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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-KSB

(Mark One)

☒ Annual report under Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2001 PE

☐ Transition report under Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from to

Commission file number: 001-14745

3TEC ENERGY CORPORATION

(Name of Small Business Issuer in Its Charter)

Delaware	*63-1081013*
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

Pennzoil Plaza
700 Milam Street, Suite 1100
Houston, Texas 77002
(713) 821-7100
(Address, including zip code, and telephone number, including area code, of registrant's principal executive offices)

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

Securities registered pursuant to Section 12(g) of the Act:
Common Stock, $.02 Par Value

Check whether the Registrant (1) filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the past 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Check if disclosure of delinquent filers in response to Item 405 of Regulation S-B is not contained in this form, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-KSB or any amendment to this Form 10-KSB. ☐

Revenues of Registrant for fiscal year ended December 31, 2001 are $122,779,077.

The aggregate market value as of March 7, 2002 of voting and nonvoting stock held by nonaffiliates of the Registrant was $230,472,833.

As of March 7, 2002 the Registrant had 16,504,503 shares of Common Stock, $.02 par value outstanding.

The Registrant's definitive proxy statement, to be filed pursuant to Regulation 14A on or before May 1, 2002, is incorporated by reference for the information set forth in Part III of this Form 10-KSB.

Transitional Small Business Disclosure Format: Yes ☐ No ☒

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Item 13(a) includes the Index of Exhibits to be filed with the Securities and Exchange Commission relative to this Report.

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Some of the information in this Annual Report on Form 10-KSB, including information incorporated by reference, contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities and Exchange Act of 1934. The forward-looking statements speak only as of the date made and the Company undertakes no obligation to update such forward-looking statements. These forward-looking statements may be identified by the use of the words "believe," "expect," "anticipate," "will," "contemplate," "would" and similar expressions that contemplate future events. These future events include the following matters:

- financial position;
- business strategy;
- budgets;
- amount, nature and timing of capital expenditures;
- drilling of wells;
- natural gas and oil reserves;
- timing and amount of future production of natural gas and oil;
- operating costs and other expenses;
- cash flow and anticipated liquidity;
- prospect development and property acquisitions; and
- marketing of natural gas and oil.

Numerous important factors, risks and uncertainties may affect the Company's operating results, including:

- the risks associated with exploration;
- the ability to find, acquire, market, develop and produce new properties;
- natural gas and oil price volatility;
- uncertainties in the estimation of proved reserves and in the projection;
- future rates of production and timing of development expenditures;
- operating hazards attendant to the natural gas and oil business;
- downhole drilling and completion risks that are generally not recoverable from third parties or insurance;
- potential mechanical failure or under-performance of significant wells;
- climactic conditions;
- availability and cost of material and equipment;
- delays in anticipated start-up dates;
- actions or inactions of third-party operators of the Company's properties;
- the ability to find and retain skilled personnel;
- availability of capital;
- the strength and financial resources of competitors;
- regulatory developments;
- environmental risks; and
- general economic conditions.

Any of the factors listed above and other factors contained in this Form 10-KSB could cause the Company's actual results to differ materially from the results implied by these or any other forward-looking statements made by the Company or on its behalf. The Company cannot assure you that future results will meet its expectations.

PART I

Item 1. *Business*

Background

3TEC Energy Corporation ("3TEC", "the Company", "we", "our" and "us") is the successor to Middle Bay Oil Company, Inc. ("Middle Bay"), an Alabama corporation formed on November 30, 1992. 3TEC was incorporated in Delaware on November 24, 1999, as a wholly owned subsidiary of Middle Bay for the sole purpose of merging with Middle Bay to effect a change in domicile to Delaware and to change our name to 3TEC Energy Corporation. Effective December 7, 1999, Middle Bay was merged into us and each share of common stock of Middle Bay was converted into one share of our common stock. Our common stock is quoted on the Nasdaq National Market under the symbol "TTEN".

We are engaged in the acquisition, development, production and exploration of oil and natural gas reserves. Our properties are concentrated in East Texas and the Gulf Coast region, both onshore and in the shallow waters of the Gulf of Mexico. As of December 31, 2001, we had estimated total net proved reserves of 263 Bcfe, of which approximately 88% were natural gas and approximately 204 Bcfe, or 77%, were proved developed, with an estimated SEC Case PV-10 value of $212 million. We exited 2001 at a net daily production rate of approximately 85 Mmcfe.

We have increased our reserves and production principally through acquisitions. We focus on properties that have a substantial proved reserve component and which management believes to have additional exploitation opportunities. Additionally, we have also acquired a number of drilling prospects covered by an extensive 3-D seismic database that we believe have exploration potential. We have assembled an experienced management team and technical staff with expertise in property acquisitions and development, reservoir engineering, exploration and financial management.

In August 1999, W/E Energy Company L.L.C. ("W/E LLC"), an entity which was owned by affiliates of EnCap Investments L.L.C. ("EnCap") and Floyd C. Wilson, purchased a controlling interest in us for approximately $20.5 million in cash and $875,000 in producing properties. Concurrently with the investment by W/E LLC, Mr. Wilson was named our Chairman and Chief Executive Officer. Following the change in control in August 1999 discussed below, during the fourth quarter of 1999 and the first half of 2000 we closed several transactions that changed our senior management team, capital structure and our property base. During the fourth quarter of 2001, W/E LLC was dissolved and its holdings of 3TEC common stock and warrants were distributed to its members. See discussion in Note 3 of the Company's notes to consolidated financial statements.

On June 30, 2000, the Company completed a public offering of 8.05 million shares of the Company's common stock priced at $9.00 per share. The net proceeds, approximately $66.6 million, were used primarily to repay a portion of the outstanding debt under the Company's Credit Facility, hereafter defined.

Recent Developments

- On December 31, 2001, the shareholders of Enex Resources Corporation ("Enex") voted to approve the merger of Enex with a wholly-owned subsidiary of the Company. Each share of Enex common stock (other than shares owned by 3TEC) was converted into the right to receive $14.00 per share in cash. 3TEC owned 80% of the outstanding common stock of Enex. A cash payment of approximately $3.8 million was made by the Company to the Enex shareholders.
- During 2001, the Company sent notices of an election to prepay to the holders or received notice of an election to convert the Company's $13.2 million senior subordinated convertible notes. Pursuant to the terms of the convertible note agreements, the holders exercised their rights to convert the principal and accrued interest outstanding into common shares of the Company. Under the terms of the convertible

note agreements, the balance of the note plus any accrued interest was to be converted at $9.00 per share. The conversion by the holders resulted in the retirement of the $13.2 million in senior subordinated debt and the issuance of an additional 1,487,806 shares of common stock of the Company.

- During 2001, the Company completed the sale of certain non-strategic oil and gas properties for net cash proceeds of approximately $36.7 million. In order to defer the tax gain on the sales of certain properties, the Company successfully replaced a portion of these properties in accordance with the Like-Kind Exchange regulations of the Internal Revenue Service. At December 31, 2001, the Company had $13.9 million of cash in like-kind escrow accounts. In January 2002, the like-kind replacement term expired in accordance with the Internal Revenue Service regulations and the balance of the escrow accounts were used to reduce borrowings under the Company's Credit Facility.

- On January 30, 2001, the Company acquired 100% of the issued and outstanding stock of Classic Resources Inc. ("Classic Acquisition") for cash consideration of approximately $53.5 million plus other acquisition costs. Classic was a privately-held exploration and production company with properties located in East Texas. The Company's estimate of total net proved reserves at the time of the acquisition for Classic's oil and gas properties was 47 Bcfe and net daily production of approximately 11 Mmcfe. The Company financed the acquisition under its existing Credit Facility.

Business Strategy

Our business strategy is focused on the following:

- *Pursuit of Strategic Acquisitions.* We continually review opportunities to acquire producing properties, leasehold acreage and drilling prospects. We seek to acquire operational control of properties that we believe have significant exploitation and exploration potential. We are especially focused on increasing our holdings in fields and basins in which we already own an interest.

- *Further Development of Existing Properties.* We intend to further develop our properties that have proved reserves. We seek to add proved reserves and increase production through the use of advanced technologies, including detailed technical analysis of our properties, and by drilling in-fill locations and selectively recompleting existing wells. We also plan to drill step-out wells to expand known field limits. We intend to enhance the efficiency and quality control of these activities by operating the majority of our properties.

- *Growth Through Exploration.* We conduct an active technology-driven exploration program that is designed to complement our property acquisition and development drilling efforts with moderate to high risk exploration projects that have greater reserve potential. We generate exploration prospects through the analysis of geological and geophysical data and the interpretation of 3-D seismic data. We intend to manage our exploration expenditures through the optimal scheduling of our drilling program and by selectively reducing our participation in certain exploratory prospects through sales of interests to industry partners.

- *Rationalization of Property Portfolio.* We intend to actively pursue opportunities to reduce and control operating costs of our existing properties and properties we may acquire in the future through the consolidation of overlapping operations, the sale of marginal properties and by increasing the number of fields we operate as a percentage of our total properties.

- *Maintenance of Financial Flexibility.* We intend to maintain a substantial unused borrowing capacity under our bank Credit Facility by periodically refinancing our bank debt in the capital markets when conditions are favorable. We believe our expanded base of internally generated cash flow and other financial resources, including our existing financial partners, provide us with the financial flexibility to pursue additional acquisitions of producing properties and leasehold acreage and to develop our project inventory in an optimal fashion.

Marketing

We have marketed the natural gas and oil produced from our properties through typical channels for these products. We generally sell our oil at local field prices paid by the principal purchasers of oil. The majority of our natural gas production is sold at current market rates.

Both natural gas and oil are purchased by marketing companies, pipelines, major oil companies, public utilities, industrial customers and other users and processors of petroleum products. We are not confined to, or dependent upon, any one purchaser or small group of purchasers. Accordingly, the loss of a single purchaser, or a few purchasers, would not have a long-term material effect on our business because there are numerous purchasers in the areas in which we sell our production.

In order to manage our exposure to price risks in the marketing of our natural gas and oil production, we have in the past and may in the future enter into natural gas and oil price hedging arrangements with respect to a portion of our expected production.

Competition

We face competition from other oil and gas companies in all aspects of our business, including acquisition of producing properties and oil and gas leases, marketing of oil and gas, and obtaining goods, services and labor. Many of our competitors have substantially larger financial and other resources. Factors that affect our ability to acquire producing properties include available funds, available information about the property and our standards established for minimum projected return on investment. Competition is also presented by alternative fuel sources, including heating oil and other fossil fuels. We believe that we are competing and will compete effectively as a result of our expertise in the acquisition, exploration, and development of oil and gas reserves and our financial ability to take advantage of such opportunities.

