information reflected in this 2001 Annual Report. We have had fun preparing this report and hope you enjoy it.

Total Employees



2001 HIGHLIGHTS

Common stock price at year end	$16.80
Acquisitions	$114.0 Million
Employees at year-end	93

Major Events

March	Acquired STB Energy properties
April	Aquired Addison Energy Inc.
June	Completed $105 Million Equity Offering
July	Acquired Pecos-Gomez properties
December	Acquired PrimeWest properties

... And It's Not Just Kansas

At EXCO the rainbow of opportunity extends from Texas up through the heart of North America. In 2001, we extended our map for the first time into Canada when we acquired Addison Energy and brought on board its team of oil and gas professionals. In the past 12 months we have positioned EXCO to become a significant player in the North American upstream energy markets. We have long believed that domestic natural gas reserves will be an increasingly valuable commodity and we continue to focus on the acquisition and development of North American reserves.

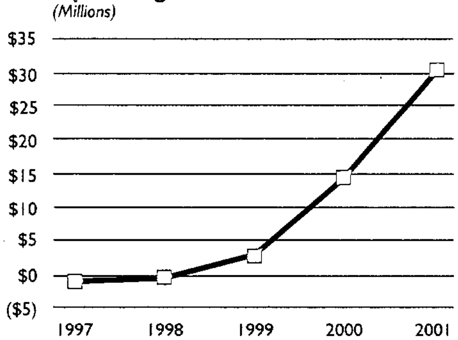
We began 2001 with an acquisition of Kansas properties and the commitment to an exploitation and development program there. In March we acquired the assets of an Oklahoma-based producer for approximately $15 million, after which we completed the $50 million acquisition of Addison Energy in April.

Our next step down the road was the completion of a $105 million rights offering of preferred stock in June, adding strength to the EXCO balance sheet. Then we continued on our growth path, ultimately completing approximately $114 million in total acquisitions for the year. Add to that our drilling and completion expenditures of $24 million and you have a year beyond ordinary.

But in the Land of OZ the Game Can Change

And what a difference a year makes! January 2001 saw gas prices above $10.00 per mcf in some markets and crude oil about $27.00 per barrel. Finding a drilling rig during the first half of the year was next to impossible, and the operating cost of services escalated almost daily. As a result, we made a prudent decision to delay a substantial portion of our capital expenditures scheduled for the first half of the year. As we look back on 2001, the wisdom to be patient paid off as commodity prices have now plummeted along with the costs of drilling and production and most related oil field services.

Operating Cash Flow*
(Millions)



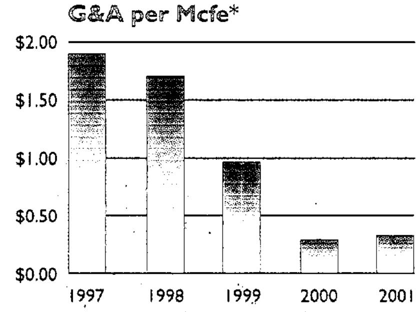
Cash flow from operations before changes in working capital.

You Gotta Have Brains

Having conserved a substantial portion of our financial flexibility, all the while adding to our intellectual capital, EXCO Resources is better positioned than ever to move on opportunity, whether through acquisition or participation in deals. Here are some of the opportunities we see in the coming year.

- Major oil companies, looking for greater efficiency, are paring their portfolios of properties after three years of aggressive consolidations and acquisitions.
- The equity markets for oil and gas investments are closed to all but a few whose performance has been extraordinary.
- Demand for natural gas and crude oil is beginning to grow in spite of a depressed world economy and one of the mildest winters on record for North America.
- Many independents with too much debt are trying to sell properties in order to comply with banking and bond covenants.

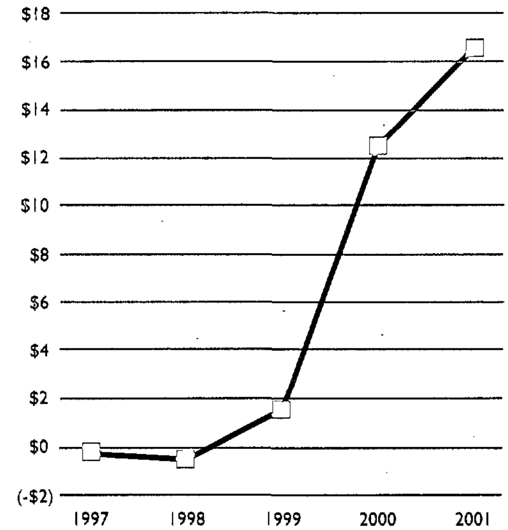
G&A per Mcfe*



General and administrative expenses per thousand cubic feet equivalent.

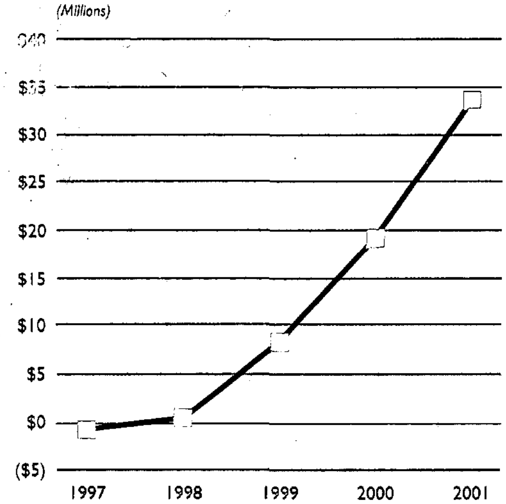
Add to these factors that the cost of borrowed funds has not been this attractive in many years and you can understand why we say that the oil patch, like the Emerald City, holds a rainbow of opportunities.

Adjusted Pre-Tax Income*
(Millions)



** Adjusted for gains from the sale of oil and natural gas properties and other assets in 1999, 2000 and 2001, and also in 2001, for full cost pool impairments, Enron related write-offs and other income from hedge ineffectiveness and derivatives for which hedge accounting was terminated.*

EBITDA*
(Millions)

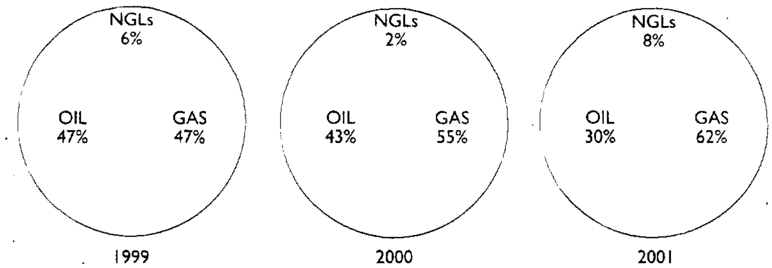


** Earnings before interest expense, income taxes, depreciation, depletion and amortization and adjusted for non-operating items in 2001 of $60.2 million for impairments of oil and natural gas properties and the uncollectible value of Enron hedges offset by $4.1 million of other income from hedge ineffectiveness and from derivatives for which hedge accounting was terminated.*

On the Yellow Brick Road You Need Courage

For years we have felt that Canada held opportunities, but until this past year, we never found exactly what we were looking for: a transaction that was large enough to justify the entry into another country, an acquisition of quality properties and, most importantly, a deal that would bring with it exceptional managers with an approach to building a company paralleling our own business strategy. Addison Energy had assembled an excellent team of professionals who grew the company in a few short years through acquisitions of producing properties and exploitation in select areas of Alberta. We recognized their professional skills and courage in the face of risk, and we convinced them to join the EXCO team in April 2001. Following the acquisition of Addison, we announced our second and third significant Canadian property acquisition agreements, one in December 2001 and another in March 2002 (scheduled to close in April) to acquire assets in and around Addison's producing properties.

Total Proved Reserve Mix
(Bcfe)



Heart — The Key to Tomorrow's Opportunities

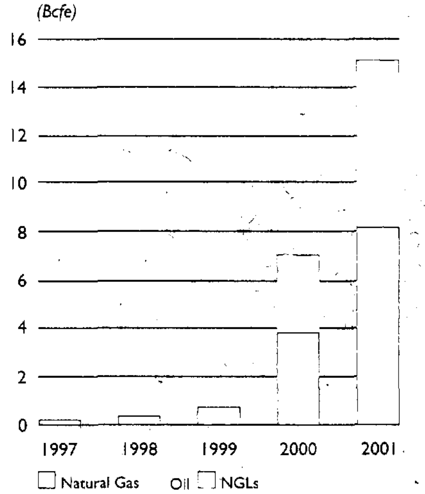
In 2001 we achieved dramatic growth in production, revenues, cash flow and reserves. In June, our shareholders gave us a tremendous vote of confidence by participating in our second rights offering to shareholders. You committed $105 million to EXCO's future by subscribing to this offering of convertible preferred stock. EXCO officers, directors and employees invested $5.4 million of that total. The heart of EXCO Resources is in its employees, where we have committed ourselves to building the finest energy resources company in North America. Please accept our heart-felt thank you for your continued support of EXCO Resources.

Sincerely,

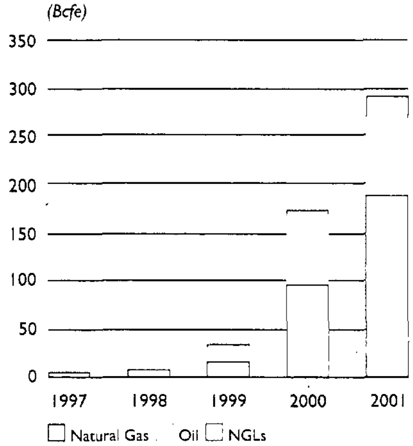
Doug Miller
Chairman

Ted Eubank
President

Production
(Bcfe)



Total Proved Reserves
(Bcfe)

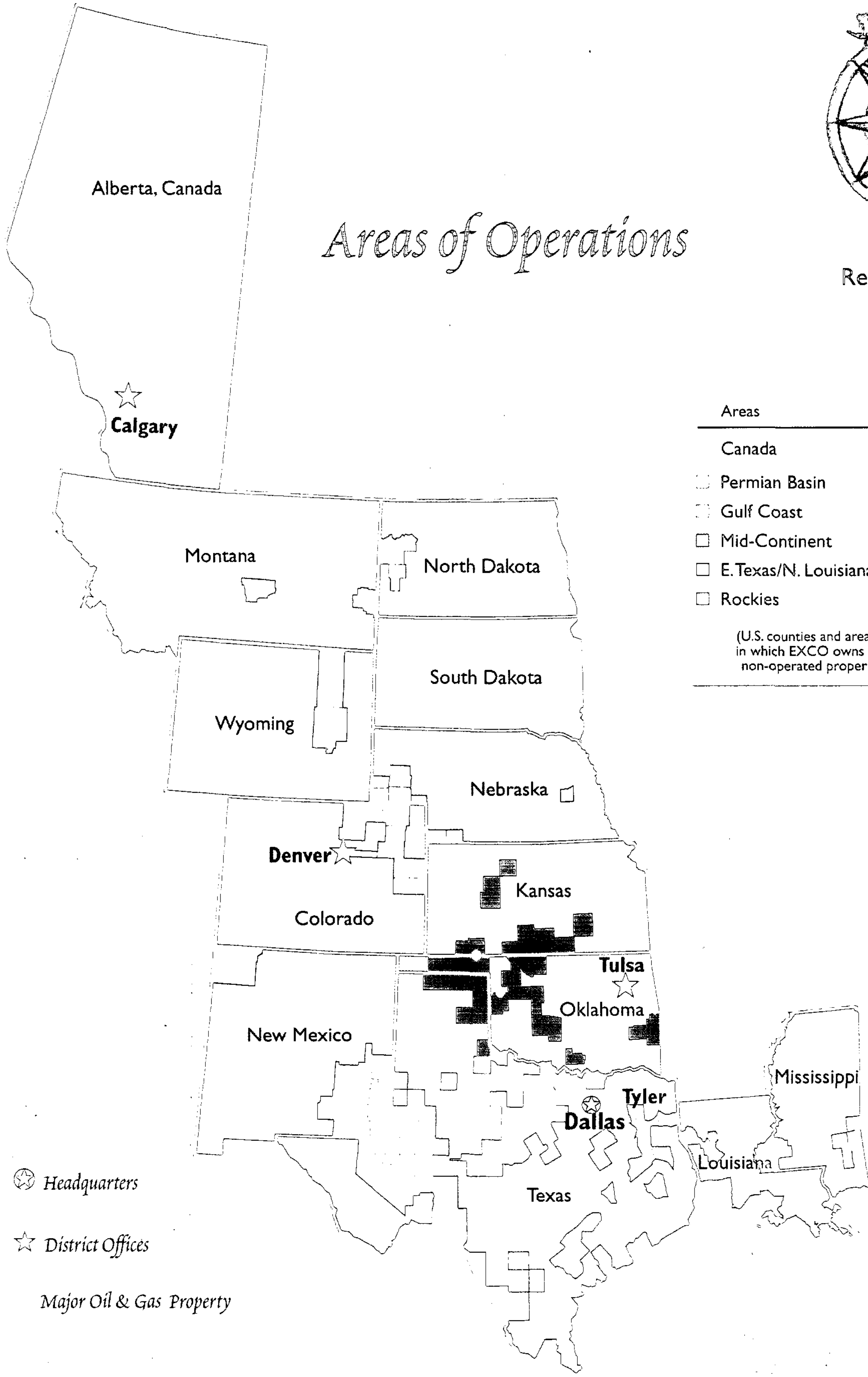


Areas of Operations

EXCO
Resources, Inc.

Areas	Total Proved Reserves (Bcfe)	Percent of Pre-tax PV-10
Canada	113	44%
Permian Basin	82	25%
Gulf Coast	51	14%
Mid-Continent	24	9%
E.Texas/N. Louisiana	14	6%
Rockies	10	2%

(U.S. counties and areas of Cananda in which EXCO owns operated and non-operated property interests.)



UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended December 31, 2001

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Transition Period from __________ to __________

Commission File Number 0-9204

EXCO RESOURCES, INC.
(Exact name of Registrant as specified in its charter)

Texas (State or other jurisdiction of incorporation or organization)	**74-1492779** (I.R.S. Employer Identification No.)
6500 Greenville Avenue, Suite 600, LB 17 **Dallas, Texas** (Address of principal executive offices)	**75206** (Zip Code)

(Registrant's telephone number, including area code) **(214) 368-2084**

Securities registered pursuant to Section 12(b) of the Act: None

Securities registered pursuant to Section 12(g) of the Act:
Common Stock, Par Value $.02 Per Share
5% Convertible Preferred Stock, Par Value $.01 Per Share
(Title of class)

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding twelve (12) months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past ninety (90) days. YES ☒ NO ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment of this Form 10-K. ☐

The number of shares of Common Stock, par value $.02 per share, of the Registrant outstanding on February 28, 2002, was 7,183,137. The aggregate market value of the voting common equity held by non-affiliates (all directors and executive officers are presumed to be affiliates) of the Registrant on February 28, 2002, was approximately $87.8 million based on the average of the closing bid and ask prices per share of the Common Stock on such date.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's Proxy Statement for the 2002 Annual Meeting of Shareholders, filed on March 19, 2002, are incorporated by reference into Part III.

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EXCO RESOURCES, INC.

PART I

ITEM 1. BUSINESS

General

EXCO Resources, Inc. is an independent energy company engaged in the acquisition, development and exploitation of oil and natural gas properties. Our primary areas of operations are onshore in Texas, Louisiana, Mississippi and Alberta, Canada.

Since our present management team purchased a significant ownership interest in us in December 1997, we have achieved substantial growth through a strategy of acquiring proved oil and natural gas properties with development and exploitation potential. Since December 1997, we have completed 44 acquisitions for total net consideration of approximately $220.0 million, including 13 acquisitions for aggregate net consideration of approximately $114.0 million since January 1, 2001. Overall, our acquisitions have been made at an average cost of approximately $0.73 per Mcfe of proved reserves. We now own interests in a number of established oil and natural gas producing basins that we intend to use as a platform for further growth. In addition, we believe that our properties, coupled with our experienced oil and natural gas operating and technical team, provide us with significant growth potential from development and exploitation activities.

Our Canadian results are converted for use in this report from Canadian dollars to U.S. dollars using an exchange rate of $0.628 per CDN $1.00 for balance sheet items including cash, oil and natural gas properties and bank debt (the rate at December 31, 2001). For income statement items such as revenue, production costs, general and administrative costs and interest, we convert Canadian dollars to U.S. dollars using the average exchange rate across the applicable period. The average exchange rate for the year 2001 was $0.644 per CDN $1.00.

Business Strategy

We intend to become a leading independent oil and natural gas acquisition, exploitation and production company. We plan to achieve asset, revenue and cash flow growth as a result of the acquisition and further development of producing oil and natural gas properties by implementing the following business strategies:

- *Acquire and Enhance Producing Oil and Natural Gas Properties.* We plan to take advantage of opportunities that currently exist in the United States and Canada to acquire producing oil and natural gas properties. We continue to focus our acquisition activities onshore in the mid-continent region of the United States and in Alberta, Canada to complement our existing properties and operations, while continuing to review potential acquisitions in other regions of the United States and Canada if we believe they represent an opportunity for exploration, exploitation and development. We believe that numerous opportunities exist for us to acquire additional energy assets and to enhance the value of these assets through improved operating practices and by developing reserve potential.
- *Emphasize Exploitation and Development Activities.* We continue to exploit existing oil and natural gas properties and we continue to conduct development evaluation and drilling on our oil and natural gas properties. We intend to concentrate on enhancement opportunities from activities such as infill drilling, recompletions, secondary recovery projects, repairs and equipment changes. We may participate, from time to time, in a limited number of exploratory wells.
- *Corporate Efficiencies.* We plan to further maximize our corporate efficiencies through the development and operation of a larger asset base with the potential to limit increases in overhead in the future while operating an expanded asset base.

- *Financial Management*. We will continue to analyze our existing capital structure and financing requirements for future acquisitions and development to maintain appropriate levels of debt and equity.
- *Technology*. We plan to increase exploitation efforts, focusing on established geological trends where we can employ geological, geophysical and engineering expertise. We utilize 3-D seismic and advanced drilling technologies.

In 2001, we evaluated approximately 175 acquisition opportunities with an aggregate estimated market value of over $3.6 billion. We made offers on properties totaling more than $885 million and successfully completed the purchase of approximately $114 million of oil and natural gas properties and related assets. Offers varied in amounts from less than $10,000 to $150 million. We intend to pursue large acquisitions that will have a significant impact on our growth and smaller projects that have the potential for high levels of profitability. We prefer to acquire properties with shallow production, which offer lower geologic and mechanical risk of operations. In evaluating prospective acquisitions, we generally focus on estimates of future cash flows, rates of return and net present values expected to be generated by the acquired properties.

Developments During 2001

We acquired oil and natural gas properties in Texas and Oklahoma.

In March 2001, we acquired from STB Energy, Inc. oil and natural gas properties located in Texas, Oklahoma, Louisiana and Nebraska. As of January 1, 2001, estimated total proved reserves net to our interest included 694,000 Bbls of oil and 9.5 Bcf of natural gas from 125 gross (78.3 net) wells. The purchase price consisted of $15.0 million in cash ($14.8 million after contractual adjustments).

We acquired Addison Energy Inc.

On April 26, 2001, we acquired all of the outstanding common stock of Addison Energy Inc. (Addison), which is headquartered in Calgary, Alberta, Canada. At the time of acquisition, Addison owned interests in 95 gross (85.03 net) wells located in Alberta, and Addison operated 91 of these wells. The Addison properties included approximately 38,947 gross and 28,795 net undeveloped acres. As of January 1, 2001, estimated total proved reserves net to our interest acquired in this acquisition included 2.1 million Bbls of oil and NGLs and 36.9 Bcf of natural gas. After adjustments for working capital and long-term debt, we paid approximately $44.4 million (CDN $68.5 million) for Addison. We paid the adjusted purchase price from the proceeds of borrowings under our U.S. and Canadian credit agreements.

We have also entered into employment agreements with the Addison management team to provide incentives for the continued growth of Addison. These incentives include a share appreciation rights plan which rewards the Addison managers for additions to Addison's reserves based upon certain established benchmarks. The incentives are payable in cash or our common stock at the election of the employee.

The Addison managers also agreed to purchase shares of our common stock with a portion of the proceeds they received from the sale of their common shares of Addison to us. They purchased in the open market 24,940 shares worth $455,144. In addition, as part of the Addison purchase, we issued 49,880 shares worth $910,310 to the Addison managers. The resale of the shares is restricted.

We entered into new credit agreements.

As a result of the acquisition of Addison, we revised our banking arrangements. On April 26, 2001, we repaid all outstanding indebtedness owed to a syndicate of banks lead by Bank of America, N.A. and canceled the credit agreement. At the same time, we entered into two new credit agreements, a U.S. credit agreement and a Canadian credit agreement. On December 18, 2001, the U.S. credit agreement and the Canadian credit agreement were restated as part of the financing of the acquisition of the PrimeWest properties (see "Our subsidiary, Addison Energy Inc., acquired additional oil and natural gas properties in Canada" below).

The restated U.S. credit agreement, with Bank One, N.A., as administrative agent, provides for borrowings of up to $124.0 million under a revolving agreement with an initial borrowing base of $58.0 million. At December 31, 2001, we had approximately $3.5 million of outstanding indebtedness, letter of credit commitments of $310,000 and approximately $54.2 million available for borrowing under the restated U.S. credit agreement. The restated Canadian credit agreement, with Bank One, N.A. Canada Branch as administrative agent, provides for borrowings of up to $48.7 million under a revolving credit agreement with an initial borrowing base of $45.0 million. At December 31, 2001, we had approximately $41.5 million of outstanding indebtedness and approximately $3.5 million available for borrowing under the restated Canadian credit agreement.

For more information about our credit agreements, please review "Our Liquidity and Capital Resources—Credit Agreements" in "Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations."

We issued over 5 million shares of 5% convertible preferred stock.

On June 29, 2001, we sold 5,004,869 shares of 5% convertible preferred stock. We raised approximately $105.1 million in gross proceeds (approximately $101.2 million in net proceeds after fees and commissions). We applied approximately $97.6 million of the offering proceeds to repay bank loans with the remaining proceeds used for general corporate purposes.

For more information about the 5% convertible preferred stock, please review "Our Liquidity and Capital Resources—Effects of the 5% Convertible Preferred Stock Offering" in "Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations."

We dissolved Pecos-Gomez, L.P. and acquired additional interest in the Pecos County Properties.

On July 3, 2001, Pecos-Gomez, L.P. (the Partnership) distributed to its partners all of the interest in the Partnership's properties. At that time, we acquired additional working interests in the properties from two of the limited partners for $8.8 million (approximately $7.5 million after contractual adjustments). In addition, we received an assignment of the existing hedge agreement that was previously entered into by the Partnership. Borrowings under the Partnership credit agreement of $3.9 million were also repaid at the time of the acquisition and the credit agreement was canceled.

We terminated our existing hedge agreements and entered into new hedge agreements.

In connection with the incurrence of debt related to our acquisition activities and to protect against commodity price fluctuations, management has adopted a policy of hedging oil and natural gas prices through the use of commodity futures, options and swap agreements. The counterparty of the swap agreements that we entered into during 2000 and through September 2001 was an affiliate of Enron Corp. (the Enron Hedges). On December 2, 2001, Enron Corp. and other Enron related entities (including the Enron affiliate that was the counterparty to our swap agreements) filed for bankruptcy under Chapter 11 of the United States Code in the United States Bankruptcy Court in the Southern District of New York. We terminated all of our hedging contracts with the Enron affiliate, effective as of December 5, 2001, as a result of the failure of the Enron affiliate to make payments totaling approximately $2.1 million due us on December 5, 2001, on hedged natural gas volumes and on December 7, 2001, on hedged oil volumes. Based upon oil and natural gas futures prices on December 5, 2001, we believe that we are owed approximately $15.3 million, including settlements already due, but the exact amount will be determined pursuant to the terms of the ISDA Master Agreement.

In December 2001, we entered into new, replacement hedge transactions with a new counterparty, BNP Paribas, (the BNP Paribas Hedges), a financial lending institution. BNP Paribas is a lender to us under our U.S. and Canadian credit agreements. For more information concerning the new hedging contracts as well as the accounting treatment of the terminated Enron Hedges, please review "Item 7A—Quantitative and Qualitative Disclosure about Market Risk".

Our subsidiary, Addison Energy Inc., acquired additional oil and natural gas properties in Canada.

On December 18, 2001, Addison acquired oil and natural gas properties located in west central Alberta, Canada from PrimeWest Energy Inc. and PrimeWest Oil and Gas Corp. for $33.8 million ($33.6 million after contractual adjustments). The properties consisted of 96 gross (73.8 net) producing oil and natural gas wells. Under the terms of the acquisition, Addison became the operator of 78 of the wells. As of December 31, 2001, estimated total proved reserves net to our interest included 3.6 million Bbls of oil and NGLs and 27.1 Bcf of natural gas. Net daily production, as of December 2001, was approximately 600 Bbls of oil and NGLs and 4.1 Mmcf of natural gas.

Developments Since December 31, 2001

Our subsidiary, Addison Energy Inc., entered into an agreement to purchase oil and natural gas assets.

On January 25, 2002, Addison entered into an agreement to purchase oil and natural gas assets in Alberta, Canada, from an independent producer totaling approximately $26.2 million (CDN $41.6 million). We estimate total proved reserves net to our interest of approximately 1.6 million Bbls of oil and NGLs and 19.0 Bcf of natural gas. We expect net daily production from these properties to be approximately 4.8 Mmcf of natural gas, 385 Bbls of oil and 195 Bbls of NGLs per day or 8.3 Mmcfe.

We entered into additional hedge agreements.

On March 12, 2002, we entered into two agreements to hedge additional natural gas volumes on a portion of our expected production for 2002 and 2003. The counterparty to these agreements was BNP Paribas. For more information concerning the additional hedging contracts, please review "Item 7A-Quantitative and Qualitative Disclosure about Market Risk".

Investment Considerations and Risk Factors

The risk factors noted in this section and other factors noted throughout this annual report, including those risks identified in "Item 7.—Management's Discussion and Analysis of Operations," provide examples of risks, uncertainties and events that may cause our actual results to differ materially from those contained in any forward-looking statement. If one or more of these risks or uncertainties materialize, or if our underlying assumptions prove incorrect, actual outcomes may vary materially from those included in this report.

Our revenue depends on oil and natural gas prices which fluctuate.

Our future financial condition, access to capital, cash flow and results of operations depend upon the prices we receive for our oil and natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors that are also beyond our control. In addition, natural gas prices in Canada have been and may continue to be subject to lower market prices than natural gas prices in the United States. Factors that affect the prices we receive for our oil and natural gas include:

- the level of domestic production;
- the availability of imported oil and natural gas;
- actions taken by foreign oil and natural gas producing nations;

- the cost and availability of transportation systems with adequate capacity;
- the cost and availability of other competitive fuels;
- fluctuating and seasonal demand for oil and natural gas;
- conservation and the extent of governmental regulation of production;
- weather;
- foreign and domestic government relations; and
- overall economic conditions.

Our ability to maintain or increase our borrowing capacity, to repay current or future indebtedness and to obtain additional capital on attractive terms substantially depends upon oil and natural gas prices.

Hedging our production may cause us to forego additional future profits.

To reduce our exposure to changes in the prices of oil and natural gas, we have entered into and may in the future enter into hedging arrangements for a portion of our oil and natural gas production. The hedges that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Hedging arrangements may expose us to the risk of financial loss in some circumstances, including the following:

- the other party to the hedging contract defaults on its contract obligations;
- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received; or
- market prices may exceed the prices at which we are hedged, resulting in our need to make significant cash payments.

Our hedging activities could have the effect of reducing our revenues which, in turn, could have an adverse effect on our financial condition. As discussed above in "Developments During 2001," we terminated the Enron Hedges due to the bankruptcy filing of Enron Corp. and certain of its affiliates and the failure of Enron North America to make payments totaling approximately $2.1 million due us on hedged oil and natural gas volumes. Based upon oil and natural gas futures prices on the effective date of termination, we believe that we are owed approximately $15.3 million, including settlements already due. For the year ended December 31, 2001, our revenues were increased by approximately $6.9 million as a result of cash settlements actually received on the Enron Hedges. As of December 31, 2001, the unrealized gain on the BNP Paribas Hedges was $696,000 and our hedged volumes represented approximately 57%—61% of our forecasted oil production and 50%—54% of our forecasted natural gas production during 2002. These hedging arrangements may limit the benefit we would otherwise receive from increases in the prices for oil and natural gas. For more information about our hedging risk and the accounting for the Enron Hedges, please review "Item 7A—Quantitative and Qualitative Disclosure about Market Risk".

We may be unable to acquire or develop additional reserves.

As is generally the case in the oil and natural gas industry, our success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are profitable to produce. Factors which may hinder our ability to acquire additional oil and natural gas reserves include competition, access to capital, prevailing oil and natural gas prices and the number of properties for sale. If we are unable to conduct successful development activities or acquire properties containing proved reserves, our proved reserves will generally decline as they are produced. Also, our production will generally decline. If our production declines then our revenues will decline unless an increase in oil and natural gas prices offsets the declines. In addition, if our reserves and production decline then the amount we are able to borrow under our credit agreements will also decline. We cannot assure you that we will be able to locate additional reserves or that we will drill economically productive wells or acquire properties containing proved reserves.

