

## 2001 FINANCIAL REVIEW

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## SELECTED FINANCIAL DATA

The selected historical financial information was derived from, and is qualified by reference to our consolidated financial statements, including the notes thereto, appearing elsewhere in this annual report. The following data should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations".

	Years Ended December 31,				
	2001	2000	1999	1998	1997
<i>(in thousands, except per share data and percentages)</i>					
Statement of Operations Data:					
Revenues:					
Oil and gas production	\$105,757	\$ 75,940	\$ 34,981	\$ 20,410	\$ 7,359
Gas sold – marketing	7,417	8,015	7,703	–	–
Gain on sale of oil and gas properties	–	33	287	–	304
<b>Total revenues</b>	<b>113,174</b>	<b>83,988</b>	<b>42,971</b>	<b>20,410</b>	<b>7,663</b>
Cost and operating expenses:					
Lease operating	14,806	11,559	5,587	3,193	1,513
Gas purchased – marketing	7,218	7,788	7,402	–	–
Geological and geophysical expenses	1,068	–	–	–	–
General and administrative	9,981	5,409	3,541	2,591	1,170
Non-cash compensation expense	3,364	–	–	–	–
Depreciation, depletion and amortization	53,428	40,569	22,521	17,442	4,206
Impairment of oil and gas properties	24,891	10,838	7,509	5,072	5,787
Loss on unsuccessful property acquisition	3,147	–	–	–	–
Other expense	–	450	–	–	–
<b>Total operating expenses</b>	<b>117,903</b>	<b>76,613</b>	<b>46,560</b>	<b>28,298</b>	<b>12,676</b>
Income (loss) from operations	(4,729)	7,375	(3,589)	(7,888)	(5,013)
Other income (expense):					
Interest income	884	451	202	141	207
Interest expense	(10,039)	(11,907)	(9,399)	(7,963)	(1,212)
Realized loss on derivative instruments	(19,348)	(4,662)	–	–	–
Unrealized gain (loss) on derivative instruments	1,265	(7,249)	–	–	–
Loss before income taxes and extraordinary gain (loss)	(31,967)	(15,992)	(12,786)	(15,710)	(6,018)
Income tax benefit	11,186	5,594	1,829	–	–
Loss before extraordinary gain (loss)	(20,781)	(10,398)	(10,957)	(15,710)	(6,018)
Extraordinary gain (loss), net of tax	(602)	–	29,185	–	–
<b>Net income (loss)</b>	<b>\$ (21,383)</b>	<b>\$ (10,398)</b>	<b>\$ 18,228</b>	<b>\$ (15,710)</b>	<b>\$ (6,018)</b>
Weighted average number of common shares outstanding:					
Basic and diluted	19,704	14,286	14,286	11,926	10,568
Loss per common share before extraordinary gain (loss):					
Basic and diluted	\$ (1.06)	\$ (0.73)	\$ (0.77)	\$ (1.32)	\$ (0.57)
Net income (loss) per common share:					
Basic and diluted	\$ (1.09)	\$ (0.73)	\$ 1.28	\$ (1.32)	\$ (0.57)

Table and footnotes continued on following page

	Years Ended December 31,				
	2001	2000	1999	1998	1997
Other Financial Data:					
Adjusted EBITDA(1)	\$ 58,490	\$ 54,570	\$ 26,643	\$ 14,767	\$ 5,187
Adjusted EBITDA margin(2)	62%	65%	62%	72%	68%
	As of December 31,				
	2001	2000	1999	1998	1997
Balance Sheet Data:					
Cash and cash equivalents	\$ 5,294	\$ 18,136	\$ 17,779	\$ 3,411	\$ 1,806
Working capital	(29,071)	(3,835)	14,115	(5,106)	3,340
Net oil and gas properties	133,033	98,725	72,278	47,612	33,355
Total assets	177,564	161,993	107,054	61,354	48,906
Total debt	100,111	116,529	91,723	62,690	42,194
Total liabilities	132,572	175,172	109,835	82,363	54,217
Shareholders' equity (deficit)	44,992	(13,179)	(2,781)	(21,009)	(5,311)

(1) Adjusted EBITDA means net income (loss) before interest expense, income taxes, depreciation, depletion and amortization, impairment of natural gas and oil properties, non-cash compensation expense, unrealized gains and losses and extraordinary items. Adjusted EBITDA is not a calculation based on generally accepted accounting principles and should not be considered as an alternative to net income (loss) or operating income (loss), as an indicator of a company's financial performance or to cash flow as a measure of liquidity. In addition, our Adjusted EBITDA calculation may not be comparable to other similarly titled measures of other companies. Adjusted EBITDA is included as a supplemental disclosure because it may provide useful information regarding our ability to service debt and to fund capital expenditures.

(2) Represents Adjusted EBITDA divided by total revenues for the years ended December 31, 1997 through 2000. For the year ended December 31, 2001, Adjusted EBITDA margin is Adjusted EBITDA divided by the sum of total revenues and realized loss on derivative instruments.

## MANAGEMENT'S DISCUSSION AND ANALYSIS

### of Financial Condition and Results of Operations

#### OVERVIEW

We are engaged in the acquisition, development and production of natural gas and oil properties in the outer continental shelf of the Gulf of Mexico, in the shallow-deep waters of the Gulf of Mexico and in the Southern Gas Basin of the North Sea. We primarily focus our efforts on natural gas and oil properties with proved undeveloped reserves that are economically attractive to us but are not strategic to major or exploration-oriented independent oil and gas companies. We attempt to achieve a high return on our investment in these properties by limiting our up-front acquisition costs and by developing our acquisitions quickly.

#### INITIAL PUBLIC OFFERING

On February 5, 2001, we priced our initial public offering ("IPO") of 6.0 million shares of common stock and commenced trading the following day. After payment of the underwriting discount we received net proceeds of \$78.3 million on February 9, 2001, excluding offering costs of approximately \$1.5 million. We used the net proceeds from our IPO, together with the proceeds from our new credit facility, to repay all of our outstanding debt under our development program credit agreement and our prior bank credit facility and to acquire natural gas and oil properties.

#### CRITICAL ACCOUNTING POLICIES

Financial Reporting Release No. 60, which was recently released by the Securities and Exchange Commission ("SEC"), recommends that all companies include a discussion of critical accounting policies or methods used in the preparation of financial statements. Note 2 of the Notes to Consolidated Financial Statements includes a summary of the significant accounting policies and methods used in the preparation of our Consolidated Financial Statements. The following is a brief discussion of the more significant accounting policies and methods used by us.

**Oil and Gas Reserves** / The process of estimating quantities of natural gas and crude oil reserves is very complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various fields make these estimates generally less precise than other estimates included in the financial statement disclosures. We use the units-of-production method to amortize our oil and gas properties. This method requires us to amortize the capitalized costs incurred in developing a property in proportion to the amount of oil and gas produced as a percentage of the amount of proved reserves contained in the property. Accordingly, changes in reserve estimates as described above will cause corresponding changes in depletion expense recognized in periods subsequent to the reserve estimate revision. See the Supplemental Information for reserve data in our Consolidated Financial Statements.

**Oil and Gas Producing Activities** / We follow the "successful efforts" method of accounting for oil and gas properties. Under this method, lease acquisition costs and intangible drilling and development costs on successful wells and development dry holes are capitalized.

Capitalized costs relating to producing properties are depleted on the unit-of-production method. Proved developed reserves are used in computing unit rates for drilling and development costs and total proved reserves for depletion rates of leasehold, platform and pipeline costs. Estimated dismantlement, restoration and abandonment costs and estimated residual salvage values are taken into account in determining amortization and depletion provisions.

Expenditures for geological and geophysical are incurred for development purposes only. These costs are generally charged to expense unless the costs can be specifically attributed to determining the placement for a future well location.

Expenditures for repairs and maintenance are charged to expense as incurred; renewals and betterments are capitalized. The costs and related accumulated depreciation, depletion, and amortization of properties sold or otherwise retired are eliminated from the accounts, and gains or losses on disposition are reflected in the statements of operations.

We perform an impairment analysis whenever events or changes in circumstances indicate that our estimate of a particular asset's fair value, or carrying amount, may not be recoverable. To determine if a depletable unit is impaired, we compare the carrying value of the depletable unit to the undiscounted future net cash flows by applying published future oil and gas prices to the estimated future production of oil and gas reserves over the economic life of the property. Future net cash flows are based upon our independent reservoir engineer's estimate of proved reserves. In addition, other factors such as probable and possible reserves are taken into consideration when justified by economic conditions and actual or planned drilling or other development activities. For properties determined to be impaired, an impairment loss equal to the differences between the carrying value and the fair value of the impaired property will be recognized. Fair value, on a depletable unit basis, is estimated to be the present value of the aforementioned expected future net cash flows. Any impairment charge incurred is recorded in accumulated depreciation, depletion, impairment and amortization to reduce our recorded basis in the asset. Each part of this calculation is subject to a large degree of judgment, including the determination of the depletable units' reserves, future cash flows and fair value.

**Contingent Liabilities** / In preparing financial statements at any point in time, management is periodically faced with uncertainties, the outcomes of which are not within its control and will not be known for prolonged periods of time. We are involved in actions, which if determined adversely, could have a material negative impact on our financial position, results of operations and cash flows. Management, with the assistance of counsel makes estimates, if determinable, of ATP's probable liabilities and records such amounts in the consolidated financial statements. Such estimates may be the minimum amount of a range of probable loss when no single best estimate is determinable. Disclosure is made, when determinable, of any additional possible amount of loss on these claims, or if such estimate cannot be made, that fact is disclosed. Along with our counsel, we monitor developments related to these legal matters and, when appropriate, we make adjustments to recorded liabilities to reflect current facts and circumstances. Although it is difficult to predict the ultimate outcome of these matters, management believes that the recorded amounts, if any, are reasonable.

Based on a critical assessment of our accounting policies and the underlying judgments and uncertainties affecting the application of those policies, management believes that our consolidated financial statements provide a meaningful and fair perspective of our company.

## **RESULTS OF OPERATIONS**

Prior to the January 1, 2001 adoption of Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standard ("SFAS") No. 133, *Accounting for Derivative Instruments and Hedging Activities* ("SFAS 133") and SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities* ("SFAS 138"), an amendment to SFAS 133, we included the effects of our risk management activities as an offset to revenue. Upon adoption of the standard, any gains or losses from these activities are now included in other income (expense), as we did not account for our hedging activities under the hedge accounting provisions allowed in the standard.

**MANAGEMENT'S DISCUSSION AND ANALYSIS**  
of Financial Condition and Results of Operations (Continued)

For comparative purposes though, the following table sets forth selected financial and operating information for our natural gas and oil operations inclusive of the effects of risk management activities:

	Years Ended December 31,		
	2001	2000	1999
<b>Production:</b>			
Natural gas (MMcf)	20,957	22,410	16,533
Oil and condensate (MBbls)	790	345	128
<b>Total (MMcfe)</b>	<b>25,696</b>	<b>24,477</b>	<b>17,301</b>
<b>Revenues (in thousands):</b>			
Natural gas	\$ 88,908	\$ 94,051	\$ 36,856
Effects of risk management activities(1)	(24,369)	(26,729)	(3,842)
<b>Total</b>	<b>\$ 64,539</b>	<b>\$ 67,322</b>	<b>\$ 33,014</b>
Oil and condensate	\$ 16,849	\$ 10,112	\$ 1,967
Effects of risk management activities	–	(1,494)	–
<b>Total</b>	<b>\$ 16,849</b>	<b>\$ 8,618</b>	<b>\$ 1,967</b>
Natural gas, oil and condensate	\$105,757	\$104,163	\$38,823
Effects of risk management activities	(24,369)	(28,223)	(3,842)
<b>Total</b>	<b>\$ 81,388</b>	<b>\$ 75,940</b>	<b>\$ 34,981</b>
<b>Average sales price per unit:</b>			
Natural gas (per Mcf)	\$ 4.24	\$ 4.20	\$ 2.23
Effects of risk management activities (per Mcf)	(1.16)	(1.19)	(0.23)
<b>Total (per Mcf)</b>	<b>\$ 3.08</b>	<b>\$ 3.01</b>	<b>\$ 2.00</b>
Oil and condensate (per Bbl)	\$ 21.33	\$ 29.35	\$ 15.37
Effects of risk management activities (per Mcf)	–	(4.34)	–
<b>Total (per Bbl)</b>	<b>\$ 21.33</b>	<b>\$ 25.01</b>	<b>\$ 15.37</b>
Natural gas, oil and condensate (per Mcfe)	\$ 4.12	\$ 4.26	\$ 2.24
Effects of risk management activities (per Mcfe)	(0.95)	(1.16)	(0.22)
<b>Total (per Mcfe)</b>	<b>\$ 3.17</b>	<b>\$ 3.10</b>	<b>\$ 2.02</b>
<b>Expenses (per Mcfe):</b>			
Lease operating	\$ 0.58	\$ 0.47	\$ 0.32
General and administrative	0.39	0.22	0.20
Depreciation, depletion and amortization	2.08	1.66	1.30

(1) For 2001, represents the net loss on the settlement of derivatives attributable to actual production.

**YEAR ENDED DECEMBER 31, 2001 COMPARED TO YEAR ENDED DECEMBER 31, 2000**

For the year ended December 31, 2001, we reported a net loss of \$21.4 million, or \$1.09 per share as compared to a net loss of \$10.4 million, or \$0.73 per share in 2000. For the year ended December 31, 1999, we reported net income of \$18.2 million or \$1.28 per share.