Regulation

Federal Regulation of Transportation of Natural Gas. Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated by the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978, and the regulations promulgated by the Federal Energy Regulatory Commission. In the past, the federal government has regulated the prices at which natural gas could be sold. Deregulation of natural gas sales by producers began with the enactment of the Natural Gas Policy Act. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining Natural Gas Act and Natural Gas Policy Act price and non-price controls affecting producer sales of natural gas effective January 1, 1993. Congress could, however, reenact price controls in the future.

Our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. The price and terms for access to pipeline transportation remain subject to extensive federal regulation. Beginning in April 1992, the Federal Energy Regulatory Commission issued Order No. 636 and a series of related orders, which required interstate pipelines to provide open-access transportation on a basis that is equal for all natural gas suppliers. The Federal Energy Regulatory Commission has stated that it intends for Order No. 636 to foster increased competition within all phases of the natural gas industry. Although Order No. 636 does not directly regulate our production and marketing activities, it does affect how buyers and sellers gain access to the necessary transportation facilities and how we and our competitors sell natural gas in the marketplace. The courts have largely affirmed the significant features of Order No. 636 and the numerous related orders, although some appeals remain pending and the Federal Energy Regulatory Commission continues to review and modify its regulations regarding the transportation of natural gas. One broad and significant pending review involves examination of several questions, including whether the transportation regulations should be changed to better operate together with changes in state law that are introducing competition in retail natural gas markets, whether the historical method of setting transportation rates based on cost should be changed for certain transportation, whether short term transportation capacity should be allocated based only on auctions, and whether additional changes need to be made to long term transportation policies to prevent a market bias in favor of short term transportation. We cannot predict what action the Federal Energy Regulatory Commission will take on these matters, nor can we accurately predict whether the Federal Energy Regulatory Commission's actions will achieve the goal of increasing competition in markets in which our natural gas is sold. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other oil and natural gas producers.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the Federal Energy Regulatory Commission and the courts. The natural gas industry historically has been very heavily regulated; therefore, we cannot assure you that the less stringent regulatory approach recently pursued by the Federal Energy Regulatory Commission and Congress will continue.

Federal Regulation of Transportation of Oil. Oil and sales of oil, condensate and natural gas liquids by us are not currently regulated and are made at market prices. Effective as of January 1, 1995, the Federal Energy Regulatory Commission implemented regulations establishing an indexing system for transportation rates for interstate common carrier oil pipelines. These rates are generally indexed to inflation, subject to conditions and limitations. These regulations may, over time, tend to increase transportation costs or reduce wellhead prices for oil. However, we do not believe that these regulations affect us any differently than other oil and gas producers, gatherers and marketers.

State Regulation. Our oil and gas operations are subject to various types of regulation at the state and local levels. These regulations require drilling permits, regulate the methods for developing new fields and the spacing and operating of wells and waste prevention, and sometimes impose production limitations. These regulations may limit our production from wells and the number of wells or locations we can drill.

Some states have adopted regulations with respect to gathering systems. These regulations have not had a material effect on the operation of our gathering systems, but we cannot predict whether any future regulations in this area may have a material impact on our gathering systems.

Federal, State and Indian Leases. Our operations on federal, state or Indian oil and gas leases are subject to numerous restrictions, including nondiscrimination statutes. We must conduct our operations on these leases pursuant to permits and authorization and other regulations issued by the Bureau of Land Management, Minerals Management Service and other agencies. The Minerals Management Service currently has under consideration a proposal to change the manner in which crude oil is valued for purposes of calculating royalty due the government. If adopted, these changes would decrease reliance on historical valuation methods and instead adopt an indexing method intended to better reflect market value, but which may not reflect the proceeds actually received in the sale of the oil. We cannot predict what action the Minerals Management Service may ultimately take or how it will affect royalty payable on our production from federal leases, however, if adopted, the changes may tend to increase costs of royalty payments.

Environmental Regulations. Our operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Our exploration and production operations and facilities for gathering, treating, processing and handling hydrocarbons and related exploration and production wastes are subject to stringent environmental regulation. These laws and regulations sometimes require government approvals before activities occur, limit or prohibit activities because of protected areas or species, impose substantial liabilities for pollution and provide penalties for noncompliance. As with the industry generally, compliance with existing and anticipated regulations increases our overall cost of business. These regulations, however, generally affect us and our competitors similarly. Environmental laws and regulations are subject to frequent change, and we are not able to predict the costs or other impacts of environmental regulation on our future operations.

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on some classes of persons that are considered to have contributed to the release or threat of release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

Our operations are also subject to regulation of air emissions under the Clean Air Act and comparable state and local requirements. Implementation of these laws could lead to the gradual imposition of new air pollution control requirements on our operations. As a result, we may incur capital expenditures over the next several years to upgrade our air pollution control equipment. We do not believe that our operations would be materially affected by any such requirements, nor do we expect such requirements to be any more burdensome to us than to other companies our size involved in natural gas and oil exploration and production activities.

In addition, legislation has been proposed in Congress from time to time that would reclassify some natural gas and oil exploration and production wastes as "hazardous wastes," which would make the reclassified wastes subject to much more stringent handling, disposal and clean-up requirements. If Congress were to enact this legislation, it could increase our operating costs, as well as those of the natural gas and oil industry in general. Initiatives to further regulate the disposal of natural gas and oil wastes are also pending in some states, and these various initiatives could have a similar impact on us.

The Clean Water Act imposes restrictions and controls on the discharge of oil and gas wastes and other forms of pollutants into waters of the United States. Federal law also imposes strict liability on owners of facilities for consequences of an oil spill where the spill is in navigable waters or along shorelines. These laws impose penalties for unauthorized discharges and substantial liability for costs of removal and damages resulting from an unauthorized discharge. State laws for the control of water pollution provide similar penalties and liabilities. The cost of compliance with water pollution laws has not historically been material to our operations. There can be no assurance that changes in federal, state or local water pollution laws and programs will not materially adversely affect our operations in the future.

Our management believes that we are in substantial compliance with current environmental laws and regulations that affect us and that continued compliance with these requirements will not have a material adverse impact on us.

Employees

At December 31, 2001, we had 67 full-time employees. We believe that our relationships with our employees are satisfactory. None of our employees are covered by a collective bargaining agreement. From time to time, we use the services of independent consultants and contractors to perform various professional services, particularly in the areas of construction, design, well-site surveillance, permitting and environmental assessment.

Our Executive Offices

Our principal executive offices are located at 700 Milam Street, Suite 1100, Houston, Texas 77002, and our telephone number is 713.821.7100. Our website is www.3tecenergy.com.

Item 2. *Properties*

Description of Our Properties

We present information regarding our natural gas and oil reserves, properties, and operating results below.

	As of December 31, 2001						
	Estimated Net Proved Reserves			PV-10 Value ($000)	Percent Total PV-10 Value	Proved Undeveloped Drilling Locations	Budgeted 2002 Capital Expenditures ($000)
	Gas (Mmcf)	Oil (MBbls)(1)	Total (Mmcfe)				
East Texas	150,934	1,322	158,866	110,546	52.1%	144	17,675
Gulf Coast Area	28,536	1,338	36,564	59,567	28.1%	2	13,170
South Texas	25,747	3	25,765	12,465	5.9%	7	15,774
Mid-Continent Area	15,442	957	21,184	14,844	7.0%	2	—
Permian/San Juan Area	10,607	1,700	20,807	14,033	6.6%	—	—
Other Areas	—	17	102	894	0.3%	—	—
Total	231,266	5,337	263,288	212,349	100.00%	155	46,619(2)

(1) Includes oil, condensate and plant products barrels.

(2) As discussed in "Liquidity and Capital Resources" within Management's Discussion and Analysis, the Company's 2002 capital expenditure budget will range between $45-65 million and be dependant on the price of natural gas. The $46.6 million reflected in the table assumes a $2.50/Mmbtu average price for 2002. Natural gas prices in excess of $2.50/Mmbtu will allow the Company to expand its average capital expenditure program up to $65 million.

East Texas. Our largest fields are located in the East Texas area. The Rosewood, Glenwood, White Oak, Beckville, Carthage, East Henderson and Oak Hill fields all produce from the Cotton Valley formation and have numerous proved undeveloped drilling locations. Many of these development drilling locations are based on a change in regulatory field rules that now permit wells to be drilled on 80 acre spacing as opposed to 160 acre spacing. At December 31, 2001 we have identified 144 proved undeveloped locations in this area. For 2002, we have budgeted approximately $18 million for drilling of development wells and exploitation activities in this area.

Gulf Coast. We have established a substantial base of proved reserves and undeveloped acreage with significant exploration potential along the Gulf Coast of Texas and Louisiana. Through acquisitions, we acquired significant interests in Breton Sound Block 34 in Louisiana state waters and the Garden City and Bay de Chene fields in south Louisiana. During 2001, we participated in one successful completion in the Breton Sound area, and at the end of the year we were drilling ahead on exploratory wells in both Breton Sound and Garden City. In 2002, we intend on drilling additional exploratory tests in each of the previously mentioned three fields. Other significant fields in south Louisiana include East Roanoke, Riceville and Raceland.

Permian, San Juan and Mid-Continent Areas. We own interests in numerous fields in the Anadarko, Permian, San Juan and Arkoma basins, Oklahoma, Texas and New Mexico. Our largest fields in these areas are Puerto Chiquito and Basin in the San Juan basin, and West Stigler in eastern Oklahoma. In 2002, we have not budgeted any capital for development drilling and exploitation activities in these areas.

South Texas. In South Texas, we are active in two main areas, the Stuart City field in the Edwards Reef Trend and the Segundo field in Webb County, Texas. In 2002, we have budgeted approximately $16 million for development and exploration drilling in this area.

Natural Gas and Oil Reserves

The following table presents our estimated net proved natural gas and oil reserves and the PV-10 value of our reserves as of December 31, 2001, 2000, and 1999. The period end prices of oil and natural gas at December 31, 2001, 2000, and 1999, used in the PV-10 calculation were $19.84, $25.31 and $23.64 per barrel of oil and $2.57, $9.40 and $2.23 per thousand cubic feet of natural gas, respectively. Our estimated net proved natural gas and oil reserves and the PV-10 value of our reserves as of December 31, 2001, 2000, and 1999, are based on a reserve report prepared by Ryder Scott Company for our properties. The PV-10 values shown in the table are not intended to represent the current market value of the estimated natural gas and oil reserves we own. For further information concerning the PV-10 values of these proved reserves, please read note 16 of the notes to our December 31, 2001 consolidated financial statements.