We cannot assure you that we will be successful in managing our growth.

We have recently completed several large acquisitions and our growth could strain our financial, technical, operational and administrative resources. Failure to manage our growth successfully could adversely affect our operations and net revenues through increased operating costs and revenues that do not meet our expectations. We cannot assure you that our recently acquired oil and natural gas properties will be successfully integrated into our operations or will achieve desired profitability.

We may encounter marketing obstacles.

Our ability to market our oil and natural gas production will depend upon the availability and capacity of natural gas gathering systems, pipelines and other transportation facilities. With the exception of a few small gathering systems, we do not currently operate our own pipelines or transportation facilities. As a result, we are dependent on third parties to transport our products. Transportation space on the gathering systems and pipelines we utilize is occasionally limited and at times unavailable due to repairs or improvements to facilities or due to space being utilized by other companies with priority transportation agreements. Our access to transportation options can also be affected by U.S. federal and state and Canadian regulation of oil and natural gas production and transportation, general economic conditions and changes in supply and demand. These factors and, consequently, the availability of markets are beyond our control. If market factors dramatically change, the financial impact on our revenues could be substantial and could adversely affect our ability to produce and market oil and natural gas.

Our Canadian operations may be adversely affected by currency fluctuations and economic and political developments.

We have significant oil and natural gas operations in Canada. As a result, our Canadian operations are subject to the risk of fluctuations in the relative value of the Canadian and U.S. dollars. We have not hedged any currency risk exposure associated with our Canadian operations. We are required to recognize foreign currency translation gains or losses related to our Canadian operations in our consolidated financial statements. Our Canadian operations may be adversely affected by political and economic developments, royalty and tax increases and other laws or policies in Canada, as well as U.S. policies affecting trade, taxation and investment in Canada.

Our Canadian properties and operations are subject to foreign regulations.

The oil and natural gas industry in Canada is subject to extensive legislation and regulation governing its operations. This legislation and regulation, enacted by various levels of government, impacts a number of areas, including royalties, land tenure, exploration, development, production, refining, transportation, marketing, environmental protection, exports, taxes, labor standards and health and safety standards. In addition, extensive legislation and regulation exists with respect to pricing and taxation of oil and natural gas and related products. Canadian governmental legislation and regulation may have a material effect on the financial results of our operations and may have a material adverse effect on our results of operations and our financial condition.

We may not identify all risks associated with the acquisition of oil and natural gas properties.

Generally, it is not feasible for us to review in detail every individual property involved in an acquisition. Our business strategy focuses on acquisitions of producing oil and natural gas properties. Any future acquisitions will require an assessment of recoverable reserves, future oil and natural gas prices, operating costs, potential environmental hazards and other liabilities and other similar factors. Ordinarily, our review efforts are focused on the higher-valued properties. However, even a detailed review of these properties and records may not reveal existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. We do not inspect every well that we acquire. Potential problems, such as deficiencies in the mechanical integrity of equipment or environmental conditions that may require significant remedial expenditures, are not necessarily observable even when we inspect a well. Even if we are able to identify problems with an acquisition, the seller may be unwilling or unable to provide effective contractual protection or indemnity against all or part of these problems. Even if a seller agreed to provide indemnity, we cannot assure you that the indemnity would be fully enforceable.

We have incurred significant debt that we may be unable to repay.

As of December 31, 2001, we have aggregate debt outstanding of approximately $45.0 million under our U.S. and Canadian credit agreements. This level of indebtedness could:

- increase our vulnerability to general adverse economic and industry conditions, especially declines in oil and natural gas prices;
- limit our ability to fund future acquisitions, capital expenditures and other general corporate requirements;
- require us to dedicate a material portion of our cash flow from operations to payments on our indebtedness;
- limit our flexibility in planning for, or reacting to, changes in our business and industry; or
- limit our ability to, among other things, borrow additional funds, sell assets and pay dividends.

Restrictive debt covenants limit our ability to finance our operations, fund our capital needs and engage in other business activities that may be in our interest.

Our U.S. and Canadian credit agreements contain significant covenants that, among other things, restrict our ability to:

- dispose of assets;
- incur additional indebtedness;
- repay other indebtedness;
- pay dividends;
- enter into specified investments or acquisitions;
- repurchase or redeem capital stock;
- merge or consolidate; or
- engage in specified transactions with subsidiaries and affiliates and our other corporate activities.

Also, our credit agreements require us to maintain compliance with specified financial ratios. Our ability to comply with these ratios may be affected by events beyond our control. A breach of any of these covenants or our inability to comply with the required financial ratios could result in a default under our credit agreements.

We may be unable to obtain additional financing to implement our growth strategy.

The growth of our business will require substantial capital on a continuing basis. Because we have pledged substantially all of our assets as collateral under our U.S. and Canadian credit agreements, it may be difficult for us in the foreseeable future to obtain financing on an unsecured basis or to obtain secured financing other than purchase money indebtedness. If we are unable to obtain additional capital on satisfactory terms and conditions, we may lose opportunities to acquire oil and natural gas properties and businesses. Our failure to obtain any required additional financing may have a material adverse effect on our growth, cash flow and earnings.

We may be unable to overcome risks associated with our drilling activity.

Our drilling involves numerous risks, including the risk that we will not encounter commercially productive oil or natural gas reservoirs. We must incur significant expenditures to identify and acquire properties and to drill and complete wells. The costs of drilling and completing wells is often uncertain and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including unexpected drilling conditions, pressure or irregularities in formations, equipment failures or accidents, weather conditions and shortages or delays in the delivery of equipment. While we use advanced technology in our operations, this technology does not allow us to know conclusively prior to drilling a well that oil or natural gas is present or economically producible.

Acquisition, development and exploitation activities are associated with many uncertainties that could adversely affect our business, financial condition and results of operations.

Our future success will depend on the success of our acquisition, development and exploitation activities. Our decisions to purchase, develop or otherwise exploit properties or prospects will depend in part on the evaluation of data obtained through production data and engineering studies, geophysical and geological analyses, and seismic and other data, the results of which are often inconclusive and subject to various interpretations.

We cannot control the development of a portion of our properties because our interests are in the form of non-operated working interests.

We do not operate wells that represent approximately 20% of the PV-10 (as of December 31, 2001) of our proved reserves. As a result, the success and timing of our drilling and development activities on those properties operated by others depend upon a number of factors outside of our control, including:

- the timing and amount of capital expenditures;
- the operator's expertise and financial resources;
- the approval of other participants in drilling wells; and
- the selection of suitable technology.

If drilling and development activities are not conducted on these properties, then we may not be able to increase our production or offset normal production declines on these properties.

Our estimates of oil, natural gas and NGL reserves involve inherent uncertainty.

Numerous uncertainties are inherent in estimating quantities of proved oil, natural gas and NGL reserves, including many factors beyond our control. This annual report contains estimates of our proved oil, natural gas and NGL reserves and the PV-10 generated by the proved oil, natural gas and NGL reserves. These estimates are based upon reports of our independent petroleum engineers. These reports rely upon various assumptions, including assumptions required by the SEC, as to constant oil, natural gas and NGL prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. These estimates should not be construed as the current market value of our estimated proved reserves. The process of estimating oil, natural gas and NGL reserves is complex, requiring significant decisions and assumptions in the evaluation of available geological, engineering and economic data for each reservoir. As a result, these estimates are an inherently imprecise evaluation of reserve quantities and future net revenues. Our actual future production, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil, natural gas and NGL reserves may vary substantially from those we have assumed in the estimates. Any significant variance in our assumptions could materially affect the quantity and value of reserves described in this annual report. In addition, our reserves may be revised downward or upward, based upon production history, results of future exploitation and development activities, prevailing oil and natural gas prices and other factors. A material decline in prices paid for our production can adversely impact the estimated volumes of our reserves.

We are exposed to operating hazards and uninsured risks.

Our operations are subject to the risks inherent in the oil and natural gas industry, including the risks of:

- fire, explosions and blowouts;
- pipe failures;
- abnormally pressured formations; and
- environmental accidents such as oil spills, gas leaks, ruptures or discharges of toxic gases, brine or well fluids into the environment (including groundwater contamination).

These events may result in substantial losses to us from:

- injury or loss of life;
- severe damage to or destruction of property, natural resources and equipment;
- pollution or other environmental damage;
- clean-up responsibilities;
- regulatory investigation; and
- penalties and suspension of operations.

As is customary in our industry, we maintain insurance against some, but not all, of these risks. We cannot assure you that our insurance will be adequate to cover these losses or liabilities. Further, with the turmoil in the commercial insurance industry as a result of the events of September 11, 2001, we cannot predict the continued availability of insurance at commercially acceptable premium levels or at all. We do not carry business interruption insurance. Losses and liabilities arising from uninsured or under-insured events may have a material adverse effect on our financial condition and operations.

The producing wells in which we own an interest have, from time to time, experienced reduced or terminated production. These curtailments are due primarily to mechanical failures, contract terms, pipeline and processing plant interruptions, market conditions and weather conditions, and these curtailments may last from a few days to many months.

Our business exposes us to liability and extensive regulation on environmental matters.

Our operations are subject to numerous federal, state and local laws and regulations controlling the discharge of materials into the environment or otherwise relating to the protection of the environment. Such laws and regulations not only expose us to liability for our own negligence, but may also expose us to liability for the conduct of others or for our actions which were in compliance with all applicable laws at the time these actions were taken.

Our business depends on a limited number of key personnel.

We are substantially dependent upon the skills of two key individuals within our management, Mr. Douglas H. Miller and Mr. T. W. Eubank. Both individuals have experience in acquiring, financing and restructuring oil and natural gas companies. They both previously served as senior management at Coda Energy, Inc., where they successfully implemented a strategy similar to our current strategy. We do not have employment agreements with these individuals or maintain key man insurance. The loss of the services of either one of these individuals could hinder our ability to successfully implement our business strategy.

We may have additional write-downs of our asset values.

As a result of low oil and natural gas prices on September 30, 2001, we recorded a pre-tax non-cash ceiling test write-down of $45.9 million (of which $25.0 million was from the United States full cost pool and $20.9 million was from the Canadian full cost pool). We recorded an additional pre-tax non-cash ceiling test write-down of approximately $3.7 million from our United States full cost pool during the fourth quarter of 2001 as a result of low oil and natural gas prices on December 31, 2001. Depending upon oil and natural gas prices, we may be required to further write-down the value of our oil and natural gas properties if the present value of the after-tax future cash flows from our oil and natural gas properties falls below the net book value of these properties. Additional write-downs would negatively affect our earnings and net worth, and could result in a violation of our covenants under our credit agreements.

We may not be permitted to pay cash dividends on our convertible preferred stock in some circumstances. We could also be prevented in some circumstances from paying dividends in our common shares.

The terms of our existing credit agreements restrict our ability to pay cash dividends. Our ability to pay cash dividends will depend on criteria set forth in our credit agreements. If there is a default under our credit agreements, we will not be able to pay dividends on the shares of convertible preferred stock. Even if our credit agreements permitted us to pay cash dividends, we can make those payments only from our surplus (the excess of the fair value of our total assets over the sum of our liabilities plus our total paid-in share capital). In addition, we can pay cash dividends only if after paying those dividends we would be able to pay our liabilities as they become due. We cannot assure you that we will have any surplus.

The convertible preferred stock is subordinated to all our existing indebtedness and other liabilities and will not limit our ability to incur future indebtedness that will rank senior to the convertible preferred stock.

The convertible preferred stock is subordinated to all of our indebtedness with respect to the payments of interest and amounts distributable upon our dissolution, liquidation or winding up. The terms of the convertible preferred stock do not limit the amount of indebtedness or other obligations that we may incur. Any indebtedness under our existing credit agreements will rank senior to the convertible preferred stock.

Sales, or the availability for sale, of substantial amounts of our common stock could adversely affect the value of the convertible preferred stock.

Sales of substantial amounts of common stock in the public market, and the availability of shares for future sale, including shares of our common stock issuable upon the conversion of shares of convertible preferred stock or upon exercise of outstanding options and warrants or other rights to acquire shares of our common stock, could adversely affect the prevailing market price of our common stock. This would adversely affect the value of the convertible preferred stock and could impair our future ability to raise capital through an offering of our equity securities.

Our stock price may be volatile due to small public float.

Because the number of shares of our common stock held by the public is relatively small, the sale of a substantial number of shares of our common stock, or conversion of another security into a substantial number of shares of our common stock, may adversely affect the market price of our common stock.

Our articles of incorporation may prevent a takeover attempt that you may favor.

Provisions in our articles of incorporation may delay, defer or prevent a tender offer or takeover attempt that you may consider to be in the best interest of our shareholders, including attempts that might result in a premium to be paid over the market price for the stock held by our shareholders. Our articles of incorporation permit our board to issue up to 4,995,131 additional shares of preferred stock and to establish, by resolution, one or more series of preferred stock and the powers, designations, preferences and participating, optional or other special rights of each series of preferred stock. The preferred stock may be issued on terms that are unfavorable to the holders of our common stock, including the grant of superior voting rights, the grant of preferences in favor of preferred shareholders in the payment of dividends and upon our liquidation and the designation of conversion rights that entitle holders of our preferred stock to convert their shares into our common stock on terms that are dilutive to holders of our common stock. The issuance of preferred stock in future offerings may make a takeover or change in control of us more difficult.

Our Oil, Natural Gas and NGLs Reserves

The term "proved reserves" refers to the estimated quantities of oil, natural gas and NGLs that we may be able to recover in the future from known reservoirs. "Proved developed reserves" are proved reserves that are recoverable from known oil or natural gas reservoirs with existing equipment and operating methods. "Proved undeveloped reserves" are proved reserves requiring a relatively large development expense to make them recoverable from existing wells, or are proved reserves located in our undeveloped acreage.

Other than the SEC, we have not filed any estimates or included estimates in reports to any other federal authority or agency since January 1, 2001. The following table summarizes our proved reserves at the dates shown, and was prepared according to the rules and regulations of the SEC:

	As of December 31,				
	1999	2000	2001		
	United States	United States	United States	Canada	Total
Oil (Mbbls)					
Developed	2,389	8,148	7,555	3,414	10,969
Undeveloped	355	4,230	3,498	386	3,884
Total	2,744	12,378	11,053	3,800	14,853
Natural Gas (Mmcf)					
Developed	14,741	66,497	87,868	65,230	153,098
Undeveloped	1,807	27,947	22,388	8,174	30,562
Total	16,548	94,444	110,256	73,404	183,660
Natural Gas Liquids (Mbbls)					
Developed	370	465	774	2,470	3,244
Undeveloped	—	—	13	359	372
Total	370	465	787	2,829	3,616
Total (Mmcfe)	35,232	171,502	181,296	113,178	294,474
Prices utilized:					
Oil (per Bbl)	$ 24.17	$ 24.82	$ 17.67	$ 18.02	$ 17.76
Natural gas (per Mcf)	2.00	9.26	2.22	2.24	2.23
NGLs (per Bbl)	19.21	21.50	14.25	15.33	15.09
Pre-tax Present Value *(in thousands)*					
Developed	$ 33,709	$ 288,864	$ 92,150	$ 76,127	$ 168,277
Undeveloped	3,269	107,536	13,540	7,338	20,878
Total	$ 36,978	$ 396,400	$ 105,690	$ 83,465	$ 189,155
Standardized Measure *(in thousands)*	$ 28,595	$ 282,436	$ 83,085	$ 60,444	$ 143,529

The reserve estimates presented as of December 31, 1999, 2000 and 2001, have been prepared by Lee Keeling and Associates, Inc., independent petroleum engineers, Tulsa, Oklahoma, and are a part of their report on our oil and natural gas properties. Estimates of oil, natural gas and NGL reserves are projections based on engineering data and are forward-looking in nature. These reports rely upon various assumptions, including assumptions required by the SEC, such as constant oil, natural gas and NGL prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. These reports should not be construed as the current market value of our estimated proved reserves. The process of estimating oil and natural gas reserves is also dependent on geological, engineering and economic data for each reservoir. Because of the uncertainties inherent in the interpretation of this data, we cannot ensure that the reserves will ultimately be realized. Our actual results could differ materially. See also Note 13 of the notes to our consolidated financial statements included in this annual report for additional information regarding our oil, natural gas and NGL reserves, including the present value of future net revenues.

The following table set forth our proved reserves and PV-10 by area as of December 31, 2001:

	Total Proved Reserves (Bcfe)	PV-10	Percent of PV-10
		(In thousands)	
United States:			
Permian Basin	82	$ 47,951	25%
Gulf Coast	51	25,835	14%
Mid-Continent	24	16,506	9%
East Texas/North Louisiana	14	10,854	6%
Rockies	10	4,544	2%
Total U.S.	181	105,690	56%
Canada:			
Alberta	113	83,465	44%
Total U.S. and Canada	**294**	**$189,155**	**100%**

Our Production, Prices and Expenses

The following table summarizes for the periods indicated, our revenues (including hedge settlements), net production of oil, natural gas and NGLs sold, the average sales price per unit of oil, natural gas and NGLs and costs and expenses associated with the production of oil, natural gas and NGLs:

	Year Ended December 31,				
	1999	2000	2001		
	United States	United States	United States	Canada	Total
	(In thousands, except production and per unit amounts)				
Sales:					
Oil:					
Revenue	$ 3,711	$ 11,846	$ 21,633	$ 1,739	$ 23,372
Production sold (Mbbls)	208	433	887	80	967
Average sales price per Bbl	$ 17.83	$ 27.39	$ 24.40	$ 21.71	$ 24.17
Natural Gas:					
Revenue	$ 1,583	$ 14,830	$ 29,558	$ 5,394	$ 34,952
Production sold (Mmcf)	765	3,982	6,243	2,086	8,329
Average sales price per Mcf	$ 2.07	$ 3.72	$ 4.73	$ 2.59	$ 4.20
Natural Gas Liquids:					
Revenue	$ —	$ 2,193	$ 1,826	$ 1,087	$ 2,913
Production sold (Mbbls)	—	89	96	68	164
Average sales price per Bbl	$ —	$ 24.60	$ 18.96	$ 15.92	$ 17.70
Costs and Expenses:					
Average production cost per Mcfe	$ 1.18	$ 1.32	$ 1.76	$ 0.85	$ 1.59
General and administrative expense per Mcfe	$ 0.96	$ 0.28	$ 0.34	$ 0.23	$ 0.32
Depreciation, depletion and amortization per Mcfe	$ 0.72	$ 0.69	$ 0.80	$ 1.50	$ 0.94

Our Interest in Productive Wells

The following table sets forth our interest in productive wells (wells that are currently producing oil or natural gas or are capable of production), including temporarily shut-in wells on December 31, 2001. The number of total gross oil and natural gas wells excludes any multiple completions. Gross wells refers to the total number of physical wells that we hold any working interest in, regardless of our percentage interest. A net well is not a physical well, but is actually a concept that reflects the actual total working interests we hold in all wells. We compute the number of net wells we own by totaling the percentage interests we hold in all our gross wells.

	Gross Wells (1)			Net Wells		
	Oil	Gas	Total	Oil	Gas	Total
United States:						
Louisiana	36	29	65	23.9	18.2	42.1
Mississippi	46	0	46	32.7	0	32.7
New Mexico	87	80	167	6.3	33.3	39.6
Oklahoma	43	36	79	35.2	6.8	42.0
Texas	922	177	1,099	172.2	95.2	267.4
Other (2)	260	82	342	89.2	30.3	119.5
Total	1,394	404	1,798	359.5	183.8	543.3
Canada:						
Alberta	83	124	207	69.4	102.9	172.3
Total	**1,477**	**528**	**2,005**	**428.9**	**286.7**	**715.6**

(1) As of December 31, 2001, we owned interests in six gross wells with multiple completions.

(2) Other includes Colorado, Kansas, Nebraska, North Dakota and Wyoming.

As of December 31, 2001, we were the operator of 621 gross (451 net) wells, which represented approximately 80% of our PV-10.

Our Drilling Activities

We intend to continue concentrating our drilling activity on lower risk, development-type properties. The number and types of wells we drill will vary depending on the amount of funds we have available for drilling, the cost of each well, the size of the fractional working interests we acquire in each well and the estimated recoverable reserves attributable to each well.

The following table summarizes our approximate gross and net interests in the development wells drilled during the years indicated and refers to the number of wells completed at any time during the year, regardless of when drilling was initiated:

	Development Wells					
	Gross			Net		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 1999 (U.S. Only)	2	2	4	1.3	1.4	2.7
Year ended December 31, 2000 (U.S. Only)	11	—	11	3.9	—	3.9
Year ended December 31, 2001						
United States	32	4	36	17.0	1.0	18.0
Canada	9	1	10	8.6	1.0	9.6
Total	**41**	**5**	**46**	**25.6**	**2.0**	**27.6**

During the three year period ended December 31, 2001, we participated in one gross (.4 net) exploratory well which was a dry hole. This well was drilled during 1999. The drilling activities during 2001 in the United States referenced in the above table were conducted in Texas, Mississippi, New Mexico and Kansas. The drilling activities during 2001 in Canada referenced in the above table were conducted in Alberta. On December 31, 2001, in the U.S., we owned a 100% working interest in each of three wells awaiting completion, a 60% working interest and a 50% working interest in two wells awaiting final facilities hook-up, and a 94% working interest in a well being evaluated for completion. On December 31, 2001, in Canada, we owned an average working interest of 92% in five wells awaiting final facilities hook-up. As of March 15, 2002, we owned an interest in one well (30% working interest) in Pecos County, Texas that was being drilled by another operator. In Alberta, Canada, we were drilling two wells. One well (72% working interest) is located in the Pine Creek Field and the second well (94% working interest) is located in the Caroline Field. The drilling and completion of these wells is expected to cost us approximately $2.5 million.

Summary of Our Development and Exploitation Projects

We are currently pursuing an active development and exploitation strategy. For the year 2002 we have budgeted up to $21 million for development drilling, recompletions, production facilities and other exploitation related projects to implement this strategy. As of March 15, 2002, we were participating in a pressure maintenance project at the Righthand Creek Field (60% working interest) in Allen Parish, Louisiana, and in a non-operated waterflood project (90% working interest) in the Milroy Field, Carter County, Oklahoma. Set forth below are highlights of our other current and planned activities.

Vinegarone Field

The Vinegarone Field is a natural gas field located in Val Verde County, Texas. We hold working interests ranging from less than 2% to 100% in 23 producing wells, of which we operate 20 wells. The wells produce from the Strawn formation at depths from 10,000 to 10,500 feet. We drilled and completed a well during the fourth quarter of 2001. This well is currently waiting on a pipeline connection. We currently plan to drill an additional well during 2002.

Gomez Field

The Gomez Field is a natural gas field located in Pecos County, Texas. We hold working interests ranging from less than 1% to 73%. We operate five of the eight producing wells in which we have an interest. Production is primarily from the Ellenburger formation at a depth of approximately 22,000 feet. During 2001, we attempted to drill the Leon #2 well to the Wolfcamp formation at approximately 15,700 feet. A blowout occurred while we were drilling at a depth of 15,878 feet. The well was successfully controlled and eventually plugged and abandoned. We believe that insurance will cover most of the cost of the blowout as well as the majority of the cost of the replacement well. We started drilling the replacement well, the Leon #3, in February 2002.

Tiger Field

The Tiger Field is an oil and natural gas field located in Jones and Perry Counties, Mississippi. We hold an 88.3% working interest in this field. We operate four wells that produce from the Hosston and Cotton Valley formations at depths from 14,300 to 15,400 feet. We drilled a well during 2001 that was being evaluated at year-end. We plan to drill an infill well during 2002.

Pecos Slope Field

The Pecos Slope Field is a natural gas field located in Chaves County, New Mexico. We have working interests ranging from 12.5% to 100% in 26 wells, 19 of which we operate. Production is from the Abo formation at depths from 3,700 to 4,500 feet. Five infill wells were drilled during 2001, of which four were successful and are waiting on pipeline connection. We plan to drill three additional infill wells during 2002.

Garrington Field

The Garrington Field is located in Alberta, Canada and produces oil and natural gas from Cretaceous and Mississippian formations at an average depth of 8,000 feet. We have an average working interest of 79% in 58 producing wells, 49 of which we operate. We plan to complete 20 exploitation projects in the Garrington Field during 2002, which include recompletions, lift optimizations and facility expansions.

Pine Creek Field

The Pine Creek Field is an oil and natural gas field located in Alberta, Canada. We hold working interests ranging from 66.7% to 100% in 30 producing wells, of which we operate. Pine Creek produces from Cretaceous formations at depths from 6,000 to 8,600 feet. We have identified five development locations to be drilled in this field during 2002.

Caroline Field

The Caroline Field produces oil and natural gas from Cretaceous formations at an average depth of 9,000 feet. It is located in Alberta, Canada and is adjacent to our Garrington Field. We have an average working interest of 87% in 33 producing wells, 32 of which we operate. We drilled four wells in the Caroline Field during 2001 and plan to drill two additional wells in 2002.

Westward Ho Field

The Westward Ho Field is located in Alberta, Canada and produces oil and natural gas from Cretaceous and Mississippian formations at an average depth of 8,000 feet. It is also located adjacent to the Garrington Field. We have an average 83% working interest in 33 wells and operate 29 of those wells. We plan to drill two wells and complete five exploitation projects in the Westward Ho Field during 2002.

Lacombe Field

The Lacombe Field, located in Alberta, Canada, produces natural gas from Cretaceous formations at depths from 800 to 5,500 feet. We operate six of seven wells in this field and our working interests range from 75% to 100%. We have identified four development locations to be drilled in 2002.

Our Interest in Developed and Undeveloped Acreage

Developed acreage are those acres spaced or assignable to producing wells. Undeveloped acreage are those acres that do not currently have completed wells capable of producing commercial quantities of oil or natural gas, regardless of whether the acreage contains proved reserves. The following table sets forth our interest in developed and undeveloped acreage at December 31, 2001:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
United States:				
Louisiana	32,124	15,134	10,527	7,546
Mississippi	8,900	3,781	4,546	3,573
Nebraska	22,011	6,892	8,918	2,429
New Mexico	30,083	11,682	9,795	5,112
Texas	83,503	34,737	31,451	16,569
Other (1)	55,285	18,812	13,344	4,182
Total	231,906	91,038	78,581	39,411
Canada:				
Alberta	76,980	59,806	63,296	49,507
Total	**308,886**	**150,844**	**141,877**	**88,918**

(1) Other includes Colorado, Kansas, Montana, North Dakota, Oklahoma and Wyoming.

The primary terms of our oil and natural gas leases expire at various dates, generally ranging from one to five years. Almost all of our undeveloped acreage is "held by production," which means that these leases are active as long as we produce oil or natural gas from the acreage. Upon ceasing production, these leases will expire.

Sales of Producing Properties and Undeveloped Acreage

We evaluate our portfolio of properties on an ongoing basis to determine the economic viability of the properties and whether these properties enhance our objectives. During the course of normal business, we may dispose of producing properties and undeveloped acreage if we believe that it is in our best interest.

In 2001, we sold our interest in several producing oil and natural gas properties, including selected royalty and overriding royalty interests for $1.4 million. In 2000, we sold a portion of our interest in one group of producing oil and natural gas properties in Louisiana for $417,000 and a group of royalty interests in producing oil and natural gas properties located in various states for $491,000. In 1999, we received an unsolicited proposal to sell our interest in a property for approximately $20.1 million resulting in a net gain of approximately $5.6 million.

Our Products, Markets and Revenues

United States

We produce oil, natural gas and NGLs. We do not refine or process the oil we produce. With the exception of our Black Lake Field in Louisiana, we do not refine or process a significant volume of the natural gas or NGLs we produce. At the Black Lake Field we operate a natural gas processing plant which is 100% dedicated to production from the field.

We sell the majority of the oil we produce under short-term contracts using market sensitive pricing. The majority of our contracts are based on New York Mercantile Exchange (NYMEX) pricing, which is typically calculated as the average of the daily closing prices of oil to be delivered one month in the future. We also sell a portion of our oil at F.O.B. field prices posted by the principal purchaser of oil where our producing properties are located. Our sales contracts are of a type common within the industry, and we negotiate a separate contract for each property. Generally, we sell our oil to purchasers and refiners near the areas of our producing properties.

We sell the majority of the natural gas we produce under short-term contracts using market sensitive pricing. The majority of our contracts are based on NYMEX pricing, which is typically calculated as the average of the closing prices on the last three traded days for natural gas to be delivered one month in the future. We also sell a portion of our natural gas based on posted indexes in the areas of our producing properties. Our sales contracts are of a type common within the industry, and we negotiate a separate contract for each property. We sell our natural gas to transmission and utility companies that have pipelines in the vicinity of our producing properties or to companies that will construct pipelines to our properties.

We sell the NGLs we produce under both short-term and long-term contracts. We sell the NGLs to refiners and processors in the vicinity of our producing properties. Our sales contracts are of a type common within the industry, and we negotiate a separate contract for each property. Typically, the prices we receive are based on the Oil Price Information Service (OPIS) index, less transportation and fractionating fees.