**Oil and Gas Revenue** / Excluding the effects of risk management activities, our revenue from natural gas and oil production for 2001 increased 2% over 2000, from \$104.2 million to \$105.8 million. This increase resulted from a slight increase in the price of natural gas and a 5% increase in production, partially offset by a 27% decrease in the price of oil. The increase in production volumes from 24.4 Bcfe to 25.7 Bcfe was attributable to 13 properties that were on production during 2001 that were not on production during 2000. This increase in production was offset by the natural decline in our existing offshore properties. Risk management activities, which were included in oil and gas revenues in 2000 would have decreased oil and natural gas revenues by \$24.4 million, or \$0.95 per Mcfe in 2001 and \$28.2 million, or \$1.16 per Mcfe in 2000.

**Marketing Revenue** / Revenues from natural gas marketing activities decreased to \$7.4 million in 2001 as compared to \$8.0 million in 2000. This decrease was due to a decrease in the sales price per MMBtu. The average sales price per MMBtu decreased from \$4.38 in 2000 to \$4.06 in 2001. For more information regarding this marketing activity, see Note 13 of Notes to Consolidated Financial Statements.

**Lease Operating Expense** / Our lease operating expense for 2001 increased 28% from \$11.6 million to \$14.8 million. This increase was primarily the result of an increase in the number of producing wells we own and an increase in their total production volume. Additionally, the lease operating expense per Mcfe on those properties acquired in 2001 was higher due to cost structures and contract obligations in place at the time of acquisition. Transportation related costs increased (\$0.6 million) and workover spending decreased (\$0.9 million) as compared to 2000.

**Gas Purchased-Marketing** / Our cost of purchased gas was \$7.2 million for 2001 compared to \$7.8 million for 2000. The average gas cost decreased from \$4.26 per MMBtu in 2000 to \$3.96 per MMBtu in 2001.

**Geological and geophysical** / In 2001, we recorded \$1.1 million of costs related to the acquisition of 3-D seismic data purchased for development purposes on certain properties in the Gulf of Mexico and the U.K.

**General and Administrative Expense** / General and administrative expense increased to \$10.0 million for 2001 compared to \$5.4 million for 2000. The primary reason for the increase was the result of compensation and related expenses due to an increase in the number of employees in our Houston office from 28 at the end of 2000 to 39 at the end of 2001 (\$0.9 million) and the opening of our U.K. office in the third quarter of 2000 (\$1.7 million). As a result of becoming a public company in 2001, we incurred costs such as insurance, filing fees, professional fees, investor relations expenses and other expenses related to public company requirements (\$1.3 million).

**Non-Cash Compensation Expense** / In 2001, we recorded a non-cash compensation expense of approximately \$3.4 million. A portion of the expense (\$2.9 million) is related to options granted from September 1999 to the date of our IPO and is based on the difference between the exercise price for those options and the fair market value of our stock as determined by the IPO price of \$14.00 per share. The expense is recognized in the periods in which the options vest. Each option is divided into three equal portions corresponding to the three vesting dates, with the related compensation cost amortized straight-line over the period between the IPO date and the vesting date. The remaining expense (\$0.5 million) was related to certain options granted prior to September 1999 and exercised in the current year. The expense was recorded on those exercises as the method in which those shares were exercised required us to account for the options under variable accounting. The remaining compensation expense to be recorded over 2002 and 2003 is approximately \$0.5 million.

**Depreciation, Depletion and Amortization Expense** / Depreciation, depletion and amortization expense ("DD&A") increased 32% from \$40.6 million in 2000 to \$53.4 million in 2001. The average DD&A rate was \$2.08 per Mcfe during 2001 compared to \$1.66 per Mcfe during 2000.

**Impairment Expense** / As of December 31, 2001, the future undiscounted cash flows for our properties were \$354.2 million and the net book value for the properties was \$157.9 million before current year impairment expense. At December 31, 2000, the future undiscounted cash flows for our properties were \$931.2 million and the net book value for the properties was \$109.6 million before current year impairment expense. However, on eight of our properties in 2001 and three of our properties in 2000, the future undiscounted cash flows were less than their individual net book value. As a result, we recorded impairments of \$24.9 million in 2001 and \$10.8 million in 2000. The impairments in 2001 were primarily the result of drilling a non-commercial development well at our Main Pass 282 property (\$8.3 million), a decrease in expected future gas prices and reductions in recoverable reserves. In 2000, the impairments were primarily the result of a reduction in recoverable reserves individually attributable to the particular properties.

## MANAGEMENT'S DISCUSSION AND ANALYSIS

### of Financial Condition and Results of Operations (Continued)

**Other Income (Expense)** / In 2001, we recorded a loss on derivative instruments of \$18.1 million comprised of a realized loss of \$19.3 million and an unrealized gain of \$1.2 million. The realized loss represents derivative contracts settled in 2001, while the offsetting gain represents the fair market value of the open derivative positions at December 31, 2001. Prior to the adoption of SFAS 133, realized gains or losses were recorded as a component of revenue. For 2000 we recorded an expense of \$4.3 million (\$1.7 million realized and \$2.6 million unrealized) on a natural gas derivative position as a result of our hedging position exceeding our expected production in an upcoming period. In addition, we recorded an expense of \$7.6 million (\$3.0 million realized and \$4.6 million unrealized) related to losses associated with our written call option contracts. In both of these situations in 2000, we were required to account for the positions using the mark-to-market method.

Interest expense decreased from \$11.9 million in 2000 to \$10.0 million in 2001 primarily due to lower debt levels following the use of proceeds from our IPO and as a result of lower interest rates. We capitalized none and \$0.7 million of interest for the years ended December 31, 2001 and 2000, respectively.

#### YEAR ENDED DECEMBER 31, 2000 COMPARED TO YEAR ENDED DECEMBER 31, 1999

**Oil and Gas Revenue** / Our revenue from natural gas and oil production for 2000 increased 117% over 1999 from \$35.0 million to \$75.9 million. This increase resulted from an increase in realized natural gas prices of 51% and realized oil prices of 63%, as well as a 41% increase in production. The increase in production volumes from 17.3 Bcfe to 24.5 Bcfe was attributable to ten properties that were on production during 2000 that were not on production during 1999. Hedging transactions reduced oil and natural gas revenues by \$28.2 million, or \$1.16 per Mcfe, in 2000 and \$3.8 million, or \$0.22 per Mcfe, in 1999.

**Marketing Revenue** / Revenues from natural gas marketing activities increased to \$8.0 million in 2000 as compared to \$7.7 million in 1999. The reason for the increase was a decrease in volumes partially offset by an increase in the sales price per MMBtu. The daily natural gas contract decreased from 9,000 MMBtu per day in 1999 to 5,000 MMBtu per day in 2000. The average sales price increased from \$2.34 per MMBtu in 1999 to \$4.38 per MMBtu in 2000.

**Lease Operating Expense** / Our lease operating expense for 2000 increased 107% from \$5.6 million to \$11.6 million. This increase was primarily the result of an increase in the number of producing wells owned by us, an increase in their total production volume and an increase in the level of workover activity. Workover spending increased from \$0.4 million in 1999 to \$2.6 million in 2000. The remaining increase in lease operating expense was primarily attributable to transportation related costs.

**Gas Purchased-Marketing** / Our cost of purchased gas was \$7.8 million for 2000 compared to \$7.4 million for 1999. The daily gas contract amount in our third party marketing arrangement decreased from 9,000 MMBtu per day in 1999 to 5,000 MMBtu per day in 2000. Lower volumes were offset by an increase in the average gas cost from \$2.25 per MMBtu in 1999 to \$4.26 per MMBtu in 2000.

**General and Administrative Expense** / General and administrative expense increased to \$5.4 million for 2000 compared to \$3.5 million for 1999. The primary reason for the increase was the result of compensation and related expenses increasing from \$1.8 million to \$3.3 million period to period. Our total employees increased from 19 at December 31, 1999 to 33 at December 31, 2000.

**Depreciation, Depletion and Amortization Expense** / Depreciation, depletion and amortization expense increased 80% from \$22.5 million in 1999 to \$40.6 million in 2000. The average DD&A rate was \$1.66 per Mcfe during 2000 compared to \$1.30 per Mcfe during 1999.

**Impairment Expense** / As of December 31, 2000, the future undiscounted cash flows for our properties were \$931.2 million and the net book value for the properties was \$109.6 million before current year impairment expense. At December 31, 1999, the future undiscounted cash flows for our properties were \$183.0 and the net book value for the properties was \$79.8 million before current year impairment expense. However, for three of our 33 properties in 2000 and four of our 26 properties in 1999, the future undiscounted cash flows were less than their individual net book value. As a result, we recorded impairments of \$10.8 million in 2000 and \$7.5 million in 1999. The impairments in 2000 and 1999 were primarily the result of a reduction in recoverable reserves individually attributable to the particular properties.

**Other Expense** / We recorded a charge of \$0.5 million in 2000 relating to the sale of a platform which was held for sale and included in other assets in 1999. There was no comparable expense for this account in 1999.

**Other Income (Expense)** / For 2000 we recorded an expense of \$4.3 million (\$1.7 million realized and \$2.6 million unrealized) on a natural gas derivative position as a result of our hedging position exceeding our expected production in an upcoming period. In this situation, we are required to account for the position using the mark-to-market method. In addition, we recorded an expense of \$7.6 million (\$3.0 million realized and \$4.6 million unrealized) related to mark-to-market losses associated with our written call option contracts.

For 2000, interest expense was \$11.9 million compared to \$9.4 million for 1999. Our borrowings increased from period to period but were offset by a decrease in interest rates under our new development program credit agreement. We capitalized \$0.7 million and \$0.6 million of interest for the years ended December 31, 2000 and 1999, respectively.

**Extraordinary Gain** / In June 1999, we agreed with the lender under a prior development program credit agreement to prepay the amount outstanding at a discount. As a result, we recorded an extraordinary gain of \$29.2 million.

## LIQUIDITY AND CAPITAL RESOURCES

**General** / We have financed our acquisition and development activities through a combination of project-based development arrangements, bank borrowings and proceeds from our February 2001 IPO, as well as cash from operations. We believe the cash flows from operating activities combined with our ability to control the timing of substantially all of our future development and acquisition requirements will provide us with the flexibility and liquidity to meet our planned capital requirements during 2002. However, future cash flows are subject to a number of variables including the level of production and oil and natural gas prices. Future borrowings under credit facilities are subject to variables including the lenders' practices and policies, changes in the prices of oil and natural gas and changes in our oil and gas reserves. No assurance can be given that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of operations and capital expenditures. A reduction in the borrowing base or an increase in the monthly reduction amount by the lender would have a material negative impact on our cash flows and our ability to fund future obligations during 2002. As operator of all of our projects in development, we have the ability to significantly control the timing of many of our capital expenditures. In periods of reduced availability of funds from either cash flows or credit sources we would anticipate delaying planned capital expenditures, which could negatively impact our future revenues and cash flows.

### Cash Flows

	Years Ended December 31,		
	2001	2000	1999
<i>(in thousands)</i>			
Cash provided by (used in):			
Operating activities	\$ 41,356	\$ 57,157	\$ 10,707
Investing activities	(110,810)	(76,835)	(55,120)
Financing activities	56,612	20,035	58,781

**MANAGEMENT'S DISCUSSION AND ANALYSIS**  
of Financial Condition and Results of Operations (Continued)

**Operating activities** / Net cash provided by operating activities in 2001 was \$41.4 million compared to \$57.2 million in 2000. The decrease in 2001 was primarily due to an increase in working capital needs in addition to unfavorable settlements related to price risk derivative contracts. The decrease was partially offset by higher operating income, excluding non-cash items, as a result of higher natural gas prices and increased production volumes.

**Investing activities** / Cash used in investing activities increased in 2001 to \$110.8 million. The 2001 amount includes expenditures on oil and gas properties of \$110.3 million, of which \$25.9 million was used for the acquisition of 17 properties in the Gulf of Mexico and Southern Gas Basin area of the North Sea, \$5.6 million was used to purchase the overriding royalty interests associated with our non-recourse debt and \$78.8 million was used for development. Comparable expenditures for acquisition and development in 2000 were \$7.5 million and \$69.0 million, respectively.

**Financing activities** / Cash provided from financing activities includes the proceeds from our IPO in February 2001 of \$78.3 million, net of the underwriters' discount. We also incurred costs of approximately \$0.9 million in connection with the offering, which in addition to costs incurred in the fourth quarter of 2000, totaled approximately \$1.5 million. Financing activities included repayments of \$116.5 million of our credit facilities in place at December 31, 2000 and net proceeds of \$100.0 million from our new credit facility and note payable (see "Credit Facilities"). Financing activities in 2000 included net proceeds of \$7.6 million and \$13.5 million from our credit facilities and non-recourse borrowings, respectively.

Amounts borrowed under our credit agreements were as follows for the dates indicated (in thousands):

	December 31,	
	2001	2000
Credit facility	\$ 70,000	\$ 27,750
Note payable, net of unamortized discount of \$1,139	30,111	-
Non-recourse borrowings	-	88,779
Total debt	<u>\$100,111</u>	<u>\$ 116,529</u>

**Credit Facilities** / In March 2001, we repaid our then existing bank credit facility and in April 2001 we repaid the full amount borrowed under a non-recourse development program credit agreement which we had used as a source of financing for the acquisition of oil and gas properties. Concurrent with the repayment of our non-recourse agreement, we negotiated with the lender to terminate the overriding royalty interest retained by it on all properties previously financed by the lender in exchange for a lump-sum payment of approximately \$5.6 million.