	December 31		
	2001	2000	1999
Proved Reserves:			
Natural gas (Mmcf)	231,266	237,693	159,699
Oil (MBbls)(1)	5,337	10,672	9,835
Natural gas equivalents (Mmcfe)	263,288	301,725	218,709
Proved Developed Reserves:			
Natural gas (Mmcf)	175,659	177,252	122,914
Oil (MBbls)(1)	4,705	9,895	9,358
Natural gas equivalents (Mmcfe)	203,889	236,622	179,062
Estimated future net cash flows before income taxes, (in thousands)	$385,335	$1,996,831	$370,258
PV-10 value, (in thousands)	$212,349	$1,047,364	$198,615

(1) Includes oil, condensate and plant product barrels

There are numerous uncertainties in estimating quantities of proved reserves and in projecting future rates of production and the timing of development expenditures, including many factors beyond our control. The reserve data herein are only estimates. Although we believe these estimates to be reasonable, reserve estimates are imprecise and may be expected to change as additional information becomes available. Estimates of oil and natural gas reserves, of necessity, are projections based on engineering data, and there are uncertainties inherent in the interpretation of this data, as well as the projection of future rates of production and the timing of development expenditures. Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be exactly measured. Therefore, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of the reserves based on risk of recovery and the estimates are a function of the quality of available data and of engineering and geological interpretation and judgment and the future net cash flows expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. There also can be no assurance that the reserves set forth herein will ultimately be produced or that the proved undeveloped reserves will be developed within the periods anticipated. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and the variances may be material. In addition, the estimates of future net revenues from our proved reserves and the present value thereof are based upon certain assumptions about future production levels, prices and costs that may not be correct. We emphasize with respect to the estimates prepared by independent petroleum engineers that PV-10 value should not be construed as representative of the fair market value of our proved oil and natural gas properties since discounted future net cash flows are based upon projected cash flows which do not provide for changes in oil and natural gas prices or for escalation of expenses and capital costs. The meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they are based. Actual future prices and costs may differ materially from those estimated.

Volumes, Prices and Operating Expenses

The following table presents information regarding the production volumes of, average sales prices received for, and average production costs associated with, our sales of oil and natural gas for the periods indicated.

	Years Ended December 31,		
	2001	2000	1999
Net Production Data:			
Natural gas (Mmcf)	22,352	17,764	4,738
Oil (MBbls)	952	1,139	532
Natural gas equivalents (Mmcfe)	28,065	24,598	7,930
Average Sale Prices:			
Natural gas ($ per Mcf) (1)	$ 4.15(1)	$ 4.12	$2.18
Oil ($ per Bbl)	23.95	25.11(2)	16.88
Natural gas equivalents ($ per Mcfe)	4.12	4.20(2)	2.53
Expenses: ($ per Mcfe)			
Lease operations	$ 0.60	$ 0.62	$0.80
Production, severance and ad valorem taxes	$ 0.27	$ 0.27	$0.17
Gathering, transportation and other	$ 0.14	$ 0.09	$0.02
General and administrative	$ 0.25	$ 0.25	$0.52
Depreciation, depletion and amortization	$ 1.10	$ 0.80	$0.84

(1) Does not include the effect of our derivatives activities, which was approximately $162,000 of cash settlements during 2001.

(2) Includes the effect of our hedging activities.

Development, Exploration and Acquisition Capital Expenditures

The following table presents information regarding our net costs incurred in the purchase of properties and in exploration and development activities.

	Years Ended December 31,		
	2001	2000	1999
		(in thousands)	
Acquisition	84,325(1)	$ 79,865	$91,424
Exploration	19,731	695	824
Development	63,358	25,346	2,154
Total costs incurred	$167,414	$105,906	$94,402

(1) Excludes approximately $29 million of deferred taxes recorded in connection with the Classic Acquisition.

Drilling Activity

The following table shows our drilling activity for the years ended December 31, 2001, 2000 and 1999. In the table, "gross" refers to the total wells in which we have a working interest and "net" refers to gross wells multiplied by our working interest in these wells.

	Year Ended December 31,					
	2001		2000		1999	
	Gross	Net	Gross	Net	Gross	Net
Exploration Wells:						
Productive	4	2.52	—	—	—	—
Non-Productive	5	1.93	—	—	5	0.90
Total	9	4.45	—	—	5	0.90
Development Wells:						
Productive	71	26.80	66	18.30	21	5.67
Non-Productive	2	1.30	—	—	—	—
Total	73	28.10	66	18.30	21	5.67

Productive Wells

The following table sets forth the number of productive natural gas and oil wells in which we owned a working interest as of December 31, 2001.

	Total Productive Wells	
	Gross	Net
Natural Gas	870	393
Oil	131	61
Total	1,001	454

Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Additionally, the Company owns a royalty interest in 177 wells and an overriding royalty interest in 826 wells. At December 31, 2001, we operated approximately 344 wells.

Acreage Data

The following table presents information regarding our developed and undeveloped leasehold acreage as of December 31, 2001. Developed acreage refers to acreage within producing units and undeveloped acreage refers to acreage that has not been placed in producing units.

	Developed Acreage		Undeveloped Acreage		Total	
	Gross	Net	Gross	Net	Gross	Net
Texas	130,720	63,767	17,089	7,150	147,809	70,917
Louisiana	24,966	9,526	15,747	6,825	40,713	16,352
Oklahoma	23,764	8,947	1,040	865	24,804	9,812
Other	81,770	31,969	1,307	776	83,077	32,745
Total	261,220	114,209	35,183	15,616	296,404	129,825

Excluded from the acreage data are approximately 33,495 net mineral acres owned by us, primarily in La Fourche, St. Mary and Terrebonne parishes of Louisiana, all of which we believe have potential for oil and natural gas exploration.

Current Activities

As of March 8, 2002, 4 wells (1.4 net wells) were being drilled. Three wells are in Texas and one is in Louisiana.

Item 3. *Legal Proceedings*

From time to time, we are party to various routine litigation proceedings incidental to our business. We currently are not a party to any material litigation.

Item 4. *Submission of Matters to a Vote of Security Holders*

None.

PART II

Item 5. *Market for Registrant's Common Equity and Related Stockholder Matters*

Market Information

Our common stock is currently quoted on the Nasdaq National Market under the market symbol "TTEN."

The following table sets forth the high and low closing prices per share of our common stock for the periods indicated on the Nasdaq National Market.

Period	High	Low
2001		
First Quarter	$18.63	$15.69
Second Quarter	$20.40	$14.88
Third Quarter	$17.30	$12.27
Fourth Quarter	$15.10	$13.20
2000		
First Quarter	$11.44	$ 6.38
Second Quarter	13.50	7.00
Third Quarter	17.25	9.63
Fourth Quarter	19.13	13.38

On March 7, 2002 the last reported sales price of our common stock on the Nasdaq National Market was $17.70 per share.

On March 7, 2002 there were 909 holders of record of our common stock.

Our transfer agent is American Stock Transfer and Trust Company located at 59 Maiden Lane, New York, New York 10038. You may call them toll free at 800.937.5449 to answer any questions about transferring your stock.

We have never declared or paid any cash dividends on our common stock. We currently intend to retain future earnings, 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. In addition, our Credit Facility prohibits us from paying cash dividends on our common stock. Any future dividends are also restricted by the terms of our outstanding preferred stock and may be restricted by any debt agreements which we may enter into from time to time.

We are obligated to pay net cash dividends in the amount of approximately $740,000 per year on our Series D Preferred Stock which may be paid, at our option, in cash or in additional shares of Series D Preferred Stock during the three years ending February 1, 2003. Our Credit Facility permits the payment of dividends on our Series D Preferred Stock.

Item 6. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

You should read the following discussion and analysis in conjunction with our audited consolidated financial statements. The following information contains forward-looking statements. See "Cautionary Statement About Forward Looking Statements".

Overview

We are engaged in the acquisition, development, production and exploration of oil and natural gas reserves. Our properties are concentrated in East Texas and the Gulf Coast region, both onshore and in the shallow waters of the Gulf of Mexico. As of December 31, 2001, we had estimated total net proved reserves of 263 Bcfe, of which approximately 88% were natural gas and approximately 204 Bcfe, or 77%, were proved developed, with an estimated SEC case PV-10 value of $212 million. We exited 2001 at a net daily production rate of approximately 85 Mmcfe.

We have increased our reserves and production principally through acquisitions. We focus on properties that have a substantial proved reserve component and which management believes to have additional exploitation opportunities. Recently, we have also acquired a number of drilling prospects covered by an extensive 3-D seismic database that we believe have exploration potential. We have assembled an experienced management team and technical staff with expertise in property acquisitions and development, reservoir engineering, exploration and financial management.

Description Of Critical Accounting Policies

Oil and Natural Gas Properties. We utilize the successful efforts method of accounting for our oil and natural gas properties. Under this method, all development and acquisition costs of proved properties are capitalized and amortized on a unit-of-production basis over the remaining life of proved developed reserves or proved reserves, as applicable. Exploration expenses, including geological and geophysical expenses and delay rentals, are charged to expense as incurred. Costs of drilling exploratory wells are initially capitalized, but charged to expense if and when the well is determined to be unsuccessful. Expenditures for repairs and maintenance to sustain or increase production from the existing producing reservoir are charged to expense as incurred. Expenditures to recomplete a current well in a different or additional proven or unproven reservoir are capitalized pending determination that economic reserves have been added. If the recompletion to an unproven reservoir is not successful, the expenditures are charged to expense. Expenditures for redrilling or directional drilling in a previously abandoned well are classified as drilling costs to a proven or unproven reservoir for determination of capital or expense. Significant tangible equipment added or replaced is capitalized. Expenditures to construct facilities or increase the productive capacity from existing reserves are capitalized. Internal costs directly associated with the development and exploitation of properties are capitalized as a cost of the property and are classified accordingly in the Company's financial statements. Crude Oil volumes are converted to equivalent Mcf's at the rate of one barrel to six Mcf.

The Company is required to assess the need for an impairment of capitalized costs of oil and natural gas properties and other long-lived assets whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. If impairment is indicated based on a comparison of the asset's carrying value to its undiscounted expected future net cash flows, then it is recognized to the extent that the carrying value exceeds fair value. Any impairment charge incurred is recorded in accumulated depletion, depreciation, and amortization ("DD&A") to reduce our recorded basis in the asset. Each part of this calculation is subject to a large degree of management judgment, including the determination of property's reserves, future cash flows, and fair value.