The availability of a ready market for oil, natural gas and NGLs and the prices of oil, natural gas and NGLs are dependent upon a number of factors that are beyond our control. These factors include, among other things:

- the level of domestic production and economic activity generally;
- the availability of imported oil and natural gas;

- actions taken by foreign oil producing nations;
- the cost and availability of natural gas pipelines with adequate capacity and other transportation facilities;
- the cost and availability of other competitive fuels, fluctuating and seasonal demand for oil, natural gas and refined products; and
- the extent of governmental regulation and taxation (under both present and future legislation) of the production, refining, transportation, pricing, use and allocation of oil, natural gas, refined products and substitute fuels.

Accordingly, in view of the many uncertainties affecting the supply and demand for oil, natural gas and refined petroleum products, we cannot accurately predict the prices or marketability of the oil, natural gas or NGLs from any producing well in which we have or may acquire an interest.

We cannot assure you that we will be able to market all the oil, natural gas or NGLs we produce. If our oil, natural gas or NGLs can be marketed, we cannot assure you that we can negotiate favorable price and contractual terms. Changes in oil or natural gas prices may significantly affect our revenues, cash flows, the value of our oil and natural gas properties, and the estimates of recoverable oil, natural gas and NGLs contained in our properties. Further, significant declines in the prices of oil or natural gas may have a material adverse effect on our business and on our financial condition.

We engage in oil and natural gas production activities in areas where, from time to time, the supply of oil or natural gas available for delivery exceeds the demand. In this situation, companies purchasing oil or natural gas in these areas reduce the amount of oil or natural gas that they purchase from us. If we cannot locate other buyers for our production or for any of our newly discovered oil or natural gas reserves, we may shut-in our oil or natural gas wells for periods of time.

Canada

Addison sells the majority of its oil to Plains Marketing Canada, L.P. at market sensitive prices less applicable tariffs, trucking and quality adjustments.

Addison's natural gas is marketed primarily through a negotiated contract with Engage Energy America, LLC (Engage) at market sensitive prices less actual transportation and fuel costs. We have a firm delivery commitment to Engage for 5,200 Mmbtus per day through November 30, 2002. The remaining volumes are being sold to Engage under a natural gas sales contract that can be terminated with 30 days notice.

Addison's NGLs are sold primarily to three different buyers under contracts which provide for index pricing less transportation and fraction fees.

Revenues

The following table sets forth the amount of our oil, natural gas and NGL sales (including hedge settlements) and the percent of these sales to total oil, natural gas and NGL revenues for the periods indicated (in thousands):

Period Ended	Oil Sales	Natural Gas Sales	NGL Sales	Total Oil, Natural Gas and NGL Sales	Percent of Sales to Total Oil, Natural Gas and NGL Revenues		
					Oil	Natural Gas	NGLs
Year ended December 31, 1999 (1)	$ 3,711	$ 1,583	$ —	$ 5,294	70%	30%	—
Year ended December 31, 2000 (1)	$ 11,846	$ 14,830	$ 2,193	$ 28,869	41%	51%	8%
Year ended December 31, 2001							
United States	$ 21,633	$ 29,558	$ 1,826	$ 53,017	41%	56%	3%
Canada	1,739	5,394	1,087	8,220	21%	66%	13%
Total	$ 23,372	$ 34,952	$ 2,913	$ 61,237	38%	57%	5%

(1) Information is for United States only.

Our Principal Customers

During 2001, sales of oil to Plains All American, Inc. and affiliates and sales of natural gas to Western Gas Resources, Inc. accounted for 14.5% and 11.8%, respectively, of our total oil and natural gas revenues. If we were to lose any one of our oil and natural gas purchasers, the loss could temporarily cease or delay production and sale of our oil and natural gas in that particular purchaser's service area. Under current economic circumstances, however, if we were to lose a purchaser, we believe we could identify a substitute purchaser.

During 2000, sales of oil and natural gas to three purchasers, Western Gas Resources, Inc., Plains All American, Inc. and OneOk Gas Marketing, LLC accounted for 23.6%, 19.9% and 11.9%, respectively, of our total oil and natural gas revenues. During 1999, sales of oil and natural gas to two purchasers, Plains All American, Inc. and EOTT Energy Operating Limited Partnership, accounted for 36% and 27%, respectively, of our total oil and natural gas revenues.

We Encounter Strong Competition

The oil and natural gas industry is highly competitive. We encounter strong competition from other independent operators and from major oil companies in acquiring properties, contracting for drilling equipment and securing trained personnel. Many of these competitors have financial and technical resources and staffs substantially larger than those available to us. As a result, our competitors may be able to pay more for desirable leases, or to evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources will permit.

We are also affected by competition for drilling rigs and the availability of related equipment. In the past, the oil and natural gas industry has experienced shortages of drilling rigs, equipment, pipe and personnel, which has delayed development drilling and other exploitation activities and caused significant price increases. We are unable to predict when, or if, such shortages may again occur or how they would affect our development and exploitation program.

Competition is also strong for attractive oil and natural gas producing properties, undeveloped leases and drilling rights, and we cannot assure you that we will be able to compete satisfactorily. Many large oil companies have been actively marketing some of their existing producing properties for sale to independent producers. We cannot assure you that we will be successful in acquiring any of these properties.

We are Affected by Various Laws and Regulations

U.S. Regulations

The availability of a ready market for oil and natural gas production depends upon numerous factors beyond our control. These factors include state and federal regulation of oil and natural gas production and transportation, as well as regulations governing environmental quality and pollution control, state limits on allowable rates of production by a well or proration unit, the amount of oil and natural gas available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. For example, a productive natural gas well may be "shut-in" because of an over-supply of natural gas or lack of an available natural gas pipeline in the areas in which we may conduct operations. State and Federal regulations generally are intended to prevent waste of oil and natural gas, protect rights to produce oil and natural gas between owners in a common reservoir, control the amount of oil and natural gas produced by assigning allowable rates of production and control contamination of the environment. Pipelines and gas plants also are subject to the jurisdiction of various Federal, state and local agencies.

Our sales of natural gas are affected by the availability, terms and costs of transportation. The rates, terms and conditions applicable to the interstate transportation of gas by pipelines are regulated by the Federal Energy Regulatory Commission (FERC) under the Natural Gas Acts, as well as under Section 311 of the Natural Gas Policy Act. Since 1985, the FERC has implemented regulations intended to increase competition within the natural gas industry by making natural gas transportation more accessible to gas buyers and sellers on an open-access, non-discriminatory basis.

Our sales of oil are also affected by the availability, terms and costs of transportation. The rates, terms, and conditions applicable to the interstate transportation of oil by pipelines are regulated by the FERC under the Interstate Commerce Act. In this connection, FERC has implemented a simplified and generally applicable rate-making methodology for interstate oil pipelines to fulfill the requirements of Title VII of the Energy Policy Act of 1992 comprised of an indexing system to establish ceilings on interstate oil pipeline rates. The FERC has announced several important transportation-related policy statements and rule changes, including a statement of policy and final rule issued February 25, 2000 concerning alternatives to its traditional cost-of-service rate-making methodology to establish the rates interstate pipelines may charge for their services. The final rule revises FERC's pricing policy and current regulatory framework to improve the efficiency of the market and further enhance competition in natural gas markets.

With respect to transportation of natural gas on or across the Outer Continental Shelf (OCS), the FERC requires, as a part of its regulation under the Outer Continental Shelf Lands Act (OCSLA), that all pipelines provide open and non-discriminatory access to both owner and non-owner shippers. Although to date the FERC has imposed light-handed regulation on offshore facilities that meet its traditional test of gathering status, it has the authority to exercise jurisdiction under the OCSLA over gathering facilities, if necessary, to permit non-discriminatory access to service. For those facilities transporting natural gas across the OCS that are not considered to be gathering facilities, the rates, terms and conditions applicable to this transportation are regulated by FERC under the NGA and NGPA, as well as the OCSLA. With respect to the transportation of oil and condensate on or across the OCS, the FERC requires, as part of its regulation under the OCSLA, that all pipelines provide open and non-discriminatory access to both owner and non-owner shippers. Accordingly, the FERC has the authority to exercise jurisdiction under the OCSLA, if necessary, to permit non-discriminatory access to service.

In the event we conduct operations on federal, state or Indian oil and gas leases, such operations must comply with numerous regulatory restrictions, including various nondiscrimination statutes, royalty and related valuation requirements, and certain of such operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by the Bureau of Land

Management (BLM) or Minerals Management Service (MMS) or other appropriate federal or state agencies.

Our OCS leases in federal waters are administered by the MMS and require compliance with detailed MMS regulations and orders. The MMS has promulgated regulations implementing restrictions on various production-related activities, including restricting the flaring or venting of natural gas. Under certain circumstances, the MMS may require any operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition and operations. On March 15, 2000, the MMS issued a final rule effective June 1, 2000, that amends its regulations governing the calculation of royalties and the valuation of crude oil produced from federal leases. Among other matters, this rule amends the valuation procedure for the sale of federal royalty oil by eliminating posted prices as a measure of value and relying instead on arm's length sales prices and spot market prices as market value indicators. Because we generally sell our production to third parties and therefore pay royalties on production from federal leases, it is not anticipated that this final rule will have any substantial impact on us.

The Mineral Leasing Act of 1920 (the Mineral Act) prohibits direct or indirect ownership of any interest in federal onshore oil and natural gas leases by a foreign citizen of a country that denies "similar or like privileges" to citizens of the United States. Such restrictions on citizens of a "non-reciprocal" country include ownership or holding or controlling stock in a corporation that holds a federal onshore oil and gas lease. If this restriction is violated, the corporation's lease can be canceled in a proceeding instituted by the United States Attorney General. Although the regulations of the BLM (which administers the Mineral Act) provide for agency designations of non-reciprocal countries, there are presently no such designations in effect. We own interest in federal onshore oil and gas leases. It is possible that some of our shareholders may be citizens of foreign countries, which at some time in the future might be determined to be non-reciprocal under the Mineral Act.

Our pipelines used to gather and transport our oil and natural gas may be subject to regulation by the Department of Transportation (DOT) under the Hazardous Liquids Pipeline Safety Act of 1979, as amended (HLPSA) relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Where applicable, the HLPSA requires us and other pipeline operators to comply with regulations issued pursuant to HLPSA designed to permit access to and allowing copying of records and to make certain reports and provide information as required by the Secretary of Transportation.

The Pipeline Safety Act of 1992 (the Pipeline Safety Act) amends the HLPSA in several important respects. It requires the Research and Special Programs Administration (RSPA) of DOT to consider environmental impacts, as well as its traditional public safety mandate, when developing pipeline safety regulations. In addition, the Pipeline Safety Act mandates the establishment by DOT of pipeline operator qualification rules requiring minimum training requirements for operators, and requires that pipeline operators provide maps and records to RSPA. It also authorizes RSPA to require certain pipeline modifications as well as operational and maintenance changes. We believe our pipelines are in substantial compliance with the HLPSA and the Pipeline Safety Act where such regulations are applicable. Nonetheless, we could incur significant expenses if new or additional safety measures are required.

U.S. Federal Taxation

The federal government may propose tax initiatives that affect us. We are unable to determine what effect, if any, future proposals would have on product demand or our results of operation.

U.S. Environmental Regulation

The exploration, development and production of oil and natural gas, including the operation of saltwater injection and disposal wells, is subject to various federal, state and local environmental laws and regulations. These laws and regulations can increase the costs of planning, designing, installing and operating oil and natural gas wells. Our domestic activities are subject to federal environmental laws and regulations, including, but not limited to:

- the Oil Pollution Act of 1990 (OPA);
- the Clean Water Act (CWA);
- the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA);
- the Resource Conservation and Recovery Act (RCRA);
- the Clean Air Act (CAA); and
- the Safe Drinking Water Act (SDWA).

Our domestic activities are also controlled by state regulations promulgated under comparable state statutes. We also are subject to regulations governing the handling, transportation, storage and disposal of naturally occurring radioactive materials that are found in our oil and natural gas operations. Civil and criminal fines and penalties may be imposed for non-compliance with these environmental laws and regulations. Additionally, these laws and regulations require the acquisition of permits or other governmental authorizations before undertaking certain activities, limit or prohibit other activities because of protected areas or species, can impose certain substantial liabilities for the cleanup of pollution, impose certain reporting requirements, and can require substantial expenditures for compliance.

Under OPA and CWA, our release of oil and hazardous substances into or upon waters of the United States, adjoining shorelines and wetlands, and offshore areas could result in our being held responsible for the (1) costs of remediating a release, (2) administrative and civil penalties or criminal fines, (3) OPA specified damages such as loss of use, and for natural resource damages. The extent of liability could be extensive depending upon the circumstances of the release. Liability can be joint and several and without regard to fault. The CWA also may impose permitting obligations for certain discharges of pollutants and requirements to develop Spill Prevention Control and Countermeasure Plans and Facility Response Plans to address potential discharges of oil into or upon waters of the United States and adjoining shorelines.

CERCLA and comparable state statutes, also known as Superfund laws, can impose joint, several and retroactive liability, without regard to fault or the legality of the original conduct, on specified classes of persons for the release of a "hazardous substance" into the environment. In practice, cleanup costs are usually allocated among various responsible parties. Liability can arise from conditions on properties where operations are conducted and/or from conditions at third party disposal facilities where wastes from operations were sent. Although CERCLA, as amended, currently exempts petroleum, (including oil, natural gas and NGLs) from the definition of hazardous substance, some similar state statutes do not provide such an exemption. Additionally, our operations may involve the use or handling of other materials that may be classified as hazardous substances under CERCLA and similar state statutes. We cannot assure you that the exemption will be preserved in any future amendments of the act.

RCRA and comparable state and local programs impose requirements on the management, including treatment, storage and disposal, of both hazardous and nonhazardous solid wastes. Although we believe we have utilized operating and waste disposal practices that were standard in the industry at the time, hydrocarbons or other solid wastes may have been disposed or released on or under the properties we own or lease or on or under locations where such wastes have been taken for disposal. In addition, many of these properties have been owned or operated by third parties. We have not had control over such parties' treatment of hydrocarbons or other solid wastes and the manner in which such substances may have been disposed or released. We generate hazardous and nonhazardous solid waste in our routine operations. From time to time, proposals have been made that would reclassify certain oil and natural gas wastes, including wastes generated during pipeline, drilling and production operations, as "hazardous wastes" under RCRA, which would make these solid wastes subject to much more stringent handling, transportation, storage, disposal and clean-up requirements. This development could have a significant impact on our operating costs. While state laws vary on this issue, state initiatives to further regulate oil and natural gas wastes could have a similar impact on our operations.

Oil and natural gas exploration and production, and possibly other activities, have been conducted at the majority of our properties by previous owners and operators. Materials from these operations remain on some of the properties and in some instances require remediation. In some instances we have agreed to indemnify the sellers of producing properties from whom we have acquired reserves against certain liabilities for environmental claims associated with the properties. We do not believe the costs to be incurred by us for compliance and remediating previously or currently owned or operated properties will be material, but we cannot guarantee that potential costs would not result in material expenditures.

If in the course of our routine oil and natural gas operations, surface spills and leaks, including casing leaks of oil or other materials occur, we may incur penalties and costs for waste handling, remediation and third party actions for damages. Moreover, we are able to directly control the operations of only the wells that we operate. Notwithstanding our lack of control over wells owned by us but operated by others, the failure of the operator to comply with applicable environmental regulations may be attributable to us and may create legal liabilities for us.

We do not anticipate that we will be required in the near future to expend amounts that are material in relation to our total capital expenditures program by reason of environmental laws and regulations, but inasmuch as these laws and regulations are frequently changed and interpreted, we are unable to predict the ultimate cost of compliance. We cannot assure you that more stringent laws and regulations protecting the environment will not be adopted or that we will not incur material expenses in complying with environmental laws and regulations in the future. If substantial liabilities to third parties or governmental entities were incurred, the payment of such claims may reduce or eliminate the funds available for project investment or result in loss of our properties. Although we maintain insurance coverage we consider to be customary in the industry, we are not fully insured against all of these risks, either because insurance is not available or because of high premium costs. Accordingly, we may be subject to liability or may lose substantial portions of properties due to hazards that cannot be insured against or have not been insured against due to prohibitive premium costs or for other reasons. The imposition of any of these liabilities on us may have a material adverse effect on our financial condition and results of operations.

OSHA and other regulations

We are subject to the requirements of the federal Occupational Safety and Health Act (OSHA) and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under the Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in substantial compliance with these applicable requirements and with other OSHA and comparable requirements.

Canadian Laws and Regulations

General

The oil and natural gas industry is subject to extensive controls and regulations imposed by various levels of government. The provincial government of Alberta has legislation and regulations which govern land tenure, royalties, production rates, environmental protection, the prevention of waste and other matters. Although it is not expected that these controls and regulations will affect our operations in a manner materially different than they would affect other oil and gas companies of similar size, the controls and regulations should be considered carefully by investors in the oil and gas industry. Outlined below are some of the principal aspects of legislation and regulations governing the oil and gas industry. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments may be enacted.

Pricing and Marketing—Oil

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. The prices we receive depend, in part, on oil type and quality, prices of competing fuels, distance to market, the value of refined products and the supply/demand balance and other contractual terms. Oil exports from Canada may be made pursuant to export contracts with terms not exceeding one year, in the case of light crude, and not exceeding two years, in the case of heavy crude, provided that an order approving any such export has been obtained from the National Energy Board (NEB). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export license from the NEB and the issue of such a license requires governmental approval.

Pricing and Marketing—Natural Gas

In Canada, producers of natural gas negotiate sales contracts directly with natural gas purchasers. The price of natural gas sold in intraprovincial, interprovincial and international trade is determined by negotiations between buyers and sellers. The price we receive depends, in part, on natural gas quality, prices of competing natural gas and other fuels, distance to market, access to downstream transportation, length of contract term, weather conditions, the supply/demand balance and other contractual terms. Natural gas exported from Canada is subject to regulation by the NEB and the government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain criteria prescribed by the NEB and the government of Canada. Natural gas exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 cubic meters per day), must be made pursuant to a NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity, requires an exporter to obtain an export license from the NEB and the issue of such a license requires governmental approval.

The provincial government of Alberta also regulates the volume of natural gas which may be removed from Alberta for consumption elsewhere, based on such factors as reserve availability, transportation arrangements and market considerations.

Pipeline Capacity

Although pipeline expansions are ongoing, the lack of firm natural gas pipeline capacity continues to affect the ability to produce and market natural gas production. The prorating of capacity on the interprovincial pipeline systems may also affect the ability to export oil.

The North American Free Trade Agreements

On January 1, 1994 the North American Free Trade Agreement, NAFTA, among the governments of Canada, the U.S. and Mexico became effective. NAFTA carries forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the U.S. or Mexico will be allowed, provided that any export restrictions do not:

- reduce the proportion of energy resource exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period);
- impose an export price higher than the domestic price; and
- disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

Land Tenure

Oil and natural gas located in the western provinces is owned predominately by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licenses and permits for varying terms and conditions set forth in provincial legislation which may include requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are generally granted by lease on such terms and conditions as may be negotiated.

Royalties and Incentives

For crude oil, natural gas and related product production from Crown lands, the royalty regime is a significant factor in the profitability of such production operations. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is also subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on the type of product being produced, well productivity, geographical location and field discovery date.

From time to time the provincial government of Alberta has established incentive programs for exploration and development. Such programs often provide for royalty reductions and royalty holidays, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. The trend in recent years has been for provincial governments to allow such programs to expire without renewal, and consequently few such programs are currently operative.

On October 13, 1992, the provincial government of Alberta implemented major changes in its royalty structure and created incentives for exploring and developing oil and natural gas reserves. The incentives created include: (1) a one year royalty holiday on new oil discovered on or after October 1, 1992; (2) incentives by way of royalty holidays and reduced royalties on reactivated, low productivity, vertical re-entry and horizontal wells; (3) introduction of separate par pricing for light/medium and heavy oil; and (4) a modification of the royalty formula structure through the implementation of the Third Tier Royalty with a base rate of 2% and a rate cap of 27% for oil pools discovered after September 30, 1992. The new oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 30%. The old oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 39%.

In Alberta, the royalty reserved to the Crown in respect of natural gas production, subject to various incentives, is between 15% and 30%, in the case of new gas, and between 15% and 35%, in the case of old gas, depending upon a prescribed or corporate average reference price.

In Alberta, certain producers of oil or natural gas are also entitled to a credit against the royalties payable to the Alberta Crown by virtue of the Alberta royalty tax credit program, ARTC. The ARTC program is based on a price-sensitive formula, and the ARTC rate varies between 75%, at prices for oil below CDN $100 per cubic meter, and 25%, at prices above $210 per cubic meter. The ARTC rate is applied to a maximum of $2,000,000 of Alberta Crown royalties payable for each producer or associated group of producers. Crown royalties on production from producing properties acquired from companies claiming maximum entitlement to ARTC will generally not be eligible for ARTC. The ARTC rate is established quarterly based on the average "par price," as determined by the Alberta Resource Development Department for the previous quarterly period. On December 22, 1997, the Government of Alberta gave notice that they intended to review the ARTC program with the objective of setting out better target objectives for a smaller program and to deal with administrative difficulties. On August 30, 1999, the Government of Alberta announced that it would not be reducing the size of the program, but that it would introduce new rules to reduce the number of persons who qualify for the program. The new rules will preclude companies that pay less than $10,000 in royalties per year and non-corporate entities from qualifying for the program.

Crude oil and natural gas royalty holidays for specific wells and royalty reduction reduce the amount of Crown royalties paid by us to the provincial governments. The ARTC provides a rebate on Alberta Crown royalties paid in respect of eligible producing properties.

Canadian Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulation pursuant to provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced or utilized in association with certain oil and gas industry operations. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. As well, applicable environmental laws may impose remediation obligations with respect to property designated as a contaminated site upon certain responsible persons, which include persons responsible for the substance causing the contamination, persons who caused the release of the substance and any past or present owner, tenant or other person in possession of the site. Compliance with such legislation can require significant expenditures. A breach of such legislation may result in the imposition of material fines and penalties, the revocation of necessary licenses and authorizations and civil liability for pollution damage.

In Alberta, environmental compliance is governed by the *Alberta Environmental Protection and Enhancement Act*, AEPEA. In addition to replacing a variety of older statutes which related to environmental matters, the AEPEA imposes certain new environmental responsibilities on oil and natural gas operators in Alberta and in certain instances also imposes greater penalties for violations.

We will be taking such steps as required to ensure compliance with the AEPEA and similar legislation in other jurisdictions in which it operates. We believe that we are in material compliance with applicable environmental laws and regulations. We also believe that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards.

Title to Our Properties

When we acquire developed properties, we conduct a title investigation. However, when we acquire undeveloped properties, as is common industry practice, we usually conduct little or no investigation of title other than a preliminary review of local mineral records. We do conduct title investigations and, in most cases, obtain a title opinion of local counsel before we begin drilling operations. We believe that the methods we utilize for investigating title prior to acquiring any property are consistent with practices customary in the oil and natural gas industry and that our practices are adequately designed to enable us to acquire good title to properties. However, some title risks cannot be avoided, despite the use of customary industry practices.

Our properties are generally burdened by:

- customary royalty and overriding royalty interests;
- liens incident to operating agreements; and
- liens for current taxes and other burdens and minor encumbrances, easements and restrictions.

We believe that none of these burdens either materially detract from the value of our properties or materially interfere with property use in the operation of our business. Substantially all of our properties are pledged as collateral under our U.S. and Canadian credit agreements.

Our Employees

As of December 31, 2001, we employed 93 persons (68 in the United States and 25 in Canada) of which 13 were involved in field operations and 80 were engaged in office and administrative activities. None of our employees are represented by unions or covered by collective bargaining agreements. To date, we have not experienced any strikes or work stoppages due to labor problems, and we consider our relations with our employees to be good. We also utilize the services of independent consultants on a contract basis.

Our Officers

Douglas H. Miller, 54, became our Chairman and Chief Executive Officer in December 1997. Mr. Miller was Chairman of the Board and Chief Executive Officer of Coda Energy, Inc., an independent oil and natural gas company, from October 1989 until November 1997 and served as a director of Coda from 1987 until November 1997.

T. W. Eubank, 59, became our President, Treasurer and a director in December 1997. Mr. Eubank was a consultant to various private companies from February 1996 to December 1997. Mr. Eubank served as President of Coda from March 1985 until February 1996. He was a director of Coda from 1981 until February 1996.

J. Douglas Ramsey, Ph.D., 41, became our Chief Financial Officer and a Vice President in December 1997. Dr. Ramsey has been one of our directors since March 1998. Dr. Ramsey most recently was Financial Planning Manager of Coda and worked in various capacities for Coda from 1992 until 1997. Dr. Ramsey also taught finance at Southern Methodist University.

Charles R. Evans, 48, joined us in February 1998, became a Vice President in March 1998, and was named our Chief Operating Officer in December 2000. Mr. Evans graduated from Oklahoma University with a B.S. degree in Petroleum Engineering in 1976. After working for Sun Oil Co., he joined TXO Production Corp. in 1979 and was appointed Vice President of Engineering and Evaluation in 1989. In 1990 he was named Vice President of Engineering and Project Development for Delhi Gas Pipeline Corporation, a natural gas gathering, processing and marketing company. Mr. Evans served as Director—Environmental Affairs and Safety for Delhi until December 1997.

Richard E. Miller, 47, became General Counsel, General Land Manager and Secretary of EXCO in December 1997 and became a Vice President in July 2000. Mr. Miller was a senior partner and head of the Energy Section of Gardere & Wynne, L.L.P., a Dallas based law firm, from December 1991 to September 1994. Mr. Miller practiced law as a sole practitioner from September 1994 to December 1997.

J. David Choisser, CPA, 51, joined us in October 2001 and became the Chief Accounting Officer in November 2001, and a Vice President in February 2002. He began his career in 1972 with Deloitte Haskins & Sells (now Deloitte & Touche) and has served in various financial and accounting management capacities with several energy and energy-related companies, including Delhi Gas Pipeline Corporation, Coda Energy, Inc., Belco Oil & Gas Corp., and The Meridian Resource Corporation during the past 25 years. He most recently served as Vice President—Finance of Noble Denton & Associates, Inc., an offshore engineering and marine consulting company.

W. Andy Bracken, CPA, 37, joined us in October 1998 and became our Controller in April 2000. Mr. Bracken was a trust and operational internal auditor for Bank One, Louisiana, N.A. from April 1991 to April 1996 and NationsBank, N.A. from April 1996 to April 1997. He then served as an accounting manager for Bank One, Texas, N.A. from April 1997 to October 1998.

Richard L. Hodges, 50, became one of our Vice Presidents in October 2000. He began his career with Texaco Inc., and has served in various land management capacities with several independent oil and gas companies during the past 27 years. He served as Vice President of Land for Central Resources, Inc. until the acquisition by EXCO of the Central properties in September 2000.

John D. Jacobi, 47, became one of our Vice Presidents in February 1999. In 1991, he co-founded Jacobi-Johnson Energy, Inc., an independent oil and natural gas producer, and served as its President until January 1997. He served as the Vice President and Treasurer of Jacobi-Johnson from January 1997 until May 8, 1998, when the company was sold to EXCO.

Daniel A. Johnson, 50, became one of our Vice Presidents in February 1999. In 1991, he co-founded Jacobi-Johnson Energy, Inc., an independent oil and natural gas producer. He served as its President from January 1997 until the company was sold to EXCO on May 8, 1998.

James M. Perkins, Jr., 59, joined us as one of our Vice Presidents in February 2002. He has thirty-eight years of experience in the oil and gas industry with major integrated oil companies, including ARCO and Texaco, and several independents, including Lyco Energy, Dorchester Exploration and General American Oil Company of Texas. He served these companies in various land management and executive positions.

Glossary of Selected Oil and Natural Gas Terms

The following are abbreviations and definitions of terms commonly used in the oil and natural gas industry and this annual report.

"Bbl." One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

"Bcf." One billion cubic feet of natural gas.

"Bcfe." One billion cubic feet equivalent calculated by converting 1 Bbl of oil or NGLs to 6 Mcf of natural gas.

"infill drilling." Drilling of a well between known producing wells to better exploit the reservoir.

"Mcf." One thousand cubic feet of natural gas.

"Mcfe." One thousand cubic feet equivalent calculated by converting 1 Bbl of oil or NGLs to 6 Mcf of natural gas.

"Mbbl." One thousand stock tank barrels.

"Mmcf." One million cubic feet of natural gas.

"NGLs." The combination of ethane, propane, butane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

"overriding royalty interest." An interest in an oil and/or natural gas property entitling the owner to a share of oil and natural gas production free of costs of production.

"present value of estimated future net revenues." The present value of estimated future net revenues is an estimate of future net revenues from a property at December 31, 2001, at its acquisition date, or as otherwise indicated, after deducting production and ad valorem taxes, future capital costs and operating expenses, but before deducting federal income taxes. The future net revenues have been discounted at an annual rate of 10% to determine their "present value." The present value is shown to indicate the effect of time on the value of the net revenue stream and should not be construed as being the fair market value of the properties. Estimates have been made using constant oil, natural gas and NGL prices and operating costs at December 31, 2001, at its acquisition date, or as otherwise indicated. We believe that the present value of estimated future net revenues before income taxes, while not in accordance with generally accepted accounting principles, is an important financial measure used by investors and independent oil and natural gas producers for evaluating the relative significance of oil and natural gas properties and acquisitions.