Upon repayment of our former credit and non-recourse facilities, we entered into a new \$100.0 million senior-secured revolving credit facility in April 2001. This facility is secured by substantially all of our oil and gas properties, as well as by approximately two-thirds of the capital stock of our U.K. subsidiary and is guaranteed by our wholly owned subsidiary, ATP Energy, Inc. As amended, the amount available for borrowing under the facility is limited to the loan value, as determined by the bank, of oil and gas properties pledged under the facility. At December 31, 2001, the borrowing base was \$70.0 million and the monthly borrowing base reduction was set at \$2.0 million a month beginning February 27, 2002 and remains in effect until there is a change, if any, at the next redetermination date. The redetermination dates are on or around the first business day of each calendar quarter at which time the lenders can increase or decrease the borrowing base and the monthly reduction amount. The next scheduled redetermination date is on or around the first business day of April 2002. Our lender has indicated this process will not be completed until mid to late April of 2002. The \$2.0 million monthly reduction included in current maturities of long-term debt assumes there is no change in the monthly reduction amount or the borrowing base in 2002. If our outstanding balance exceeds our borrowing base at any time, we are required to repay such excess within 30 days and our interest rate during the time an excess exists is increased by 2.00%. A reduction in the borrowing base or an increase in the monthly reduction amount by the lender would have a material negative impact on our cash flows and our ability to fund future operations during 2002. As of December 31, 2001, all of our borrowing base under the agreement was outstanding.

Advances under the credit facility can be in the form of either base rate loans or Eurodollar loans. The interest on a base rate loan is a fluctuating rate equal to the higher of the Federal funds rate plus 0.5% and the bank base rate, plus a margin of 0.25%, 0.50%, 0.75% or 1.00% depending on the amount outstanding under the credit agreement. The interest on a Eurodollar loan is equal to the Eurodollar rate, plus a margin of 2.25%, 2.50%, 2.875% or 3.125% depending on the amount outstanding under the credit facility. The amended credit facility matures in November 2003. Our credit facility contains conditions and restrictive provisions, among other things, (1) prohibiting us to enter into any arrangement to sell or transfer any of our material property, (2) prohibiting a merger into or consolidation with any other person or sell or dispose of all or substantially all of our assets, and (3) maintaining certain financial ratios.

**Note Payable** / Effective June 29, 2001, we issued note payable to a purchaser for a face principal amount of \$31.3 million which matures in June 2005 and bears interest at a fixed rate of 11.5% per annum. The note is secured by second priority liens on substantially all of our oil and gas properties and is subordinated in right of payment to our existing senior indebtedness. We executed an agreement in connection with the note which contains conditions and restrictive provisions and requires the maintenance of certain financial ratios. Upon consent of the purchaser, which shall not be unreasonably withheld, the note may be repaid prior to the maturity date with an additional repayment premium based on the percentage of the principal amount paid, ranging from 4.5% during the first year to 16.5% in the final year of payment. If the note is paid at maturity, the maximum payment premium of 16.5% is required. The expected repayment premium is being amortized to interest expense straight-line, over the term of the note which approximates the effective interest method. The resulting liability is included in other long-term liabilities on the consolidated balance sheet. In July 2001, we received proceeds of \$30.0 million in consideration for the issuance of the note. The discount of \$1.3 million is being amortized to interest expense using the effective interest method. The amount available for borrowing under the note is limited to the loan value of oil and gas properties pledged under the note, as determined by the purchaser. The purchaser has the right to make a redetermination of the borrowing base at least once every six months. We have assumed there is no change in the borrowing base in 2002. If our outstanding balance exceeds the borrowing base at any time, we are required to repay such excess within 10 days subject to the provisions of the agreement. A reduction in the borrowing base by the lender would have a material negative impact on our cash flows and our ability to fund future obligations during 2002. As of December 31, 2001, all of our borrowing base under the agreement was outstanding.

As of December 31, 2001, we were in compliance with all of the financial covenants of our credit facility and note payable agreements other than our working capital covenant (as defined by the agreements) for which we have obtained amendments from our lenders. Both of the amendments require that our working capital at December 31, 2001 and March 31, 2002 shall not exceed deficits of \$10.0 million and \$5.0 million, respectively.

**Working Capital** / During the second half of 2001 we operated with a working capital deficit. In compliance with the definition of working capital in our credit facilities which excludes current maturities of long-term debt and the current portion of future commodity contracts and other derivatives, we ended the year with a deficit of approximately \$9.0 million, an improvement over our deficits of \$37.1 million at June 30, 2001 and \$35.1 million at September 30, 2001. The improvement in our working capital was the result of the November 2001 increase in the borrowing base of our existing credit facility, the reduction of our current liabilities through cash flows from operations and the reduction of expenditures related to the curtailment of current development activity. We executed this improvement in working capital despite the devastating national and financial events in the U.S. that occurred in the third and fourth quarters of 2001. In efforts to preserve cash flow during this period of negative working capital, we reached agreement with several of our suppliers for extended payments. In response to lower gas prices received in the fourth quarter of 2001 and the early part of 2002 and our desire to completely eliminate our working capital deficit, we have reduced certain previously planned development activities for 2002. Four projects that can be developed in 2002 have been postponed until 2003.

In addition to these measures, we are currently in discussions with potential investors to provide additional capital. These discussions involve increases to our current credit facilities, new credit facilities, sale of interests in selected properties and the potential sale and lease back of certain of our platforms and pipelines. We have also explored

**MANAGEMENT'S DISCUSSION AND ANALYSIS**  
of Financial Condition and Results of Operations (Continued)

the possibility of the issuance of new debt or equity in both the public and private markets. Completion of any of these potential financings will expand our capabilities to further reduce our outstanding indebtedness, increase our working capital and expand our 2002 development and acquisition program. There can be no assurance however, that we will be successful in negotiating any of these transactions or that the form of the transaction will be acceptable to both the potential investor and our management or our board of directors. If we are not successful in closing these transactions, our ability to reduce our debt below projected levels or to develop and produce our oil and gas properties as desired may be negatively impacted. Other items that could have a negative impact on our working capital include a significant decrease in oil or gas prices from expected levels, a redetermination by our lenders of our borrowing base or our monthly reduction amount in excess of the amounts forecasted in our cash flow projection, the increase in costs and expenses above projected levels or any significant payments related to the contingencies described below. Our planned development, acquisition and debt reduction programs are projected to be funded by available cash flow from our 2002 operations. We believe the cash flows from operating activities combined with our ability to control the timing of substantially all of our future development and acquisition requirements will provide us with the flexibility and liquidity to meet our future capital requirements. Realization of any of the aforementioned negative items could limit our ability to fund operations during 2002.

**Commitments** / We have various commitments primarily related to leases for office space, other property and equipment and other agreements. We expect to fund these commitments with cash generated from operations.

The following table summarizes our contractual obligations at December 31, 2001 (in thousands):

Contractual Obligation(1)	Payments Due By Period				
	Total	Less Than 1 Year	1-2 Years	3-4 Years	After 4 Years
Total debt	\$ 101,250	\$ 22,000	\$ 48,000	\$ 31,250	\$ –
Interest expense on credit facility(2)	4,787	3,145	1,642	–	–
Interest expense on note payable(3)	17,272	4,940	9,883	2,449	–
Non-cancelable operating leases	2,545	375	688	368	1,114
Contractor commitment(4)	3,450	–	3,450	–	–
<b>Total contractual obligations</b>	<b>\$ 129,304</b>	<b>\$ 30,460</b>	<b>\$ 63,663</b>	<b>\$ 34,067</b>	<b>\$ 1,114</b>

(1) Does not include any amounts related to contingencies discussed below.

(2) Includes interest based on rates and monthly reduction amounts in effect at December 31, 2001.

(3) Includes 11.5% interest and repayment premium.

(4) Does not include 7.5% interest due monthly.

**Contingencies** / On August 28, 2001 ATP entered into a written agreement to acquire a property in the Gulf of Mexico during September 2001. On October 9, 2001 the agreement was amended to ultimately extend the closing date until October 31, 2001 in exchange for payments made by ATP totaling \$3.0 million. This amendment also contained an arrangement whereby if ATP did not close on the property, and if sellers sold the property to a third party with a sale that met specific contract requirements, ATP would be required to execute a six month note for payment of the differential. Since ATP did not obtain the financing for the acquisition by October 31, 2001, the transaction did not close by that date; however, the parties' intensive work toward closing continued beyond that date without interruption.

While working on the closing for the property with ATP, the sellers sold the property to a third party without informing ATP until after the closing had taken place. ATP filed an action in the District Court of Harris County, Texas against the sellers, generally alleging improper sale of the offshore property to a third party and breach of contract, and seeking unspecified damages from the sellers. The case is captioned *ATP Oil & Gas Corporation vs. Legacy Resources Co., L.P. et al*, No. 2001-63224 in the 269th Judicial District Court of Harris County, Texas. At the same time sellers notified ATP of their sale to a third party, the sellers had a demand made upon ATP for execution of a six month note for the amount of an alleged differential of approximately \$12.3 million plus interest at 16%.

Substantiation of the amount and validity of the demand could not be ascertained based on the content of the demand received. ATP contested the entire demand. The litigation is in its very early stages with written discovery propounded by ATP, but no answers received, and no depositions taken. The judge has abated the litigation, until arbitration pursuant to the underlying agreements between the sellers and ATP is completed. Since the legal proceedings have just begun, and a prediction of the outcome would be premature and uncertain, we have not accrued any amount related to this matter. And while we are seeking recovery of the amounts previously paid and discussed above, the \$3.0 million has been charged to earnings along with certain other costs related to this matter. ATP intends to vigorously defend against the sellers' claims and forcefully pursue its own claims in this matter.

In August 2001, Burlington Resources Inc. filed suit against us alleging formation of a contract with us and our breach of the alleged contract. The complaint seeks compensatory damages of approximately \$1.1 million. We believe that this claim is without merit, and we intend to defend it vigorously.

We are, in the ordinary course of business, a claimant and/or defendant in various legal proceedings. Management does not believe that the outcome of these legal proceedings, individually, and in the aggregate will have a materially adverse effect on our financial condition, results of operations or cash flows.

#### **RECENT ACCOUNTING PRONOUNCEMENTS**

In 2001, the FASB approved SFAS No. 141 "*Business Combinations*" ("SFAS 141"), No. 142 "*Goodwill and Other Intangible Assets*" ("SFAS 142"), No. 143 "*Accounting for Asset Retirement Obligations*" ("SFAS 143") and No. 144 "*Accounting for the Impairment or Disposal of Long-Lived Assets*" ("SFAS 144"). SFAS 141 requires all business combinations completed after June 30, 2001, be accounted for under the purchase method. This standard also establishes for all business combinations made after June 30, 2001, specific criteria for the recognition of intangible assets separately from goodwill. SFAS 141 also requires that the excess of fair value of acquired assets over cost (negative goodwill) be recognized immediately as an extraordinary gain, rather than deferred and amortized.

SFAS 142 addresses the accounting for goodwill and other intangible assets after an acquisition. The most significant changes made by SFAS 142 are: 1) goodwill and intangible assets with indefinite lives will no longer be amortized; 2) goodwill and intangible assets with indefinite lives must be tested for impairment at least annually; and 3) the amortization period for the intangible assets with finite lives will no longer be limited to forty years. We will adopt SFAS 142 effective January 1, 2002, as required. Additionally, SFAS 142 requires that unamortized negative goodwill associated with investments accounted for under the equity method and acquired before July 1, 2001, be recognized in income as a cumulative effect of change in accounting principle.

SFAS 143 provides accounting requirements for retirement obligations associated with tangible long-lived assets, including: 1) the timing of liability recognition; 2) initial measurement of the liability; 3) allocation of asset retirement cost to expense; 4) subsequent measurement of the liability; and 5) financial statement disclosures. SFAS 143 requires that an asset retirement cost should be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. We will adopt the Statement effective January 1, 2003. The transition adjustment resulting from the adoption of SFAS 143 will be reported as a cumulative effect of a change in accounting principle.

SFAS 144 provides that long-lived assets to be disposed of by sale be measured at the lower of carrying amount or fair value less cost to sell, whether reported in continuing operations or in discontinued operations, and broadens the reporting of discontinued operations to include all components of an entity with operations that can be distinguished from the rest of the entity and that will be eliminated from the ongoing operations of the entity in a disposal transaction. SFAS 144 is effective for fiscal years beginning after December 15, 2001.

SFAS 141 and SFAS 142 will not apply to us unless we enter into a future business combination. We are currently assessing the impact of SFAS 143 and SFAS 144 on our financial condition and results of operations.

**MANAGEMENT'S DISCUSSION AND ANALYSIS**  
of Financial Condition and Results of Operations (Continued)

**QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK**

**Interest Rate Risk** / We are exposed to changes in interest rates. Changes in interest rates affect the interest earned on our cash and cash equivalents and the interest rate paid on borrowings under the credit agreements. Under our current policies, we do not use interest rate derivative instruments to manage exposure to interest rate changes.