Management's assumptions used in calculating oil and natural gas reserves or regarding the future cash flows or fair value of our properties are subject to change in the future. Any change could cause impairment expense to be recorded, reducing our net income and our basis in the related asset. Future prices received for production and future production costs may vary, perhaps significantly, from the prices and costs assumed for purposes of calculating reserve estimates. There can be no assurance that the proved reserves will be developed within the periods estimated or that prices and costs will remain constant. Actual production may not equal the estimated amounts used in the preparation of reserve projections. As these estimates change, the amount of calculated reserves change. Any change in reserves directly impacts our estimate of future cash flows from the property, as well as the property's fair value. Additionally, as management's views related to future prices change, this changes the calculation of future net cash flows and also affects fair value estimates. Changes in either of these amounts will directly impact the calculation of impairment.

DD&A expense is also directly affected by the Company's reserve estimates. Any change in reserves directly impacts the amount of DD&A expense the Company recognizes in a given period. Assuming no other changes, such as an increase in depreciable base, as the Company's reserves increase, the amount of DD&A expense in a given period decreases and vice versa. Changes in future commodity prices would likely result in increases or decreases in estimated recoverable reserves.

The Company also uses estimates to record its accrual for oil and natural gas revenues. The volume portion of the accrual of revenue for a given period is based upon field production reports (both operated and non-operated), estimates of production added via drilling or acquisitions, historical production averages and natural production declines of the Company's properties. The price component of the Company's accrual for revenue incorporates historical averages of the Company's sales as compared to the monthly closing NYMEX price for natural gas and the West Texas Intermediate index price for crude oil.

Several factors can impact the Company's ability to estimate its production volume such as the fact that a significant portion of the Company's production is operated by third parties. Reliance on accurate and timely data from the operators of these properties can change the actual amounts of production for which the Company receives payment. Additionally, production meters that are manually read can be different than the volume metered at the Company's sales points.

Both the Company's estimate of sold volumes and the estimate of the price received for these sales is adjusted on an on-going basis as the Company receives payment for the accrued volumes. Changes in the estimates of the accrual are adjusted for in the subsequent periods as payment is received or additional supporting data is obtained.

Bad Debt Expense. The Company routinely assesses the recoverability of all material trade and other receivables to determine their collectibility. The Company historically has not required collateral or other performance guarantees from creditworthy counterparties. Many of our receivables are from joint interest owners on property of which we are the operator. Thus, we may have the ability to withhold future revenue disbursements to cover any non-payment of joint interest billings. Our oil and natural gas receivables quickly turnover, usually one month for oil and two months for gas; thus, signaling any problem accounts in a timely manner. Counterparties to our derivative commodity contracts are routinely reviewed for creditworthiness to determine the realizability of any related derivative assets we might carry on our books. This review of receivables and counterparties is heavily dependent on the judgment of management. If it is determined that the carrying value of a receivable or financial instrument might not be recoverable, we record an allowance to the extent we believe the receivable or asset is not recoverable. The determination as to what extent a receivable or asset might be impaired is also heavily dependent on the judgment of management. As more information becomes known related to a particular counterparty or customer, management will continually reassess previous judgments and any resulting change in the related allowance could have a material positive or negative effect on our financial position and results of operations in the period of the change.

Derivative Activities. We use various financial instruments in the normal course of our business to manage and reduce price volatility and other market risks associated with our crude oil and natural gas production. This activity is referred to as risk management. These arrangements are structured to reduce our exposure to commodity price decreases, but they can also limit the benefit we might otherwise receive from commodity price increases. Our risk management activity is generally accomplished through over-the-counter forward derivative contracts executed with large financial institutions.

Effective January 1, 2001, the Company adopted Statement of Financial Accounting Standards No. 133 ("SFAS 133"), "Accounting for Derivative Instruments and Hedging Activities". This standard requires us to recognize all of our derivative and hedging instruments in our consolidated balance sheets as either assets or liabilities and measure them at fair value. If a derivative does not qualify for hedge accounting, it must be adjusted to fair value through earnings. However, if a derivative does qualify for hedge accounting, depending on the nature of the hedge, changes in fair value can be offset against the change in fair value of the hedged item through earnings or recognized in other comprehensive income until such time as the hedged item is recognized in earnings.

To qualify for cash flow hedge accounting, the cash flows from the hedging instrument must be highly effective in offsetting changes in cash flows due to changes in the underlying items being hedged. In addition, all hedging relationships must be designated, documented, and reassesed periodically. The Company's natural gas derivative financial instruments were not designated as hedges at the time the instruments were executed. According to the provisions of SFAS 133, these instruments are marked-to-market through earnings each period.

Liquidity and Capital Resources

Cash Flow. We believe that our cash flows from operations are adequate to meet the requirements of operating our business. However, future cash flows are subject to a number of variables, including our level of production and prices, and we cannot assure you that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures. Our principal operating sources of cash include sales of natural gas and oil.

Our earnings before interest, taxes, minority interest, depletion and exploration (impairment, dry hole and geological and geophysical) ("EBITDAX") for the years ended December 31, 2001 and 2000, were $75.8 million and $74.4 million, respectively. For the year 2002, we have budgeted approximately $45-65 million for capital expenditures depending on the price of natural gas and drilling costs in 2002. The low-end of the range is based on an average natural gas price of $2.50/Mmbtu. Pricing increases to $3.00/Mmbtu and above will move the Company's capital expenditures into the higher end of the range. We are obligated to pay dividends of approximately $740,000 per year on the Series D Preferred Stock which we may pay in either cash or in additional shares of Series D Preferred Stock during the three years ending February 1, 2003.

Our activities in 2001 have been financed through operating cash flow and bank borrowings. Our primary source of financing for acquisitions has been borrowing under our Credit Facility described below.

We believe we will have sufficient cash flow from operations and borrowings under our Credit Facility to meet our obligations and operating needs for the coming year. However, future cash flows are subject to a number of variables, including our level of production and prices, and we cannot assure you that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures.

Credit Facility. The Company has in place a $250 million credit facility (the "Credit Facility") with Bank One, NA as agent and seven other banks. The Credit Facility, as amended, matures May 31, 2003. On March 7, 2002, the Company's borrowing base under its Credit Facility was set at $145 million. The borrowing base is to be redetermined semi-annually on May 1 and November 1 and provides for interest as revised under the Credit Facility to accrue at a rate calculated at the Company's option as either the bank's prime rate plus a low of zero to a high of 50 basis points or LIBOR plus basis points increasing from a low of 150 to a high of 212.5 as loans outstanding increase as a percentage of the borrowing base. As of December 31, 2001, the borrowing base was set at $145 million. As of December 31, 2001, the Company was paying an average of 3.68% per annum interest on the principal balance of $108 million under the Credit Facility. Prior to maturity, no payments of principal are required so long as the borrowing base exceeds the loan balance. The borrowings under the Credit Facility are secured by substantially all of the Company's oil and natural gas properties. At December 31, 2001, the amount available to be borrowed under the Credit Facility was approximately $37 million. At December 31, 2001, the Company had approximately $13.9 million in cash held in like-kind exchange escrow accounts. During January, 2002, the Company repaid borrowings under the Credit Facility with the escrow funds. At March 7, 2002, borrowings under the Credit Facility totaled $97 million.

In connection with the Credit Facility we are required to adhere to certain affirmative and negative covenants. The loan agreement contains a number of dividend restrictions and restrictive covenants which, among other things, require the maintenance of minimum current and interest coverage ratios.

The following table illustrates the Company's contractual obligations outstanding at December 31, 2001:

		Payments Due By Period			
Contractual Obligations	**Total**	**2002**	**2003-2004**	**2005-2006**	**Thereafter**
			(in thousands)		
Long-term debt	108,000	—	108,000	—	—
Operating leases	7,298	1,142	2,650	1,737	1,769
Totals	115,298	1,142	110,650	1,737	1,769

Market Risk. We generally sell our oil at local field prices paid by the principal purchasers of oil. The majority of our natural gas production is sold at spot prices. Accordingly, we are generally subject to the commodity prices for these resources as they vary from time to time.

Inflation and Changes in Prices. Our revenues and the value of our oil and gas properties have been and will be affected by changes in natural gas and crude oil prices. Our ability to maintain current borrowing capacity and to obtain additional capital on attractive terms is also substantially dependent on natural gas and crude oil prices. These prices are subject to significant seasonal and other fluctuations that are beyond our ability to control or predict. During 2001, we received an average of $23.95 per barrel of crude oil and $4.15 per Mcf of gas. Costs and expenses are affected by the level of inflation, which has had a significant effect in 2001. Should current conditions in the industry be sustained, increased competition resulting in a relative shortage of oilfield supplies and/or services, inflationary cost pressures may continue.

Results of Operations

Our revenue, profitability, and future rate of growth are dependent upon prevailing prices for oil and gas, which, in turn, depend upon numerous factors such as economic, political, and regulatory developments as well as competition from other sources of energy. The energy markets historically have been highly volatile, and future decreases in prices could have an adverse effect on our financial position, results of operations, quantities of reserves that may be economically produced, and access to capital.

You should read the following discussion and analysis together with our audited consolidated financial statements and the related notes for the fiscal years ended December 31, 2001 and 2000.

2001 Compared With 2000

Revenue. Total revenue for the year ended December 31, 2001 was $122.8 million, an increase of $18.0 million (17%) over total revenue for 2000 of $104.8 million. Oil, natural gas and plant income revenues for the 2001 period were $117.9 million compared to $103.2 million in 2000, an increase of $14.7 million (14%). Realized prices for the Company's production was $4.12/Mcfe in 2001 compared to $4.20/Mcfe in 2000, while production volumes increased to 28,065 Mmcfe in 2001 compared to 24,598 Mmcfe in 2000. Realized price increases for 2001 and 2000 were reflective of the continued strong commodity price environment in the industry. Comparability of the Company's revenues and volumes were both driven by an significant drilling program in

2001 and 2000 and the acquisitions of Magellan Properties in February 2000, the CWR Properties in May 2000 and the Classic Properties in January 2001, offset by the 2001 property divestments which were all significant contributors to the year over year increases.

Gain on Sale of Properties and Other Revenue. In 2001 vs. 2000, property divestments resulted in the recognition of gains of $0.8 million and $0.8 million, respectively. The Company continues to actively review and manage its property portfolio for divestiture of non-strategic properties. Other revenues in 2001 were $1.0 million compared to $0.8 in 2000. Other revenue consists primarily of interest, delay rental and lease bonus income.