ITEM 2. PROPERTIES

General

We lease approximately 13,400 square feet of office space in Dallas, Texas, 7,450 square feet in Denver, Colorado, and 5,000 square feet in Calgary, Alberta for our corporate offices. The leases expire December 31, 2005, September 30, 2004, and March 31, 2004, respectively, and require monthly rental payments of approximately $16,700, $11,700, and $7,800 respectively. In February 2002, we leased approximately 5,100 square feet of additional office space in Dallas for monthly rental payments of approximately $6,400. We also anticipate that we will need to relocate our Calgary, Alberta office during 2002 to meet increased needs resulting from recent acquisitions. We also have small offices in Tyler, Texas and Tulsa, Oklahoma.

Other

We have described our oil and natural gas properties, oil, natural gas and NGL reserves, acreage, wells, production and drilling activity in "Item 1. Business" beginning on page 2 of this annual report.

ITEM 3. LEGAL PROCEEDINGS

We are a defendant in various lawsuits and other natural gas contract issues. We do not believe that any outcome of such lawsuits or other issues would have a material adverse effect on our financial position. During 2001, we were not a party to any material legal proceeding.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

During the last three months of the year ended December 31, 2001, we did not submit any matter to a vote by our shareholders through the solicitation of proxies or otherwise.

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY AND RELATED SHAREHOLDER MATTERS

Market Information for Our Common Stock

Our common stock is quoted on the Nasdaq National Market System (Nasdaq NMS) under the symbol "EXCO." The following table sets forth the high and low bid prices from January 1, 2000 through December 31, 2001, based upon quotations periodically published on the Nasdaq NMS. All price quotations represent prices between dealers, without accounting for retail mark-ups, mark-downs or commissions, and may not represent actual transactions.

	High	Low
Year ended December 31, 2000:		
First Quarter	$ 7.38	$ 6.38
Second Quarter	9.63	6.50
Third Quarter	14.25	8.75
Fourth Quarter	15.56	13.88
Year ended December 31, 2001:		
First Quarter	$ 20.13	$ 15.25
Second Quarter	21.06	18.19
Third Quarter	17.10	14.45
Fourth Quarter	16.72	13.26

The last bid price for our common stock was $15.49 on March 15, 2002.

Our Shareholders

According to our transfer agent, Continental Stock Transfer & Trust Company, there were approximately 741 holders of record of our common stock on February 28, 2002 (including nominee holders such as banks and brokerage firms who hold shares for beneficial holders).

Our Dividend Policy

We have not paid any cash dividends on our common stock, and do not anticipate paying cash dividends on our common stock in the foreseeable future. In addition, our credit agreements currently prohibit us from paying dividends on our common stock. Our credit agreements do not prohibit us from paying dividends on our convertible preferred stock. We anticipate that any income generated in the foreseeable future that is in excess of our dividend payments on our 5% convertible preferred stock will be retained for the development and expansion of our business. Our future dividend policy is subject to the discretion of the board of directors and will depend upon a number of factors, including future earnings, debt service, capital requirements, restrictions in our credit agreements, business conditions, our financial condition and other factors that our board of directors deems relevant.

ITEM 6. SELECTED FINANCIAL DATA

The following table presents our selected historical financial data. You should read this financial data in conjunction with our "Management's Discussion and Analysis of Financial Condition and Results of Operations," our consolidated financial statements, the notes to our consolidated financial statements and the other financial information, included in this annual report. This information does not replace the consolidated financial statements. In our opinion, the data we have presented reflects all adjustments we consider necessary for a fair presentation of the results for the periods. We have completed numerous acquisitions since 1997 which materially impact the comparability of this data between periods.

	Year Ended December 31,				
	1997	1998	1999	2000	2001
	(In thousands, except per share amounts)				
Statement of Operations Data:					
Revenues:					
Oil and natural gas	$ 670	$ 1,385	$ 5,294	$ 28,869	$ 61,237
Other	28	690	2,008	1,252	5,567
Gain on disposition of properties, equipment and other assets	—	—	5,102	538	136
Total revenues	698	2,075	12,404	30,659	66,940
Costs and expenses:					
Oil and natural gas production	322	786	2,375	9,484	23,914
Depreciation, depletion and amortization	84	465	1,446	4,949	14,244
General and administrative	486	1,231	1,934	2,003	4,806
Interest expense	11	104	17	1,369	3,133
Impairment of oil and natural gas properties	—	—	—	—	49,575
Uncollectible value of Enron hedges	—	—	—	—	10,669
Total costs and expenses	903	2,586	5,772	17,805	106,341
Income (loss) before income taxes and minority interest	(205)	(511)	6,632	12,854	(39,401)
Minority interest in limited partnership	—	—	(7)	—	—
Income (loss) before income taxes	(205)	(511)	6,639	12,854	(39,401)
Income tax expense (benefit)	—	—	2,139	4,400	(54)
Income (loss) before extraordinary items	(205)	(511)	4,500	8,454	(39,347)
Fee income from early extinguishment of debt, net of tax	—	—	165	—	—
Net income (loss)	(205)	(511)	4,665	8,454	(39,347)
Dividends on preferred stock	—	—	—	—	2,653
Earnings (loss) on common stock	$ (205)	$ (511)	$ 4,665	$ 8,454	$ (42,000)
Basic earnings (loss) per share (1)	$ (.51)	$ (.18)	$ .69	$ 1.23	$ (5.96)
Diluted net income (loss) per share (1)	$ (.51)	$ (.18)	$ .69	$ 1.18	$ (5.96)
Weighted average common and common equivalent shares outstanding:					
Basic	403	2,871	6,698	6,835	7,046
Diluted	403	2,874	6,714	7,122	7,046
Ratio of combined fixed charges and preference dividends to earnings (2)	(0.06)	(0.33)	0.04	0.11	(0.19)

	Year Ended December 31,				
	1997	1998	1999	2000	2001
	(In thousands, except per share amounts)				
Statement of Cash Flows Data:					
Net cash provided by (used in):					
Operating activities	$ (181)	$ (127)	$ (8,620)	$ 27,297	$ 25,916
Investing activities	204	(14,060)	(2,862)	(66,519)	(134,532)
Financing activities	427	35,184	(39)	37,450	102,891
Other Financial Data:					
Capital expenditures (3)	$ 74	$ 257	$ 1,062	$ 847	$ 23,835
EBITDA (4)	(110)	58	8,267	19,172	34,074
Cash flow (5)	(111)	(46)	2,918	14,148	30,041

	December 31,				
	1997	1998	1999	2000	2001
	(In thousands)				
Balance Sheet Data:					
Current assets	$ 727	$ 22,157	$ 31,599	$ 20,262	$ 21,121
Oil and natural gas properties, net	473	7,554	18,674	80,355	164,835
Total assets	1,270	36,888	50,932	102,372	191,056
Current liabilities	328	648	10,017	8,655	13,322
Long-term debt, less current maturities	15	—	—	42,488	44,994
Stockholders' equity	927	36,240	40,880	49,791	120,379
Total liabilities and stockholders' equity	1,270	36,888	50,932	102,372	191,056

(1) Per share data has been restated to reflect the one-for-two reverse stock split effective March 31, 1998. The adoption of Financial Accounting Standards Board No. 128, "Earnings per Share," did not have a material impact on earnings per share amounts. We have neither declared nor paid any dividends on common stock during any of the periods presented.

(2) The ratio of combined fixed charges and preference dividends to earnings is calculated by adding fixed charges, defined as the sum of interest expense and amortized deferred financing costs, to preference security dividends, defined as the amount of pre-tax earnings that are required to pay the dividends on outstanding preference securities, divided by earnings, defined as the sum of pre-tax income from continuing operations before minority interests, or income or loss from equity investees and fixed charges, less the minority interest in pre-tax income of subsidiaries that have not incurred fixed charges.

(3) Capital expenditures are capitalized workovers, exploration, exploitation and plugging costs incurred and exclude property acquisition costs.

(4) EBITDA is defined as net income, plus interest expense, income taxes, and depreciation, depletion and amortization expenses, and, for 2001, plus $60.2 million for impairments of oil and natural gas properties and the uncollectible value of Enron hedges offset by $4.1 million of other income from hedge ineffectiveness and from derivatives for which hedge accounting was terminated. EBITDA is a financial measure commonly used in our industry and should not be considered in isolation or as a substitute for net income, net cash provided by operating activities or other income or cash flow data prepared in accordance with generally accepted accounting principles or as a measure of our profitability or liquidity. Because EBITDA excludes some, but not all, items that affect net income and may vary among companies, the EBITDA presented above may not be comparable to similarly titled measures of other companies.

(5) Cash flow represents cash flows from operating activities before changes in working capital.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Forward-Looking Statements.

The statements contained in this report regarding our future financial and operating performance and results, business strategy and market prices and future hedging activities, and other statements, including, in particular statements about our plans and forecasts under "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Business," that are not historical facts are forward-looking statements, as defined in Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Among these forward-looking statements are statements regarding our anticipated performance in the year 2002, specifically statements relating to our net sales, gross profit, production, general and administrative expenses, production costs, and capital expenditures. We have based these forward-looking statements on our current assumptions, expectations and projections about future events.

We use the words "may," "will," "expect," "anticipate," "estimate," "believe," "continue," "intend," "plan," "budget," or other similar words to identify forward-looking statements. You should read statements that contain these words carefully because they discuss future expectations, contain projections of results of operations or of our financial conditions, and/or state other "forward-looking" information. We do not undertake any obligation to update or revise publicly any forward-looking statements. These statements also involve risks and uncertainties, that could cause our actual results to materially differ from our expectations in this report, including, but not limited to:

- estimates of reserves;
- market factors;
- market prices (including regional basis differentials) of oil and natural gas;
- results of future drilling;
- marketing activity;
- future production and costs;
- and other factors discussed in this report and in our other SEC filings.

We believe that it is important to communicate our expectations of future performance to our investors. However, events may occur in the future that we are unable to accurately predict, or over which we have no control. When considering our forward-looking statements, keep in mind the risk factors and other cautionary statements in this annual report.

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for oil and natural gas. Declines in oil or natural gas prices may materially adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower oil or natural gas prices also may reduce the amount of oil or natural gas that we can produce economically. Current oil and natural gas prices have declined significantly during 2001 and at December 31, 2001 from the historically high levels at December 31, 2000. The valuations and estimated quantities of our oil and natural gas reserves at December 31, 2001, in this annual report are based upon these lower prices. Oil and natural gas prices at their current level, or a further decline in oil and/or natural gas prices, could have a material adverse effect on the estimated value and estimated quantities of our oil and natural gas reserves, our ability to fund our operations and our financial condition, cash flow, results of operations and access to capital. Historically, oil and natural gas prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile.

2001 Performance

The year ended December 31, 2001, was a very active year with respect to the implementation of our business strategy. During the year, we completed 13 acquisitions for net consideration of approximately $114.0 million and spent approximately $23.8 million on development and exploitation activities. Our acquisitions added approximately 128.2 Bcfe of proved reserves, resulting in an acquisition cost of $0.89 per Mcfe. Our largest acquisition during the year was the purchase of Addison Energy Inc., which also marked our entry into Canada. Our reserves grew by 72% from 171.5 Bcfe at December 31, 2000, to 294.5 Bcfe at December 31, 2001.

In June 2001, we raised $105.1 million ($101.2 million net after fees and commissions) through a rights offering to our existing shareholders. We applied approximately $97.6 million of the proceeds to repay our bank loans. At year end, we had approximately $45.0 million of long-term debt outstanding, resulting in a debt to book capitalization ratio of 27%. At December 31, 2000, we had approximately $42.5 million of long-term debt outstanding, with a debt to book capitalization ratio of 46%. We had a total of approximately $57.7 million available for borrowing under our U.S. and Canadian credit agreements at December 31, 2001.

Our production grew by 112% from 7.1 Bcfe in 2000 to 15.1 Bcfe in 2001, as a result of our acquisition, development and exploitation activities. During 2001, we experienced a general decline in the prices we received for oil, natural gas and NGLs. Our realized oil price, before hedge settlements, declined from an average of $26.95 per Bbl during the first quarter to an average of $18.07 per Bbl during the fourth quarter. Our realized natural gas price, before hedge settlements, declined from an average of $6.60 per Mcf during the first quarter to an average of $2.17 per Mcf during the fourth quarter. Our realized NGLs price declined from an average of $25.98 per Bbl during the first quarter to an average of $12.57 per Bbl during the fourth quarter. Production costs, including production and ad valorem taxes, increased on a per Mcfe basis from $1.32 in 2000 to $1.59 in 2001 mainly as a result of workovers and equipment repairs during the first six months of 2001 relating to production enhancement projects on the Central Resources properties we acquired on September 22, 2000, and the inclusion of production costs for the full year from these properties which have higher historic average per unit costs. During 2001, we experienced a general decline in our per unit production costs. Our production costs, including production and ad valorem taxes, declined from an average of $1.86 per Mcfe during the first quarter to an average of $1.42 per Mcfe during the fourth quarter.

We also recorded non-cash income and expense items related to our hedging activities as well as non-cash write-offs of our oil and natural gas properties as further described in "Our Results of Operations—Comparison of Years Ended December 31, 2000 and 2001" below.

2002 Outlook

Commodity Prices

During 2001, commodity prices declined from historically high levels at the beginning of the year to more moderate levels by year end. Our outlook for 2002 commodity prices is uncertain. Significant factors that will impact 2002 commodity prices include the extent to which members of the Organization of Petroleum Exporting Countries (OPEC) and other oil exporting nations are able to manage oil supply through export quotas, the overall North American natural gas supply and demand fundamentals and the extent of any worldwide economic recovery, especially any economic recovery in the United States. Political events and turmoil in the Middle East as well as the U.S. war on terrorism may exacerbate commodity price volatility. We will continue to moderate our debt levels, follow cost management measures and strategically hedge oil and natural price risk to mitigate the impact of price volatility on our oil, natural gas and NGLs. We will continue to review our hedge position each time we make a material acquisition.

As of December 31, 2001, we had a hedge in place covering 761,000 Bbls of our 2002 oil production under a swap contract with a weighted average fixed price to be received of $20.77 per Bbl. We have hedged approximately 57%-61% of our forecasted oil production for 2002. We also had hedges in place covering 7,365,000 Mmbtus of 2002 natural gas production under swap contracts with a weighted average fixed price to be received of $2.82 per Mmbtu. In March 2002, we increased our 2002 commodity hedge positions by entering into a hedge covering 150,000 Mmbtus of natural gas per month with a fixed price to be received of $3.165 per Mmbtu, beginning in May 2002 through the end of 2002. With this increase in our natural gas hedge positions, we have hedged approximately 58%-63% of our forecasted natural gas production for 2002. We also entered into a hedge covering 455,000 Mmbtus of natural gas per month for all of 2003 with a fixed price to be received of $3.50 per Mmbtu. Additionally, at December 31, 2001, we had approximately $9.0 million remaining in accumulated other comprehensive income related to our terminated hedge contracts with Enron North America. Of this amount, approximately $7.0 million will be reclassified into earnings during 2002 and the balance of approximately $2.0 million will be reclassified into earnings in 2003. For more information regarding our hedging contracts as well as the accounting treatment of the terminated Enron Hedges, please review "Item 7A—Quantitative and Qualitative Disclosure About Market Risk".

First Quarter 2002

Based on our current estimates, we expect that our first quarter production will be between 4.8 Bcfe and 5.1 Bcfe. We expect first quarter production costs, including production and ad valorem taxes, to average between $1.30 to $1.40 per Mcfe. Depreciation, depletion and amortization expense is expected to be between $0.80 to $0.85 per Mcfe and general and administrative expense is expected to be between $1.7 million and $1.8 million during the first quarter of 2002. Our interest expense is expected to be between $400,000 and $500,000.

Production Growth

We currently forecast that our annual 2002 production will be between 23.3 Bcfe and 25.1 Bcfe. This estimate includes approximately 2.3 Bcfe to 2.8 Bcfe of production related to our pending Canadian acquisition which is expected to close in April 2002. For purposes of this forecast we have assumed that the pending Canadian acquisition closes in April 2002. If this transaction is delayed or terminated, this forecast could differ materially from our actual results.

Acquisitions and Capital Expenditures

For 2002, we have budgeted up to $21 million for development efforts plus related facilities. Approximately 50% of our capital budget is allocated to the U.S. and approximately 50% is allocated to Canada. Our capital expenditures budget is based on an expected range of future oil, natural gas and NGL prices as well as the expected costs of the capital additions. Should our price expectations for our future production or rig availability change sufficiently, we may accelerate some projects or defer some projects and, consequently, may increase or decrease total 2002 and future capital expenditures. In addition, if the actual costs of the budgeted items vary significantly from the anticipated amounts, actual capital expenditures could vary materially from our estimates.

We plan to fund our pending Canadian acquisition from borrowings under our current credit agreements. Although we have completed several major property acquisitions in recent years, these transactions are opportunity driven. Thus, we do not budget, nor can we reasonably predict, the timing or size of any acquisitions we do not describe in this report.

Critical Accounting Policies

In response to the SEC's Release No. 33-8040, "Cautionary Advice Regarding Disclosure About Critical Accounting Policies," we have identified the most critical accounting principles upon which our financial status depends. We determined the critical principles by considering accounting policies that involve the most complex or subjective decisions or assessments. We identified our most critical accounting policies to be those related to our proved reserve estimates, impairment assessments, functional currency assessment, deferred tax asset valuations and our choice of accounting method.

We prepared our consolidated financial statements for inclusion in this report in accordance with accounting principles that are generally accepted in the United States (GAAP). GAAP represents a comprehensive set of accounting and disclosure rules and requirements, the application of which requires management judgments and estimates including, in certain circumstances, choices between acceptable GAAP alternatives. The following is a discussion of our most critical accounting policies, judgments and uncertainties that are inherent in our application of GAAP.

Proved reserve estimates

Estimates of our proved reserves included in this report are prepared in accordance with GAAP and SEC guidelines. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgment of the persons preparing the estimate.

Our proved reserve information included in this report is based on estimates prepared by our independent petroleum engineers.

Because these estimates depend on many assumptions, all of which may substantially differ from actual results, reserve estimates may be different from the quantities of oil and natural gas that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may justify material revisions to the estimate.

You should not assume that the present value of future net cash flows is the current market value of our estimated proved reserves. In accordance with SEC requirements, we based the estimated discounted future net cash flows from proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate.

Estimates of proved reserves materially impact depletion expense. If the estimates of proved reserves decline, then the rate at which we record depletion expense increases, reducing net income. A decline may result from lower market prices, which may make it uneconomic to drill or produce from higher cost fields. In addition, the decline in proved reserve estimates may impact the outcome of our assessment of our oil and gas properties for impairment.

Impairment of unproved oil and gas properties

We periodically assess individually significant unproved oil and natural gas properties for impairment, on a project-by-project basis. Our assessment of the results of exploitation activities, commodity price outlooks, planned future sales or the expiration of all or a portion of the leases for potential projects impact the amount and timing of impairment provisions.

Assessments of functional currencies

We determine the functional currencies of our subsidiaries based on an assessment of the currency of the economic environment in which a subsidiary primarily realizes and expends its operating revenues, costs and expenses. We have determined that the Canadian dollar is the functional currency of our international operations in Canada. The assessment of functional currencies can have a significant impact on periodic results of operations and financial position.

Deferred tax asset valuations

We periodically assess the probability of recovery of recorded deferred tax assets based on our assessment of future earnings outlooks by tax jurisdiction. These estimates are inherently imprecise since many assumptions are utilized in the assessments that may prove to be incorrect in the future.

Accounting for oil and natural gas properties

The accounting for and disclosure of oil and natural gas producing activities requires that we choose between GAAP alternatives and to make judgments about estimates of future uncertainties.

We use the full cost method of accounting, which involves capitalizing all acquisition, exploration, exploitation and development costs. Once incurred, costs are recorded in the full cost pool or in unevaluated properties. Unevaluated property costs are not subject to depletion. We review our unevaluated costs on an ongoing basis, and we expect these costs to be evaluated in one to three years and transferred to the full cost pool during that time.

We calculate depletion using the unit-of-production method. Under this method, the sum of the full cost pool and all estimated future development costs is divided by the total amount of proved reserves. This rate is applied to our total production for the period, and the appropriate expense is recorded. We capitalize the portion of general and administrative costs that are attributable to our acquisition, exploration and development activities.

To the extent that total capitalized oil and natural gas property costs (net of related deferred income taxes and accumulated depreciation, depletion and amortization) exceeds the estimated future net revenues from proved properties using current period-end prices discounted at 10%, adjusted for related income tax effects, and the lower of cost and fair value of unproved properties, excess costs are charged to operations. Once incurred, a write-down of oil and natural gas properties is not reversible at a later date even if oil or natural gas prices increase. We could be required to write-down our oil and gas properties if there is a decline in oil or natural gas prices, or downward adjustments are made to our proved reserves.

Recently Issued Accounting Standards

Effective January 1, 2001, we adopted SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activity," which established accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results from the hedged item on the income statement. Companies must formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. To date, we have only used cash flow hedges related to our anticipated production. For derivatives classified as cash flow hedges, changes in fair value are recognized in other comprehensive income until the hedged item is recognized in earnings. The ineffective portion of any change in the fair value of a derivative designated as a hedge is immediately recognized as earnings. Hedge effectiveness is measured quarterly based on the relative fair value between the derivative contract and the hedged item over time. At adoption, we recognized a net derivative liability and a reduction in other comprehensive income of approximately $1.1 million as a cumulative effect of an accounting change for all cash flow hedges. Oil and natural gas revenues include net gains from the settlement of cash flow hedges of $6.9 million for the year ended December 31, 2001, and net losses of $1.1 million for the year ended December 31, 2000. During the year ended December 31, 2001, we recognized $3.5 million in other income for hedging ineffectiveness.

In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 141, "Business Combinations," which addresses financial accounting and reporting for business combinations. SFAS No. 141 is effective for all business combinations completed after June 30, 2001. The adoption of SFAS No. 141 has not had a material impact on our financial position or results of operation.

In June 2001, the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets," which addresses, among other things, the financial accounting and reporting for goodwill subsequent to an acquisition. The new standard eliminates the requirement to amortize acquired goodwill; instead, such goodwill shall be reviewed at least annually for impairment. SFAS No. 142 is required to be adopted on January 1, 2002. We do not believe the adoption of these provisions will impact our financial statements.

SFAS No. 143, "Accounting for Asset Retirement Obligations," which was also issued by the FASB in June 2001, requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. We are currently evaluating the impact SFAS No. 143 will have on our financial position and results of operations.

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," which addresses financial accounting and reporting for the impairment or disposal of long-lived assets. SFAS No. 144 supersedes other accounting pronouncements to eliminate certain exceptions and alternatives. We do not believe the adoption of these provisions will impact our financial statements.

Our Results of Operations

The following tables present production and average unit prices and costs for the periods and geographics segments indicated:

	Year Ended December 31,		
	1999	2000	2001
Production:			
Oil (Mbbls)			
U.S.	208	433	**887**
Canada	—	—	**80**
Total	208	433	**967**
Natural gas (Mmcf)			
U.S.	765	3,982	**6,243**
Canada	—	—	**2,086**
Total	765	3,982	**8,329**
Natural gas liquids (Mbbls)			
U.S.	—	89	**96**
Canada	—	—	**68**
Total	—	89	**164**
Mmcfe			
U.S.	2,013	7,114	**12,141**
Canada	—	—	**2,974**
Total	2,013	7,114	**15,115**

	Year Ended December 31,		
	1999	2000	2001
Average Sales Price (including hedge settlements):			
Oil (per Bbl)			
U.S. (1)	$ 17.83	$ 27.39	$ 24.40
Canada	$ —	$ —	$ 21.71
Total (2)	$ 17.83	$ 27.39	$ 24.17
Natural gas (per Mcf)			
U.S. (3)	$ 2.07	$ 3.72	$ 4.73
Canada	$ —	$ —	$ 2.59
Total (4)	$ 2.07	$ 3.72	$ 4.20
Natural gas liquids (per Bbl)			
U.S.	$ —	$ 24.60	$ 18.96
Canada	$ —	$ —	$ 15.92
Total	$ —	$ 24.60	$ 17.70
Total oil and natural gas revenues (per Mcfe)			
U.S.	$ 2.63	$ 4.06	$ 4.37
Canada	$ —	$ —	$ 2.76
Total	$ 2.63	$ 4.06	$ 4.05

(1) Reflects the impact of monthly hedge settlements which decreased the U.S. average oil price by $1.85 per Bbl for the year ended December 31, 2000 and increased the U.S. average oil price by $0.86 per Bbl for the year ended December 31, 2001.

(2) Reflects the impact of monthly hedge settlements which decreased the total average oil price by $1.85 per Bbl for the year ended December 31, 2000 and increased the total average oil price by $0.79 per Bbl for the year ended December 31, 2001.

(3) Reflects the impact of monthly hedge settlements which decreased the U.S. average natural gas price by $0.09 per Mcf for the year ended December 31, 2000 and increased the U.S. average natural gas price by $0.87 per Mcf for the year ended December 31, 2001.

(4) Reflects the impact of monthly hedge settlements which decreased the total average natural gas price by $0.09 per Mcf for the year ended December 31, 2000 and increased the total average natural gas price by $0.65 per Mcf for the year ended December 31, 2001.

	Year Ended December 31,		
	1999	2000	2001
Expenses (per Mcfe):			
Oil and natural gas production			
U.S.	$ 0.95	$ 1.05	$ 1.43
Canada	$ —	$ —	$ 0.81
Total	$ 0.95	$ 1.05	$ 1.32
Production and ad valorem taxes			
U.S.	$ 0.23	$ 0.27	$ 0.33
Canada	$ —	$ —	$ 0.04
Total	$ 0.23	$ 0.27	$ 0.27
General and administrative			
U.S.	$ 0.96	$ 0.28	$ 0.34
Canada	$ —	$ —	$ 0.23
Total	$ 0.96	$ 0.28	$ 0.32
Depreciation, depletion and amortization			
U.S.	$ 0.72	$ 0.69	$ 0.80
Canada	$ —	$ —	$ 1.50
Total	$ 0.72	$ 0.69	$ 0.94

Comparison of Years Ended December 31, 2000 and 2001

Revenues. Our revenues from the sale of oil, natural gas and NGLs for the year ended December 31, 2001, increased by $32.3 million, or 112%, to $61.2 million from $28.9 million for 2000. This increase resulted primarily from production increases of approximately 97,900 Bbls of oil, 2.7 Bcf of natural gas and 68,300 Bbls of NGLs from our acquisition of the STB Energy properties, completed in March 2001, and Addison, completed in April 2001. Additionally, our acquisition of the Central Resources properties, completed in September 2000, was included for the full year in 2001, as compared to four months during 2000.

The increase in revenues was also attributable to higher natural gas prices which were partially offset by lower oil and NGL prices. Our average oil, natural gas and NGL prices include the effects of quality, gathering and transportation costs as well as the effect of monthly oil and natural gas hedge settlements. Our average oil price received during 2001 was $24.17 per Bbl as compared to $27.39 per Bbl for 2000, which decreased revenue by $1.3 million. Our average natural gas price received during 2001 was $4.20 per Mcf as compared to $3.72 per Mcf for 2000, which increased revenue by $2.1 million. Our average NGLs price received during 2001 was $17.70 per Bbl as compared to $24.60 per Bbl for 2000, which decreased revenue by $615,000.

Our other income for 2001 was $5.7 million as compared to $1.8 million for 2000. This income primarily consisted of income from derivative ineffectiveness, income from hedges terminated prior to their expiration, interest income, salt water disposal income and well supervision fees. The increase in other income was primarily attributable to $3.5 million from the ineffectiveness of derivative contracts and $1.3 million in income from hedges that we terminated prior to their expiration. See "Item 7A. Quantitative and Qualitative Disclosure About Market Risk" for a discussion of the accounting for terminated hedges in future periods.

Costs and Expenses. Our total costs and expenses for 2001 increased by $88.5 million to $106.3 million from $17.8 million for 2000. This increase was mainly attributable to (1) our acquisitions of the Central Resources properties, the STB Energy properties and Addison (2) the non-cash ceiling test limitation write-down of $49.6 million, and (3) the write-off of $10.7 million, which represents 80% of the value, as of November 30, 2001, of the Enron derivative assets.

Our oil and natural gas production costs for 2001 increased by $12.4 million, or 165%, to $19.9 million from $7.5 million for 2000. Our acquisitions of the STB Energy properties and Addison increased oil and natural gas production costs by $3.3 million. Production and ad valorem taxes for 2001 increased by $2.1 million, or 105%, to $4.1 million from $2.0 million last year. Additionally, oil and natural gas production costs and production and ad valorem taxes related to our acquisition of the Central Resources properties were included for the full year, as compared to four months during 2000.

Our depreciation, depletion and amortization costs for 2001 increased by $9.3 million, or 190%, to $14.2 million from $4.9 million for 2000. Our acquisitions of the STB Energy properties and Addison increased depreciation, depletion and amortization costs by $5.0 million. Additionally, depreciation, depletion and amortization costs related to our acquisition of the Central Resources properties were included for the full year, as compared to four months during 2000.