**Commodity Price Risk** / Our revenues, profitability and future growth depend substantially on prevailing prices for natural gas and oil. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount we can borrow under our bank credit facility is subject to periodic re-determination based in part on changing expectations of future prices. Lower prices may also reduce the amount of natural gas and oil that we can economically produce. We currently sell most of our natural gas and oil production under price sensitive or market price contracts. To reduce exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow, we periodically enter into hedging arrangements that usually consist of swaps or price collars that are settled in cash. However, these contracts also limit the benefits we would realize if commodity prices increase. Our internal hedging policy provides that we examine the economic effect of entering into a commodity contract with respect to the properties that we acquire. We generally acquire properties at prices that are below the management's estimated value of the estimated proved reserves at the then current natural gas and oil prices. We will enter into short term hedging arrangements if (1) we are able to obtain commodity contracts at prices sufficient to secure an acceptable internal rate of return on a particular property or on a group of properties or (2) if deemed necessary by the terms of our existing credit agreements. During 2001, we hedged approximately 82% of our natural gas production.

Effective January 1, 2001, we adopted SFAS No. 133 and SFAS No. 138, an amendment to SFAS 133. SFAS 133 and 138 require that derivatives be reported on the balance sheet at fair value and, if the derivative is not designated as a hedging instrument, changes in fair value must be recognized in earnings in the period of change. If the derivative is designated as a hedge and to the extent such hedge is determined to be effective, changes in fair value are either (a) offset by the change in fair value of the hedged asset or liability (if applicable) or (b) reported as a component of other comprehensive income (loss) in the period of change, and subsequently recognized in earnings when the offsetting hedged transaction occurs. We use derivatives to hedge the price of crude oil and natural gas. Effective January 1, 2001, we did not attempt to qualify for the hedge provisions under SFAS 133 and thus have not designated our derivatives as hedging instruments. Accordingly, we account for the changes in market value of these derivatives through current earnings. This method will result in increased earnings volatility associated with commodity price fluctuations. Gains and losses on all derivative instruments related to accumulated other comprehensive income (loss) are included in other income (expense) on the consolidated financial statements.

On January 1, 2001, in accordance with the transition provisions of SFAS 133, we recorded a non-cash loss of \$52.7 million (\$34.3 million after tax) in accumulated other comprehensive loss, representing the cumulative effect of an accounting change to recognize at fair value all cash flow type derivatives. Also on January 1, 2001, we recorded derivative liabilities of \$52.7 million. During the year ended December 31, 2001, losses of \$52.7 million (\$34.3 million after tax) were reclassified from accumulated other comprehensive loss to earnings. Prior to the adoption of this standard, we included gains and losses on hedging instruments as a component of revenue. As of December 31, 2001, the fair market value of our derivatives consisted of a \$1.9 million current asset and a \$0.7 million long-term liability.

As of December 31, 2001, all of our natural gas swap agreements were with one counterparty whose investment grade ratings were Baa2 from Moody's and BBB from Standard & Poor's. Those agreements outstanding were as follows:

Period	MMBtu/Day	Average \$/MMBtu
January 2002 – October 2003	20,000	3.02

Thus far, in 2002, we have entered into the following swap agreements:

Period	Volume/Day	\$/Unit
Natural gas (MMBtu):		
February 2002 – October 2002	6,000	2.41
April 2002 – July 2002	6,000	2.81
April 2002 – October 2002	2,000	3.31
Oil (Bbl):		
April 2002 – December 2002	500	23.50
April 2002 – December 2002	500	25.25

## MANAGEMENT'S RESPONSIBILITIES FOR FINANCIAL STATEMENTS

### REPORT OF MANAGEMENT

The consolidated financial statements of ATP Oil & Gas Corporation and subsidiary and the related information included in this Annual Report have been prepared by management in conformity with accounting principles generally accepted in the United States of America. The financial statements include certain estimates and judgments which management believes are reasonable under the circumstances.

Management maintains a system of internal control including internal accounting controls that provide management with reasonable assurance that our assets are protected and that published financial statements are reliable and free of material misstatement. Management is responsible for the effectiveness of internal controls. This is accomplished through established codes of conduct, accounting and other control systems, policies and procedures, employee selection and training, appropriate delegation of authority and segregation of responsibilities.

The Audit Committee of the Board of Directors, composed solely of directors who are not officers or employees, meets periodically with the independent certified accountants, financial management and counsel. To ensure complete independence, the certified public accountants have full and free access to the Audit Committee to discuss the results of their audits, the adequacy of internal controls and the quality of financial reporting.

Our independent certified public accountants provide an objective independent review by their audit of the Company's financial statements. Their audit is conducted in accordance with generally accepted auditing standards and includes a review of the system of internal accounting controls to the extent deemed necessary for the purpose of their audit.



T. Paul Bulmahn  
*Chairman & President*



Albert L. Reese, Jr.  
*Senior Vice President & CFO*

## INDEPENDENT AUDITORS' REPORT

### THE BOARD OF DIRECTORS ATP OIL & GAS CORPORATION:

We have audited the accompanying consolidated balance sheets of ATP Oil & Gas Corporation and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of operations, shareholders' equity (deficit), and cash flows for each of the years in the three-year period ended December 31, 2001. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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 financial position of ATP Oil & Gas Corporation and subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2001, the Company changed its method of accounting for derivative financial instruments.

**KPMG LLP**

KPMG LLP

Houston, Texas  
March 29, 2002

**ATP OIL & GAS CORPORATION AND SUBSIDIARIES**  
**CONSOLIDATED BALANCE SHEETS**

	December 31,	
	2001	2000
<i>(In Thousands, Except Share Amounts)</i>		
<b>Assets</b>		
Current assets:		
Cash and cash equivalents	\$ 5,294	\$ 18,136
Accounts receivable (net of allowance of \$1,423 and \$443, respectively)	10,371	32,542
Commodity contracts and other derivatives	1,936	-
Other current assets	1,754	2,597
<b>Total current assets</b>	<b>19,355</b>	<b>53,275</b>
Oil and gas properties:		
Oil and gas properties (using the successful efforts method of accounting)	319,506	209,548
Less: Accumulated depreciation, depletion, impairment and amortization	(186,473)	(110,823)
<b>Oil and gas properties, net</b>	<b>133,033</b>	<b>98,725</b>
Furniture and fixtures (net of accumulated depreciation)	794	487
Deferred tax asset	19,228	7,652
Other assets, net	5,154	1,854
<b>Total assets</b>	<b>\$ 177,564</b>	<b>\$ 161,993</b>
<b>Liabilities and Shareholders' Equity (Deficit)</b>		
Current liabilities:		
Accounts payable and accruals	\$ 26,426	\$ 49,799
Current maturities of long-term debt	22,000	-
Commodity contracts and other derivatives	-	7,248
Other deferred obligations	-	63
<b>Total current liabilities</b>	<b>48,426</b>	<b>57,110</b>
Long-term debt	78,111	27,750
Non-recourse borrowings	-	88,779
Commodity contracts and other derivatives	671	-
Deferred revenue	1,296	1,481
Other long-term liabilities and deferred obligations	4,068	52
<b>Total liabilities</b>	<b>132,572</b>	<b>175,172</b>
Commitments and Contingencies		
Shareholders' equity (deficit):		
Preferred stock: \$0.001 par value, 10,000,000 shares authorized; none issued	-	-
Common stock: \$0.001 par value, 100,000,000 shares authorized in December 31, 2001 and 2000	20	14
Additional paid in capital	80,478	38
Accumulated deficit	(34,614)	(13,231)
Accumulated other comprehensive income	19	-
Treasury stock, at cost	(911)	-
<b>Total shareholders' equity (deficit)</b>	<b>44,992</b>	<b>(13,179)</b>
<b>Total liabilities and shareholders' equity (deficit)</b>	<b>\$ 177,564</b>	<b>\$ 161,993</b>

See accompanying notes to the consolidated financial statements.

**ATP OIL & GAS CORPORATION AND SUBSIDIARIES**  
**CONSOLIDATED STATEMENTS OF OPERATIONS**

	Years Ended December 31,		
	2001	2000	1999
<i>(In Thousands, Except Per Share Amounts)</i>			
Revenues:			
Oil and gas production	\$ 105,757	\$ 75,940	\$ 34,981
Gas sold – marketing	7,417	8,015	7,703
Gain on sale of oil and gas properties	–	33	287
	<u>113,174</u>	<u>83,988</u>	<u>42,971</u>
Costs and operating expenses:			
Lease operating expenses	14,806	11,559	5,587
Gas purchased – marketing	7,218	7,788	7,402
Geological and geophysical expenses	1,068	–	–
General and administrative expenses	9,981	5,409	3,541
Non-cash compensation expense (general and administrative)	3,364	–	–
Depreciation, depletion and amortization	53,428	40,569	22,521
Impairment of oil and gas properties	24,891	10,838	7,509
Loss on unsuccessful property acquisition	3,147	–	–
Other expense	–	450	–
	<u>117,903</u>	<u>76,613</u>	<u>46,560</u>
Income (loss) from operations	<u>(4,729)</u>	<u>7,375</u>	<u>(3,589)</u>
Other income (expense):			
Interest income	884	451	202
Interest expense	(10,039)	(11,907)	(9,399)
Loss on derivative instruments	(18,083)	(11,911)	–
	<u>(27,238)</u>	<u>(23,367)</u>	<u>(9,197)</u>
Loss before income taxes and extraordinary gain (loss)	<u>(31,967)</u>	<u>(15,992)</u>	<u>(12,786)</u>
Income tax benefit	11,186	5,594	1,829
Loss before extraordinary gain (loss)	<u>(20,781)</u>	<u>(10,398)</u>	<u>(10,957)</u>
Extraordinary gain (loss), net of tax	(602)	–	29,185
Net income (loss)	<u>\$ (21,383)</u>	<u>\$ (10,398)</u>	<u>\$ 18,228</u>
Basic and diluted earnings (loss) per common share:			
Loss before extraordinary gain (loss)	\$ (1.06)	\$ (0.73)	\$ (0.77)
Extraordinary gain (loss), net of tax	(0.03)	–	2.05
Net income (loss) per common share	<u>\$ (1.09)</u>	<u>\$ (0.73)</u>	<u>\$ 1.28</u>
Weighted average number of common shares:			
Basic and diluted	<u>19,704</u>	<u>14,286</u>	<u>14,286</u>

See accompanying notes to the consolidated financial statements.

**ATP OIL & GAS CORPORATION AND SUBSIDIARIES**  
**CONSOLIDATED STATEMENTS OF CASH FLOWS**

	Years Ended December 31,		
	2001	2000	1999
<i>(In Thousands)</i>			
<b>Cash flows from operating activities:</b>			
Net income (loss)	\$ (21,383)	\$ (10,398)	\$ 18,228
Adjustments to reconcile net income (loss) to net cash provided by operating activities –			
Depreciation, depletion and amortization	53,428	40,569	22,521
Impairment of oil and gas properties	24,891	10,838	7,509
Amortization of deferred financing costs	797	376	256
Extraordinary item	926	–	(29,185)
Deferred tax assets	(11,576)	(5,594)	(2,058)
Non-cash compensation expense	3,364	–	–
Gain on sale of oil and gas properties	–	(33)	(287)
Other expense	–	450	–
Other non-cash items	196	431	566
Changes in assets and liabilities –			
Accounts receivable and other	23,014	(22,772)	(7,197)
Restricted cash	–	471	3,529
Cash held in escrow	–	–	439
Net (assets) liabilities from risk management activities	(8,513)	7,249	–
Accounts payable and accruals	(23,436)	37,309	(2,403)
Other long-term assets	(4,183)	(1,462)	(803)
Other long-term liabilities and deferred credits	3,831	(277)	(408)
<b>Net cash provided by operating activities</b>	<b>41,356</b>	<b>57,157</b>	<b>10,707</b>
<b>Cash flows from investing activities:</b>			
Additions and acquisitions of oil and gas properties	(110,264)	(76,474)	(56,051)
Proceeds from sale of oil and gas properties	–	–	1,137
Additions to furniture and fixtures	(546)	(361)	(206)
<b>Net cash used in investing activities</b>	<b>(110,810)</b>	<b>(76,835)</b>	<b>(55,120)</b>
<b>Cash flows from financing activities:</b>			
Proceeds of initial public offering	78,330	–	–
Payment of offering costs	(893)	(621)	–
Proceeds from long-term debt	119,000	15,800	19,800
Payments of long-term debt	(46,750)	(8,250)	(14,100)
Proceeds from non-recourse borrowings	3,359	42,745	93,728
Payments of non-recourse borrowings	(92,138)	(29,239)	(39,420)
Deferred financing costs	(3,586)	(400)	(1,227)
Treasury stock purchases	(911)	–	–
Other	201	–	–
<b>Net cash provided by financing activities</b>	<b>56,612</b>	<b>20,035</b>	<b>58,781</b>
Increase (decrease) in cash and cash equivalents	(12,842)	357	14,368
Cash and cash equivalents, beginning of period	18,136	17,779	3,411
<b>Cash and cash equivalents, end of period</b>	<b>\$ 5,294</b>	<b>\$ 18,136</b>	<b>\$ 17,779</b>
<b>Supplemental disclosures of cash flow information:</b>			
Cash paid during the period for interest	\$ 4,177	\$ 2,531	\$ 600
Cash paid during the period for taxes	\$ –	\$ 497	\$ –

See accompanying notes to the consolidated financial statements.