Gain on Derivative Fair Value. During the fourth quarter of 2001, the Company entered into certain derivative transactions that were not designated as hedges and therefore are required under generally accepted accounting principals to be "marked-to-market." At December 31, 2001, these contracts had a fair market value of $3.1 million. See further discussion in Note 13 of the Company's Notes to Consolidated Financial Statements.

Expenses. Total expenses for the year ended December 31, 2001 were $94.8 million, an increase of $36.4 million (62%) from total expenses in 2000 of $58.4 million. Comparability of total expenses was impacted by the increase in dry hole and impairment expenses, surrendered and expired acreage and the increase in depreciation, depletion and amortization. On a per Mcfe basis, the Company's lease operating expenses decreased by 3% to $0.60 in 2001 from $0.62 in 2000. Production, severance and ad valorem tax was flat at $0.27/Mcfe in 2001 vs. $0.27/Mcfe in 2000. General and administrative expense was $0.25/Mcfe in 2001 compared to $0.25/Mcfe in 2000, interest expense $0.24/Mcfe vs. $0.31/Mcfe in 2000, and DD&A $1.10/Mcfe in 2001 compared to $0.80/Mcfe in 2000. Lease operating expenses on a unit basis were impacted by the Company's Classic Acquisition and 2001 divestiture program. The properties in the Classic Acquisition were natural gas wells with lower lease operating costs as compared to the divested properties that had higher lease operating costs which were primarily oil producers.

Production, severance and ad valorem taxes were comparable year over year as expected with average sales prices on an mcfe basis being $4.12/Mcfe in 2001 vs. $4.20/Mcfe in 2000.

The increase on a per unit basis to depreciation, depletion and amortization ("DD&A") is attributed to the Classic Acquisition and the Company's developmental drilling program. As the Company acquired the stock of Classic Resources, Inc., the historical tax basis of the Classic Acquisition properties were carried over to the Company's books. A corresponding deferred tax liability was recorded in the Company's purchase price allocation for the difference between the allocated value and the historical tax basis. This "gross-up" to record the deferred tax liability, resulted in approximately $29 million being added to the depletable book basis of the Classic Acquisition properties. The Company's development drilling activities during 2001 also contributed to the increase in the Company's DD&A rate in 2001 due to a majority of the proved undeveloped reserves associated with these capitalized costs associated having been already included in the Company's December 31, 2000 reserve report estimate. Thus, additional costs were added to a relatively static reserve figure, thereby increasing the per unit rate.

Income Taxes. The Company recorded a $10.6 million income tax provision during 2001 as compared to a $14.4 million income tax provision for 2000. The results from the Company's operations generated pre-tax income of $28.0 million during 2001 vs. a pre-tax income of $46.4 million in 2000. During 2001, the Company's effective tax rate was approximately 38%. In 2001, the Company expects to pay approximately $1.6 million in current taxes. The Company paid $7.9 million in taxes for 2000.

Net Income. The Company's 2001 net income of $16.8 million is compared to $31.7 million in 2000.

Dividends to Preferred Shareholders. Dividends to preferred shareholders of $0.7 million in 2001 is a $0.8 million decrease (53%) over 2000 dividends of $1.5 million. The Company redeemed its Series C preferred stock in September, 2000 and recognized a non-cash charge to dividend expense of $0.5 million in 2000.

2000 Compared With 1999

Revenue. Total revenue for the year ended December 31, 2000 was $104.8 million, an increase of $82.6 million (372%) over total revenue for 1999 of $22.2 million. Oil, natural gas and plant income revenues for the 2000 period were $103.2 million compared to $20.0 million in 1999, an increase of $83.2 million (416%). Realized prices for the Company's production was $4.20/Mcfe in 2000 compared to $2.43/Mcfe in 1999, while production volumes increased to 24,598 Mmcfe in 2000 compared to 7,930 Mmcfe in 1999. Realized price increases for 2000 over 1999 were reflective of the strong commodity price environment in the industry, while being only minimally impacted by the Company's hedging activities in both years ($2.1 million loss in 2000 on oil hedging, and $0.2 million loss on gas hedging in 1999). Comparability of the Company's revenues and volumes were both driven by an aggressive developmental drilling program in 2000 and the acquisition of the Floyd Oil Properties in November 1999, the Magellan Properties in February 2000 and the CWR Properties in May 2000, which were all significant contributors to the year over year increases.

Gain on Sale of Properties and Other Revenue. In 2000 vs. 1999, property divestments resulted in the recognition of gains of $0.8 million and $1.0 million, respectively. The Company continues to actively review and manage its property portfolio for divestiture of non-strategic properties. Other revenues in 2000 were $0.8 million compared to $1.0 million in 1999. Other revenue consists primarily of interest, delay rental and lease bonus income.

Expenses. Total expenses for the year ended December 31, 2000 were $58.4 million, an increase of $31.4 million (116%) from total expenses in 1999 of $27.0 million. Comparability of total expenses was significantly impacted by the Company's aggressive developmental drilling program and the acquisition of the Floyd Oil Properties in November 1999, the Magellan Properties in February 2000 and the CWR Properties in May 2000. On a per Mcfe basis, the Company's lease operating expenses decreased by 23% to $0.62 in 2000 from $0.80 in 1999. Production, severance and ad valorem tax increased by 59% to $0.27/Mcfe in 2000 from $0.17/Mcfe in 1999. Additionally, general and administrative, interest and depreciation, depletion and amortization ("DD&A") expenses all rose on a dollar basis in 2000 but decreased on a per Mcfe basis. General and administrative expense was $0.25/Mcfe in 2000 compared to $0.52/Mcfe in 1999, interest expense $0.31/Mcfe vs. $0.40/Mcfe in 1999, and DD&A $0.80/Mcfe in 2000 compared to $0.84/Mcfe in 1999.

Income Taxes. The Company recorded a $14.4 million income tax provision during 2000 as compared to a $1.4 million income tax benefit for 1999. The results from the Company's operations generated pre-tax income of $46.1 million during 2000 vs. a pre-tax loss of $4.9 million in 1999. During 2000, the Company's effective tax rate was approximately 32%. Also, the Company became a cash taxpayer in 2000, with $8.0 million of the 2000 provision recorded as a current tax payable.

Net Income. The Company's 2000 net income of $31.7 million is compared to the $3.4 million net loss in 1999. As discussed in the revenue and expenses paragraphs above, the Company's significant drilling and acquisition success during 2000, coupled with a very strong commodity price environment and cost containment and improved efficiencies on a per unit basis, all attributed to the current year net income result.

Dividends to Preferred Shareholders. Dividends to preferred shareholders of $1.5 million in 2000 is a $0.9 million increase (150%) over 1999 dividends of $0.6 million. During 2000, the Company issued a new preferred stock series, Series D, in connection with the Magellan Acquisition, which accounted for $0.6 million of the increase. Additionally, during the third quarter of 2000, the Company redeemed its Series C preferred stock and recognized a non-cash charge to dividend expense of $0.5 million.

Item 7. *Financial Statements*

The Consolidated Financial Statements that constitute this item follow the text of this report. An index to the Consolidated Financial Statements and Schedules appears in Item 13 of this report.

Item 8. *Changes in and Disagreements With Accountants on Accounting and Financial Disclosure*

None.

PART III

Item 9. *Directors and Executive Officers of the Registrant; Compliance with Section 16(a) of the Exchange Act*

The Company's Definitive Proxy Statement for its 2002 Annual Meeting of Stockholders, when filed pursuant to Regulation 14A under the Securities Exchange Act of 1934, will be incorporated by reference into this Annual Report on Form 10-KSB pursuant to General Instruction E(3) of Form 10-KSB and will provide the information required for Items 9, 10, 11 and 12 under Part III.

Item 10. *Executive Compensation*

The Company's Definitive Proxy Statement for its 2002 Annual Meeting of Stockholders, when filed pursuant to Regulation 14A under the Securities Exchange Act of 1934, will be incorporated by reference into this Annual Report on Form 10-KSB pursuant to General Instruction E(3) of Form 10-KSB and will provide the information required for Items 9, 10, 11 and 12 under Part III.

Item 11. *Security Ownership of Certain Beneficial Owners and Management*

The Company's Definitive Proxy Statement for its 2002 Annual Meeting of Stockholders, when filed pursuant to Regulation 14A under the Securities Exchange Act of 1934, will be incorporated by reference into this Annual Report on Form 10-KSB pursuant to General Instruction E(3) of Form 10-KSB and will provide the information required for Items 9, 10, 11 and 12 under Part III.

Item 12. *Certain Relationships and Related Transactions*

The Company's Definitive Proxy Statement for its 2002 Annual Meeting of Stockholders, when filed pursuant to Regulation 14A under the Securities Exchange Act of 1934, will be incorporated by reference into this Annual Report on Form 10-KSB pursuant to General Instruction E(3) of Form 10-KSB and will provide the information required for Items 9, 10, 11 and 12 under Part III.

Item 13. *Exhibits, Financial Statement Schedules and Reports on Form 8-K*

(a) 1. Consolidated Financial Statements: See Index to Consolidated Financial Statements on page F-1

2. Exhibits: The following documents are filed as exhibits to this report:

2.1 Agreement and Plan of Merger, dated December 21, 1999, by and between 3TEC Energy Corporation, 3TM Acquisition L.L.C., Magellan Exploration, LLC and ECIC Corporation, EnCap Energy Capital Fund III, L.P., EnCap Energy Acquisition III-B, Inc., BOCP Energy Partners, L.P., and Pel-Tex Partners, L.L.C. (Incorporated by reference to Exhibit C to Form DEF14A, filed January 11, 2000.)

2.2 Agreement and Plan of Merger, dated November 24, 1999, by and between 3TEC Energy Corporation, a Delaware corporation, and Middle Bay Oil Company, Inc., an Alabama corporation. (Incorporated by reference to Exhibit A to Form DEF14A, filed October 25, 1999.)

2.3 First Amendment to Agreement and Plan of Merger, effective as of January 14, 2000, by and among 3TEC Energy Corporation, 3TM Acquisition L.L.C., Magellan Exploration, LLC, ECIC Corporation, EnCap Energy Capital Fund III, L.P., EnCap Energy Acquisition III-B, Inc., BOCP Energy Partners, L.P., and Pel-Tex Partners, L.L.C. (Incorporated by reference to Exhibit 2.1 to Form 8-K filed February 4, 2000.)

2.4 Second Amendment to Agreement and Plan of Merger, effective as of February 2, 2000, by and among 3TEC Energy Corporation, 3TM Acquisition L.L.C., Magellan Exploration, LLC, ECIC Corporation, EnCap Energy Capital Fund III, L.P., EnCap Energy Acquisition III-B, Inc., BOCP Energy Partners, L.P., and Pel-Tex Partners, L.L.C. (Incorporated by reference to Exhibit 2.2 to Form 8-K filed February 4, 2000.)