Our general and administrative costs for 2001 increased by $2.8 million, or 140%, to $4.8 million from $2.0 million for 2000. The increase in general and administrative costs was primarily attributable to our increased staffing needs as a result of our acquisitions of the Central Resources properties, the STB Energy properties and Addison.

Our interest expense for 2001 increased to $3.1 million from $1.4 million for 2000. This increase was primarily attributable to relatively high debt levels following the acquisitions of the STB Energy properties and Addison during the first half of the year. These borrowings were repaid in June from the proceeds of the 5% convertible preferred stock offering.

We acquired Addison in April 2001 and we also completed significant property acquisitions during the second half of 2000 and during 2001. Oil and natural gas prices trended higher throughout 2000 and were at historically high levels at December 31, 2000. During 2001, oil and natural gas prices decreased throughout most of the year. We evaluate acquisitions utilizing our best estimate of product prices and the amount of capital expenditures and operating expense to be incurred over the life of the reserves. Under full cost accounting rules, we must compare the amount in our full cost pools (separate pools exist for the United States and Canada) to a ceiling test limit. The ceiling test limit is calculated using product prices as of the last day of the fiscal quarter. Capital expenditures and operating expenses are calculated without any escalation for inflation. As a result of lower oil and natural gas prices at the end of both the third and fourth quarters of 2001, we had non-cash write-downs of our oil and natural gas properties of $49.6 million, of which $28.7 million was from our United States full cost pool and $20.9 million was from our Canadian full cost pool. At December 31, 2001, we used a realized oil price of $17.76 per Bbl, natural gas price of $2.23 per Mcf and an NGLs price of $15.09 per Bbl as the basis for determining the value of our reserves. We did not use our hedge contracts in determining reserve values. If product prices decline from the December 31, 2001 levels, it is probable that we will incur additional non-cash ceiling test write-downs in the future.

In connection with the incurrence of debt related to our acquisition activities and to protect against commodity price fluctuations, management adopted a policy of hedging oil and natural gas prices through the use of commodity futures, options and swap agreements. During 2000 and through the third quarter of 2001, we entered into several hedging contracts with Enron North America. As a result of the failure of Enron North America to make payments due us in December 2001, we terminated all of our hedging contracts with Enron North America. Prior to this termination, Enron North America and its parent, Enron Corp., filed for bankruptcy under Chapter 11 of the United States Code. We believe, based upon oil and natural gas prices on the date of termination, that we were owed approximately $15.3 million, including settlements already due, but the exact amount will be determined pursuant to the terms of the ISDA Master Agreement. As of November 30, 2001, we had recorded a $13.2 million derivative asset for oil and natural gas hedge derivatives from Enron North America. This amount, calculated in accordance with SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities", represents the estimated value of future monthly settlements to be received from the derivatives contracts. As a result of our termination of the derivatives contracts and the bankruptcy of the counterparty, we must record the derivative asset related to the oil and natural gas hedge derivatives from Enron North America at their estimated fair value. There currently exists an informal market for Enron North America's bankruptcy claims. Based upon informal offers that we have received from third parties attempting to purchase these claims, management currently believes the fair value of the derivative asset was approximately $2.8 million. As a result, we have written-off to expense $10.7 million of the derivative asset for oil and natural gas hedge derivatives from Enron North America. See "Item 1. Business Developments During 2001—We terminated our existing hedge agreements and entered into new hedge agreements" and "Item 7A. Quantitative and Qualitative Disclosure About Market Risk—Commodity Price Risk" for additional information concerning our hedging transactions.

Our effective tax rate in 2000 was 34%. In 2001, the effective rate was less than 1% due to the ceiling test write-down and write-off of the Enron derivative asset. We could not utilize our net loss in the U.S. because it is uncertain whether we will be able to realize the deferred tax asset resulting from the ceiling test write-downs and the write-off of the Enron derivative asset. The resulting valuation allowance of $7.6 million at December 31, 2001, should significantly reduce income tax expense in the U.S. going forward until such time as the net deferred tax asset position is fully realized or conditions warrant a reduction in the valuation allowance. The valuation allowance will have no effect on future Canadian income tax expense.

Net Income (Loss). We had a net loss for 2001 of $39.3 million representing $5.96 per basic share. This compares to net income during 2000 of $8.5 million representing $1.23 per basic share and $1.18 per diluted share.

Comparison of Years Ended December 31, 1999 and 2000

Revenues. Our total revenues for 2000 increased $23.4 million, or 349% increase, to $30.1 million (excluding a one-time pre-tax gain of $538,000 from the sale of properties and equipment) from $6.7 million (excluding a one-time pre-tax gain of $5.1 million from the sale of properties and equipment and equity earnings in EXUS Energy, LLC of $584,000) for 1999. Our oil revenues for 2000 increased $8.1 million, or 219% increase, to $11.8 million from $3.7 million for 1999. For 2000, our oil revenues accounted for 39% of our total revenues as compared to 55% of our total revenues for 1999. Our natural gas revenues for 2000 increased $13.2 million, or 825%, to $14.8 million from $1.6 million. For 2000, our natural gas revenues were 49% of our total revenues as compared to 24% of our total revenues for 1999. Our NGLs revenues for 2000 were $2.2 million and accounted for 8% of our total revenues for 2000. We did not sell any NGLs during 1999. The increase in revenues was due to both (1) production increases resulting from the acquisitions of the Natchitoches Parish properties (December 1999), the Val Verde County properties (February 2000), the Pecos County properties (March 2000), and the Central Resources, Inc. properties (September 2000), and (2) oil and natural gas price increases.

We sold approximately 432,500 Bbls of oil during 2000 as compared to approximately 208,000 Bbls during 1999, an increase of 108%. We sold approximately 4.0 Bcf of natural gas in 2000 as compared to approximately .8 Bcf in 1999, an increase of 400%. We sold approximately 89,100 Bbls of NGLs in 2000 as compared to no Bbls in 1999. Overall, for 2000, our total production was approximately 7.1 Bcfe as compared to approximately 2.0 Bcfe, an increase of 5.1 Bcfe or 255%. The increases in production were primarily attributable to the acquisitions of the Natchitoches Parish properties, the Val Verde County properties, the Pecos County properties and the Central Resources properties.

The average oil price received during 2000 was $27.39 as compared to $17.83 for 1999, an increase of $9.56 per barrel or 54%. The average natural gas price received during 2000 was $3.72 as compared to $2.07 in 1999, an increase of $1.65 per Mcf or 80%. The average NGLs price received during 2000 was $24.60 per barrel. We did not sell any NGLs during 1999.

Our other income for 2000 was $1.3 million compared to $1.4 million in 1999. For 2000, our other income was 4% of our total revenues as compared to 21% of our total revenues for 1999. This income primarily consisted of interest income, salt water disposal income and well supervision fees. The decrease in other income was primarily attributable to decreased interest income from a lower average cash balance during 2000 than 1999.

We recorded a one-time pre-tax gain of approximately $538,000 and $5.1 million for 2000 and 1999, respectively, from the sale of properties and equipment. We also recorded equity earnings in EXUS Energy, LLC of $584,000 for 1999.

Costs and Expenses. Our total costs and expenses for 2000 increased by $12.0 million, or 208%, to $17.8 million as compared to $5.8 million for 1999. For 2000, our total costs and expenses were 59% of our total revenues as compared to 86% of our total revenues for 1999.

Our oil and natural gas production costs for 2000 increased by $5.6 million to $7.5 million from $1.9 million for 1999. On a per Mcfe basis, the increase in costs was mainly attributable to the Central Resources properties we acquired on September 22, 2000, which had higher average operating costs than our other producing properties. On an Mcfe basis, our total production taxes for 2000 increased by $.04 to $.27 from $.23 for 1999 and were 6% of our total revenues for 2000 as compared to 7% of our total revenues for 1999. This per Mcfe increase was mainly due to the increase in oil and natural gas prices. Our depletion, depreciation and amortization costs for 2000 increased by $3.5 million to $4.9 million from $1.4 million for 1999. On an Mcfe basis, our depreciation, depletion and amortization costs for 2000 decreased by $.03 to $.69 from $.72 for 1999 and were 16% of our total revenues for 2000 as compared to 22% of our total revenues for 1999. This per Mcfe decrease was attributable to our acquisitions of the Natchitoches Parish properties, the Val Verde County properties, the Pecos County properties, and the Central Resources, Inc. properties.

General and administrative costs for 2000 were $2.0 million compared to $1.9 million for 1999. For 2000, general and administrative costs were 7% of our total revenues for 2000 as compared to 29% of our total revenues for 1999. Our general and administrative costs decreased as a percentage of our total revenues, as a result of the growth in our revenues.

Interest expense for 2000 increased to $1.4 million from $17,000 for 1999. For 2000, our interest expense was 5% of our total revenues. Our interest expense was less than 1% of our total revenues in 1999. The increase in interest expense was due to borrowings under our credit agreement to partially fund the acquisitions of the Val Verde County properties and the Central Resources properties, and our share of the borrowings under the Pecos-Gomez, L.P. credit facility to partially fund the acquisition of the Pecos County properties.

Extraordinary Item. For 2000 we had no extraordinary income, whereas for 1999 we had extraordinary income of $165,000, or $.02 per basic and diluted share, net of income taxes, from the proceeds of the prepayment of a promissory note we received from Venus Exploration, Inc. on June 30, 1999.

Net Income. We had net income of $8.4 million for 2000 representing $1.23 per basic share and $1.18 per diluted share compared to net income of $4.7 million for 1999 representing $.69 per basic and diluted share.

Our Liquidity, Capital Resources and Capital Commitments

General

Most of our growth has resulted from recent acquisitions and the success of our drilling program. Consistent with our strategy of acquiring and developing reserves, we have an objective of maintaining financing flexibility. In the past, we have utilized a variety of sources of capital to fund our acquisition, development and exploitation programs and to fund our operations. Our general financial strategy is to use a combination of cash flow from operations, bank financing and the sale or issuance of equity securities to fund our operations, conduct development and exploitation activities and to fund acquisitions. We do not have a set budget for acquisitions as these tend to be opportunity driven. Historically, we have used the proceeds from the issuance of equity securities and borrowings under our credit agreements to raise cash to fund acquisitions. We cannot assure you that funds will be available to us in the future to meet our budgeted capital spending or to fund acquisitions. Furthermore, our ability to borrow other than under our credit agreements is subject to restrictions imposed by our lenders. If we cannot secure additional funds for our planned development and exploitation activities or for future acquisitions, then we will be required to delay or reduce substantially these activities.

During 2001, we increased our long-term debt by 6% to approximately $45.0 million at December 31, 2001. We generated cash flow from operations before changes in working capital in 2001 of approximately $30.0 million which helped fund our acquisition, development and exploitation activities. At December 31, 2001, our cash and cash equivalents balances decreased 77% versus December 31, 2000. Working capital at December 31, 2001 was 33% lower than at December 31, 2000. These decreases are due to the effect of our acquisition and development activities during 2001.

Acquisitions and Capital Expenditures

During 2001, we acquired all of the outstanding common stock of Addison, which is headquartered in Calgary, Alberta, Canada. After adjustments for working capital and long-term debt, we paid approximately \$44.4 million for Addison. Also during 2001, we completed several property acquisitions totaling \$63.8 million before contractual adjustments of which \$29.5 million was in the United States and \$34.3 million was in Canada. These acquisitions were funded primarily from borrowings under our credit agreements. Our development and exploitation capital expenditures during 2001 totaled \$23.8 million, of which \$15.0 million was in the United States and \$8.8 million was in Canada. These expenditures were internally funded by approximately \$22.4 million of net cash provided by operating activities and approximately \$1.4 million from disposition of assets. Our 2000 and 1999 capital expenditures were internally funded by net cash provided by operating activities.

We have planned development and exploitation activities for our major operating areas. We have budgeted up to \$21.0 million for our development and exploitation activities in 2002, of which \$10.5 million is for the United States and \$10.5 million is for Canada. In addition, we are continuing to evaluate oil and natural gas properties for future acquisitions. The amount that will be ultimately spent during 2002 on acquisitions, development and exploitation activities will be determined based on a variety of factors, including prevailing prices for oil and natural gas, our expectations as to future pricing, the level of cash flow from operations and the availability of additional debt and/or equity capital. If oil and natural gas prices drop significantly for an extended period of time we may reduce our anticipated capital expenditure budget for 2002. We strive to maintain our indebtedness at moderate levels in order to provide sufficient financial flexibility to take advantage of future acquisition opportunities.

We expect to continue to utilize cash from operations as well as our available funds under our credit agreements to fund our capital expenditures and working capital during 2002. We believe that our capital resources from existing cash balances, cash flow from operating activities and borrowing capacity under our credit agreements are adequate to meet the cash requirements of our business. However, future cash flows are subject to a number of variables including production volumes and oil and natural gas prices. If cash flows decline we would be required to reduce our capital expenditure budget which in turn may effect our production in future periods. We cannot assure you that operations and other capital resources will provide cash in sufficient amounts to maintain or initiate planned levels of capital expenditures.

On February 28, 2002, Addison, our Canadian subsidiary entered into an agreement to purchase oil and natural gas assets totaling approximately \$26.2 million (CDN \$41.6 million). The transaction, which is expected to close on April 15, 2002, will be funded with borrowings under our U.S. credit agreement.

Credit Agreements

On December 18, 2001, we entered into restated U.S. and Canadian credit agreements as part of the financing for the acquisition of the PrimeWest properties.

U.S. Credit Agreement. Our restated U.S. credit agreement provides for borrowings of up to \$124.0 million under a revolving credit facility with a borrowing base of \$58.0 million. Our borrowing base is determined based on a number of factors including commodity prices, however, we use hedges to lessen the impact of volatility in commodity prices. The borrowing base is to be redetermined as of May 1, 2002, and each November 1 and May 1 thereafter. At December 31, 2001, we had approximately \$3.5 million of outstanding indebtedness, letter of credit commitments of \$310,000 and approximately \$54.2 million available for borrowing under our U.S. credit agreement. At March 15, 2002, we had \$11.5 million of outstanding indebtedness, letter of credit commitments of \$310,000 and approximately \$46.2 million available for borrowing. The U.S. credit agreement contains financial covenants and other restrictions that require us to maintain a minimum consolidated tangible net worth as well as financial ratios. As of December 31, 2001, we were in compliance with the covenants contained in the U.S. credit agreement. Borrowings under the credit agreement are secured by a first lien mortgage providing a security interest in 90% of our U.S. oil and natural gas properties. At our election, interest on borrowings may be (i) the greater of the administrative agent's prime rate or the federal funds effective rate plus an applicable margin or (ii) LIBOR (London InterBank Offered Rate) plus an applicable margin. At December 31, 2001, the six month LIBOR rate was 1.98%, which would result in an interest rate of approximately 2.98% on any new indebtedness we may incur under the U.S. credit agreement. At March 15, 2002, our weighted average cost of outstanding U.S. indebtedness was 2.96%.

Canadian Credit Agreement. Our restated Canadian credit agreement provides for borrowings of up to U.S. $48.7 million under a revolving credit facility with a borrowing base of U.S. $41.5 million. Our borrowing base is determined based on a number of factors including commodity prices, however, we use hedges to lessen the impact of volatility in commodity prices. The borrowing base is to be redetermined as of May 1, 2002, and each November 1 and May 1 thereafter. At December 31, 2001, we had approximately U.S. $41.5 million of outstanding indebtedness and approximately U.S. $3.5 million available for borrowing under our Canadian credit agreement. At March 15, 2002, we had approximately U.S. $43.0 million of outstanding indebtedness and approximately U.S. $2.0 million available for borrowing. The Canadian credit agreement contains financial covenants and other restrictions that require us to maintain a minimum consolidated tangible net worth as well as financial ratios. As of December 31, 2001, we were in compliance with the covenants contained in the Canadian credit agreement. Borrowings under the credit agreement are secured by a first lien mortgage providing a security interest in 90% of our Canadian oil and natural gas properties. At our election, interest on borrowings may be (i) the Canadian prime rate plus an applicable margin or (ii) the Banker's Acceptance rate plus an applicable margin. At December 31, 2001, the six month Banker's Acceptance rate was 2.06%, which would result in an interest rate of approximately 3.81% on any new indebtedness we incur under the Canadian credit agreement. At March 15, 2002, our weighted average cost of outstanding Canadian indebtedness was 3.91%.

Dividend Restrictions. We have not paid any cash dividends on our common stock, and do not anticipate paying cash dividends on our common stock in the foreseeable future. In addition, our credit agreements currently prohibit us from paying dividends on our common stock. If there is a default under our credit agreements, we will not be able to pay dividends on the shares of our convertible preferred stock. Even if our credit agreements permitted us to pay cash dividends, we can make those payments only from our surplus (the excess of the fair value of our total assets over the sum of our liabilities plus our total paid-in share capital). In addition, we can pay cash dividends only if after paying those dividends we would be able to pay our liabilities as they become due. We cannot assure you that we will have any surplus.

Financial covenants and ratios. The U.S. and the Canadian credit agreements contain financial covenants and other restrictions which require that we:

- maintain a ratio of our consolidated current assets to consolidated current liabilities of at least 1.0 to 1.0 at the end of any fiscal quarter;
- maintain a minimum consolidated tangible net worth of not less than $48.0 million (adjusted upward by 50% of quarterly net income and 75% of the net proceeds from the issuance of any equity securities after April 26, 2001);
- not permit the ratio of consolidated debt to consolidated total capital to be greater than 65% at the end of each fiscal quarter; and

- not permit the ratio of indebtedness to earnings before interest expense, state and federal taxes and depreciation, depletion and amortization expense to be more than 2.5 to 1.0 at the end of each fiscal quarter.

Our current assets to current liabilities ratio as defined under our credit agreements was 5.9 to 1.0 at December 31, 2001.

Our consolidated tangible net worth at December 31, 2001 as defined under our credit agreements was approximately $168.4 million, as compared to approximately $130.1 million required under our credit agreements.

At December 31, 2001 our consolidated debt to consolidated total capital was 25% and our ratio of indebtedness to earnings before interest expense, state and federal taxes and depreciation, depletion and amortization expense was 1.33 to 1.0.

Contractual Obligations and Commercial Commitments

The following table presents a summary of our contractual obligations at December 31, 2001, with set and determinable payments:

	Payments Due by Period				
Contractual Obligations	**1 Year or Less**	**2-3 Years**	**4-5 Years**	**After 5 Years**	**Total**
			(In thousands)		
Long-term debt	$ —	$ 44,994	$ —	$ —	$ 44,994
Operating leases	547	781	223	—	1,551
Drilling/work commitments	2,938	—	—	—	2,938
Preferred stock dividends	5,255	2,598	$ —	$ —	7,853
Total contractual cash obligations	**$ 8,740**	**$ 48,373**	**$ 223**	**$ —**	**$ 57,336**

We also have $310,000 in letters of credit that have been issued to various state regulatory agencies and all of which expire in 2002. See "Item 7A—Quantitative and Qualitative Disclosure About Market Risk," for a discussion of our derivative positions.

Effects of the 5% Convertible Preferred Stock Offering

On June 29, 2001, we sold 5,004,869 shares of 5% convertible preferred stock. We raised approximately $105.1 million in gross proceeds (approximately $101.2 million in net proceeds after fees and commissions). We applied approximately $97.6 million of the offering proceeds to pay-off our bank loans, which were incurred for the acquisition of producing oil and natural gas properties and for the acquisition of Addison, and have used the remaining proceeds for general corporate purposes.

Dividends on our preferred stock, which are payable quarterly beginning September 30, 2001, are payable only in cash. Currently, the requirement for such dividend payments is approximately $1.3 million per quarter. The board has declared and we have paid $2.7 million in preferred stock dividends during 2001. Each share of our 5% convertible preferred stock is convertible into one share of our common stock on or before June 30, 2003. Each share of 5% convertible preferred stock that has not been converted into our common stock by June 30, 2003, will be automatically converted into one share of our common stock on that date.

Common Stock

As part of the consideration paid in 2000 for the acquisition of the Central Resources properties, we issued a warrant to Central Resources, Inc. to purchase 200,000 shares of our common stock. This warrant was assigned and then exercised by a new registered holder on May 21, 2001, for the full 200,000 shares at which time we received $2.2 million cash.

In conjunction with our purchase of Addison, the Addison managers agreed to purchase shares of our common stock with a portion of the proceeds they received from the sale of their common shares of Addison to us. They purchased in the open market 24,940 shares worth $455,144. In addition, as part of the Addison purchase, we issued 49,880 shares, worth $910,310, to the Addison managers. The resale of these shares is subject to restriction.

During 2001, employees exercised stock options on a total of 69,511 shares of our common stock resulting in proceeds to us of approximately $486,000. Of these proceeds $305,600 was paid in cash and $181,000 was being borrowed from us.

During 2001 we engaged in a stock buyback program in which we purchased 56,000 shares of our common stock for a total of $760,964.

We have not paid any dividends on our common stock and we do not anticipate paying any cash dividends on our common stock in the foreseeable future.

Hedging Transactions

Our production is generally sold at prevailing market prices. However, we periodically enter into hedging transactions for a portion of our production when market conditions are deemed favorable and oil and natural gas prices exceed our minimum internal price targets. Under the terms of our U.S. credit agreement we are required to hedge at least 75% of our expected oil and natural gas production from our U.S. proved developed producing reserves. See the discussions in "Item 7A—Quantitative and Qualitative Disclosure About Market Risk."

Our objective in entering into hedging transactions is to manage price fluctuations and achieve a more predictable cash flow associated with our acquisition activities and borrowings under our credit agreements. These transactions limit exposure to declines in prices, but also limit the benefits we would realize if prices increase. As of December 31, 2001, we had entered into the following contracts to hedge our natural gas and oil production under the following terms:

- 620-605 Mmbtus per month from January 1, 2002 through December 31, 2002, and
- 67-60 Mbbls per month from January 1, 2002 through December 31, 2002, and

On March 12, 2002, we entered into two additional contracts to sell our natural gas under the following terms:

- 150 Mmbtus per month from May 1, 2002 through December 31, 2002, and
- 455 Mmbtus per month from January 1, 2003 through December 31, 2003.

We may use derivative instruments to manage our exposure to commodity prices, foreign currency and interest rate risks. Our objectives for holding derivatives are to minimize risks using the most effective methods to eliminate or reduce the impacts of these exposures.

We occasionally enter into fixed-price physical delivery contracts as discussed above as well as commodity price swap derivatives to manage price risk with regard to a portion of our oil and natural gas production. Commodity price swap derivative contracts are designated as cash flow hedges. As a cash flow hedge, the effective portions of changes in the fair value of the derivative are recorded in other comprehensive income and are recognized in the statement of income when the associated production occurs and the resulting cash flows are reported as cash flows from operations. Ineffective portions of changes in the fair value of cash flow hedges are recognized as earnings. To qualify as a cash flow hedge, these swap contracts must be designated as cash flow hedges and changes in their fair value must correlate with changes in the price of anticipated future production such that our exposure to the effects of commodity price changes is reduced.

Item 7A. Quantitative and Qualitative Disclosure About Market Risk

Some of the information below contains forward-looking statements. The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil and natural gas prices, and interest rates charged on borrowings and earned on cash equivalent investments. The disclosure is not meant to be a precise indicator of expected future losses, but rather an indicator of reasonably possible losses. This forward-looking information provides an indicator of how we view and manage our ongoing market risk exposures. Our market risk sensitive instruments were entered into for hedging purposes, not for trading purposes.

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices for natural gas. Pricing for oil and natural gas production is volatile.

In connection with the incurrence of debt related to our acquisition activities and to protect against commodity price fluctuations to achieve a more predictable cash flow, management has adopted a policy of hedging oil and natural gas prices through the use of commodity futures, options and swap agreements. Effective January 1, 2001, we adopted SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activity," which established accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results from the hedged item on the income statement. Companies must formally document, designate and assess the effectiveness of transactions that receive hedge accounting. To date, we have only used cash flow hedges related to our anticipated production. For derivatives classified as cash flow hedges, changes in fair value are recognized in other comprehensive income until the hedged item is recognized in earnings. The ineffective portion of any change in the fair value of a derivative designated as a hedge is immediately recognized as earnings. Hedge effectiveness is measured quarterly based on the relative fair value between the derivative contract and the hedged item over time. At adoption, we recognized a net derivative liability and a reduction in other comprehensive income of approximately $1.1 million as a cumulative effect of an accounting change for all cash flow hedges. Oil and natural gas revenues include net gains from the settlement of cash flow hedges of $6.9 million for the year ended December 31, 2001, and net losses of $1.1 million for the year ended December 31, 2000. During the year ended December 31, 2001, we recognized $3.5 million in other income for hedging ineffectiveness.

The following table sets forth our oil and natural gas hedging activities as of March 15, 2002. Our contracts are swap agreements for the sale of oil or natural gas based on NYMEX pricing.

Oil Swaps		
2002 Contract Period	Volumes (Bbls)	Weighted Average Strike Price
First Quarter	199,000	$ 20.77 per Bbl
Second Quarter	196,000	$ 20.77 per Bbl
Third Quarter	186,000	$ 20.77 per Bbl
Fourth Quarter	180,000	$ 20.77 per Bbl

Natural Gas Swaps		
2002 Contract Period	Volumes (Mmbtus)	Weighted Average Strike Price
First Quarter	1,855,000	$ 2.82 per Mmbtu
Second Quarter	2,156,000	$ 2.87 per Mmbtu
Third Quarter	2,285,000	$ 2.89 per Mmbtu
Fourth Quarter	2,269,000	$ 2.89 per Mmbtu
2003 Contract Period	Volumes (Mmbtus)	Weighted Average Strike Price
First Quarter	1,365,000	$ 3.50 per Mmbtu
Second Quarter	1,365,000	$ 3.50 per Mmbtu
Third Quarter	1,365,000	$ 3.50 per Mmbtu
Fourth Quarter	1,365,000	$ 3.50 per Mmbtu

In accordance with management's policy of hedging oil and natural gas prices, we entered into several swap transactions during 2000 and through September 2001. The counterparty of all of these swap transactions was Enron North America Corp., an affiliate of Enron Corp. (the Enron Hedges). On December 2, 2001, Enron Corp. and other Enron related entities, including Enron North America, filed for bankruptcy under Chapter 11 of the United States Code in the United States Bankruptcy Court in the Southern District of New York. We terminated all of our hedging contracts with Enron North America, effective as of December 5, 2001, as a result of the failure of the Enron affiliate to make payments totaling approximately $2.1 million due us on December 5, 2001, on hedged natural gas volumes and on December 7, 2001, on hedged oil volumes. Based upon oil and natural gas futures prices on December 5, 2001, we believe that we are owned approximately $15.3 million, including settlements already due, but the exact amount will be determined pursuant to the terms of the ISDA Master Agreement.

In accordance with the provisions of SFAS No. 133, we had recognized, as of November 30, 2001, a $13.2 million derivative asset on our balance sheet. This amount represented the estimated fair value of the future cash flows to us based upon the market price of oil and natural gas at that date. Due to the complex nature of the Enron bankruptcy proceedings and the extensive litigation involving Enron, we do not expect that we will receive any settlement as a result of the bankruptcies for an extended period of time; therefore, at December 31, 2001, we have classified the Enron derivative asset as an other long-term asset and reduced the asset balance to approximately $2.8 million, which represents our estimate of the fair market value of our bankruptcy claim against Enron North America. Our estimate of the value of our bankruptcy claim is based upon informal offers that we have received from third parties attempting to purchase such claims as well as management's best estimate of the financial condition of Enron's bankruptcy estate as determined from published reports and court filings related to the bankruptcy. As a result, we have charged $10.7 million to expense during 2001.

As stated above, we terminated the Enron Hedges effective as of December 5, 2001. Under the requirements of SFAS No. 133, we are required to reclassify amounts related to the Enron Hedges that remain in other comprehensive income as of the date of the termination into revenue as the oil and natural gas volumes that were hedged are produced. During the fourth quarter of 2001, we reclassified $1.3 million related to the Enron Hedges from other comprehensive income to other income. At December 31, 2001, approximately $9.0 million remained in other comprehensive income related to the Enron Hedges will be reclassified into revenue as other income as shown in the following table:

	Amount
	(In thousands)
During 2002:	
Quarter ending March 31, 2002	$ 2,134
Quarter ending June 30, 2002	1,649
Quarter ending September 30, 2002	1,599
Quarter ending December 31, 2002	1,593
Total amount in 2002	**$ 6,975**
During 2003:	
Quarter ending March 31, 2003	$ 976
Quarter ending June 30, 2003	631
Quarter ending September 30, 2003	464
Total amount in 2003	**$ 2,071**

In December 2001, we entered into hedge transactions with a new counterparty, BNP Paribas, a financial lending institution (the BNP Hedges), to replace the Enron Hedges. The following table sets forth the BNP Hedges for our oil and natural gas volumes as of December 31, 2001. Our contracts are swap arrangements for the sale of oil and natural gas based upon NYMEX pricing. The market values at December 31, 2001, are estimated and are based on quotes from the counterparty and represent the amount that we would expect to receive to terminate the contract at December 31, 2001.