**ATP OIL & GAS CORPORATION AND SUBSIDIARIES**  
**CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY (DEFICIT)**

	2001		2000		1999	
	Shares	Amount	Shares	Amount	Shares	Amount
<i>(In Thousands)</i>						
<b>Common Stock</b>						
Balance, beginning of year	14,286	\$ 14	14,286	\$ 14	14,286	\$ 14
Issuances of common stock						
Public offering	6,000	6	—	—	—	—
Exercise of stock options	103	—	—	—	—	—
Purchase of treasury stock	(76)	—	—	—	—	—
Balance, end of year	<u>20,313</u>	<u>\$ 20</u>	<u>14,286</u>	<u>\$ 14</u>	<u>14,286</u>	<u>\$ 14</u>
<b>Paid-in Capital</b>						
Balance, beginning of year		\$ 38		\$ 38		\$ 38
Issuances of common stock						
Public offering		76,809		—		—
Exercise of stock options		267		—		—
Non-cash compensation expense		3,364		—		—
Balance, end of year		<u>\$ 80,478</u>		<u>\$ 38</u>		<u>\$ 38</u>
<b>Accumulated Deficit</b>						
Balance, beginning of year		\$ (13,231)		\$ (2,833)		\$ (21,061)
Net income (loss)		(21,383)		(10,398)		18,228
Balance, end of year		<u>\$ (34,614)</u>		<u>\$ (13,231)</u>		<u>\$ (2,833)</u>
<b>Accumulated Other</b>						
<b>Comprehensive Income</b>						
Balance, beginning of year		\$ —		\$ —		\$ —
Other comprehensive income		19		—		—
Balance, end of year		<u>\$ 19</u>		<u>\$ —</u>		<u>\$ —</u>
<b>Treasury Stock</b>						
Balance, beginning of year	—	\$ —	—	\$ —	—	\$ —
Purchase of treasury stock	76	(911)	—	—	—	—
Balance, end of year	<u>76</u>	<u>\$ (911)</u>	<u>—</u>	<u>\$ —</u>	<u>—</u>	<u>\$ —</u>
<b>Total Shareholders' Equity (Deficit)</b>		<u><u>\$ 44,992</u></u>		<u><u>\$ (13,179)</u></u>		<u><u>\$ (2,781)</u></u>

See accompanying notes to the consolidated financial statements.

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

### NOTE 1 — ORGANIZATION AND BASIS OF PRESENTATION

**Organization** / ATP Oil & Gas Corporation (“ATP”) was incorporated in Texas in 1991. We are engaged in the acquisition, development and production of natural gas and oil properties in the outer continental shelf of the Gulf of Mexico, in the shallow-deep waters of the Gulf of Mexico and in the Southern Gas Basin of the North Sea. We primarily focus our efforts on natural gas and oil properties with proved undeveloped reserves that are economically attractive to us but are not strategic to major or exploration-oriented independent oil and gas companies. We attempt to achieve a high rate of return on our investment in these properties by limiting our up-front acquisition costs and by developing our acquisitions quickly.

**Basis of Presentation** / The consolidated financial statements include our accounts and our wholly-owned subsidiaries, ATP Energy, Inc. (ATP Energy) and ATP Oil & Gas (UK) Limited. All significant intercompany transactions are eliminated upon consolidation. Certain reclassifications have been made to the prior year statements to conform to the current year presentation.

### NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

**Use of Estimates** / The preparation of financial statements in accordance with generally accepted accounting principles and pursuant to the rules and regulations of the Securities and Exchange Commission (“SEC”) requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and disclosure of contingent assets and liabilities in the financial statements, including the use of estimates for oil and gas reserve information and the valuation allowance for deferred income taxes. Actual results could differ from those estimates.

**Cash and Cash Equivalents** / Cash and cash equivalents primarily consist of cash on deposit and investments in money market funds with original maturities of three months or less, stated at market value.

**Oil and Gas Producing Activities** / We follow the “successful efforts” method of accounting for oil and gas properties. Under this method, lease acquisition costs and intangible drilling and development costs on successful wells and development dry holes are capitalized.

Capitalized costs relating to producing properties are depleted on the unit-of-production method. Proved developed reserves are used in computing unit rates for drilling and development costs and total proved reserves for depletion rates of leasehold, platform and pipeline costs. Estimated dismantlement, restoration and abandonment costs and estimated residual salvage values are taken into account in determining amortization and depletion provisions.

Expenditures for geological and geophysical are incurred for development purposes only. These costs are generally charged to expense unless the costs can be specifically attributed to determining the placement for a future well location.

Expenditures for repairs and maintenance are charged to expense as incurred; renewals and betterments are capitalized. The costs and related accumulated depreciation, depletion, and amortization of properties sold or otherwise retired are eliminated from the accounts, and gains or losses on disposition are reflected in the statements of operations.

We perform a review for impairment of proved oil and gas properties on a depletable unit basis when circumstances suggest there is a need for such a review in accordance with Financial Accounting Standards Board (“FASB”) Statement of Financial Accounting Standard (“SFAS”) No. 121, “*Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of*” (“SFAS 121”). To determine if a depletable unit is impaired, we compare the carrying value of the depletable unit to the undiscounted future net cash flows by applying published future oil and gas prices to the estimated future production of oil and gas reserves over the economic life of the property. Future net cash flows are based upon our independent reservoir engineer’s estimate of proved reserves. In addition, other factors such as probable and possible reserves are taken into consideration when justified by economic conditions and actual or planned drilling or other development activities. For properties determined

to be impaired, an impairment loss equal to the differences between the carrying value and the fair value of the impaired property will be recognized. Fair value, on a depletable unit basis, is estimated to be the present value of the aforementioned expected future net cash flows. Any impairment charge incurred is recorded in accumulated depreciation, depletion, impairment and amortization to reduce our recorded basis in the asset. Each part of this calculation is subject to a large degree of judgment, including the determination of the depletable units' reserves, future cash flows and fair value. We recorded impairments during the years ended December 31, 2001, 2000 and 1999 of \$24.9 million, \$10.8 million and \$7.5 million, respectively, primarily due to depressed oil and natural gas prices, unfavorable operating performance and downward revisions of recoverable reserves.

**Furniture and Fixtures** / Furniture and fixtures consists of office furniture, computer hardware and software and leasehold improvements. Depreciation of furniture and fixtures is computed using the straight-line method over their estimated useful lives, which vary from three to five years.

**Other Assets** / Other assets consist of the following (in thousands):

	December 31,	
	2001	2000
Debt financing costs	\$3,584	\$1,794
Offering costs	—	621
Spare parts inventory	2,138	77
Other	9	10
	5,731	2,502
Accumulated amortization	(577)	(648)
	<u>\$5,154</u>	<u>\$1,854</u>

Costs incurred in connection with the issuance of long-term debt are capitalized and amortized to interest expense over the term of the related agreement, using the effective interest or straight-line method (which approximates the effective interest method).

**Environmental Liabilities** / Environmental liabilities are recognized when the expenditures are considerable probable and can be reasonably estimated. Measurement of liabilities is based on currently enacted laws and regulations, existing technology and undiscounted site-specific costs. Generally, such recognition coincides with our commitment to a formal plan of action. We have never had an environmental claim.

**Revenue Recognition** / We record as revenue only that portion of production sold and allocable to our ownership interest in the related property in the month the production is sold. Imbalances arise when a purchaser takes delivery of more or less volume from a property than our actual interest in the production from that property. Such imbalances are reduced either by subsequent recoupment of over-and-under deliveries or by cash settlement, as required by applicable contracts. Under-deliveries are included in accounts receivable and over-deliveries are included in accounts payable.

**Major Customers** / We sell a portion of our oil and gas to end users through various gas marketing companies. For the year ended December 31, 2001, revenues from three purchasers accounted for 53%, 17% and 10%, respectively, of oil and gas revenues. For the year ended December 31, 2000, revenues from two purchasers accounted for 41% each of oil and gas revenues and for the year ended December 31, 1999, revenues from three customers accounted for 48%, 19% and 12%, respectively, of oil and gas revenues. Percentages are calculated on oil and gas revenues before any effects of price risk management activities.

**Translation of Foreign Currencies** / Financial statement amounts related to our U.K. subsidiary, which has a functional currency of the British pound sterling, are translated into the U.S. dollar equivalents at exchange rates as follows: (1) balance sheet accounts at year-end exchange rates and (2) statement of operations accounts at the weighted average exchange rate for the period. The gains or losses resulting from such translations are deferred and included in accumulated other comprehensive income as a separate component of shareholders' equity (deficit).

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Continued)

**Income Taxes** / Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carry forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes that enactment date.

**Comprehensive Income (Loss)** / Comprehensive income (loss) is net income (loss), plus certain other items that are recorded directly to shareholders' equity. In 2001, comprehensive loss was \$21.4 million. In 2000 and 1999, we had no comprehensive income (loss) other than net income (loss).

**Stock Options** / We have elected to follow Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" ("APB 25") and related interpretations in accounting for our employee stock options. Under APB 25, no compensation expense is recognized when the exercise price of options equals the fair value (market price) of the underlying stock on the date of grant.

**Fair Value of Financial Instruments** / The following methods and assumptions were used in estimating the fair value of each class of financial instruments for which it is practicable to estimate fair value.

For cash and cash equivalents, receivables and payables, the carrying amounts approximate fair value because of the short maturity of these instruments.

On January 1, 2001, we adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133"). Accordingly, natural gas and oil swaps and option contracts are recorded at fair value in our consolidated balance sheet. Information concerning our price risk management activities is included in Note 12.

The following table provides information on other financial instruments (in thousands):

	December 31,			
	2001		2000	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Debt:				
Bank debt	\$ 70,000	\$ 70,000	\$ 27,750	\$ 27,750
Note payable	30,111	33,400	—	—
Non-recourse borrowings	—	—	88,779	88,779
Total	<u>100,111</u>	<u>103,400</u>	<u>116,529</u>	<u>116,529</u>

Our bank debt and non-recourse borrowings are variable rate debt and as such, approximate their fair values, as interest rates are variable based on prevailing market rates. Our note payable is a fixed rate note and the fair value has been determined by discounting the future payments using our incremental borrowing rate, based on the differential between the fixed interest rate and interest rates of long-term treasury securities at the date of the borrowing and the balance sheet date.

**New Accounting Standards** / In 2001, the FASB approved SFAS No. 141 "Business Combinations" ("SFAS 141"), No. 142 "Goodwill and Other Intangible Assets" ("SFAS 142"), No. 143 "Accounting for Asset Retirement Obligations" ("SFAS 143") and No. 144 "Accounting for the Impairment or Disposal of Long-Lived Assets" ("SFAS 144"). SFAS 141 requires all business combinations completed after June 30, 2001, be accounted for under the purchase method. This standard also establishes for all business combinations made after June 30, 2001, specific criteria for the recognition of intangible assets separately from goodwill. SFAS 141 also requires that the excess of fair value of acquired assets over cost (negative goodwill) be recognized immediately as an extraordinary gain, rather than deferred and amortized.

SFAS 142 addresses the accounting for goodwill and other intangible assets after an acquisition. The most significant changes made by SFAS 142 are: 1) goodwill and intangible assets with indefinite lives will no longer be amortized; 2) goodwill and intangible assets with indefinite lives must be tested for impairment at least annually; and 3) the amortization period for the intangible assets with finite lives will no longer be limited to forty years. We will adopt SFAS 142 effective January 1, 2002, as required. Additionally, SFAS 142 requires that unamortized negative goodwill associated with investments accounted for under the equity method and acquired before July 1, 2001, be recognized in income as a cumulative effect of change in accounting principle.

SFAS 143 provides accounting requirements for retirement obligations associated with tangible long-lived assets, including: 1) the timing of liability recognition; 2) initial measurement of the liability; 3) allocation of asset retirement cost to expense; 4) subsequent measurement of the liability; and 5) financial statement disclosures. SFAS 143 requires that an asset retirement cost should be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. We will adopt the Statement effective January 1, 2003. The transition adjustment resulting from the adoption of SFAS 143 will be reported as a cumulative effect of a change in accounting principle.

SFAS 144 provides that long-lived assets to be disposed of by sale be measured at the lower of carrying amount or fair value less cost to sell, whether reported in continuing operations or in discontinued operations, and broadens the reporting of discontinued operations to include all components of an entity with operations that can be distinguished from the rest of the entity and that will be eliminated from the ongoing operations of the entity in a disposal transaction. SFAS 144 is effective for fiscal years beginning after December 15, 2001.

SFAS 141 and SFAS 142 will not apply to us unless we enter into a future business combination. We are currently assessing the impact of SFAS 143 and SFAS 144 on our financial condition and results of operations.

### **NOTE 3 — ACQUISITIONS**

**Gulf of Mexico** / During 2001, we acquired interests in 15 lease blocks covering 14 properties in six separate transactions. Total reserves associated with these transactions were approximately 60.6 Bcfe (unaudited), based on third party reservoir engineering estimates at year-end, for total acquisition costs of approximately \$22.7 million. Our working interests in these properties range from 25% to 100%. Ten of these properties produced in 2001 with additional development and production planned on the remaining four in 2002 and beyond.

During 2000 we acquired an interest in 11 lease blocks covering nine separate properties for total acquisition costs of \$7.5 million. Total proved reserves associated with these acquisitions were approximately 66.0 Bcfe (unaudited) net to our interest. Our working interests in these properties range from 50% to 100%. We are the operator of all of the properties. Included in these acquisitions were four blocks on three separate properties which represent our first acquisitions in the shallow-deep waters of the Gulf of Mexico. Of these nine properties, five were producing in 2001, including "Ladybug", one of the properties in the shallow-deep waters of the Gulf of Mexico, and a sixth property commenced production in the first quarter of 2002. Two of the properties are scheduled for future development in 2002 and beyond and the remaining property was abandoned without commencing production in 2001.