2.5 Form of Agreement of Sale and Purchase by and between C.W. Resources, Inc., Westerman Royalty, Inc., and Carl A. Westerman and 3TEC Energy Corporation. (Incorporated by Reference to Exhibit 10.32 to Form S-2 filed April 28, 2000.)

2.6 Form of Stock Purchase Agreement by and between 3TEC Energy Corporation and Classic Resources, Inc., Natural Gas Partners IV, L.P., Natural Gas Partners V, L.P., and certain individual signatories. (Incorporated by reference to Exhibit 2.1 to Form 8-K filed February 13, 2001.)

2.7 Merger Agreement, dated October 25, 2001, by and among 3TEC Energy Corporation, 3NEX Acquisition Corporation and Enex Resources Corporation.*

2.8 Certificate of Ownership and Merger Merging Enex Resources Corporation into 3TEC Energy Corporation filed with the Delaware Secretary of State January 31, 2002.*

3.1 Certificate of Incorporation of 3TEC Energy Corporation. (Incorporated by reference to Exhibit 3.1 of Form 8-K filed December 6, 1999.)

3.2 Certificate of Amendment to the Certificate of Incorporation of 3TEC Energy Corporation. (Incorporated by reference to Exhibit 3.3 of Form 10-KSB filed March 30, 2000.)

3.3 Certificate of Amendment of the Certificate of Incorporation of 3TEC Energy Corporation, dated June 14, 2001 (Incorporated by reference to Exhibit 3.5 Form 10-QSB filed August 8, 2001.)

3.4 Certificate of Merger of Middle Bay Oil Company, Inc. into 3TEC Energy Corporation. (Incorporated by reference to Exhibit 3.3 of Form 8-K/A filed December 16, 1999.)

3.5 Bylaws of the Company. (Incorporated by reference to Exhibit C to Form DEF14A filed October 25, 1999.)

3.6 Amendment No. 1 to Bylaws of the Company. (Incorporated by reference to Exhibit 4.5 Form S-8 filed October 26, 2001.)

3.7 Amendment No. 2 to Bylaws of 3TEC Energy Corporation. (Incorporated by reference to Exhibit 3.6 to Form 10-QSB filed August 8, 2001.)

4.1 Certificate of Designation of Series B Preferred Stock of 3TEC Energy Corporation. (Incorporated by reference to Exhibit 3.1 to Form 8-K/A filed December 16, 1999.)

4.2 Certificate of Designation of Series D Preferred Stock of 3TEC Energy Corporation. (Incorporated by reference to Exhibit 4.3 to Form 10-QSB filed May 15, 2000.)

10.1 Securities Purchase Agreement, dated July 1, 1999 by and between the Company and 3TEC Energy Corporation. (Incorporated by reference to Exhibit C Form DEF14A filed July 19, 1999.)

10.2 Securities Purchase Agreement, dated August 27, 1999 by and between the Company and Shoemaker Family Partners, LP. (Incorporated by reference to Exhibit 10.2 to Form 10-QSB filed November 15, 1999.)

10.3 Securities Purchase Agreement, dated August 27, 1999 by and between the Company and Shoeinvest II, LP. (Incorporated by reference to Exhibits to Exhibit 10.3 to Form 10-QSB filed November 15, 1999.)

10.4 Securities Purchase Agreement, dated October 19, 1999 between The Prudential Insurance Company of America and the Company. (Incorporated by reference to Exhibit 10.1 to Form 8-K filed November 2, 1999.)

10.5 Shareholders Agreement, dated August 27, 1999 by and among the Company, 3TEC Energy Corporation and the Major Shareholders. (Incorporated by reference to Exhibit 10.5 to Form 10-QSB filed November 15, 1999.)

10.6 Agreement to Terminate Shareholders' Agreement, dated April 30, 2001, by and among the Company and the Major Shareholders. (Incorporated by reference to Exhibit 10.6 to Form 10-QSB filed November 8, 2001.)

10.7 Registration Rights Agreement, dated August 27, 1999 by and among the Company, 3TEC Energy Corporation, the Major Shareholders, Shoemaker Family Partners, LP and Shoeinvest II, LP. (Incorporated by reference to Exhibit 10.6 to Form 10-QSB filed November 15, 1999.)

10.8 Amendment to Registration Rights Agreement, dated October 19, 1999 by and among the Company, W/E Energy Company, L.L.C. f/k/a 3TEC Energy Company L.L.C., f/k/a 3TEC Energy Corporation, Shoemaker Family Partners, LP, Shoeinvest II, LP, and The Prudential Insurance Company of America. (Incorporated by reference to Exhibit 10.2 to Form 8-K filed November 2, 1999.)

10.9 Participation Rights Agreement, dated October 19, 1999 by and among the Company, The Prudential Insurance Company of America and W/E Energy Company L.L.C. (Incorporated by reference to Exhibit 10.3 to Form 8-K filed November 2, 1999.)

10.10 Employment Agreement, dated April 15, 2000 by and between Floyd C. Wilson and the Company. (Incorporated by reference to Exhibit 10.9 to Form S-2 filed April 28, 2000.)

10.11 Employment Agreement, dated May 1, 2000, by and between R.A. Walker and the Company. (Incorporated by reference to Exhibit 10.9 to Form S-2 filed April 28, 2000.)

10.12 Restated Credit Agreement by and among Middle Bay Oil Company, Inc., Enex Resources Corporation and Middle Bay Production Company, Inc. as borrowers, and Bank One, Texas, N.A. and other institutions as lenders. (Incorporated by reference to Exhibit 10.1 to Form 8-K/A filed December 17, 1999.)

10.13 Subordination Agreement, dated August 27, 1999 by and among Shoeinvest II, LP, Compass Bank, and Bank of Oklahoma, National Association. (Incorporated by reference to Exhibit 10.16 to Form 10-QSB filed November 15, 1999.)

10.14 Subordination Agreement, dated August 27, 1999 by and among Shoeinvest II, LP, Compass Bank, and Bank of Oklahoma, National Association. (Incorporated by reference to Exhibit 10.16 to Form 10-QSB filed November 15, 1999.)

10.15 Letter Amendment No. 1 to Middle Bay Oil Company, Inc. Securities Purchase Agreement, dated November 23, 1999, by and between Middle Bay Oil Company, Inc. (n/k/a 3TEC Energy Corporation) and The Prudential Insurance Company of America (Incorporated by reference to Exhibit 10.21 to Form S-2 filed April 28, 2000 and replacing the unexecuted Exhibit 10.17 of Form 10-QSB filed November 15, 1999.)

10.16 Intercreditor Agreement, dated as of November 23, 1999, among Middle Bay Oil Company, Inc., Bank One Texas, N.A. and 3TEC Energy Company L.L.C. (Incorporated by reference to Exhibit 10.18 to Form S-2 filed April 28, 2000.)

10.17 Intercreditor Agreement, dated as of November 23, 1999, among Middle Bay Oil Company, Inc., Bank One Texas, N.A. and Shoemaker Family Partners, LP. (Incorporated by reference to Exhibit 10.19 to Form S-2 filed April 28, 2000.)

10.18 Intercreditor Agreement, dated as of November 23, 1999, among Middle Bay Oil Company, Inc., Bank One Texas, N.A. and Shoeinvest II, LP. (Incorporated by reference to Exhibit 10.20 to Form S-2 filed April 28, 2000.)

10.19 Amendment to Securities Purchase Agreement, dated as of November 23, 1999, among Middle Bay Oil Company, Inc. and 3TEC Energy Company L.L.C. (Incorporated by reference to Exhibit 10.22 to Form S-2 filed April 28, 2000.)

10.20 Amendment to Securities Purchase Agreement, dated as of November 23, 1999, among Middle Bay Oil Company, Inc. and Shoemaker Family Partners, LP. (Incorporated by reference to Exhibit 10.23 to Form S-2 filed April 28, 2000.)

10.21 Amendment to Securities Purchase Agreement, dated as of November 23, 1999, among Middle Bay Oil Company, Inc. and Shoeinvest II, LP. (Incorporated by reference to Exhibit 10.24 to Form S-2 filed April 28, 2000.)

10.22 Amended and Restated 1995 Stock Option and Stock Appreciation Rights Plan. (Incorporated by reference to Exhibit B to Form DEF 14A filed May 5, 1997.)

10.23 Amendment No. 1 to the Amended and Restated 1995 Stock Option and Stock Appreciation Rights Plan. (Incorporated by reference to Exhibit B to Form DEF 14A filed May 5, 1998.)

10.24 Amendment No. 1 to Amended and Restated 1995 Stock Option and Stock Appreciation Rights Plan. (Incorporated by reference to Exhibit 99.7 Form S-8 filed November 6, 2000.)

10.25 Amendment No. 3 to Amended and Restated 1995 Stock Option and Stock Appreciation Rights Plan. (Incorporated by reference to Exhibit 99.8 Form S-8 filed November 6, 2000.)

10.26 1999 Stock Option Plan. (Incorporated by reference to Exhibit E to Form DEF 14A filed October 25, 1999.)

10.27 Amendment No. 1 to 3TEC Energy Corporation 1999 Stock Option Plan. (Incorporated by reference to Exhibit 99.4 Form S-8 filed November 6, 2000.)

10.28 2000 Stock Option Plan (Incorporated by reference to Exhibit A to Form DEF 14A filed on May 1, 2000.)

10.29 Amendment No. 1 to 3TEC Energy Corporation 2000 Stock Option Plan. (Incorporated by reference to Exhibit 99.2 Form S-8 filed November 6, 2000.)

10.30 3TEC Energy Corporation 2001 Stock Option Plan. (Incorporated by reference to Exhibit 99.1 Form S-8 filed October 26, 2001.)

10.31 3TEC Energy Corporation 2000 Non-Employee Directors Stock Option Plan. (Incorporated by reference to Exhibit 99.2 Form S-8 filed October 26, 2001.)

10.32 Second Restated Credit Agreement among 3TEC Energy Corporation, Enex Resources Corporation, Middle Bay Production Company, Inc., and Magellan Exploration, LLC, as Borrowers, and Bank One, Texas, N.A. and the Institutions named therein, as Lenders, Bank One, Texas, N.A., as Administrative Agent, Bank of Montreal as Syndication Agent and Banc One Capital Markets, Inc., as Arranger, dated May 31, 2000. (Incorporated by reference to Exhibit 10.28 to Form S-2/A filed June 6, 2000.)