Commodity	Contract Date	Effective Date	Termination Date	Notional Quantity Per Month	Aggregate Volume	Strike Price	Market Value at December 31, 2001(1)
Oil	12/3/2001	1/1/2002	12/31/2002	67,000 Bbls- 60,000 Bbls	761,000 Bbls	$20.77	**$212,576**
Natural Gas	12/4/2001	1/1/2002	12/31/2002	280,000 Mmbtus- 310,000 Mmbtus	3,650,000 Mmbtus	$ 2.85	**$320,163**
Natural Gas	12/7/2001	1/1/2002	12/31/2002	339,000 Mmbtus- 295,000 Mmbtus	3,715,000 Mmbtus	$ 2.80	**$163,066**

(1) On December 31, 2001, the average forward NYMEX oil and natural gas prices for 2002 were $20.50 per Bbl and $2.76 per Mmbtu, respectively.

A summary of the changes in the fair value of our hedging transactions during 2001 follows (in thousands):

Fair value of contracts outstanding as of December 31, 2000	$ (1,068)
Contracts realized or otherwise settled during the year	(10,687)
Fair value of terminated Enron hedges	(13,192)
Change in fair values of outstanding hedge positions	25,643
Fair value of contracts outstanding as of December 31, 2001	**$ 696**

At December 31, 2001, there was approximately $696,000 in other comprehensive income related to the BNP Paribas Hedge. Based upon contractual volumes, we expect to reclassify the entire amount to oil and natural gas revenues during 2002.

Oil and natural gas revenues for the years ended December 31, 1999, 2000 and 2001, include a net loss of $74,000, a net loss of $1.1 million and a net gain of $6.9 million, respectively, from the settlement of cash flow hedges.

Realized gains or losses from the settlement of the swaps are recorded in our financial statements as increases or decreases in oil and natural gas revenues. For example, using the oil swaps in place as of December 31, 2001, if the settlement price exceeded the actual weighted average strike price of $20.77, then a reduction in oil revenues would have been recorded for the difference between the settlement price and $20.77 multiplied by the actual notional volume. Conversely, if the settlement price was less than $20.77, then an increase in oil revenues would have been recorded for the difference between the settlement price and $20.77 multiplied by the notional volume. For example, for a notional volume of 67,000 Bbls, if the settlement price was $21.77, then oil revenues would have decreased by $67,000. Conversely, if the settlement price was $19.77, oil revenues would have increased by $67,000.

We report average oil, natural gas and NGLs prices including the effects of quality, gathering and transportation costs as well as the net effect of monthly oil and natural gas hedge settlements. The following table sets forth our oil, natural gas and NGL prices, both realized before monthly hedge settlements and realized including monthly hedge settlements, the net effects of the monthly settlements of our oil and natural gas price hedges on revenue, and effects of the amortization of gains attributable to gains recognized in prior periods from derivative ineffectiveness:

	Year Ended December 31,		
	1999	2000	2001
	(in thousands, except per unit amounts)		
Average price per Bbl of oil—realized before monthly hedge settlements	$ 18.18	$ 29.24	$ 23.39
Average price per Bbl of oil—realized including monthly hedge settlements	17.83	27.39	24.17
Average price per Bbl of NGLs—realized before monthly hedge settlements	N/A	24.60	17.70
Average price per Bbl of NGLs—realized including monthly hedge settlements	N/A	24.60	17.70
Average price per Mcf of natural gas—realized before monthly hedge settlements	2.07	3.81	3.53
Average price per Mcf of natural gas—realized including monthly hedge settlements	2.07	3.72	4.20
Increase (reduction) in revenue of monthly hedge settlements	(74)	(1,141)	6,990
Effects of the amortization of (gains) losses from derivative ineffectiveness	—	—	(717)
Total increase (reduction) in revenue of hedging results	$ (74)	$ (1,141)	$ 6,273

Interest Rate Risk

At December 31, 2001, our exposure to interest rates related primarily to borrowings under our credit agreements and interest earned on short-term investments. As of December 31, 2001, we were not using any derivatives to manage interest rate risk. Interest is payable on borrowings under the credit agreements based on a floating rate as more fully described in "Item 7. Management's

Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources." If short-term interest rates would have averaged 1% higher during the year ended December 31, 2001, our interest expense would have increased by approximately $447,000. This amount was determined by applying the hypothetical interest rate change of 1% to our outstanding borrowings under the credit agreements during the year ended December 31, 2001.

Foreign Currency Exchange Rate Risk

We account for a significant portion of our business in Canadian dollars. We are therefore subject to foreign currency exchange rate risk on cash flows of our Canadian operations that are not denominated in Canadian dollars. Presently, a significant portion of the sales of our Canadian oil and natural gas is denominated in U.S. dollars. Foreign currency exchange gains and/or losses related to these transactions have not been significant. The borrowings under our Canadian credit agreement are denominated in Canadian dollars. The asset and liability balances of our Canadian business are translated monthly using current exchange rates, with any resulting unrealized translation gains or losses included in other comprehensive income.

Other Market Risk

We discontinued hedge accounting for our Enron derivatives effective November 30, 2001 and recognized a charge of $10.7 million for the impairment of our derivative asset from Enron. At December 31, 2001 we have valued our derivative asset from Enron at $2.8 million, or approximately 20% of the value on the day we terminated our positions. This valuation is based on informal offers we have received for our position with Enron. We will continue to monitor activities related to Enron and may adjust the value of our derivative asset in the future based on new developments and market information.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

EXCO RESOURCES, INC.
INDEX TO FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT ACCOUNTANTS

The Board of Directors
EXCO Resources, Inc.

We have audited the accompanying consolidated balance sheets of EXCO Resources, Inc. as of December 31, 2000 and 2001, and the related consolidated statements of operations, cash flows, changes in stockholders' equity, and comprehensive income (loss) for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of EXCO Resources, Inc. at December 31, 2000 and 2001, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As discussed in Note 1 to the consolidated financial statements, in 2001 EXCO Resources, Inc. adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities".

Ernst & Young LLP

Dallas, Texas
March 1, 2002

EXCO RESOURCES, INC.

CONSOLIDATED BALANCE SHEETS

	December 31, 2000	December 31, 2001
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 8,200	$ 1,856
Accounts receivable:		
Oil and natural gas sales	8,591	6,151
Joint interest	1,202	4,156
Interest and other	286	3,563
Oil and natural gas hedge derivatives	—	696
Other	1,983	4,699
Total current assets	20,262	21,121
Oil and natural gas properties (full cost accounting method):		
Unproved oil and natural gas properties	—	6,647
Proved developed and undeveloped oil and natural gas properties	90,586	233,889
Accumulated depreciation, depletion and amortization	(10,231)	(75,701)
Oil and natural gas properties, net	80,355	164,835
Office and field equipment, net	681	966
Deferred financing costs	310	1,249
Other assets	764	2,885
Total assets	$ 102,372	$ 191,056
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 2,678	$ 11,008
Revenues and royalties payable	3,652	2,186
Accrued interest payable	81	128
Current maturities of long-term debt	55	—
Income taxes payable	2,189	—
Total current liabilities	8,655	13,322
Long-term debt, less current maturities	42,488	44,994
Deferred abandonment	227	1,466
Deferred income taxes	1,211	10,895
Commitments and contingencies	—	—
Stockholders' equity:		
Preferred stock, $.01 par value: Authorized shares—10,000,000 Issued and outstanding shares—0 and 5,004,869 at December 31, 2000 and 2001, respectively	—	101,175
Common stock, $.02 par value: Authorized shares—25,000,000 Issued and outstanding shares— 6,853,196 and 7,172,587 at December 31, 2000 and 2001, respectively	137	143
Additional paid-in capital	47,500	51,138
Notes receivable—employees	(1,551)	(1,117)
Deficit eliminated in quasi-reorganization	(8,799)	(8,799)
Retained earnings (deficit) since December 31, 1997	12,608	(29,392)
Accumulated other comprehensive income	—	8,096
Treasury stock, at cost: 11,446 and 67,446 shares at December 31, 2000 and 2001, respectively	(104)	(865)
Total stockholders' equity	49,791	120,379
Total liabilities and stockholders' equity	$ 102,372	$ 191,056

See accompanying notes.

EXCO RESOURCES, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	1999	2000	2001
	(In thousands, except per share amounts)		
Revenues:			
Oil and natural gas	$ 5,294	$ 28,869	$ 61,237
Other income	1,424	1,252	5,567
Equity in the earnings of EXUS Energy, LLC	584	—	—
Gain on disposition of property, equipment and other assets	5,102	538	136
Total revenues	12,404	30,659	66,940
Cost and expenses:			
Oil and natural gas production	2,375	9,484	23,914
Depreciation, depletion and amortization	1,446	4,949	14,244
General and administrative	1,934	2,003	4,806
Interest	17	1,369	3,133
Impairment of oil and natural gas properties	—	—	49,575
Uncollectible value of Enron hedges	—	—	10,669
Total cost and expenses	5,772	17,805	106,341
Income (loss) before income taxes and minority interest	6,632	12,854	(39,401)
Minority interest in limited partnership	(7)	—	—
Income (loss) before income taxes	6,639	12,854	(39,401)
Income tax expense (benefit)	2,139	4,400	(54)
Net income (loss) before extraordinary item	4,500	8,454	(39,347)
Fee income from early extinguishment of debt, net of tax	165	—	—
Net income (loss)	4,665	8,454	(39,347)
Dividends on preferred stock	—	—	2,653
Earnings (loss) on common stock	$ 4,665	$ 8,454	$ (42,000)
Basic earnings (loss) per share	$ .69	$ 1.23	$ (5.96)
Diluted income (loss) per share	$ .69	$ 1.18	$ (5.96)
Weighted average number of common and common equivalent shares outstanding:			
Basic	6,698	6,835	7,046
Diluted	6,714	7,122	7,046

See accompanying notes.

EXCO RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	1999	2000	2001
	(In thousands)		
Operating Activities:			
Net income (loss)	$ 4,665	$ 8,454	$ (39,347)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	1,446	4,949	14,638
Impairment of oil and natural gas properties	—	—	49,575
Gain on disposition of property, equipment and other assets	(5,102)	(538)	(136)
Deferred income taxes	2,139	1,283	(1,211)
Income from derivative ineffectiveness and terminated hedges	—	—	(4,147)
Allowance for uncollectible value of Enron hedges	—	—	10,669
Gain on investment in EXCO Energy Investors, L.L.C.	(65)	—	—
Extraordinary item, net of tax	(165)	—	—
Cash flow before changes in working capital	2,918	14,148	30,041
Effect of changes in:			
Accounts receivable	(20,663)	11,477	(470)
Other current assets	123	(1,912)	(2,655)
Accounts payable and other current liabilities	9,002	3,584	(1,000)
Net cash provided by (used in) operating activities	(8,620)	27,297	25,916
Investing Activities:			
Additions to oil and natural gas properties and equipment	(30,497)	(67,534)	(90,876)
Acquisition of Addison Energy Inc.	—	—	(44,864)
Proceeds from the dissolution of EXCO Energy Investors, L.L.C.	409	—	—
Investment in Rio Grande, Inc. promissory note	7,451	—	—
Purchase of note from Venus Exploration, Inc.	(7,000)	—	—
Payment of note from Venus Exploration, Inc.	7,000	—	—
Investment in EXUS Energy, LLC	(257)	257	—
Other investing activities	(216)	(735)	(191)
Proceeds from disposition of property and equipment	20,248	1,493	1,399
Net cash used in investing activities	(2,862)	(66,519)	(134,532)
Financing Activities:			
Proceeds from note payable and long-term debt	3,000	50,536	165,463
Proceeds from issuance of preferred stock	—	—	101,175
Payments on long-term debt	(3,010)	(12,994)	(162,484)
Principal and interest on notes receivable—employees	(20)	1	615
Deferred financing costs	(9)	(381)	(1,731)
Proceeds from exercise of stock options and warrant	—	288	2,506
Preferred stock dividends	—	—	(2,653)
Net cash provided by (used in) financing activities	(39)	37,450	102,891
Net decrease in cash	(11,521)	(1,772)	(5,725)
Effect of exchange rates on cash and cash equivalents	—	—	(619)
Cash at beginning of year	21,493	9,972	8,200
Cash at end of year	$ 9,972	$ 8,200	$ 1,856
Supplemental Cash Flow Information:			
Interest paid	$ 7	$ 1,300	$ 2,667
Income taxes paid	$ —	$ —	$ 6,350

See accompanying notes.

EXCO RESOURCES, INC.

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

	5% Preferred Stock		Common Stock								
	Number of Shares	Amount	Number of Shares	Amount	Additional Paid-In Capital	Notes Receivable-Officers and Employees	Deficit Eliminated	Retained Earnings (Deficit)	Treasury Stock	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
	(In thousands, except per share amount)										
Balance on December 31, 1998	—	$ —	6,688	$134	$46,241	$ (825)	$(8,799)	$ (511)	$ —	$ —	$ 36,240
Principal and interest on notes receivable—officers	—	—	—	—	—	(21)	—	—	—	—	(21)
1998 rights offering expense	—	—	—	—	(4)	—	—	—	—	—	(4)
Exercise of options	—	—	117	2	704	—	—	—	—	—	706
Notes issued by officers	—	—	—	—	—	(706)	—	—	—	—	(706)
Net income	—	—	—	—	—	—	—	4,665	—	—	4,665
Balance on December 31, 1999	—	—	6,805	136	46,941	(1,552)	(8,799)	4,154	—	—	40,880
Principal and interest on notes receivable—officers	—	—	—	—	—	1	—	—	—	—	1
Exercise of options	—	—	48	1	287	—	—	—	—	—	288
Realization of deferred tax asset	—	—	—	—	72	—	—	—	—	—	72
Realization of stock warrant value	—	—	—	—	200	—	—	—	—	—	200
Purchase of treasury stock, at cost	—	—	—	—	—	—	—	—	(104)	—	(104)
Net income	—	—	—	—	—	—	—	8,454	—	—	8,454
Balance on December 31, 2000	—	—	6,853	137	47,500	(1,551)	(8,799)	12,608	(104)	—	49,791
Issuance of 5% convertible preferred stock	5,005	101,175	—	—	—	—	—	—	—	—	101,175
Exercise of stock options and warrant	—	—	270	5	2,682	(181)	—	—	—	—	2,506
Purchase of Addison Energy Inc.	—	—	50	1	909	—	—	—	—	—	910
Realization of deferred tax asset	—	—	—	—	47	—	—	—	—	—	47
Principal and interest on notes receivable—employees	—	—	—	—	—	615	—	—	—	—	615
Purchase of treasury stock	—	—	—	—	—	—	—	—	(761)	—	(761)
Dividends on preferred stock ($.53 per share)	—	—	—	—	—	—	—	(2,653)	—	—	(2,653)
Net loss	—	—	—	—	—	—	—	(39,347)	—	—	(39,347)
Other comprehensive income:											
Foreign currency translation adjustment	—	—	—	—	—	—	—	—	—	(1,646)	(1,646)
Hedging activities:											
Cumulative effect of change in accounting principle	—	—	—	—	—	—	—	—	—	(1,068)	(1,068)
Reclassification adjustments for settled contracts	—	—	—	—	—	—	—	—	—	(10,687)	(10,687)
Amortization of gains from terminated Enron hedges	—	—	—	—	—	—	—	—	—	(1,346)	(1,346)
Changes in fair value of outstanding hedge positions	—	—	—	—	—	—	—	—	—	22,843	22,843
Balance on December 31, 2001	**5,005**	**$101,175**	**7,173**	**$143**	**$51,138**	**$(1,117)**	**$(8,799)**	**$(29,392)**	**$(865)**	**$ 8,096**	**$120,379**

See accompanying notes.

EXCO RESOURCES, INC.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	1999	2000	2001
		(In thousands)	
Net income (loss)	$ 4,665	$ 8,454	$ (39,347)
Other comprehensive income (loss):			
Foreign currency translation adjustment	—	—	(1,646)
Hedging activities			
Enron hedges:			
Cumulative effect of change in accounting principle— January 1, 2001	—	—	(1,068)
Effective changes in fair value	—	—	22,147
Reclassification adjustments for settled contracts	—	—	(10,687)
Amortization of terminated contracts	—	—	(1,346)
	—	—	9,046
New hedges:			
Effective changes in fair value	—	—	696
Total hedging activities	—	—	9,742
Total comprehensive income (loss)	$ 4,665	$ 8,454	$ (31,251)

See accompanying notes.

1. Summary of Significant Accounting Policies

Organization

EXCO Resources, Inc., (the Company), a Texas corporation, was formed in 1955. Our operations consist primarily of acquiring interests in producing oil and natural gas properties located in the continental United States and Canada. We also act as the operator on some of these properties and receive overhead reimbursement fees as a result.

Principles of Consolidation

The accompanying consolidated financial statements include the financial statements of EXCO Resources, Inc. and its subsidiaries. We accounted for our investment in Pecos-Gomez, L.P., which ceased operations during 2001 with all remaining net assets distributed to the partners, using the proportional method of consolidation. Under this method, only our combined 55.13742% interest in the partnership is reflected in the financial statements with no recording of minority interest. All inter-company transactions have been eliminated.

Functional Currency

The assets, liabilities and operations of Addison Energy Inc. (Addison), our Canadian subsidiary, are measured using the Canadian dollar as the functional currency. These assets and liabilities are translated into U.S. dollars using end-of-period exchange rates. Revenue and expenses are translated into U.S. dollars at the average exchange rates in effect during the period. Translation adjustments are deferred and accumulated in other comprehensive income.

Accounting for Unconsolidated Investments

During 1999 we accounted for our 50% interest in EXUS Energy, LLC using the equity method of accounting for investments because control was temporary. Equity in the pre-tax earnings of EXUS included in our 1999 consolidated statement of operations was $584,000. During 1999, EXCO's share of the EXUS oil and natural gas revenues, depreciation, depletion and amortization, direct operating expenses and interest expense were $1.6 million, $449,000, $244,000 and $253,000, respectively.

Quasi-Reorganization

Effective December 31, 1997, we effected a quasi-reorganization by applying approximately $8.8 million of our additional paid-in capital account to eliminate our accumulated deficit. Our board of directors decided to effect a quasi-reorganization given the change in management, the infusion of new equity capital and an increase in activities. Our accumulated deficit was primarily related to past operations and properties that have been sold or abandoned. We did not adjust the historical carrying values of our assets and liabilities in connection with the quasi-reorganization.

Management Estimates

In preparing financial statements in conformity with accounting principles generally accepted in the United States, we are required to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses during the reporting period. The most significant estimates pertain to proved oil, natural gas and NGL reserve volumes and the future development, dismantlement and abandonment costs as well as estimates relating to certain oil, natural gas and NGL revenues and expenses. Actual results may differ from management's estimates.

Cash Equivalents

We consider all highly liquid investments with maturities of three months or less when purchased, to be cash equivalents.

Concentration of Credit Risk and Accounts Receivable

Financial instruments that potentially subject us to a concentration of credit risk consist principally of cash, trade receivables and our hedging and derivative financial instruments. We place our cash with high credit quality financial institutions. We sell oil and natural gas to various customers. In addition, we participate with other parties in the drilling, completion and operation of oil and natural gas wells. Substantially all of our accounts receivable are due from either purchasers of oil, natural gas or NGLs or participants in oil and natural gas wells for which we serve as the operator. Generally, operators of oil and natural gas properties have the right to offset future revenues against unpaid charges related to operated wells. Oil, natural gas and NGL sales are generally unsecured. We have provided for credit losses in the financial statements and these losses have been within management's expectations. The allowance for doubtful accounts receivable aggregated $34,000 and $111,000 at December 31, 2000 and 2001, respectively. We place our hedging and derivative financial instruments with financial institutions and other firms that we believe have high credit ratings. For a discussion of the credit risks associated with our hedging activities, please see "Note 9. Hedging Activities."

Hedging and Derivative Financial Instruments

In connection with the incurrence of debt related to our acquisition activities and to protect against commodity price fluctuations to achieve a more predictable cash flow, our management has adopted a policy of hedging oil and natural gas prices whenever such prices are in excess of the prices anticipated in our operating budget and profit plan through the use of commodity futures, options and swap agreements. These derivatives are not held for trading purposes. Hedging transactions require the approval of the board of directors.

We adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" on January 1, 2001. In accordance with the transition provisions of SFAS 133, we recorded a cumulative-effect loss in other comprehensive income of $1.1 million to recognize the fair value of our derivatives designated as cash flow hedging instruments at the date of adoption.

On the date the derivative contract is entered into, we designate the derivative as a hedge. All of our derivative instruments at December 31, 2000 and 2001, were designated as cash flow hedges. Changes in the fair value of a derivative that is highly effective as a cash flow hedge are recorded in other comprehensive income, until earnings are affected by the variability of cash flows.

We formally document all relationships between hedging instruments and hedged items, as well as our risk-management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives that are designated as cash flow hedges to forecasted transactions. We also formally assess, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items.

When it is determined that a derivative is not highly effective as a hedge or that it has ceased to be a highly effective hedge, we discontinue hedge accounting prospectively, as discussed below.

We discontinue hedge accounting prospectively when: (1) it is determined that the derivative is no longer effective in offsetting changes in cash flows of a hedged item; (2) the derivative expires or is sold, terminated or exercised; (3) the derivative is designated as a hedge instrument, because it is unlikely that a forecasted transaction will occur; or (4) management determines that designation of the derivative as a hedge instrument is no longer appropriate.

When hedge accounting is discontinued because it is probable that a forecasted transaction will not occur, the derivative will continue to be carried on the balance sheet at its fair value, and gains and losses that were accumulated in other comprehensive income will be recognized immediately in earnings. In all other situations in which hedge accounting is discontinued, the derivative will be carried as its fair value on the balance sheet, with changes in its fair value recognized in current-period earnings. Amounts previously recognized in other comprehensive income will remain there until the previously designated hedged item affects earnings. Please see "Note 9. Hedging Activities" for a discussion of certain derivative transactions for which hedge accounting was discontinued during 2001. For the year ended December 31, 2001, we recorded as other income in the statement of operations, $3.5 million from hedge ineffectiveness and $1.3 million from derivative transactions for which hedge accounting was discontinued.

Oil and Natural Gas Properties

We have recorded oil and natural gas properties at cost using the full cost method of accounting. Under the full cost method, all costs associated with the acquisition, exploration or development of oil and natural gas properties are capitalized as part of the full cost pool. Capitalized costs are limited to the aggregate of the after-tax present value of future net reserves plus the lower of cost or fair market value of unproved properties.

Unproved oil and natural gas properties are excluded from the calculation of depreciation, depletion and amortization until it is determined whether or not proved reserves can be assigned to such properties. At December 31, 2001, the $6.6 million in unproved oil and natural gas properties resulted from the allocation of the purchase price of Canadian properties to undeveloped acreage and possible and probable reserves. We will assess our unproved oil and natural gas properties for impairment on a quarterly basis.

Depreciation, depletion and amortization of evaluated oil and natural gas properties is provided using the unit-of-production method based on total proved reserves, as determined by independent petroleum reservoir engineers.

Sales, dispositions and other oil and natural gas property retirements are accounted for as adjustments to the full cost pool, with no recognition of gain or loss unless the disposition would significantly alter the amortization rate.

At the end of each quarterly period, the unamortized cost of proved oil and natural gas properties, net of related deferred income taxes, is limited to the sum of the estimated future net revenues from proved properties using current period-end prices discounted at 10%, adjusted for related income tax effects (ceiling test). This calculation is done separately for the United States and Canadian full cost pools.

The calculation of the ceiling test is based upon estimates of proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production, and plan of development. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities or oil and natural gas that are ultimately recovered.

As a result of low oil and natural gas prices on September 30 and December 31, 2001, we have recorded pre-tax non-cash ceiling test write-downs totaling approximately $49.6 million (of which $28.7 million was from the United States full cost pool and $20.9 million was from the Canadian full cost pool). For the period ending September 30, 2001 the United States ceiling test write-down was $25.0 million and the pricing utilized was $21.51 per Bbl for oil, $1.95 per Mcf for natural gas, and $16.77 per Bbl for NGLs. Pricing utilized for the write-down of the Canadian full cost pool of $20.9 million on September 30, 2001, was $22.06 per Bbl for oil, $1.70 per Mcf for natural gas, and $18.59 per Bbl for NGLs. For the period ending December 31, 2001, the United States ceiling test write-down was $3.7 million and the pricing utilized was $17.67 per Bbl for oil, $2.22 per Mcf for gas, and $14.25 per Bbl for NGLs.

Office and Field Equipment

Office and field equipment are capitalized at cost and depreciated on a straight line basis over their estimated useful lives.

Deferred Abandonment

We are providing for future site restoration costs on our Canadian oil and natural gas properties based upon management's estimates. The costs are being recognized over the remaining life of proved reserves by a charge to depreciation, depletion and amortization in the statement of operations with a related increase in the non-current deferred abandonment liability. Actual expenditures incurred for site restoration will be charged to the deferred abandonment liability.

Revenue Recognition

We use the sales method of accounting for oil and natural gas revenues. Under the sales method, revenues are recognized based on actual volumes of oil and natural gas sold to purchasers.

Overhead Reimbursement Fees

We have classified fees from overhead charges billed to working interest owners, including ourselves, of $661,000, $1.5 million and $2.9 million for the years ended December 31, 1999, 2000, and 2001, respectively, as a reduction of general and administrative expenses in the accompanying statements of operations.

Earnings Per Share

SFAS No. 128, "Earnings per Share," requires presentation of two calculations of earnings per common share. Basic earnings per common share equals earnings on common stock divided by weighted average common shares outstanding during the period. Diluted earnings per common share equals net income divided by the sum of weighted average common shares outstanding during the period plus any dilutive common stock equivalents assumed to be issued. Common stock equivalents are shares assumed to be issued if our 5% convertible preferred stock was converted and our outstanding stock options and warrants were exercised.

Since we reported a net loss for the year ended December 31, 2001, our common stock equivalents are considered to be anti-dilutive and are not considered in the earnings per share calculation. For the year ended December 31, 2001, employee and director stock options and our convertible preferred stock would have increased the weighted average number of shares outstanding by approximately 469,000 shares and 2,537,000 shares respectively.

Recently Issued Accounting Standards

In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 141, "Business Combinations," which addresses financial accounting and reporting for business combinations. SFAS No. 141 is effective for all business combinations completed after June 30, 2001. The adoption of SFAS No. 141 has not had a material impact on our financial position or results of operations.

In June 2001, the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets," which addresses, among other things, the financial accounting and reporting for goodwill subsequent to an acquisition. The new standard eliminates the requirement to amortize goodwill; instead, such goodwill shall be reviewed at least annually for impairment. SFAS No. 142 is required to be adopted on January 1, 2002. We do not believe the adoption of these provisions will significantly impact our financial statements.

SFAS No. 143, "Accounting for Asset Retirement Obligations," which was also issued by the FASB in June 2001, requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. We are currently evaluating the impact SFAS No. 143 will have on our financial position and results of operations.

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," which addresses financial accounting and reporting for the impairment or disposal of long-lived assets. SFAS No. 144 supersedes other accounting pronouncements to eliminate certain exceptions and alternatives. We do not believe the adoption of these provisions will impact our financial statements.

Reverse Stock Splits

At our 1996 annual meeting of shareholders, our shareholders approved an amendment to our articles of incorporation, authorizing a one-for-five reverse stock split of our common stock, which became effective July 19, 1996. At our 1998 annual meeting of shareholders, our shareholders approved an amendment to our articles of incorporation, authorizing a one-for-two reverse stock split of our common stock, which became effective March 31, 1998. We have adjusted all share and per share numbers retroactively to record the effects of the reverse stock split.

Reclassified Prior Year Amounts

Certain prior year amounts have been reclassified to conform to current year presentation.

2. Term Debt

Long-term debt is summarized as follows:

	December 31, 2000	December 31, 2001
	(In thousands)	
Notes payable	$ 42,543	$ 44,994
Less current maturities	(55)	—
Long-term debt	$ 42,488	$ 44,994

Credit Agreements

On September 22, 2000, we entered into an amended and restated $150.0 million credit agreement with Bank of America, N.A., as administrative agent, Bank One, Texas, N.A., as syndication agent, and a syndicate of banks as lenders. The amended and restated credit agreement provided for an initial borrowing base of $45.0 million. On March 7, 2001, we entered into an amendment that increased the borrowing base to $60.0 million.

On April 26, 2001, as part of the financing of the acquisition of Addison, see Note 10. Acquisitions—Addison Energy Inc. Acquisition", we repaid and canceled the Bank of America credit agreement and entered into two new credit agreements, a U.S. credit agreement and a Canadian credit agreement.

On December 18, 2001, as part of the financing of the acquisition of the PrimeWest properties, see "Note 10. Acquisitions—PrimeWest Properties Acquisition", we entered into restated U.S. and Canadian credit agreements. The U.S. credit agreement is with Bank One, NA, as administrative agent, BNP Paribas, as syndication agent, The Bank of Nova Scotia, as documentation agent, Bank One Capital Markets, Inc. as lead arranger and bookrunner, and certain financial institutions as lenders. The Canadian credit agreement is with Bank One, NA, Canada Branch, as administrative agent, BNP Paribas (Canada), as syndication agent, The Bank of Nova Scotia, as documentation agent, Bank One Capital Markets, Inc. as lead arranger and bookrunner, and certain financial institutions as lenders. The credit agreements mature on April 30, 2004.