**Southern Gas Basin of the North Sea** / In October 2000, we entered into a letter of intent to acquire interests in three properties (five blocks) in the Southern Gas Basin of the North Sea which included a 50% interest in one block, a 100% interest in one block and an 86% interest in three blocks. In 2001, we acquired all three properties for total acquisition costs of approximately \$3.1 million. At December 31, 2001, net proved reserves were approximately 80.6 Bcfe (unaudited), based on third party reservoir engineering estimates at year-end. None of the properties were producing when acquired and we expect to pursue development operations in 2002 through 2004.

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Continued)

### NOTE 4 — FINANCING AND DEBT

Long-term debt at December 31, 2001 and 2000 consisted of the following balances (in thousands):

	December 31,	
	2001	2000
Credit facility, bearing interest at 5.26% and 10% at December 31, 2001 and 2000, respectively	\$ 70,000	\$ 27,750
11.5 % Note payable, net of unamortized discount of \$1,139	30,111	—
Non-recourse borrowings, bearing interest at 12.7%, at December 31, 2000	—	88,779
Total debt	100,111	116,529
Less current maturities	(22,000)	—
Total long-term debt	<u>\$ 78,111</u>	<u>\$ 116,529</u>

**Credit Facilities** / In March 2001, we repaid our then existing bank credit facility and in April 2001 we repaid the full amount borrowed under a non-recourse development program credit agreement which we had used as a source of financing for the acquisition of oil and gas properties. Concurrent with the repayment of our non-recourse agreement, we negotiated with the lender to terminate the overriding royalty interest retained by it on all properties previously financed by the lender in exchange for a lump-sum payment of approximately \$5.6 million.

Upon repayment of our former credit and non-recourse facilities, we entered into a new \$100.0 million senior-secured revolving credit facility in April 2001. This facility is secured by substantially all of our oil and gas properties, as well as by approximately two-thirds of the capital stock of our U.K. subsidiary and is guaranteed by our wholly owned subsidiary, ATP Energy, Inc. As amended, the amount available for borrowing under the facility is limited to the loan value, as determined by the bank, of oil and gas properties pledged under the facility. At December 31, 2001, the borrowing base was \$70.0 million and the monthly borrowing base reduction was set at \$2.0 million a month beginning February 27, 2002 and remains in effect until there is a change, if any, at the next redetermination date at which time the lenders can increase or decrease the borrowing base and the monthly reduction amount. The redetermination dates are on or around the first business day of each calendar quarter. The next scheduled redetermination date is on or around the first business day of April 2002. Our lender has indicated this process will not be completed until mid to late April of 2002. The \$2.0 million monthly reduction included in current maturities of long-term debt assumes there is no change in the monthly reduction amount or the borrowing base in 2002. If our outstanding balance exceeds our borrowing base at any time, we are required to repay such excess within 30 days and our interest rate during the time an excess exists is increased by 2.00%. A reduction in the borrowing base or the monthly reduction amount by the lender would have a material negative impact on our cash flows and our ability to fund future operations during 2002. As of December 31, 2001, all of our borrowing base under the agreement was outstanding.

Advances under the credit facility can be in the form of either base rate loans or Eurodollar loans. The interest on a base rate loan is a fluctuating rate equal to the higher of the Federal funds rate plus 0.5% and the bank base rate, plus a margin of 0.25%, 0.50%, 0.75% or 1.00% depending on the amount outstanding under the credit agreement. The interest on a Eurodollar loan is equal to the Eurodollar rate, plus a margin of 2.25%, 2.50%, 2.875% or 3.125% depending on the amount outstanding under the credit facility. The amended credit facility matures in November 2003. Our credit facility contains conditions and restrictive provisions, among other things, (1) prohibiting us to enter into any arrangement to sell or transfer any of our material property, (2) prohibiting a merger into or consolidation with any other person or sell or dispose of all or substantially all of our assets, and (3) maintaining certain financial ratios.

**Note Payable** / Effective June 29, 2001, we issued a note payable to a purchaser for a face principal amount of \$31.3 million which matures in June 2005 and bears interest at a fixed rate of 11.5% per annum. The note is secured by second priority liens on substantially all of our oil and gas properties and is subordinated in right of payment to our existing senior indebtedness. We executed an agreement in connection with the note which contains

conditions and restrictive provisions and requires the maintenance of certain financial ratios. Upon consent of the purchaser, which shall not be unreasonably withheld, the note may be repaid prior to the maturity date with an additional repayment premium based on the percentage of the principal amount paid, ranging from 4.5% during the first year to 16.5% in the final year of payment. If the note is paid at maturity, the maximum payment premium of 16.5% is required. The expected repayment premium is being amortized to interest expense straight-line, over the term of the note which approximates the effective interest method. The resulting liability is included in other long-term liabilities on the consolidated balance sheet. In July 2001, we received proceeds of \$30.0 million in consideration for the issuance of the note. The discount of \$1.3 million is being amortized to interest expense using the effective interest method. The amount available for borrowing under the note is limited to the loan value of oil and gas properties pledged under the note, as determined by the purchaser. The purchaser has the right to make redetermination of the borrowing base at least once every six months. We have assumed there is no change in the borrowing base in 2002. If our outstanding balance exceeds the borrowing base at any time, we are required to repay such excess within 10 days subject to the provisions of the agreement. A reduction in the borrowing base by the lender would have a material negative impact on our cash flows and our ability to fund future obligations during 2002. As of December 31, 2001, all of our borrowing base under the agreement was outstanding.

As of December 31, 2001, we were in compliance with all of the financial covenants of our credit facility and note payable agreements other than our working capital covenant (as defined by the agreements) for which we have obtained amendments from our lenders. Both of the amendments require that our working capital at December 31, 2001 and March 31, 2002 shall not exceed deficits of \$10.0 million and \$5.0 million, respectively.

**Maturities** / The aggregate amount of maturities of our long-term debt for the next five years is: 2002 – \$22.0 million, 2003 – \$48.0 million, 2004 – none, 2005 – \$31.3 million, 2006 – none.

#### **NOTE 5 — EQUITY**

**Initial Public Offering** / On February 5, 2001, we priced our initial public offering (“IPO”) of 6.0 million shares of common stock and commenced trading the following day. After payment of the underwriting discount we received net proceeds of \$78.3 million on February 9, 2001.

**Common Stock** / At December 31, 2001, we had 100,000,000 shares authorized, 20,388,488 shares issued, 20,312,648 shares outstanding and 75,840 shares in treasury. At December 31, 2000, we had 100,000,000 shares authorized, 14,285,714 shares issued and outstanding.

**Treasury Stock** / During the second quarter, the first option vesting date occurred for certain options granted since September 1999 through the date of our IPO on February 5, 2001, as well as for certain options granted prior to September 1999. Of those options exercised during the second quarter, certain optionees elected to receive cash upon exercise of their options, whereby we purchased 75,840 shares for approximately \$0.9 million and recorded such purchase as treasury stock using the cost method.

**Change in Authorized Capitalization** / On December 12, 2000, the Board of Directors approved an increase in the authorized common stock from 50,000,000 shares to 100,000,000 shares, the authorization of 10,000,000 shares of preferred stock and a 1.4-for-1 reverse split of the common stock. Par value of the common stock remained \$.001 per share. The reverse stock split was effective December 12, 2000.

#### **NOTE 6 — STOCK OPTION PLANS**

In May 1994, the Board of Directors approved the 1994 Stock Option Plan (the “1994 Plan”) under which it was authorized to issue up to 55,902,930 shares of common stock. The exercise price of the options under the 1994 Plan was not less than the greater of par value per share or fair market value, at date of grant. These options had a maximum term of 10 years, subject to vesting requirements in the individual option agreements. In April 2000, the only outstanding option to purchase 18,937,397 shares under the 1994 Plan was amended to limit the number

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Continued)

of shares that could be purchased pursuant to the option to such number that enables the holder to maintain ownership of a majority of the outstanding shares. Because the holder of this option owned a majority of the shares, the number of shares exercisable as of April 2000 was zero. Upon the closing of the IPO in February 2001, the 1994 Plan and all outstanding options under this plan were cancelled.

In December 1998, the Board of Directors approved the 1998 Stock Option Plan (the "1998 Plan") to provide increased incentive for its employees and directors. The 1998 Plan authorizes the granting of incentive and nonqualified stock options for up to 2,678,571 shares of common stock to eligible participants and expire five years after the closing date of our IPO. One third of the options were exercisable on April 10, 2001 with each remaining third exercisable on the first and second anniversaries of the IPO. Options granted under this plan remain exercisable by the employees owning such options, but no new options will be granted under this plan.

In January 2001, the Board of Directors approved the 2000 Stock Option Plan (the "2000 Plan") to provide increased incentive for its employees and directors. The 2000 Plan authorizes the granting of options and awards for up to 4,000,000 shares of common stock. Generally, options are granted at prices equal to at least 100% of the fair value of the stock at the date of grant, expire not later than five years from the date of grant and vest ratably over a four-year period following the date of grant. From time to time, as approved by the Board of Directors, options with differing terms have also been granted.

The following table is a summary of stock option activity:

	2001		2000		1999	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding at beginning of year	646,608	\$ 2.710	19,394,362	\$ 0.040	19,378,111	\$ 0.040
Granted	1,117,000	11.200	368,215	3.690	18,573	1.400
Exercised	(102,774)	1.960	—	—	—	—
Forfeited	(23,025)	4.000	(178,572)	1.400	(2,322)	1.400
Cancelled	—	—	(18,937,397)	0.004	—	—
Outstanding end of year	<u>1,637,809</u>	<u>\$ 8.520</u>	<u>646,608</u>	<u>\$ 2.710</u>	<u>19,394,362</u>	<u>\$ 0.040</u>
Exercisable at end of period	<u>112,760</u>	<u>\$ 3.370</u>	<u>—</u>	<u>\$ —</u>	<u>18,937,397</u>	<u>\$ 0.004</u>
Weighted average fair value of options granted during the year	\$ 4.65		\$ —		\$ —	

The following table summarizes information about all stock options outstanding at December 31, 2001:

Range of Exercise Prices	Options Outstanding		Options Exercisable		
	Number Outstanding	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
\$ 1.40 — \$ 3.85	537,809	3.0 Years	\$ 2.82	112,760	\$ 3.37
\$ 6.95 — \$ 6.95	25,000	4.8 Years	6.95	—	—
\$ 11.24 — \$ 11.40	1,055,000	4.4 Years	11.37	—	—
\$ 14.00 — \$ 14.00	20,000	4.1 Years	14.00	—	—
\$ 1.40 — \$ 14.00	<u>1,637,809</u>	3.9 Years	<u>\$ 8.52</u>	<u>112,760</u>	<u>\$ 3.37</u>

We have elected to follow APB 25 and related interpretations in accounting for our stock option plans. Accordingly, no compensation expense, except as specifically described below, has been recognized for employee stock option plans. Since options granted under the 1998 Plan did not vest nor were exercisable until 60 days after the date of our IPO, under the provisions of SFAS No. 123 *“Accounting for Stock Based Compensation”* (“SFAS 123”), our pro forma net loss and per share amounts would have been unchanged for the years ended December 31, 2000 and 1999. Had compensation expense been determined based on the fair value of the options at the date of or subsequent to the IPO, our loss and the related per share amount would have been reduced as is reflected by the pro forma amount indicated below (in thousands, except per share data):

**As Reported**

Net loss before extraordinary item	\$(20,781)
Net loss per common share, basic and diluted	(1.06)

**Pro Forma**

Net loss before extraordinary item	\$(20,934)
Net loss per common share, basic and diluted	(1.06)

The fair value of these option grants were estimated on the latter of the date of grant or date of our IPO using a Black-Scholes option-pricing model with the following weighted-average assumptions: zero dividend yield; risk-free interest rate of 4.5% and volatility of 80.2% and an expected life of 2.4 years.

Because the determination of the fair value of all options granted after we became a public entity includes an expected volatility factor, additional option grants are expected to be made and most options will vest over several years, the above effects of applying SFAS 123 in this pro forma disclosure are not likely to be representative of the effects on reported net income for future years. SFAS 123 does not apply to awards granted prior to fiscal year 1996.

In 2001, we recorded a non-cash compensation expense of approximately \$3.4 million. A portion of the expense (\$2.9 million) is related to options granted from September 1999 to the date of our IPO and is based on the difference between the exercise price for those options and the fair market value of our stock as determined by the IPO price of \$14.00 per share. The expense is recognized in the periods in which the options vest. Each option is divided into three equal portions corresponding to the three vesting dates, with the related compensation cost amortized straight-line over the period between the IPO date and the vesting date. The remaining expense (\$0.5 million) was related to certain options granted prior to September 1999 and exercised in the current year. The expense was recorded on those exercises as the method in which those shares were exercised required us to account for the options under variable accounting. The remaining compensation expense to be recorded over 2002 and 2003 is approximately \$0.5 million.

We have a 401(k) Savings Plan which covers all domestic employees. At our discretion, we may match a certain percentage of the employees’ contributions to the plan. The matching percentage is discretionary and is currently 50% of each participant’s contributions up to 6% of the participant’s compensation. Our matching contributions to the plan were approximately \$70,000, \$56,000 and \$31,000, for the years ended December 31, 2001, 2000 and 1999, respectively.

We also have a defined contribution plan for our U.K. employees. We currently contribute 3% to the plan and such contributions are subject to the Pensions Act 1999 (U.K.). For the year ended December 31, 2001, we contributed approximately \$14,000.