10.33 First Amendment to Shareholders' Agreement by and among 3TEC Energy Corporation, the W/E Shareholders and the Major Shareholders, dated May 30, 2000. (Incorporated by reference to Exhibit 10.29 to Form S-2/A filed June 6, 2000.)

10.34 Third Restated Credit Agreement among 3TEC Energy Corporation, Enex Resources Corporation and 3TEC/CRI Corporation, as Borrowers, and Bank One, N.A. and the Institutions named therein, as Lenders, Bank One, N.A., as Administrative Agent, Bank of Montreal as Syndication Agent and Banc One Capital Markets, Inc., as Arranger, dated March 12, 2001. (Incorporated by reference to Exhibit 10.27 to Form 10-QSB filed May 14, 2001.)

21.1 Subsidiaries of 3TEC Energy Corporation.*

23.1 Consent of KPMG LLP, independent certified public accountants. *

23.2 Consent of Ryder Scott Company, independent petroleum engineers. *

* Filed herewith

(b) The following reports were filed on Form 8-K during the fourth quarter of 2001:

On October 26, 2001, the Company filed a Form 8-K under item 5 describing the announcement of the definitive merger agreement entered into with Enex Resources Corporation.

GLOSSARY OF CERTAIN OIL AND GAS TERMS

The following are abbreviations and definitions of certain terms commonly used in the oil and gas industry and herein:

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

Bcf. One billion cubic feet of natural gas.

Bcfe. One billion cubic feet of natural gas equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

Btu or British Thermal Unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Completion. The installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Development well. A well drilled into a proved natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

Exploratory well. A well drilled to find and produce natural gas or oil reserves that are not proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic level.

MBbls. One thousand barrels of oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet of natural gas.

Mcfe. One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

Mmbtu. One million British Thermal Units.

Mmcf. One million cubic feet of natural gas.

Mmcfe. One million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

Productive well. A well that is found to be capable of producing sufficient quantities of oil and gas so that proceeds from the sale of the production are greater than production expenses and taxes.

Prospect A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of oil and natural gas.

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

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

Proved undeveloped reserves. Reserves that are expected to be recovered from new wells on developed acreage where the subject reserves cannot be recovered without drilling additional wells.

PV-10 value. The estimated future net revenue to be generated from the production of proved reserves discounted to present value using an annual discount rate of 10%. These amounts are calculated net of estimated production costs and future development costs, using prices and costs in effect as of a certain date, without escalation and without giving effect to non-property related expenses, such as general and administrative expenses, debt service, future income tax expense, or depreciation, depletion, and amortization.

Recompletion. The completion of an existing well for production from a formation that exists behind the casing of the well.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Royalty interest. An interest in a natural gas and oil property entitling the owner to a share of natural gas and oil production free of costs of production.

Standardized measure. The estimated future net cash flows from proved natural gas and oil reserves computed using prices and costs, at a specific date, after income taxes and discounted at 10%.

Tcfe. One trillion cubic feet of natural gas equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether such acreage contains proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed by the undersigned, thereunto duly authorized, as of April 1, 2002.

3TEC ENERGY CORPORATION
(Registrant)

By: /s/ FLOYD C. WILSON
Floyd C. Wilson
Chairman and Chief Executive Officer

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Floyd C. Wilson, his true and lawful attorney-in-fact and agent, each with full power of substitution and resubstitution, to sign any and all amendments (including post-effective amendments) to this Annual Report on Form 10-KSB and to file the same, with exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorney-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done in connection therewith, as fully to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact, or their substitute or substitutes, or any of them, shall do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated:

Signature	Title	Date
/s/ FLOYD C. WILSON Floyd C. Wilson	Chairman and Chief Executive Officer	April 1, 2002
/s/ R.A. WALKER R.A. Walker	President, Chief Financial Officer, Director	April 1, 2002
/s/ SHANE M. BAYLESS Shane M. Bayless	Vice President—Controller & Treasurer Principal Accounting Officer	April 1, 2002
/s/ LARRY J. BUMP Larry J. Bump	Director	April 1, 2002
/s/ LARRY L. HELM Larry L. Helm	Director	April 1, 2002
/s/ DAVID B. MILLER David B. Miller	Director	April 1, 2002
/s/ D. MARTIN PHILLIPS D. Martin Phillips	Director	April 1, 2002
/s/ JAMES L. IRISH III James L. Irish III	Director	April 1, 2002

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INDEPENDENT AUDITORS' REPORT

The Board of Directors and Stockholders
3TEC Energy Corporation

We have audited the accompanying consolidated balance sheets of 3TEC Energy Corporation and subsidiaries as of December 31, 2001 and 2000 and the related consolidated statements of operations, changes in stockholders' equity, and cash flows for each of the years then ended. 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 3TEC Energy 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 then ended in conformity with accounting principles generally accepted in the United States of America.

As explained in Note 1 to the Consolidated Financial Statements, the Company changed its method of accounting for derivative instruments and hedging activities in 2001.

KPMG LLP

Houston Texas
March 26, 2002

3TEC ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(in thousands, except per share data)

	December 31, 2001	December 31, 2000
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 17,762	$ 4,436
Accounts receivable	16,835	26,138
Income tax receivable	4,464	—
Other	4,473	5,390
Total Current Assets	43,534	35,964
Properties and Equipment, at cost:		
Oil and gas properties, successful efforts method	385,264	269,531
Other property and equipment	3,549	2,030
	388,813	271,561
Accumulated depletion, depreciation and amortization	(71,039)	(55,064)
Net Properties and Equipment	317,774	216,497
Other Assets, net	1,730	2,303
TOTAL ASSETS	$363,038	$254,764
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable	$ 25,052	$ 10,746
Accrued liabilities	1,322	2,192
Series C Preferred stock redemption payable	1,349	2,855
Income taxes payable	—	4,462
Other current liabilities	1,468	467
Total Current Liabilities	29,191	20,722
Long-Term Liabilities:		
Bank Debt	108,000	63,000
Senior Subordinated convertible notes	—	13,224
Other long-term liabilities	—	58
Minority Interest	—	1,394
Total Long-Term Liabilities	108,000	77,676
Deferred income taxes	45,135	6,771
TOTAL LIABILITIES	182,326	105,169
Commitments and Contingencies	—	—
STOCKHOLDERS' EQUITY		
Preferred stock, $.02 par value, 20,000,000 shares authorized 266,667 designated Series B, 2,300,000 shares designated Series C and 725,167 shares designated Series D, none other designated	—	—
Convertible preferred stock Series B, $7.50 stated value, 266,667 shares issued and outstanding. $2,000 aggregate liquidation preference	3,627	3,627
Convertible preferred stock Series D, 5% $24.00 stated value, 614,776 shares and 621,930 issued and outstanding at December 31, 2001 and December 31,2000, respectively, $14,755 aggregate liquidation preference at December 31, 2001	7,485	7,572
Common stock, $.02 par value, 60,000,000 shares authorized, 16,547,595 and 14,687,906 shares issued at December 31, 2001 and December 31, 2000, respectively	331	294
Additional paid-in capital	151,412	136,383
Retained earnings	18,906	2,768
Treasury stock; 69,807 shares at December 31, 2001 and December 31, 2000	(1,049)	(1,049)
TOTAL STOCKHOLDERS' EQUITY	180,712	149,595
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$363,038	$254,764

See accompanying notes to consolidated financial statements.

3TEC ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share data)

	Year Ended December 31, 2001	Year Ended December 31, 2000
REVENUES:		
Oil, natural gas and plant income	$ 117,885	$ 103,210
Gain on sale of properties	815	800
Gain on derivative fair value	3,081	—
Other	998	813
TOTAL REVENUES	$ 122,779	$ 104,823
EXPENSES:		
Production —		
Lease operations	$ 16,935	$ 15,326
Production, severance and ad valorem tax	7,711	6,692
Gathering, transportation and other	3,829	2,223
Geological and geophysical	1,172	666
Dry hole and impairments	12,261	29
Surrendered and expired acreage	7,875	—
General and administrative	6,991	6,141
Interest	6,773	7,556
Depreciation, depletion and amortization	30,983	19,779
Other	250	—
TOTAL EXPENSES	$ 94,780	$ 58,412
INCOME BEFORE INCOME TAXES, MINORITY INTEREST AND DIVIDENDS TO PREFERRED STOCKHOLDERS	27,999	46,411
Minority Interest	511	305
Income Tax Expense	10,640	14,442
NET INCOME	16,848	31,664
Dividends to preferred stockholders	710	1,488
NET INCOME ATTRIBUTABLE TO COMMON STOCKHOLDERS	$ 16,138	$ 30,176
EARNINGS PER COMMON SHARE:		
Basic	$ 1.06	$ 2.91
Diluted	$ 0.91	$ 2.28
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:		
Basic	15,170,116	10,382,836
Diluted	18,968,973	13,894,961

See accompanying notes to consolidated financial statements.

3TEC ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31, 2001	Year Ended December 31, 2000
OPERATING ACTIVITIES		
Net income	16,848	31,664
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	30,265	18,713
Amortization of debt issue costs and other	967	1,066
Dry hole and impairments	12,261	29
Surrendered and expired leases	7,875	—
Gain on derivative fair value	(3,081)	—
Gain on sale of properties	(815)	(800)
Deferred income taxes	9,017	6,480
Minority interest	511	305
Other changes	166	—
Changes in operating assets and liabilities:		
Accounts receivable and other current assets	9,961	(21,706)
Account payable and accrued liabilities	5,805	8,717
CASH PROVIDED BY OPERATING ACTIVITIES	89,780	44,468
INVESTING ACTIVITIES		
Proceeds from sales of oil and gas properties	36,818	5,840
Acquisition of Magellan Exploration LLC, net of cash acquired	—	418
Acquisition of Classic Resources, Inc. net of cash acquired	(58,670)	—
Acquisition of Enex Resources Corporation	(3,803)	—
Acquisition of oil and gas properties	(22,380)	(64,612)
Development of oil and gas properties	(72,554)	(24,091)
Additions of other assets	(1,930)	(1,326)
CASH USED BY INVESTING ACTIVITIES	(122,519)	(83,771)
FINANCING ACTIVITIES		
Proceeds from long-term debt	130,000	66,100
Proceeds from issuance of common stock	—	68,103
Proceeds from exercise of stock options and warrants	1,590	705
Payments on long-term debt	(85,000)	(90,600)
Preferred stock dividends	(525)	(1,369)
Treasury stock purchase—Alabama dissenters	—	(981)
Redemption of Preferred Series C stock	—	(1,433)
Debt, common stock and preferred stock issue and registration costs	—	(2,927)
CASH PROVIDED BY FINANCING ACTIVITIES	46,065	37,598
(DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	13,326	(1,705)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	4,436	6,141
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 17,762	$ 4,436
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:		
Cash paid during the year for:		
Interest	$ 6,795	$ 7,539
Income Taxes	10,571	3,500
Non-cash investing and financing activities:		
Common stock and warrants issued in acquisition of Magellan Exploration LLC	—	10,573
Preferred Stock Series D issued in acquisition of Magellan Exploration LLC	—	7,453
Preferred Stock Series C conversions to common stock	—	362
Preferred dividends incurred but not paid	185	—
Common stock repurchase contingency accrual—Alabama dissenters	—	138
Conversion of Preferred Series C into Common Stock	—	910
Preferred dividends paid in-kind	—	118
Liability for redemption of Preferred Stock Series C	—	2,856
Deferred taxes recorded in acquisition of Classic Resources, Inc.	29,347	—

See accompanying notes to consolidated financial statements.