U.S. Credit Agreement. Our restated U.S. credit agreement provides for borrowings of up to $124.0 million under a revolving credit facility with a borrowing base of $58.0 million. The borrowing base is to be redetermined as of May 1, 2002, and each November 1 and May 1 thereafter. At December 31, 2001, we had approximately $3.5 million of outstanding indebtedness, letter of credit commitments of $310,000 and approximately $54.2 million available for borrowing under our U.S. credit agreement. Borrowings under the credit agreement are secured by a first lien mortgage providing a security interest in 90% of our U.S. oil and natural gas properties. At our election, interest on borrowings may be either (i) the greater of the administrative agent's prime rate or the federal funds effective rate plus an applicable margin or (ii) LIBOR (London InterBank Offered Rate) plus an applicable margin.

As part of the financing of the acquisition of Addison, the U.S. credit agreement provided for a bridge loan to us in the amount of $16.0 million. We repaid the $16.0 million borrowed under the bridge loan on June 29, 2001, from net proceeds from our 5% convertible preferred stock offering and from proceeds from the exercise of employee stock options and the 200,000 share warrant. By the terms of the U.S. credit agreement, we may not make any additional borrowings under the bridge loan after it has been repaid.

Canadian Credit Agreement. Our restated Canadian credit agreement provides for borrowings of up to U.S. $48.6 million under a revolving credit facility with a borrowing base of U.S. $45.0 million. The borrowing base is to be redetermined as of May 1, 2002, and each November 1 and May 1 thereafter. At December 31, 2001, we had approximately U.S. $41.5 million of outstanding indebtedness and approximately $3.5 million available for borrowing under our Canadian credit agreement. Borrowings under the credit agreement are secured by a first lien mortgage providing a security interest in 90% of our Canadian oil and natural gas properties. At our election, interest on borrowings may be either (i) the Canadian prime rate plus an applicable margin or (ii) the Banker's Acceptance rate plus an applicable margin.

The U.S. and the Canadian credit agreements contain certain financial covenants and other restrictions which require that we:

- maintain a ratio of our consolidated current assets to consolidated current liabilities of at least 1.0 to 1.0 at the end of any fiscal quarter;
- maintain a minimum consolidated tangible net worth of not less than $48.0 million (adjusted upward by 50% of quarterly net income and 75% of the net proceeds from the issuance of any equity securities after April 26, 2001);
- not permit the ratio of consolidated debt to consolidated total capital to be greater than 65% at the end of each fiscal quarter; and
- not permit the ratio of indebtedness to earnings before interest expense, state and federal taxes and depreciation, depletion and amortization expense to be more than 2.5 to 1.0 at the end of each fiscal quarter.

Additionally, the credit agreements contain a number of other covenants regarding our liquidity and capital resources, including restrictions on our ability to incur additional indebtedness, restrictions on our ability to pledge assets, and prohibit the payment of dividends on our common stock. The U.S. credit agreement further required that we hedge at least 75% of our anticipated production from our U.S. proved developed producing reserves, within ten days of the time we entered into the agreement, for a period of up to 24 months. As of December 31, 2001, we were in compliance with the covenants contained in the U.S. and Canadian credit agreements.

Dividend Restrictions. We have not paid any cash dividends on our common stock, and do not anticipate paying cash dividends on our common stock in the foreseeable future. In addition, our credit agreements currently prohibit us from paying dividends on our common stock. If there is a default under our credit agreements, we will not be able to pay dividends on the shares of our convertible preferred stock. Even if our credit agreements permitted us to pay cash dividends, we can make those payments only from our surplus (the excess of the fair value of our total assets over the sum of our liabilities plus our total paid-in share capital). In addition, we can pay cash dividends only if after paying those dividends we would be able to pay our liabilities as they become due.

Pecos-Gomez, L.P.

See Note 10. Acquisitions and Dispositions—Pecos County Properties Acquisition for a description of the Pecos-Gomez, L.P. credit agreement.

3. Income Taxes

The income tax provision attributable to the income (loss) before extraordinary item consists of the following:

	December 31,		
	1999	2000	2001
	(In thousands)		
Current:			
U.S. federal	—	$ 2,022	$ 1,063
Canadian federal	—	—	—
U.S. state and local	—	178	94
	—	2,200	1,157
Deferred:			
U.S. federal	2,139	2,022	(1,113)
Canadian federal	—	—	—
U.S. state and local	—	178	(98)
	2,139	2,200	(1,211)
Total	$ 2,139	$ 4,400	$ (54)

At December 31, 2001, we had net operating loss carryforwards (NOLs) for income tax purposes that began to expire in 2001. Our ability to use the NOLs has been significantly restricted because of a change in our ownership, which occurred December 19, 1997, as well as the change in ownership of Rio Grande, Inc. which occurred on March 16, 1999. We estimate that approximately $4.9 million of the NOLs will become available in the future at the rate of approximately $460,000 per year. For financial reporting purposes, a valuation allowance has been recognized to offset the deferred tax assets related to carryforwards prior to our quasi-reorganization. When realized, the tax benefit for those carryforwards will be credited to additional paid-in capital, which, in 2001 amounted to $47,000. In addition, a valuation allowance has been recognized to offset deferred tax assets acquired in the Rio Grande transaction, for the impairment of oil and natural gas properties and the uncollectible value of the Enron Hedges.

We have not provided any U.S. deferred income taxes on the undistributed earnings of our Canadian subsidiary based upon the determination that at this time those earnings will be indefinitely reinvested in Canada. As of December 31, 2001, there were no material cumulative undistributed earnings of this subsidiary.

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of our deferred tax liabilities and assets are as follows:

	December 31,		
	1999	2000	2001
	(In thousands)		
Deferred tax assets:			
Net operating loss carryforwards—United States	$ 1,922	$ 1,984	$ 1,814
Tax basis of oil and natural gas properties in excess of book basis—United States	—	—	3,280
Basis difference in fair value of hedges	—	—	2,482
Credit carryforwards	29	5	2
Statutory depletion carryforwards	16	—	—
Other	4	13	41
Valuation allowance for deferred tax assets	(1,728)	(1,306)	(7,619)
Total deferred tax assets	243	696	—
Deferred tax liabilities:			
Book basis of oil and natural gas properties in excess of tax basis—United States	243	1,907	—
Book basis of oil and natural gas properties in excess of tax basis—Canada	—	—	10,895
Total deferred tax liabilities	243	1,907	10,895
Net deferred tax liabilities	$ —	$ 1,211	$ 10,895

A reconciliation our income tax provision (benefit) computed by applying the statutory United States federal income tax rate to our income (loss) before income taxes for the years ended December 31, 1999, 2000 and 2001 is presented in the following table:

	December 31,		
	1999	2000	2001
	(In thousands)		
United States federal income taxes (benefit) at statutory rate of 34%	$ 2,139	$ 4,374	$ (13,396)
Increases (reductions) resulting from:			
Depletion	—	—	(383)
State income taxes	—	448	(516)
Adjustments to the valuation allowance	—	(422)	6,313
Non-deductible charges	—	—	7,928
Tax provision	$ 2,139	$ 4,400	$ (54)

4. Stock Transactions

Issuance of Common Stock

On September 15, 1998, several of our directors and executive officers exercised stock options covering 150,000 shares of common stock at a strike price of $6.00 per share. Of the $900,000 in aggregate proceeds, these directors and executive officers paid $75,000 in cash with $825,000 being borrowed from us. On November 29, 1999, several of our executive officers who are also directors exercised stock options covering 117,500 shares of common stock, 112,500 at a strike price of $6.00 per share and 5,000 at a strike price of $6.25 per share. Of the $706,250 in aggregate proceeds, these executive officers who are also directors paid $0 in cash with $706,250 being borrowed from us.

During the year ended December 31, 2000, two of our directors and three of our employees exercised stock options covering 48,000 shares of our common stock, 46,375 at a strike price of $6.00 per share and 1,625 shares at $6.25 per share. We received net proceeds of approximately $288,400 for these shares.

During the year ended December 31, 2001, 17 of our employees, one is also a director, exercised stock options covering 69,511 shares of our common stock at stock prices ranging from $6.00 per share to $15.125 per share. We received aggregate proceeds of approximately $486,600 for these shares with $305,600 paid in cash and $181,000 being borrowed from us.

The following table summarizes our stock option activity:

	Stock Options	Weighted Average Exercise Price Per Share
Outstanding at December 31, 1998	922,500	$ 6.00
Granted	268,309	$ 6.10
Expired or canceled	(6,600)	$ 6.16
Exercised	(117,500)	$ 6.01
Options outstanding at December 31, 1999	1,066,709	$ 6.02
Granted	414,637	$ 13.77
Expired or canceled	(34,747)	$ 6.01
Exercised	(48,000)	$ 6.01
Options outstanding at December 31, 2000	1,398,599	$ 8.32
Granted	761,625	$ 14.55
Expired or canceled	(40,933)	$ 14.88
Exercised	(69,511)	$ 7.00
Options outstanding at December 31, 2001	**2,049,780**	**$ 10.55**
Options exercisable at December 31, 2001	**1,239,045**	**$ 8.50**

SFAS No. 123, "Accounting for Stock-Based Compensation" defines a fair value based method of accounting for employee stock compensation plans, but allows for the continuation of the intrinsic value based method of accounting to measure compensation cost prescribed by Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" (APB 25). For companies electing not to change their accounting, SFAS 123 requires pro forma disclosures of earnings and earnings per share as if the change in accounting provision of SFAS 123 has been adopted.

We have elected to continue to utilize the accounting method prescribed by APB 25, under which no compensation cost has been recognized, and adopt the disclosure requirements of SFAS 123. As a result, SFAS 123 has no effect on our financial condition or our results of operations at December 31, 1999, 2000 and 2001.

Had compensation costs for these plans been determined consistent with SFAS 123, our net income (loss) and earnings per share (EPS) would have been adjusted to the following pro forma amounts:

		December 31,		
		1999	2000	2001
		(In thousands, except per share amounts)		
Net income (loss)	As Reported	$ 4,665	$ 8,454	$ (39,347)
	Pro Forma	$ 3,889	$ 7,776	$ (40,465)
Basic EPS	As Reported	$ .69	$ 1.23	$ (5.96)
	Pro Forma	$ .58	$ 1.14	$ (6.12)
Diluted EPS	As Reported	$ .69	$ 1.18	$ (5.96)
	Pro Forma	$ .58	$ 1.09	$ (6.12)

The present value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model. The following assumptions were used: fair market values of stock at date of grant ranged from $6.00 to $20.62; option exercise prices ranged from $6.00 to $15.125; option term of 10 years; risk-free rate of return is based on 10-year U.S. Treasury Notes; company stock volatility is based on daily stock prices from January 1, 1999 through December 31, 2001; company dividend yield of 0%; and calculated Black-Scholes values ranging from $2.60 to $8.94 per option.

As part of the consideration paid for the acquisition of the Central Properties, we issued a warrant to Central Resources, Inc. to purchase 200,000 shares of our common stock for $11.00 per share. This warrant was assigned and then exercised on May 21, 2001, for the full 200,000 shares at which time we received $2.2 million cash. We filed a registration statement on Form S-3 with the SEC to register the resale of the 200,000 shares of common stock issued upon the exercise of the warrant. The registration statement was declared effective by the SEC on October 15, 2001.

As part of the acquisition of Addison, see "Note 10. Acquisitions and Dispositions—Addison Energy Inc. Acquisition", we have entered into employment agreements with the Addison management team to provide incentives for the continued growth of Addison. These incentives include a share appreciation rights plan which rewards the Addison managers for additions to Addison's reserves based upon certain established benchmarks. The incentives are payable in cash or our common stock at the election of the employee.

The Addison managers also agreed to purchase shares of the Company's common stock with a portion of the proceeds they received from the sale of their common shares of Addison to us. They purchased in the open market 24,940 shares worth $455,144. In addition, as part of the Addison purchase, we issued 49,880 shares worth $910,310 to the Addison managers. The resale of the shares is restricted.

Issuance of Preferred Stock

We are authorized to issue up to 10,000,000 shares of preferred stock, $.01 par value per share, that the board of directors may issue from time to time in one or more series. With respect to each series of preferred stock, the board is authorized to fix and determine by resolution the number of shares of each series, the designation thereof and all rights and preferences including voting, dividend, conversion, redemption and liquidation rights.

On June 29, 2001, we closed our rights offering to existing shareholders that resulted in the sale of 5,004,869 shares of 5% convertible preferred stock at $21.00 per share. We raised a total of approximately $105.1 million in gross proceeds (approximately $101.2 million in net proceeds after fees and commissions), through the exercise of 4,466,869 rights and the sale of 538,000 shares of preferred stock by dealer managers. We applied approximately $97.6 million of the offering proceeds to pay-off our bank loans and have used the remaining proceeds for general corporate purposes. Dividends on our preferred stock are payable quarterly in cash. Currently, the requirement for such dividend payment is approximately $1.3 million per quarter beginning September 30, 2001. During 2001, preferred stock dividends of approximately $2.7 million have been paid. Each share of 5% convertible preferred stock is convertible into one share of our common stock, at the option of the holder, on or before June 30, 2003.

The remaining authorized but unissued shares of preferred stock are available for future equity financings through issuance to the general public, future acquisitions, stock dividends or splits or for other corporate purposes for which the issuance of preferred shares may be advisable.

5. Related Party Transactions

In the past, certain of our directors, and the companies with which they are affiliated, participated in oil and natural gas joint ventures with us upon the same terms and conditions as unrelated parties. In addition, we have purchased certain oil and natural gas prospects as well as drilling services and oil field supplies and services in the normal course of business from directors or from companies in which certain directors have a financial interest. During 1999, one of our directors participated under a farmout agreement for an interest in one development well. During 1999, approximately $42,000 in costs associated with this well were paid by the director.

6. Commitments and Contingencies

We lease our offices and certain equipment. Our rental expenses were approximately $134,000, $202,000 and $476,000 for 1999, 2000 and 2001, respectively. Our future minimum rental payments under operating leases with remaining noncancellable lease terms at December 31, 2001, are as follows:

	Amount *(In thousands)*
2002	$ 547
2003	470
2004	311
2005	223
Thereafter	—
	$ 1,551

7. Environmental Regulation

Various federal, state and local laws and regulations covering discharge of materials into the environment, or otherwise relating to the protection of the environment, may affect our operations and the costs of our oil and natural gas exploitation, development and production operations. We do not anticipate that we will be required in the near future to expend amounts material in relation to the financial statements taken as a whole by reason of environmental laws and regulations. Because these laws and regulations are constantly being changed, we are unable to predict the conditions and other factors, over which we do not exercise control, that may give rise to environment liabilities affecting us.

8. Geographic Operating Segment Information and Oil and Natural Gas Disclosures

We have operations in only one industry segment, that being the oil and natural gas exploration and production industry; however, we are organizationally structured along geographic operating segments. We have reportable operations in the United States and Canada. The following tables provide our geographic operating segment data. Operating segment data represents Canadian activity beginning April 26, 2001, when we acquired Addison Energy Inc.

The following table presents total capitalized costs of proved and unproved properties and accumulated depreciation, depletion and amortization related to oil and natural gas producing operating and total assets:

	United States	Canada	Total
		(In thousands)	
As of December 31, 1999:			
Oil and natural gas properties	$ 24,177	$ —	$ 24,177
Accumulated depreciation, depletion and amortization	(5,503)	—	(5,503)
Oil and natural gas properties, net	$ 18,674	$ —	$ 18,674
Total assets	$ 50,932	$ —	$ 50,932
As of December 31, 2000:			
Oil and natural gas properties	$ 90,586	$ —	$ 90,586
Accumulated depreciation, depletion and amortization	(10,231)	—	(10,231)
Oil and natural gas properties, net	$ 80,355	$ —	$ 80,355
Total assets	$ 102,372	$ —	$ 102,372
As of December 31, 2001:			
Oil and natural gas properties	$ 135,306	$ 105,230	$ 240,536
Accumulated depreciation, depletion and amortization	(48,006)	(27,695)	(75,701)
Oil and natural gas properties, net	$ 87,300	$ 77,535	$ 164,835
Total assets	$ 109,682	$ 81,374	$ 191,056

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Presented below are costs incurred in oil and natural gas property acquisition, exploration and development activities:

	United States	Canada	Total
	(In thousands, except per unit amounts)		
1999:			
Property acquisition costs	$ 14,803	$ —	$ 14,803
Development costs	940	—	940
Exploration costs	122	—	122
Production costs	2,375	—	2,375
Depreciation, depletion and amortization per Boe	$ 4.31	$ —	$ 4.31
Depreciation, depletion and amortization per Mcfe	$ 0.72	$ —	$ 0.72
2000:			
Property acquisition costs	$ 66,270	$ —	$ 66,270
Development costs	847	—	847
Production costs	9,484	—	9,484
Depreciation, depletion and amortization per Boe	$ 4.18	$ —	$ 4.18
Depreciation, depletion and amortization per Mcfe	$ 0.70	$ —	$ 0.70
2001:			
Property acquisition costs	$ 29,471	$ 84,576	$ 114,047
Development costs	14,977	8,858	23,835
Production costs	21,395	2,519	23,914
Depreciation, depletion and amortization per Boe	$ 4.82	$ 9.07	$ 5.65
Depreciation, depletion and amortization per Mcfe	$ 0.80	$ 1.50	$ 0.94

The results of operations from our oil and natural gas producing activities are as follows:

	United States	Canada	Total
		(In thousands)	
Year ended December 31, 1999:			
Oil and natural gas sales	$ 5,294	$ —	$ 5,294
Production costs	(2,375)	—	(2,375)
Depreciation, depletion and amortization	(1,446)	—	(1,446)
Income tax expense, net of extraordinary item	(2,139)	—	(2,139)
Results of operations from oil and natural gas producing activities (excluding corporate overhead and interest costs)	$ (666)	$ —	$ (666)
Year ended December 31, 2000:			
Oil and natural gas sales	$ 28,869	$ —	$ 28,869
Production costs	(9,484)	—	(9,484)
Depreciation, depletion and amortization	(4,949)	—	(4,949)
Income tax expense	(4,400)	—	(4,400)
Results of operations from oil and natural gas producing activities (excluding corporate overhead and interest costs)	$ 10,036	$ —	$ 10,036
Year ended December 31, 2001:			
Oil and natural gas sales	$ 53,017	$ 8,220	$ 61,237
Income from derivative ineffectiveness and terminated hedges	4,147	—	4,147
Production costs	(21,395)	(2,519)	(23,914)
Depreciation, depletion and amortization	(9,743)	(4,501)	(14,244)
Impairment of oil and natural gas properties	(28,646)	(20,929)	(49,575)
Uncollectible value of Enron hedges	(10,669)	—	(10,669)
Income tax benefit	54	—	54
Results of operations from oil and natural gas producing activities (excluding corporate overhead and interest costs)	$ (13,235)	$ (19,729)	$ (32,964)

9. **Hedging Activities**

In connection with the incurrence of debt related to our acquisition activities and to protect against commodity price fluctuations, management has adopted a policy of hedging oil and natural gas prices through the use of commodity futures, options and swap agreements. Effective January 1, 2001, we adopted SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activity," which established accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results from the hedged item on the income statement. Companies must formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. For derivatives classified as cash flow hedges, changes in fair value are recognized in other comprehensive income until the hedged item is recognized in earnings. The ineffective portion of any change in the fair value of a derivative designated as a hedge is immediately recognized in earnings. Hedge effectiveness is measured quarterly based on the relative fair value between the derivative contract and the hedged item over time. At adoption, we recognized a net derivative liability and a reduction in other comprehensive income of approximately $1.1 million as a cumulative effect of an accounting change for all cash flow hedges.

In accordance with management's policy of hedging oil and natural gas prices, we entered into several swap transactions during 2000 and through September 2001. The counterparty of all of these swap transactions was Enron North America Corp., an affiliate of Enron Corp. (the Enron Hedges). On December 2, 2001, Enron Corp. and other Enron related entities, including Enron North America, filed for bankruptcy under Chapter 11 of the United States Code in the United States Bankruptcy Court in the Southern District of New York. We terminated all of our hedging contracts with Enron North America, effective as of December 5, 2001, as a result of the failure of the Enron affiliate to make payments totaling approximately $2.1 million due us on December 5, 2001, on hedged natural gas volumes and on December 7, 2001, on hedged oil volumes. Based upon oil and natural gas futures prices on December 5, 2001, we believe that we are owned approximately $15.3 million, including settlements already due, but the exact amount will be determined pursuant to the terms of the ISDA Master Agreement.

In accordance with the provisions of SFAS No. 133, we had recognized, as of November 30, 2001, a $13.2 million derivative asset on our balance sheet. This amount represented the estimated fair value of the future cash flows to us based upon the market price of oil and natural gas at that date. Due to the complex nature of the Enron bankruptcy proceedings and the extensive litigation involving Enron, we do not expect that we will receive any settlement as a result of the bankruptcies for an extended period of time; therefore, at December 31, 2001, we have classified the Enron derivative asset as an other long-term asset and reduced the asset balance to $2.8 million, which represents our estimate of the fair market value of our bankruptcy claim against Enron North America. Our estimate of the value of our bankruptcy claim is based upon informal offers that we have received from third parties attempting to purchase those claims as well as management's best estimate of the financial condition of Enron's bankruptcy estate as determined from published reports and court filings related to the bankruptcy. As a result, we have charged $10.7 million to expense during 2001.

As stated above, we terminated hedge accounting for the Enron Hedges effective as of November 30, 2001. Under the requirements of SFAS No. 133, we are required to reclassify amounts related to the Enron Hedges that remain in other comprehensive income as of the date of the termination into revenue as the oil and natural gas volumes that were hedged are produced. During

December 2001, we reclassified $1.3 million related to the Enron Hedges from other comprehensive income to other income. At December 31, 2001, approximately $9.0 million remained in other comprehensive income related to the Enron Hedges and will be reclassified into revenue as shown in the following table:

	Amount
	(In thousands)
During 2002:	
Quarter ending March 31, 2002	$ 2,134
Quarter ending June 30, 2002	1,649
Quarter ending September 30, 2002	1,599
Quarter ending December 31, 2002	1,593
Total amount in 2002	**$ 6,975**
During 2003:	
Quarter ending March 31, 2003	$ 976
Quarter ending June 30, 2003	631
Quarter ending September 30, 2003	464
Total amount in 2003	**$ 2,071**

In December 2001, we entered into hedge agreements with a new counterparty, BNP Paribas, a financial lending institution (the BNP Hedges), to replace the Enron Hedges. The following table sets forth the BNP Hedges for our oil and natural gas volumes as of December 31, 2001. Our contracts are swap arrangements for the sale of oil and natural gas based upon NYMEX pricing. The market values at December 31, 2001, are estimated from quotes from the counterparty and represent the amount that we would expect to receive to terminate the contract at December 31, 2001.

Commodity	Contract Date	Effective Date	Termination Date	Notional Quantity Per Month(1)(2)	Aggregate Volume(1)(2)	Strike Price	Market Value at December 31, 2001(3)
Oil	12/3/2001	1/1/2002	12/31/2002	67,000 Bbls - 60,000 Bbls	761,000 Bbls	$ 20.77	**$ 212,576**
Natural Gas	12/4/2001	1/1/2002	12/31/2002	280,000 Mmbtus - 310,000 Mmbtus	3,650,000 Mmbtus	$ 2.85	**$ 320,163**
Natural Gas	12/7/2001	1/1/2002	12/31/2002	339,000 Mmbtus - 295,000 Mmbtus	3,715,000 Mmbtus	$ 2.80	**$ 163,066**

(1) Bbls—Barrels

(2) Mmbtus—Million British thermal units.

(3) On December 31, 2001, the average forward NYMEX oil and natural gas prices for 2002 were $20.50 per Bbl and $2.76 per Mmbtu, respectively.

At December 31, 2001, there was approximately $696,000 in other comprehensive income related to the BNP Paribas Hedge. Based upon contractual volumes, we expect to reclassify the entire amount to oil and natural gas revenues during 2002.

Oil and natural gas revenues for the years ended December 31, 1999, 2000 and 2001, include a net loss of $74,000, a net loss of $1.1 million and a net gain of $6.9 million, respectively, from the settlement of cash flow hedges. In 2001, other income included $3.5 million from hedge ineffectiveness.

10. Acquisitions and Dispositions

We have accounted for the following acquisitions in accordance with APB No. 16, "Business Combinations" and FAS 141 where applicable.

Entity	Transactions in 1999	Event Date
EXCO Resources, Inc.	Exchanged promissory note of Rio Grande, Inc. for 100% of outstanding capital stock of Rio Grande, Inc.	March 16, 1999
	Merged Rio Grande, Inc. into EXCO Resources, Inc.	March 30, 1999
	Purchased Natchitoches Parish Properties	December 31, 1999
EXUS Energy, LLC	Purchased Jackson Parish Properties	June 30, 1999
	Sold Jackson Parish Properties	December 31, 1999
EXCO Energy Investors, L.L.C. . .	Sold debt securities of National Energy Group, Inc.	November 11, 1999

Entity	Transactions in 2000	Event Date
EXCO Resources, Inc.	Purchased Val Verde County Properties	February 25, 2000
	Purchased Central Properties	September 22, 2000
Pecos-Gomez, L.P.	Purchased Pecos County Properties	March 24, 2000

Entity	Transactions in 2001	Event Date
EXCO Resources, Inc.	Purchased STB Energy Properties	March 8, 2001
EXCO Resources, Inc.	Purchased Addison Energy Inc.	April 26, 2001
EXCO Resources, Inc.	Purchased additional interests in Pecos County Properties	July 3, 2001
Addison Energy Inc.	Purchased PrimeWest Properties	December 18, 2001

Significant transactions which closed during 2001 are more fully described below.

STB Energy Properties Acquisition

In March 2001, we acquired from STB Energy, Inc. oil and natural gas properties located in Louisiana, Oklahoma, Texas and Nebraska. As of January 1, 2001, estimated total proved reserves net to our interest included 694,000 Bbls of oil and 9.5 Bcf of natural gas from 125 gross (78.3 net) wells. The purchase price consisted of $15.0 million in cash ($14.8 million after contractual adjustments).

Addison Energy Inc. Acquisition

On April 26, 2001, we acquired all of the outstanding common stock of Addison Energy Inc. (Addison), which is headquartered in Calgary, Alberta, Canada. At the date of acquisition, Addison owned interests in 95 gross (85.03 net) wells located in Alberta and Addison operated 91 of these wells.

The Addison properties included approximately 27,672 gross and 23,994 net developed acres and approximately 38,947 gross and 28,795 net undeveloped acres. As of January 1, 2001, estimated total proved reserves net to our interest acquired in this acquisition included 2.1 million Bbls of oil and NGLs and 36.9 Bcf of natural gas. After adjustments for working capital and long-term debt, we paid approximately $44.4 million (CDN $68.5 million) for Addison. We paid the adjusted purchase price from the proceeds of borrowings under our new U.S. and Canadian credit agreements. The price was determined through arms-length negotiation between the parties.

Pecos County Properties Acquisitions

On March 24, 2000, Pecos-Gomez, L.P. (previously known as Humphrey-Hill, L.P.) (the Partnership) acquired 8 gross (4.25 net) producing wells in Pecos County, Texas for $10.2 million. As of January 1, 2000, the acquired properties were estimated to contain total proved reserves of 25.1 Bcf of natural gas. At the time of the acquisition, EXCO was the general partner of the Partnership and owned a 1% interest in the Partnership as the general partner and a 50% interests as a limited partner. The acquisition price was partially funded from the proceeds of a credit facility established by the Partnership with Bank of America, N.A. On May 16, 2000, EXCO acquired an additional 4.1% limited partnership interest in the Partnership. On July 3, 2001, the Partnership conveyed all of its oil and natural gas property interests to its partners and began the process to dissolve the Partnership. Also on July 3, 2001, EXCO acquired additional interests in the properties from two of the limited partners for $8.8 million (approximately $7.5 million after contractual adjustments). In addition, EXCO received an assignment of the existing Partnership hedge contract. Borrowings under the Partnership credit facility of $3.9 million were also repaid at the time of the acquisition and the credit facility was canceled.

PrimeWest Properties Acquisition

On December 18, 2001, Addison, our Canadian subsidiary, acquired oil and natural gas properties located in Alberta, Canada. As of December 31, 2001, total proved reserves net to our interest included approximately 3.6 million barrels of oil and NGLs, and 27.1 Bcf of natural gas. Estimated daily production, net to our interest, in December was approximately 600 barrels of oil and NGLs, and 4,100 Mcf of natural gas from the acquired properties. The effective date of this transaction was December 18, 2001. The purchase price was approximately $33.8 million or CDN $53.6 million cash ($33.6 million or CDN $53.3 million after contractual adjustments), funded with borrowings under our Canadian credit agreement.

Pro Forma Results of Operations

The following reflects the Pro forma results of operations as though the acquisition of the Val Verde County Properties, the Pecos County Properties, the Central Properties, the STB Energy Properties, Addison Energy Inc., and the PrimeWest Properties, the related borrowings and our 5% convertible preferred stock offering had been consummated on January 1, 2000.