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Continued)

### NOTE 7 — EARNINGS PER SHARE

Basic earnings per share is computed by dividing net income (loss) available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share is determined on the assumption that outstanding stock options have been converted using the average price for the period. For purposes of computing earnings per share in a loss year, potential common shares have been excluded from the computation of weighted average common shares outstanding because their effect is antidilutive.

Basic and diluted net income (loss) per share is computed based on the following information (in thousands, except share and per share amounts):

	For the Years Ended December 31,		
	2001	2000	1999
Net income (loss) available to common shareholders	\$ (21,383)	\$ (10,398)	\$ 18,228
Weighted average shares – basic and diluted	19,704	14,286	14,286
Net income (loss) per share:			
Basic and diluted:			
Loss before extraordinary gain (loss)	\$ (1.06)	\$ (0.73)	\$ (0.77)
Extraordinary gain (loss), net of income taxes	(0.03)	–	2.05
Net income (loss) per common share	\$ (1.09)	\$ (0.73)	\$ 1.28

### NOTE 8 — EXTRAORDINARY ITEMS

For the year ended December 31, 2001, we recognized an extraordinary loss of \$0.6 million, net of income taxes, related to the early extinguishment of our non-recourse borrowings. For the year ended December 31, 1999, we prepaid the amount outstanding under a development program credit agreement at a discount and recorded an extraordinary gain of \$29.2 million, net of income taxes.

### NOTE 9 — INCOME TAXES

The benefit (provision) for income taxes before extraordinary gain (loss) consisted of the following (in thousands):

	For the Years Ended December 31,		
	2001	2000	1999
Current:			
State	\$ –	\$ –	\$ –
Federal	–	–	(229)
Deferred:			
State	–	–	(82)
Federal	11,186	5,594	2,140
Benefit for income taxes before extraordinary gain (loss)	\$ 11,186	\$ 5,594	\$ 1,829

Additionally, a tax benefit of \$0.3 million and none was recognized related to the extraordinary gain (loss) for the years ended December 31, 2001 and 1999, respectively.

The reconciliation of income tax computed at the U.S. federal statutory tax rates to the provision for income taxes is as follows:

	For the Years Ended December 31,		
	2001	2000	1999
Before any valuation allowance:			
Statutory federal income tax rate	(35.00)%	(35.00)%	35.00%
State income taxes, net of federal benefit	0.00	0.00	0.32
Adjustment to valuation allowance	0.00	0.00	(46.53)
Nondeductible and other	0.01	0.02	0.05
	<u>(34.99)%</u>	<u>(34.98)%</u>	<u>(11.16)%</u>

At December 31, 2001 we have determined that it is more likely than not the deferred tax assets will be realized based on current projections of future taxable income due to higher commodity prices at year-end.

Significant components of our deferred tax assets (liabilities) as of December 31, 2001 and 2000 are as follows (in thousands):

	December 31,	
	2001	2000
Deferred tax assets:		
Net operating loss carryforwards	\$ 3,809	\$ 3,826
Minimum tax credit carryforwards	229	229
Fixed asset basis differences	11,367	554
State taxes	17	17
Unrealized book (gains) losses	(443)	2,537
Stock based compensation expense	1,177	–
Litigation	1,050	–
Foreign equity in subsidiary	1,152	–
Other	870	489
Net deferred tax assets	<u>\$19,228</u>	<u>\$7,652</u>

At December 31, 2001, 2000 and 1999, we had net operating loss carryforwards for federal income tax purposes of approximately \$10.7 million, \$11.0 million, and \$11.0 million respectively, which are available to offset future federal taxable income through 2021.

A tax benefit related to the exercise of employee stock options of approximately \$0.1 million was allocated directly to additional paid-in capital in 2001.

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Continued)

### NOTE 10 — COMPREHENSIVE LOSS

Comprehensive loss consists of net loss, as reflected on the consolidated statement of operations, and other gains and losses affecting shareholders' equity that are excluded from net loss. We recorded other comprehensive income for the first time in 2001. Total comprehensive loss for the year ended December 31, 2001 is as follows (in thousands):

Net loss	\$(21,383)
Other comprehensive income, net of tax:	
Cumulative effect of change in accounting principle – January 1, 2001	(34,252)
Reclassification adjustment for settled contracts	34,252
Foreign currency translation adjustment	19
Other comprehensive income	19
Comprehensive loss	<u>\$(21,364)</u>

### NOTE 11 — COMMITMENTS AND CONTINGENCIES

**Operating Leases** / We have commitments under an operating lease agreement for office space. Total rent expense for the years ended December 31, 2001, 2000 and 1999 was approximately \$0.3 million, \$0.2 million and \$0.1 million respectively. At December 31, 2001, the future minimum rental payments due under the lease are as follows (in thousands amounts):

2002	\$ 375
2003	346
2004	342
2005	214
2006	154
Later Years	1,114
Total	<u>\$2,545</u>

**Litigation** / On August 28, 2001 ATP entered into a written agreement to acquire a property in the Gulf of Mexico during September 2001. On October 9, 2001 the agreement was amended to ultimately extend the closing date until October 31, 2001 in exchange for payments made by ATP totaling \$3.0 million. This amendment also contained an arrangement whereby if ATP did not close on the property, and if sellers sold the property to a third party with a sale that met specific contract requirements, ATP would be required to execute a six month note for payment of the differential. Since ATP did not obtain the financing for the acquisition by October 31, 2001, the transaction did not close by that date; however, the parties' intensive work toward closing continued beyond that date without interruption.

While working on the closing for the property with ATP, the sellers sold the property to a third party without informing ATP until after the closing had taken place. ATP filed an action in the District Court of Harris County, Texas against the sellers, generally alleging improper sale of the offshore property to a third party and breach of contract, and seeking unspecified damages from the sellers. The case is captioned *ATP Oil & Gas Corporation vs. Legacy Resources Co., L.P. et al*, No. 2001-63224 in the 269th Judicial District Court of Harris County, Texas. At the same time sellers notified ATP of their sale to a third party, the sellers had a demand made upon ATP for execution of a six month note for the amount of an alleged differential of approximately \$12.3 million plus interest at 16%. Substantiation of the amount and validity of the demand could not be ascertained based on the content of the demand received. ATP contested the entire demand. The litigation is in its very early stages with written discovery propounded by ATP, but no answers received, and no depositions taken. The judge has abated the litigation, until arbitration pursuant to the underlying agreements between the sellers and ATP is completed. Since the legal proceedings have just begun, and a prediction of the outcome would be premature and uncertain, we have not accrued any amount related to this matter. And while we are seeking recovery of the amounts previously paid and discussed above, the \$3.0 million has been charged to earnings along with certain other costs related to this matter. ATP intends to vigorously defend against the sellers' claims and forcefully pursue its own claims in this matter.

In August 2001, Burlington Resources Inc. filed suit against us alleging formation of a contract with us and our breach of the alleged contract. The complaint seeks compensatory damages of approximately \$1.1 million. We believe that this claim is without merit, and we intend to defend it vigorously.

We are, in the ordinary course of business, a claimant and/or defendant in various legal proceedings. Management does not believe that the outcome of these legal proceedings, individually, and in the aggregate will have a materially adverse effect on our financial condition, results of operations or cash flows.

#### NOTE 12 — DERIVATIVE INSTRUMENTS

We utilize various derivative instruments, for purposes other than trading, to hedge our exposure to price fluctuations on natural gas and oil sales. The derivative instruments consist primarily of swap contracts entered into with financial institutions. Under our current policies, we do not use interest rate derivative instruments to manage exposure to interest rate changes.

Effective January 1, 2001, we adopted SFAS No. 133 and SFAS No. 138, an amendment to SFAS 133. SFAS 133 and 138 require that derivatives be reported on the balance sheet at fair value and, if the derivative is not designated as a hedging instrument, changes in fair value must be recognized in earnings in the period of change. If the derivative is designated as a hedge and to the extent such hedge is determined to be effective, changes in fair value are either (a) offset by the change in fair value of the hedged asset or liability (if applicable) or (b) reported as a component of other comprehensive income (loss) in the period of change, and subsequently recognized in earnings when the offsetting hedged transaction occurs. We use derivatives to hedge the price of crude oil and natural gas. Effective January 1, 2001, we did not attempt to qualify for the hedge provisions under SFAS 133 and thus have not designated our derivatives as hedging instruments. Accordingly, we account for the changes in market value of these derivatives through current earnings. This method will result in increased earnings volatility associated with commodity price fluctuations. Gains and losses on all derivative instruments related to accumulated other comprehensive income (loss) are included in other income (expense) on the consolidated financial statements.

On January 1, 2001, in accordance with the transition provisions of SFAS 133, we recorded a non-cash loss of \$52.7 million (\$34.3 million after tax) in accumulated other comprehensive loss, representing the cumulative effect of an accounting change to recognize at fair value all cash flow type derivatives. Also on January 1, 2001, we recorded derivative liabilities of \$52.7 million. During the year ended December 31, 2001, losses of \$52.7 million (\$34.3 million after tax) were reclassified from accumulated other comprehensive loss to earnings. Prior to the adoption of this standard, we included gains and losses on hedging instruments as a component of revenue.

As of December 31, 2001, all of our natural gas swap agreements were with one counterparty whose investment grade ratings were Baa2 from Moody's and BBB from Standard & Poor's. Those agreements outstanding were as follows:

Period	Average MMBtu/Day	\$/MMBtu
January 2002 – October 2003	20,000	3.02

At December 31, 2001, the fair value of our open derivative positions consisted of a \$1.9 million current asset and a \$0.7 million long-term liability. The \$18.1 million loss on derivative instruments for the year ended December 31, 2001 includes the following items:

- a \$26.5 million loss related to contracts settled during 2001,
- \$7.2 million related to the reversal of a speculative position (\$2.6 million) and settlement of a written call option (\$4.6 million), both recorded at December 31, 2000 and settled during 2001; and
- a \$1.2 million gain on open positions at December 31, 2001.

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Continued)

On occasion, we may find ourselves in speculative positions as a result of actual production being less than projected production when the derivative products were consummated or as a result of entering into speculative derivative instruments. Any speculative positions are accounted for using the mark-to-market method. For the year ended December 31, 2000, we recognized a loss on derivative instruments in the amount of \$11.9 million from certain speculative positions. At December 31, 2000, the fair value of our derivative positions was a \$7.2 million current liability.

Thus far, in 2002 we have entered into the following swap agreements:

Period	Volume/Day	\$/Unit
Natural gas (MMBtu):		
February 2002 – October 2002	6,000	2.41
April 2002 – July 2002	6,000	2.81
April 2002 – October 2002	2,000	3.31
Oil (Bbl):		
April 2002 – December 2002	500	23.50
April 2002 – December 2002	500	25.25

### NOTE 13 — ATP ENERGY GAS PURCHASE TRANSACTION

ATP Energy entered an agreement in December 1998 with American Citigas Company (“American Citigas”) to purchase gas over a ten-year period commencing January 1999. The amount of gas to be purchased was 9,000 MMBtu per day for the first year and 5,000 MMBtu per day for years two through ten. The contract requires ATP Energy to purchase on a monthly basis the gas at a premium of approximately \$2.50 per MMBtu to the *Gas Daily* Henry Hub Index. American Citigas is required to reimburse ATP Energy on a monthly basis for a portion of this premium during the term of the contract. This portion of the reimbursement is accomplished by a note receivable in favor of ATP. The note receivable bears interest at 6% and has monthly payments of approximately \$0.4 million until January 2009. The balance of the note receivable at December 31, 2001 and 2000 was \$25.9 million and \$28.8 million, respectively. At December 31, 2001 and 2000, the present value of the remaining premium payments to be made by ATP Energy, using a discount rate of 6%, was \$25.8 million and \$28.7 million, respectively. The note receivable and the premium payable to American Citigas have been offset in the consolidated financial statements in accordance with the prescribed accounting in FASB Interpretation No. 39, “*Offsetting of Amounts Related to Certain Contracts*”. The aggregate amount of premium payments to be paid by ATP Energy over the term of the contract is approximately \$49.0 million and the aggregate amount of payments to be paid to ATP Energy over the term of the note is approximately \$45.0 million. At December 31, 2001 the remaining premium to be paid was \$31.7 million, which will be reimbursed by the monthly reimbursement from American Citigas and the remaining deferred obligation discussed below. The terms provide for the immediate termination of the agreement upon non-performance by American Citigas. ATP Energy entered into a contract with El Paso Energy Marketing in December 1998 to sell an identical quantity of natural gas at the *Gas Daily* Henry Hub index price less \$0.015 until December 2001. This contract has been renewed on a month-to-month basis.

ATP Energy received \$6.0 million in connection with these transactions, of which \$2.0 million was recorded as deferred revenue and \$4.0 million was recorded as deferred obligations. The deferred revenue amount of \$2.0 million is a non-refundable fee received by ATP Energy and is recognized into income as earned over the life of the contract. At December 31, 2001 and 2000, the deferred revenue amount was \$1.3 million and \$1.5 million, respectively. The deferred obligation amount of \$4.0 million represented the difference between the premium we agreed to pay for natural gas under the American Citigas contract and the obligation of American Citigas to

partially reimburse us for such premium. Any deferred obligation amount not utilized is refundable if the contract is terminated. The transaction is structured with American Citigas such that there is no financial impact to ATP Energy associated with the premium paid and reimbursement received other than the \$2.0 million realized by ATP Energy. The remaining balance of the deferred obligation was \$0.05 million and \$0.1 million at December 31, 2001 and 2000, respectively. The premium we pay to American Citigas will be approximately the same as the reimbursement obligation for the remainder of the contract. ATP Energy entered into the transactions to earn the fee for agreeing to market the volumes of natural gas specified in the American Citigas contract.