	Year Ended December 31,	
	2000	**2001**
	(In thousands, except per share data) (Unaudited)	
Revenues	$ 82,904	**$ 86,008**
Earnings (loss) on common stock	$ 16,048	**$ (38,077)**
Income (loss) per share before extraordinary item:		
Basic	$ 2.25	**$ (5.29)**
Diluted	$ 1.74	**$ (5.29)**

11. Concentration of Credit Risk

During 2001, sales of oil to Plains All American, Inc. and affiliates and sales of natural gas to Western Gas Resources, Inc. accounted for 14.5% and 11.8%, respectively, of our total oil and natural gas revenues. If we were to lose any one of our oil and natural gas purchasers, the loss could temporarily cease or delay production and sale of our oil and natural gas in that particular purchaser's service area. Under current economic circumstances, however, if we were to lose a purchaser, we believe we could identify a substitute purchaser.

During 2000, sales of oil and natural gas to three purchasers, Western Gas Resources, Inc., Plains All American, Inc. and OneOk Gas Marketing, LLC accounted for 23.6%, 19.9% and 11.9%, respectively, of our total oil and natural gas revenues. During 1999, sales of oil and natural gas to two purchasers, Plains All American, Inc. and EOTT Energy Operating Limited Partnership, accounted for 36% and 27%, respectively, of our total oil and natural gas revenues.

12. Subsequent Event (Unaudited)

On February 28, 2002, Addison, our Canadian subsidiary, entered into an agreement to purchase oil and natural gas assets totaling approximately $26.2 million (CDN $41.6 million). The transaction is expected to close on April 15, 2002, with a January 1, 2002 effective date.

13. Supplemental Oil and Natural Gas Reserve and Standardized Measure Information (Unaudited)

We retain independent engineering firms to provide annual year-end estimates of our future net recoverable oil, natural gas and NGL reserves. Estimated proved net recoverable reserves we have shown below include only those quantities that you can expect to be commercially recoverable at prices and costs in effect at the balance sheet dates under existing regulatory practices and with conventional equipment and operating methods. Proved developed reserves represent only those reserves that we may recover through existing wells. Proved undeveloped reserves include those reserves that we may recover from new wells on undrilled acreage or from existing wells on which we must make a relatively major expenditure for recompletion or secondary recovery operations.

Discounted future cash flow estimates like those shown below are not intended to represent estimates of the fair value of oil and gas properties. Estimates of fair value should also consider probable reserves, anticipated future oil and gas prices, interest rates, changes in development and production costs and risks associated with future production. Because of these and other considerations, any estimate of fair value is necessarily subjective and imprecise.

Estimated Quantities of Proved Reserves

	United States			Canada			Total			
	Oil (Bbls)	Natural Gas (Mcf)	NGL (Bbls)	Oil (Bbls)	Natural Gas (Mcf)	NGL (Bbls)	Oil (Bbls)	Natural Gas (Mcf)	NGL (Bbls)	Mcfe
					(In thousands)					
December 31, 1998	963	7,712	—	—	—	—	963	7,712	—	13,490
Purchase of reserves in place	2,022	11,033	370	—	—	—	2,022	11,033	370	25,385
New discoveries and extensions	15	—	—	—	—	—	15	—	—	90
Revisions of previous estimates	298	(942)	—	—	—	—	298	(942)	—	846
Production	(208)	(765)	—	—	—	—	(208)	(765)	—	(2,013)
Sales of reserves in place	(346)	(490)	—	—	—	—	(346)	(490)	—	(2,566)
December 31, 1999	2,744	16,548	370	—	—	—	2,744	16,548	370	35,232
Purchase of reserves in place	10,043	80,279	126	—	—	—	10,043	80,279	126	141,293
New discoveries and extensions	—	—	—	—	—	—	—	—	—	—
Revisions of previous estimates	93	2,543	112	—	—	—	93	2,543	112	3,773
Production	(433)	(3,982)	(89)	—	—	—	(433)	(3,982)	(89)	(7,114)
Sales of reserves in place	(69)	(944)	(54)	—	—	—	(69)	(944)	(54)	(1,682)
December 31, 2000	12,378	94,444	465	—	—	—	**12,378**	**94,444**	**465**	**171,502**
Purchase of reserves in place	809	23,463	329	3,137	63,901	2,539	**3,946**	**87,364**	**2,868**	**128,248**
New discoveries and extensions	79	72	—	318	4,611	198	**397**	**4,683**	**198**	**8,253**
Revisions of previous estimates	(1,200)	(956)	98	425	6,978	160	**(775)**	**6,022**	**258**	**2,920**
Production	(887)	(6,243)	(96)	(80)	(2,086)	(68)	**(967)**	**(8,329)**	**(164)**	**(15,115)**
Sales of reserves in place	(126)	(524)	(9)	—	—	—	**(126)**	**(524)**	**(9)**	**(1,334)**
December 31, 2001	11,053	110,256	787	3,800	73,404	2,829	**14,853**	**183,660**	**3,616**	**294,474**

Estimated Quantities of Proved Developed Reserves

	United States			Canada			Total			
	Oil (Bbls)	Natural Gas (Mcf)	NGL (Bbls)	Oil (Bbls)	Natural Gas (Mcf)	NGL (Bbls)	Oil (Bbls)	Natural Gas (Mcf)	NGL (Bbls)	Mcfe(1)
					(In thousands)					
December 31, 1999	2,389	14,741	370	—	—	—	2,389	14,741	370	31,295
December 31, 2000	8,148	66,497	465	—	—	—	8,148	66,497	465	118,175
December 31, 2001	7,555	87,868	774	3,414	65,230	2,470	**10,969**	**153,098**	**3,244**	**238,376**

(1) Mcfe—Thousand cubic feet equivalent calculated by converting 1 Bbl of oil to 6 Mcf of natural gas.

Standardized Measure of Discounted Future Net Cash Flows

We have summarized the standardized measure of discounted net cash flows related to our proved oil, natural gas, and NGL reserves. We have based the following summary on a valuation of proved reserves using discounted cash flows based on year-end prices, costs and economic conditions and a 10% discount rate. The additions to proved reserves from purchase of reserves in place and new discoveries and extensions could vary significantly from year to year; additionally, the impact of changes to reflect current prices and costs of reserves proved in prior years could also be significant.

Accordingly, you should not view the information presented below as an estimate of the fair value of our oil and natural gas properties, nor should you consider the information indicative of any trends.

	United States	Canada	Total
		(In thousands)	
Year ended December 31, 1999:			
Future cash inflows	$ 106,878	$ —	$ 106,878
Future production and development costs	46,740	—	46,740
Future income taxes	12,173	—	12,173
Future net cash flows	47,965	—	47,965
Discount of future net cash flows at 10% per annum	19,370	—	19,370
Standardized measure of discounted future net cash flows	$ 28,595	$ —	$ 28,595
Year ended December 31, 2000:			
Future cash inflows	$1,192,705	$ —	$1,192,705
Future production and development costs	344,013	—	344,013
Future income taxes	274,899	—	274,899
Future net cash flows	573,793	—	573,793
Discount of future net cash flows at 10% per annum	291,357	—	291,357
Standardized measure of discounted future net cash flows	$ 282,436	$ —	$ 282,436
Year ended December 31, 2001			
Future cash inflows	$ 453,313	$ 280,001	$ 733,314
Future production and development costs	225,167	122,212	347,379
Future income taxes	41,855	47,345	89,200
Future net cash flows	186,291	110,444	296,735
Discount of future net cash flows at 10% per annum	103,206	50,000	153,206
Standardized measure of discounted future net cash flows	$ 83,085	$ 60,444	$ 143,529

At December 31, 2001, the present value of our future net cash flows before income taxes discounted at 10% was approximately $189.2 million.

During recent years, prices paid for oil and natural gas have fluctuated significantly. The prices of oil, natural gas and NGLs at December 31, 1999, 2000 and 2001 used in the above table, were $24.17, $24.82 and $17.76 per Bbl of oil, respectively, $2.00, $9.26 and $2.23 per Mcf of natural gas, respectively, and $19.21, $21.50 and $15.09 per Bbl of NGLs, respectively.

Changes in Standardized Measure

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

	United States	Canada	Total
		(In thousands)	
Year ended December 31, 1999:			
Sales and transfers of oil and natural gas produced, net of production costs	$ (2,993)	$ —	$ (2,993)
Net changes in prices and production costs	3,601	—	3,601
Extensions and discoveries, net of future development and production costs	144	—	144
Development costs during the period	111	—	111
Revisions of previous quantity estimates	499	—	499
Sales of reserves in place	(1,968)	—	(1,968)
Purchases of reserves in place	27,804	—	27,804
Accretion of discount before income taxes	796	—	796
Net change in income taxes	(7,352)	—	(7,352)
Net change	$ 20,642	$ —	$ 20,642
Year ended December 31, 2000:			
Sales and transfers of oil and natural gas produced, net of production costs	$ (20,526)	$ —	$ (20,526)
Net changes in prices and production costs	234,122	—	234,122
Extensions and discoveries, net of future development and production costs	—	—	—
Development costs during the period	352	—	352
Revisions of previous quantity estimates	9,880	—	9,880
Sales of reserves in place	(4,740)	—	(4,740)
Purchases of reserves in place	155,648	—	155,648
Accretion of discount before income taxes	3,595	—	3,595
Net change in income taxes	(124,490)	—	(124,490)
Net change	$ 253,841	$ —	$ 253,841
Year ended December 31, 2001:			
Sales and transfers of oil and natural gas produced, net of production costs	$ (25,348)	$ (5,701)	**$ (31,049)**
Net changes in prices and production costs	(340,536)	(54,809)	**(395,345)**
Extensions and discoveries, net of future development and production costs	607	6,112	**6,719**
Development costs during the period	8,340	8,858	**17,198**
Revisions of previous quantity estimates	(6,499)	6,836	**337**
Sales of reserves in place	(1,062)	—	**(1,062)**
Purchases of reserves in place	41,547	114,120	**155,667**
Accretion of discount before income taxes	10,147	8,380	**18,527**
Net change in income taxes	113,453	(23,352)	**90,101**
Net change	$(199,351)	$ 60,444	**$(138,907)**

14. Selected Quarterly Financial Information (Unaudited)

	2000			
	March 31	June 30	September 30	December 31
	(In thousands, except per share amounts)			
Total revenues	$ 4,953	$ 5,558	$ 6,832	$ 13,316
Earnings (loss) on common stock	1,474	1,295	1,804	3,881
Basic earnings (loss) per share	0.21	0.19	0.26	0.57
Diluted income (loss) per share	0.21	0.19	0.26	0.52
Total assets	55,786	59,171	95,163	102,372
Long-term debt, less current maturities	10,555	10,834	42,874	42,488
Stockholders' equity	42,458	43,863	45,741	49,791

	2001			
	March 31	June 30	September 30	December 31
	(In thousands, except per share amounts)			
Total revenues	$ 13,663	$ 17,870	$ 18,032	$ 17,375
Impairment of oil and natural gas properties	—	—	45,942	3,633
Uncollectible value of Enron hedges	—	—	—	10,669
Earnings (loss) on common stock	2,962	2,821	(38,819)	(8,964)
Basic earnings (loss) per share	0.43	0.40	(5.41)	(1.25)
Diluted income (loss) per share	0.40	0.37	(5.41)	(1.25)
Total assets	121,421	224,240	166,885	191,056
Long-term debt, less current maturities	56,157	2,151	1,361	44,994
Stockholders' equity	54,137	170,822	133,370	120,379

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required by this item will be set forth under the captions "Election of Directors," "Section 16(a) Beneficial Ownership Reporting Compliance," "Certain Relationships Between the Company and Directors, Officers or Shareholders," and "Directors and Executive Officers" of our proxy statement for our 2001 annual meeting of shareholders which was filed with the SEC pursuant to Regulation 14A under the Securities Exchange Act of 1934 and is incorporated herein by reference. The proxy statement was filed on March 19, 2002.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item is set forth under the caption "Executive Compensation" in Appendix C of our proxy statement which was filed with the SEC pursuant to Regulation 14A under the Securities Exchange Act of 1934 and is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required by this item is set forth in Appendix B under the caption "Shareholders" of our proxy statement which was filed with the SEC pursuant to Regulation 14A under the Securities Exchange Act of 1934 and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by this item is set forth under the captions "Certain Relationships Between the Company and Directors, Officers or Shareholders" of our proxy statement which was filed with the SEC pursuant to Regulation 14A under the Securities Exchange Act of 1934 and is incorporated herein by reference.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

1. **Financial Statements**

See Index to Financial Statements on page 54 to this annual report.

2. **Financial Statement Schedules**

All schedules are omitted because the information is not required under the related instructions or is inapplicable or because the information is included in the Financial Statements or related Notes.

3. **Exhibits**

No.	Description of Exhibit
2.1	Pre-Acquisition Agreement between EXCO Resources, Inc., and EXCO Resources Canada Inc., and Addison Energy, Inc., dated March 22, 2001, filed as an Exhibit to EXCO's Form 10-Q filed May 8, 2001 and incorporated by reference herein.
3.1	Restated Articles of Incorporation of EXCO filed as an Exhibit to EXCO's Form S-3/A filed June 2, 1998 and incorporated by reference herein.
3.2	Bylaws of EXCO, as amended, filed as an Exhibit to EXCO's Form S-3/A filed June 2, 1998 and incorporated by reference herein.
4.1	Restated Articles of Incorporation of EXCO filed as an Exhibit to EXCO's Form S-3/A filed June 2, 1998 and incorporated by reference herein.
4.2	Restated Bylaws of EXCO, as amended, filed as an Exhibit to EXCO's Form S-3/A filed June 2, 1998 and incorporated by reference herein.
4.3	Specimen Stock Certificate for the Common Stock of EXCO filed as an Exhibit to EXCO's Form S-3/A filed on June 2, 1998 and incorporated by reference herein.
4.4	Credit Agreement among EXCO Resources, Inc. as borrower, and Bank One, NA and the institutions named herein as lenders, Bank One, NA, as administrative agent and Fleet National Bank, as syndication agent and BNP Paribas, as documentation agent and Banc One Capital Markets, Inc. as lead arranger and bookrunner, dated April 26, 2001, filed as an Exhibit to EXCO's Form 10-Q filed May 8, 2001 and incorporated by reference herein.
4.5	Credit Agreement among EXCO Resources Canada Inc. as borrower, and Bank One Canada and the institutions named herein as lenders, Bank One Canada, as administrative agent and BNP Paribas (Canada) as documentation agent and Banc One Capital Markets, Inc. as lead arranger and bookrunner, dated April 26, 2001, filed as an Exhibit to EXCO's Form 10-Q filed May 8, 2001 and incorporated by reference herein.
4.6	Statement of Designation for 5% Convertible Preferred Stock, dated June 21, 2001, filed as an Exhibit to EXCO's Form 8-K/A filed June 29, 2001 and incorporated by reference herein.
4.7	First Amendment to Credit Agreement among EXCO Resources Canada Inc. as borrower, and Bank One Canada and the institutions named herein as lenders, Bank One Canada, as administrative agent and BNP Paribas (Canada) as documentation agent and Banc One Capital Markets, Inc. as lead arranger and bookrunner, dated April 26, 2001, filed as an Exhibit to EXCO's Form 10-Q filed May 8, 2001 and incorporated by reference herein.

No.	Description of Exhibit
4.8	First Amendment to Credit Agreement among EXCO Resources, Inc. as borrower, and Bank One, NA and the institutions named herein as lenders, Bank One, NA, as administrative agent and Fleet National Bank, as syndication agent and BNP Paribas, as documentation agent and Banc One Capital Markets, Inc. as lead arranger and bookrunner, dated November 14, 2001, filed as an Exhibit to EXCO's Form 10-Q filed November 14, 2001 and incorporated by reference herein.
4.9	Second Amendment to Credit Agreement among EXCO Resources Canada Inc. as borrower, and Bank One Canada and the institutions named herein as lenders, Bank One Canada, as administrative agent and BNP Paribas (Canada) as documentation agent and Banc One Capital Markets, Inc. as lead arranger and bookrunner, dated November 14, 2001, filed as an Exhibit to EXCO's Form 10-Q filed November 14, 2001 and incorporated by reference herein.
4.10	Restated Credit Agreement among EXCO Resources, Inc. and EXCO Operating, LP, as borrowers, Bank One, NA, as administrative agent, BNP Paribas, as syndication agent, The Bank of Nova Scotia, as documentation agent, Bank One Capital Markets, Inc. as lead arranger and bookrunner, and the financial institutions which are or may become Lenders, dated December 18, 2001, filed as an Exhibit to EXCO's Form 8-K filed January 2, 2002 and incorporated by reference herein.
4.11	Restated Credit Agreement among Addison Energy Inc., as borrowers, Bank One, NA, Canada Branch, as administrative agent, BNP Paribas (Canada), as syndication agent, The Bank of Nova Scotia, as documentation agent, Bank One Capital Markets, Inc. as lead arranger and bookrunner, and the financial institutions which are or may become Lenders, dated December 18, 2001, filed as an Exhibit to EXCO's Form 8-K filed January 2, 2002 and incorporated by reference herein.
10.1*	EXCO Resources, Inc. 1998 Stock Option Plan, filed as Appendix A to EXCO's Proxy Statement dated March 17, 1998 and incorporated by reference herein.
10.2*	Amendment No. 1 to the EXCO Resources, Inc. 1998 Stock Option Plan, filed as Exhibit 10.10 to EXCO's Form 10-Q dated May 17, 1999 and incorporated by reference herein.
10.3*	EXCO Resources, Inc. 1998 Director Compensation Plan filed as Appendix D to EXCO's Proxy Statement dated March 16, 1999 and incorporated by reference herein.
10.4	Purchase and Sale Agreement between Nebraska Public Gas Authority as seller, and Humphrey-Hill, L.P., as buyer, dated February 22, 2000, filed as an Exhibit to EXCO's Form 10-Q for the quarter ended March 31, 2000 and incorporated by reference herein.
10.5	Credit Agreement among Humphrey-Hill, L.P., as borrower, Bank of America, N.A., as administrative agent, and financial institutions listed on Schedule I, dated March 24, 2000, filed as an Exhibit to EXCO's Form 10-Q for the quarter ended March 31, 2000 and incorporated by reference herein.
10.6	Amended and Restated Agreement of Limited Partnership of Humphrey-Hill, L.P., dated March 24, 2000, filed as an Exhibit to EXCO's Form 10-Q for the quarter ended March 31, 2000 and incorporated by reference herein.
10.7	Amendment to Amended and Restated Agreement of Limited Partnership of Humphrey-Hill, L.P., dated April 14, 2000, filed as an Exhibit to EXCO's Form 10-Q for the quarter ended March 31, 2000 and incorporated by reference herein.
10.8	First Amendment to Credit Agreement among Pecos-Gomez, L.P., as borrower, and Bank of America, N.A., as agent and sole bank, dated June 30, 2000, filed as an Exhibit to EXCO's Form 10-Q filed August 8, 2000 and incorporated by reference herein.

No.	Description of Exhibit
10.9	Purchase and Sale Agreement between Central Resources, Inc., as seller, and EXCO Resources, Inc., as buyer, dated August 31, 2000, filed as an Exhibit to EXCO's Form 8-K filed October 2, 2000 and incorporated by reference herein.
10.10	Amended and Restated Credit Agreement among EXCO Resources, Inc., as borrower, Bank of America, N.A., as administrative agent, Bank One, Texas, N.A., as syndication agent and the financial institutions listed on Schedule I, dated September 22, 2000, filed as an Exhibit to EXCO's Form 8-K filed October 2, 2000 and incorporated by reference herein.
10.11	Warrant Agreement including Exhibit 3, the Form of Registration Rights Agreement among EXCO Resources, Inc., as issuer, and Central Resources, Inc., as registered holder, dated September 22, 2000, as Exhibit E to the Purchase and Sale Agreement between Central Resources, Inc., as seller, and EXCO Resources, Inc., as buyer, dated August 31, 2000, filed as an Exhibit to EXCO's Form 8-K filed October 2, 2000 and incorporated by reference herein.
10.12	Credit Agreement among EXCO Resources, Inc. as borrower, and Bank One, NA and the institutions named herein as lenders, Bank One, NA, as administrative agent and Fleet National Bank, as syndication agent and BNP Paribas, as documentation agent and Banc One Capital Markets, Inc. as lead arranger and bookrunner, dated April 26, 2001, filed as an Exhibit to EXCO's Form 10-Q filed May 8, 2001 and incorporated by reference herein.
10.13	Credit Agreement among EXCO Resources Canada Inc. as borrower, and Bank One Canada and the institutions named herein as lenders, Bank One Canada, as administrative agent and BNP Paribas (Canada) as documentation agent and Banc One Capital Markets, Inc. as lead arranger and bookrunner, dated April 26, 2001, filed as an Exhibit to EXCO's Form 10-Q filed May 8, 2001 and incorporated by reference herein.
10.14	First Amendment to Credit Agreement among EXCO Resources Canada Inc. as borrower, and Bank One Canada and the institutions named herein as lenders, Bank One Canada, as administrative agent and BNP Paribas (Canada) as documentation agent and Banc One Capital Markets, Inc. as lead arranger and bookrunner, dated April 26, 2001, filed as an Exhibit to EXCO's Form 10-Q filed May 8, 2001 and incorporated by reference herein.
10.15	First Amendment to Credit Agreement among EXCO Resources, Inc. as borrower, and Bank One, NA and the institutions named herein as lenders, Bank One, NA, as administrative agent and Fleet National Bank, as syndication agent and BNP Paribas, as documentation agent and Banc One Capital Markets, Inc. as lead arranger and bookrunner, dated November 14, 2001, filed as an Exhibit to EXCO's Form 10-Q filed November 14, 2001 and incorporated by reference herein.
10.16	Second Amendment to Credit Agreement among EXCO Resources Canada Inc. as borrower, and Bank One Canada and the institutions named herein as lenders, Bank One Canada, as administrative agent and BNP Paribas (Canada) as documentation agent and Banc One Capital Markets, Inc. as lead arranger and bookrunner, dated November 14, 2001, filed as an Exhibit to EXCO's Form 10-Q filed November 14, 2001 and incorporated by reference herein.
10.17	Agreement of Purchase and Sale among PrimeWest Energy Inc. and PrimeWest Oil and Gas Corp., as sellers, and Addison Energy Inc., as buyer, dated November 22, 2001, filed as an Exhibit to EXCO's Form 8-K filed January 2, 2002 and incorporated by reference herein.
10.18	Restated Credit Agreement among EXCO Resources, Inc. and EXCO Operating, LP, as borrowers, Bank One, NA, as administrative agent, BNP Paribas, as syndication agent, The Bank of Nova Scotia, as documentation agent, Bank One Capital Markets, Inc. as lead arranger and bookrunner, and the financial institutions which are or may become Lenders, dated December 18, 2001, filed as an Exhibit to EXCO's Form 8-K filed January 2, 2002 and incorporated by reference herein.

No.	Description of Exhibit
10.19	Restated Credit Agreement among Addison Energy Inc., as borrowers, Bank One, NA, Canada Branch, as administrative agent, BNP Paribas (Canada), as syndication agent, The Bank of Nova Scotia, as documentation agent, Bank One Capital Markets, Inc. as lead arranger and bookrunner, and the financial institutions which are or may become Lenders, dated December 18, 2001, filed as an Exhibit to EXCO's Form 8-K filed January 2, 2002 and incorporated by reference herein.
10.20*	Promissory Note dated September 15, 1998 by and between Douglas H. Miller, as maker, and EXCO Resources, Inc., as payee, filed as an Exhibit to Mr. Miller's Schedule 13 D/A filed September 23, 1998 and incorporated by reference herein.
10.21*	Pledge Agreement dated September 15, 1998 by and between Douglas H. Miller, as pledgor, and EXCO Resources, Inc., as the secured party, filed as an Exhibit to Mr. Miller's Schedule 13 D/A filed September 23, 1998 and incorporated by reference herein.
10.22*	Promissory Note dated November 29, 1999 by and between Douglas H. Miller, as maker, and EXCO Resources, Inc., as payee, filed as an Exhibit to Mr. Miller's Schedule 13 D/A filed February 11, 2002 and incorporated by reference herein.
10.23	Pledge Agreement dated November 29, 1999 by and between Douglas H. Miller, as pledgor, and EXCO Resources, Inc., as the secured party, filed as an Exhibit to Miller's Schedule 13 D/A filed February 11, 2002 and incorporated by reference herein.
12.1	Statements regarding computation of ratios (filed herewith).
21.1	Subsidiaries of EXCO Resources, Inc. (filed herewith).
23.1	Consent of Independent Accountants, Ernst & Young LLP (filed herewith).
23.2	Consent of Independent Petroleum Engineers, Lee Keeling and Associates, Inc. (filed herewith).

* These exhibits are Management contracts.

4. **Reports on Form 8-K**

Current report on Form 8-K dated November 7, 2001 filed November 14, 2001 pursuant to Item 9 containing Regulation FD Disclosure.

Current report on Form 8-K dated December 18, 2001 filed January 2, 2002 pursuant to Item 2 and Item 7 reporting the acquisition of properties by Addison Energy Inc., a wholly owned subsidiary of EXCO Resources, Inc., from PrimeWest Energy Inc. and PrimeWest Oil and Gas Corp. and containing the PrimeWest Properties Purchase and Sale Agreement and Financial Statements.

Current report on Form 8-K/A dated December 18, 2001 filed February 14, 2002 pursuant to Item 7 containing the PrimeWest Properties Financial Statements.

SIGNATURE PAGE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act, the Registrant has duly caused this report to be signed on its behalf by the undersigned, there unto duly authorized in the City of Dallas, Texas on the 19th of March, 2002.

EXCO RESOURCES. INC.

By: ______________________________
Douglas H. Miller
Chairman of the Board of Directors
and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

March 19, 2002	Douglas H. Miller Chairman of the Board of Directors and Chief Executive Officer
March 19, 2002	T. W. Eubank Director, President and Treasurer
March 19, 2002	J. Douglas Ramsey, Ph.D. Director, Vice President and Chief Financial Officer (Principal Financial Officer)
March 19, 2002	J. David Choisser Vice President and Chief Accounting Officer (Principal Accounting Officer)

March 19, 2002

Jeffrey D. Benjamin
Director

March 19, 2002

Earl E. Ellis
Director

March 19, 2002

J. Michael Muckleroy
Director

March 19, 2002

Boone Pickens
Director

March 19, 2002

Stephen F. Smith
Director

INFORMATION FOR SHAREHOLDERS AND INVESTORS

EXCO Resources, Inc.
6500 Greenville Avenue
Suite 600, LB17
Dallas, Texas 75206
214-368-2084

Shareholder Relations
Donna Sablotny
214-706-3310

Nasdaq NMS Symbols
EXCO - Common Stock
EXCOP - Preferred Stock

Legal Counsel
Haynes and Boone, LLP
901 Main Street, Suite 3100
Dallas, Texas 75202

Auditors
Ernst & Young LLP
2121 San Jacinto Street, Suite 1500
Dallas, Texas 75201

Stock Transfer Agent
Continental Stock Transfer & Trust Company
Communications concerning transfer or exchange requirements, lost certificates, share holdings or changes of address should be directed to:
17 Battery Place, 8th Floor
New York, New York 10004
212-845-3208

Number of Shareholders
741
(As of February 28, 2002)

2002 Annual Shareholders Meeting
The Annual Meeting of EXCO Resources, Inc. Shareholders will be held on Thursday, April 25, 2002 at 9:00 am at the Royal Oaks Country Club, 7915 Greenville Avenue, Dallas, Texas. Shareholders are cordially invited to be present at the annual meeting. Whether or not you attend, please complete and return your proxy so that you will be represented at the meeting.

OFFICERS

Douglas H. Miller
Chairman of the Board and
Chief Executive Officer

T.W. Eubank
President and Treasurer

J. Douglas Ramsey, Ph.D.
Vice President and
Chief Financial Officer

Richard E. Miller
Vice President, Secretary
and General Counsel

Charles R. Evans
Vice President and
Chief Operating Officer

J. David Choisser, CPA
Vice President and
Chief Accounting Officer

Richard L. Hodges
Vice President

John D. Jacobi
Vice President

Daniel A. Johnson
Vice President

James M. Perkins, Jr.
Vice President

W. Andy Bracken, CPA
Controller

DIRECTORS

Douglas H. Miller
Chairman of the Board and
Chief Executive Officer,
EXCO Resources, Inc.

T.W. Eubank
President and Treasurer,
EXCO Resources, Inc.

J. Douglas Ramsey, Ph.D.
Vice President and
Chief Financial Officer,
EXCO Resources, Inc.

Jeffrey D. Benjamin[1,2]
Managing Director,
Libra Securities LLC

Earl E. Ellis[1]
Private Investments
Former Managing Partner,
Benjamin Jacobson & Sons, LLC

J. Michael Muckleroy[2]
Private Investments
Former Chairman
and Chief Executive Officer,
Enron Liquid Fuels

Boone Pickens[2]
Chairman,
BP Capital LLC

Stephen F. Smith[1,2]
Executive Vice President,
Sandefer Oil & Gas, Inc.

[1] Audit Committee Member
[2] Compensation Committee Member

Reverse Stock Split History

March 2, 1992	1 for 10 Reverse Stock Split — Mineral Development, Inc. (predecessor name)
July 19, 1996	1 for 5 Reverse Stock Split — EXCO Resources, Inc.
March 31, 1998	1 for 2 Reverse Stock Split — EXCO Resources, Inc.

EXCO Resources, Inc.

6500 Greenville Avenue
Suite 600, LB17
Dallas, Texas 75206
Phone 214-368-2084
Fax 214-368-2087