Our officers were paid \$152,125 and \$97,875 for the years ended December 31, 2000, and 1999, respectively, for negotiating and monitoring ATP Energy's gas supply contract. We have recognized these amounts in general and administrative expense in the respective periods. No amounts were paid in 2001 and we do not intend to pay any further amounts.

#### NOTE 14 — RELATED PARTY TRANSACTIONS

We have granted to certain of our officers overriding royalty interests ranging in amounts from 0.2% to 3.0% in four of its oil and gas properties. The overriding royalty interest entitles the holder to a portion, 0.2% to 3.0%, of the future revenue for the life of each property. As a result, we recognized \$0.3 million and \$0.6 million in general and administrative expense for the years ended December 31, 2000 and 1999. No amounts were paid in 2001 and we do not intend to pay any further amounts.

#### NOTE 15 — SUMMARIZED QUARTERLY FINANCIAL DATA (UNAUDITED)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
<i>(In Thousands, Except Share Amounts)</i>				
<b>2001</b>				
Revenues	\$ 41,443	\$ 31,035	\$ 20,883	\$ 19,813
Costs and expenses	28,701(1)	29,694(1)	24,659(1)	34,849(1)
Income (loss) from operations	12,742	1,341	(3,776)	(15,036)
Income (loss) before extraordinary item	(6,873)	3,813	(6,499)	(11,222)
Net income (loss)	(6,873)	3,211	(6,499)	(11,222)
Income (loss) per common share before extraordinary item, basic and diluted	\$ (0.38)	\$ 0.19	\$ (0.32)	\$ (0.55)
Net income (loss) per common share: Basic and diluted	\$ (0.38)	\$ 0.16	\$ (0.32)	\$ (0.55)
<b>2000</b>				
Revenues	\$ 15,127	\$ 24,558	\$ 20,462	\$ 23,841
Costs and expenses	11,682	23,230(2)	20,049(2)	21,652(2)
Income (loss) from operations	3,445	(1,185)	(3,316)	(3,480)
Net income (loss)	1,029	(2,742)	(4,251)	(4,434)
Net income (loss) per common share: Basic and diluted	\$ 0.07	\$ (0.19)	\$ (0.30)	\$ (0.31)

(1) Includes impairment charges of \$8.5 million, \$5.7 million, \$3.7 million and \$7.0 million during the first, second, third and fourth quarters, respectively, for eight properties.

(2) Includes impairment charges of \$6.2 million, \$0.8 million and \$3.8 million during the second, third and fourth quarters, respectively, for three properties.

## SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS

### OIL AND GAS RESERVES AND RELATED FINANCIAL DATA (UNAUDITED)

**Costs Incurred** / The following table summarizes costs incurred in natural gas and oil property acquisition, exploration and development activities are summarized below (in thousands):

	Years Ended December 31,				
	2001			2000	1999
	U.S.	U.K.	Total	U.S.	U.S.
Property costs:					
Acquisition costs	\$ 28,344	\$ 3,112	\$ 31,456	\$ 7,534	\$ 25,274
Development costs	77,783	719	78,502	68,982	30,777
Total costs incurred	\$ 106,127	\$ 3,831	\$ 109,958	\$ 76,516	\$ 56,051

**Natural Gas and Oil Reserves** / Proved reserves are estimated quantities of natural gas and oil which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can reasonably be expected to be recovered through existing wells with existing equipment and operating methods.

Reserves quantities as well as certain information regarding future production and discounted cash flows were prepared by independent petroleum engineers Ryder Scott Company, L.P. for all years presented and Schlumberger Holditch-Reservoir Technologies Consulting Services for one property for 2000 and 1999. Our U.K. reserves at December 31, 2001 were prepared by independent petroleum consultants Troy Ikoda Limited.

At December 31, 2001, our U.K. reserves included one property that was subject to an agreement with our joint venture partner to earn an additional 11% interest in that property upon their performance of future obligations. We expect the conditions of that agreement to be satisfied in the first half of 2002. At that time our ownership in the property will be reduced by 11%, resulting in a reduction of our net reserves of approximately 5.5 Bcfe. Our future revenues and costs in the project will be reduced accordingly. The reserves included in the tables below reflect our ownership interest in that property prior to the satisfaction of the conditions of the earn-in agreement.

The following table sets forth our net proved oil and gas reserves at December 31, 1998, 1999, 2000 and 2001 and the changes in net proved oil and gas reserves for the years ended December 31, 1999, 2000 and 2001:

	Natural Gas (MMcf)			Oil, Condensate and Natural Gas Liquids (MMBbls)		
	U.S.	U.K.	Total	U.S.	U.K.	Total
Proved Reserves at December 31, 1998	46,424	—	46,424	586	—	586
Revisions of previous estimates	3,033	—	3,033	(131)	—	(131)
Extensions and discoveries	2,257	—	2,257	—	—	—
Purchase of properties	58,816	—	58,816	1,362	—	1,362
Production	(16,533)	—	(16,533)	(128)	—	(128)
Proved Reserves at December 31, 1999	93,997	—	93,997	1,689	—	1,689
Revisions of previous estimates	(19,423)	—	(19,423)	(46)	—	(46)
Extensions and discoveries	7,239	—	7,239	77	—	77
Purchase of properties	42,318	—	42,318	2,602	—	2,602
Disposition of properties	(151)	—	(151)	—	—	—
Production	(22,410)	—	(22,410)	(345)	—	(345)
Proved Reserves at December 31, 2000	101,570	—	101,570	3,977	—	3,977
Revisions of previous estimates	(6,793)	—	(6,793)	134	—	134
Purchase of properties	40,060	80,629	120,689	3,432	—	3,432
Production	(20,957)	—	(20,957)	(790)	—	(790)
Proved Reserves at December 31, 2001	113,880	80,629	194,509	6,753	—	6,753

	Natural Gas (MMcf)			Oil, Condensate and Natural Gas Liquids (MMBbls)		
	U.S.	U.K.	Total	U.S.	U.K.	Total
Proved Developed Reserves at December 31, 1998	39,728	—	39,728	579	—	579
December 31, 1999	67,314	—	67,314	710	—	710
December 31, 2000	42,502	—	42,502	851	—	851
December 31, 2001	56,704	—	56,704	3,115	—	3,115

**Standardized Measure** / The standardized measure of discounted future net cash flows relating to proved natural gas and oil reserves as of year-end is shown below (in thousands):

	Years Ended December 31,				
	2001			2000	1999
	U.S.	U.K.	Total	U.S.	U.S.
Future cash inflows	\$ 423,273	\$ 302,894	\$ 726,167	\$1,139,404	\$272,047
Future operating expenses	(59,722)	(100,330)	(160,052)	(70,719)	(40,794)
Future development costs	(100,919)	(111,044)	(211,963)	(137,453)	(48,204)
Future net cash flows	262,632	91,520	354,152	931,232	183,049
Future income taxes	(35,469)	(26,188)	(61,657)	(285,587)	(27,611)
Future net cash flows, after income taxes	227,163	65,332	292,495	645,645	155,438
10% annual discount per annum	(54,247)	(25,584)	(79,831)	(121,164)	(26,732)
Standardized measure of discounted future net cash flows	\$ 172,916	\$ 39,748	\$ 212,664	\$ 524,481	\$ 128,706

## SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS

(Continued)

Future cash inflows are computed by applying year-end prices of oil and gas to the year-end estimated future production of proved oil and gas reserves. The base prices used for the Pretax PV-10 calculation were public market prices on December 31 adjusted by differentials to those market prices. These price adjustments were done on a property-by-property basis for the quality of the oil and natural gas and for transportation to the appropriate location. The Henry Hub and West Texas Intermediate prices, before adjustment for quality and transportation, utilized in the Pretax PV-10 value at December 31, 2001 were \$2.65 per MMBtu of natural gas and \$19.78 per barrel of oil. The National Balancing Point, before adjustment for quality and transportation, utilized in the Pretax PV-10 value at December 31, 2001 was \$3.88 per MMBtu of natural gas. Estimates of future development and production costs are based on year-end costs and assume continuation of existing economic conditions and year-end prices. We will incur significant capital in the development of our U.S. and U.K. oil and gas properties. We believe with reasonable certainty that we will be able to obtain such capital in the normal course of business. The estimated future net cash flows are then discounted using a rate of 10 percent per year to reflect the estimated timing of the future cash flows. The standardized measure of discounted cash flows is the future net cash flows less the computed discount.

**Changes in Standardized Measure /** Changes in standardized measure of future net cash flows relating to proved natural gas and oil reserves are summarized below (in thousands):

	Years Ended December 31,				
	U.S.	2001 U.K.	Total	2000 U.S.	1999 U.S.
Beginning of year	\$ 524,481	\$ -	\$ 524,481	\$ 128,706	\$ 61,308
Sales of oil and gas, net of production costs	(90,951)	-	(90,951)	(64,381)	(29,394)
Net changes in income taxes	193,247	(24,517)	168,730	(193,613)	(27,611)
Net changes in price and production costs	(593,914)	-	(593,914)	416,738	9,931
Revisions of quantity estimates	(11,220)	-	(11,220)	(147,777)	4,176
Accretion of discount	74,483	-	74,483	15,632	6,131
Development costs incurred	57,119	-	57,119	18,134	15,550
Changes in estimated future development	22,413	-	22,413	(14,709)	(15,664)
Purchases of minerals-in-place	64,322	64,265	128,587	300,706	105,514
Sales of minerals-in-place	-	-	-	(525)	-
Extensions and discoveries	-	-	-	51,795	218
Changes in production rates, timing and other	(67,064)	-	(67,064)	13,775	(1,453)
	(351,565)	39,748	(311,817)	395,775	67,398
End of year	\$ 172,916	\$ 39,748	\$ 212,664	\$ 524,481	\$ 128,706

Sales of natural gas and oil, net of natural gas and oil operating expenses, are based on historical pre-tax results. Sales of natural gas and oil properties, extensions and discoveries, purchases of minerals-in-place and the changes due to revisions in standardized variables are reported on a pre-tax discounted basis, while the accretion of discount is presented on an after-tax basis.

## FORWARD-LOOKING STATEMENTS

This annual report on Form 10-K includes assumptions, expectations, projections, intentions or beliefs about future events. These statements are intended as “forward-looking statements” under the Private Securities Litigation Reform Act of 1995. We caution that assumptions, expectations, projections, intentions and beliefs about future events may and often do vary from actual results and the differences can be material.

All statements in this document that are not statements of historical fact are forward looking statements. Forward looking statements include, but are not limited to:

- projected operating or financial results;
- budgeted or projected capital expenditures;
- statements about pending or recent acquisitions, including the anticipated closing dates;
- expectations regarding our planned expansions and the availability of acquisition opportunities;
- statements about the expected drilling of wells and other planned development activities;
- expectations regarding natural gas and oil markets in the United States and the United Kingdom; and
- timing and amount of future production of natural gas and oil.

When used in this document, the words “anticipate,” “estimate,” “project,” “forecast,” “may,” “should,” and “expect” reflect forward-looking statements.

There can be no assurance that actual results will not differ materially from those expressed or implied in such forward looking statements. Some of the key factors which could cause actual results to vary from those expected include:

- the timing and extent of changes in natural gas and oil prices;
- the timing of planned capital expenditures and availability of acquisitions;
- the inherent uncertainties in estimating proved reserves and forecasting production results;
- operational factors affecting the commencement or maintenance of producing wells, including catastrophic weather related damage, unscheduled outages or repairs, or unanticipated changes in drilling equipment costs or rig availability;
- the condition of the capital markets generally, which will be affected by interest rates, foreign currency fluctuations and general economic conditions;
- cost and other effects of legal and administrative proceedings, settlements, investigations and claims, including environmental liabilities which may not be covered by indemnity or insurance; and
- other United States or United Kingdom regulatory or legislative developments which affect the demand for natural gas or oil generally increase the environmental compliance cost for our production wells or impose liabilities on the owners of such wells.

## MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Our authorized capital stock consists of 100,000,000 shares of common stock, par value \$0.001 per share, and 10,000,000 shares of preferred stock, par value \$0.001 per share. There were 20,312,648 shares of common stock and no shares of preferred stock outstanding as of March 21, 2002. There were 24 holders of record of our common stock as of March 21, 2002. Our common stock is traded on the Nasdaq National Market under the ticker symbol ATPG. There was no public market for our common stock before February 6, 2001.

The following tables sets forth the range of high and low closing sales prices for the common stock as reported on the Nasdaq National Market for the periods indicated below:

	High	Low
<b>2001:</b>		
1st Quarter	\$ 14.5625	\$9.8750
2nd Quarter	12.9600	8.7100
3rd Quarter	12.0000	6.6100
4th Quarter	7.1500	2.0000

We have never declared or paid any cash dividends on our common stock. We currently intend to retain future earnings and other cash resources, if any, for the operation and development of our business and do not anticipate paying any cash dividends on our common stock in the foreseeable future. Payment of any future dividends will be at the discretion of our board of directors after taking into account many factors, including our financial condition, operating results, current and anticipated cash needs and plans for expansion. In addition, our current credit facility prohibits us from paying cash dividends on our common stock. Any future dividends may also be restricted by any loan agreements which we may enter into from time to time.