3TEC ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

YEARS ENDED DECEMBER 31, 2001 AND 2000
(in thousands, except shares)

	Preferred Stock											
	Series B		Series C		Series D		Common Stock			Accumulated Earnings (Deficit)	Treasury Stock Par	Stockholders' Equity
	Shares	Par	Shares	Par	Shares	Par	Shares	Par	Paid-in			
Balance January 1, 2000	266,667	$3,627	1,139,506	$5,198	—	—	5,338,771	$107	$ 57,775	$(27,408)	$(1,187)	$ 38,112
Common stock ussued in merger with Magellan Exploration LLC							1,085,934	22	10,251			10,273
Warrants issued in merger with Magellan Exploration LLC									300			300
Preferred Series D issued in merger with Magellan Exploration LLC					617,009	7,453						7,453
Stockholder dissenters repurchase contingency adjustment											138	138
Preferred Series C conversions			(72,496)	(362)			63,465	1	361			—
Common stock issued							8,050,000	161	67,943			68,104
Common stock offering and registration costs									(1,497)			(1,497)
Preferred Series C redemption			(1,067,010)	(4,836)			36,527	1	547			(4,288)
Reverse split fractional shares							(314)					—
Employee stock option exercises							95,190	2	648			650
Warrant exercises							18,333		55			55
Net Income										31,664		31,664
Preferred stock dividends					4,921	119				(1,488)		(1,369)
Balance December 31, 2000	266,667	$3,627	—	—	621,930	$7,572	14,687,906	$294	$136,383	$ 2,768	$(1,049)	$149,595
Employee stock option exercises							81,682	2	739			741
Preferred Series D Conversions					(7,154)	(87)	7,154		85			(2)
Warrant exercises							283,047	6	843			849
Senior subordinated debt conversions							1,487,806	29	13,362			13,391
Net Income										16,848		16,848
Preferred stock dividends										(710)		(710)
Balance December 31, 2001	266,667	$3,627	—	$ —	614,776	$7,485	16,547,595	$331	$151,412	$ 18,906	$(1,049)	$180,712

See accompanying notes to consolidated financial statements

(1) ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization

3TEC Energy Corporation, (formerly Middle Bay Oil Company, Inc.), was incorporated under the laws of the state of Alabama on November 20, 1992. The Company was reincorporated in Delaware on December 7, 1999 and changed its name to 3TEC Energy Corporation. The reincorporation and name change were part of a series of transactions related to a securities purchase agreement that closed on August 27, 1999 between the Company and W/E Energy Company, LLC ("W/E LLC"), formerly known as 3TEC Energy Company, LLC, whereby the Company received $21.4 million in cash and oil and natural gas properties for the sale of common stock, warrants and debt securities (See Note 3).

3TEC Energy Corporation and its subsidiaries (the "Company") are engaged in the acquisition, development, production and exploration of oil and natural gas in the contiguous United States. The Company considers its business to be a single operating segment. Effective November 23, 1999, the Company acquired oil and natural gas properties and interests managed by Floyd Oil Company from a group of private sellers. Effective February 3, 2000, the Company acquired oil and natural gas properties through a merger with Magellan Exploration, LLC. Effective May 31, 2000, the Company acquired oil and natural gas properties from C.W. Resources, Inc. Effective November 15, 2000, the Company acquired oil and natural gas properties from H.G. Westerman and a group of private sellers. Effective January 31, 2001, the Company acquired oil and natural gas properties through the purchase of the stock of Classic Resources, Inc.

Significant Accounting Policies

The Company's accounting policies reflect industry standards and conform to generally accepted accounting principles. The more significant of such policies are described below.

Principles of Consolidation

The consolidated financial statements include the accounts of the Company and Enex Resources Corporation ("Enex") which prior to December 31, 2001 was an 80% owned subsidiary. The equity of the minority interests in Enex is shown in the consolidated financial statements as "minority interest". On December 31, 2001, the Company acquired the remaining 20% of Enex pursuant to the merger of Enex into a wholly-owned subsidiary of the Company for cash consideration of $14.00 per share. All significant intercompany balances and transactions have been eliminated in consolidation.

Reclassifications

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

Consolidated Statements of Cash Flows

For the purpose of cash flows, the Company considers all highly liquid investments with a maturity date of three months or less to be cash equivalents. Significant transactions may occur which do not directly affect cash balances and as such will not be disclosed in the Consolidated Statements of Cash Flows. Certain of such non-cash transactions are disclosed in the Consolidated Statements of Shareholders' Equity relating to shares issued as compensation, and shares issued for stock and debt of an acquired company.

Oil and Gas Properties

The Company follows the successful efforts method of accounting for oil and natural gas properties, and accordingly, capitalizes all direct costs incurred in connection with the acquisition, drilling and development of productive oil and natural gas properties. Costs associated with unsuccessful exploration are charged to expense currently. Geological and geophysical costs and costs of carrying and retaining unevaluated properties are charged to expense. Depreciation, depletion and amortization of capitalized costs are computed separately for each field based on the unit-of-production method using only proved oil and natural gas reserves. In arriving at such rates, commercially recoverable reserves have been estimated by an independent petroleum engineering firm. The Company reviews its undeveloped properties continually and charges them to expense on a property-by-property basis when it is determined that they have been condemned by dry holes, or have otherwise diminished in value. The Company recorded surrendered and expired acreage expense on its undeveloped properties for the year ended December 31, 2001 of approximately $7.9 million and no surrendered and expired acreage expense during 2000. Gains and losses are recorded on sales of interests in proved properties and on sales of entire interests in unproved properties. For the years ended December 31, 2001 and 2000, the Company realized gains on sales of properties of $0.8 million and $0.8 million, respectively.

Proved oil and natural gas reserves are the estimated quantities of oil, natural gas and natural gas liquids which are expected to be recoverable in future years from known reservoirs under existing economic and operating conditions. Reservoirs are considered proved if economic productability is supported by either actual production or conclusive formation tests.

The Company reviews long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such an asset may not be recoverable. This review consists of a comparison of the carrying value of the asset to the asset's expected future undiscounted cash flows. Estimates of expected future cash flows represent management's best estimate based on reasonable and supportable assumptions and projections. If the expected future cash flows, assuming escalated prices, are less than the carrying value of the asset, an impairment exists and is measured as the excess of the carrying value over the estimated fair value of the asset. The Company estimates discounted future net cash flows to determine fair value. Any impairment provisions recognized are permanent and may not be restored in the future. For the years ended December 31, 2001 and 2000, the Company's proved properties were assessed for impairment on an individual field basis and the Company recorded impairment provisions on certain producing properties of $3.4 and $-0- million, respectively.

Revenue Recognition of Production Imbalances

Oil and natural gas revenues are recorded using the sales method, whereby the Company recognizes revenues based on the amount of oil and natural gas sold to purchasers on its behalf not-withstanding its ownership percentage. At December 31, 2001 and 2000, the Company's net imbalance position was immaterial.

Hedging

In June 1998, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities ("SFAS 133"). In June 2000, the FASB issued SFAS 138, Accounting for Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133. SFAS 133, as amended, establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or liability measured at its fair market value. The statement requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement, and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting. The Company adopted SFAS 133 effective January 1, 2001. Based upon the historical volatility of oil and gas commodity prices, the Company expects that SFAS 133 could increase volatility in the Company's earnings and other comprehensive income for periods where hedging activities are present.

SFAS 133, in part, allows hedge accounting. SFAS 133 provides that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of other comprehensive income and be reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument, if any, must be recognized currently in earnings.

To qualify for cash flow hedge accounting, the cash flows from the hedging instrument must be highly effective in offsetting changes in cash flows due to changes in the underlying items being hedged. In addition, all hedging relationships must be designated, documented, and reassessed periodically. The Company's natural gas derivative instruments entered into during the period were not designated as hedges at the time the instruments were executed. In accordance with provisions of SFAS 133, these instruments have been marked-to-market through earnings at December 31, 2001, resulting in an increase to revenues of $3.1 million. There were no derivatives in place at December 31, 2000.

Earnings Per Share

Basic earnings and loss per common share are based on the weighted average shares outstanding without any dilutive effects considered. Diluted earnings and loss per share reflect dilution from all potential common shares, including options, warrants and convertible preferred stock and convertible notes. Diluted loss per share does not include the effect of any potential common shares if the effect would be to decrease the loss per share.

At December 31, 2001, the Company had a weighted average of 3,798,857, combined stock options, warrants and convertible preferred stock outstanding included in the Company's fully-diluted per share calculation. At December 31, 2000, the Company had a weighted average of 3,789,456, combined stock options, warrants and convertible preferred stock and notes outstanding.

All share and per share amounts have been retroactively adjusted for a one-for-three reverse split that was approved by the Company's shareholders on January 14, 2000.

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 carryforwards. 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 the enactment date.

Concentrations of Market Risk

The future results of the Company will be affected by the market prices of oil and natural gas. The availability of a ready market for oil and natural gas in the future will depend on numerous factors beyond the control of the Company, including weather, production of other oil and natural gas, imports, marketing of competitive fuels, proximity and capacity of oil and natural gas pipelines and other transportation facilities, any oversupply or undersupply of oil and natural gas, the regulatory environment, and other regional and political events, none of which can be predicted with certainty.

Concentrations of Credit Risk

Financial instruments which subject the Company to concentrations of credit risk consist primarily of cash and accounts receivable. The Company places its cash investments with high credit qualified financial institutions. Risk with respect to receivables is concentrated primarily in the current production revenue receivable from multiple oil and natural gas purchasers, and is typical in the industry. For 2001, Calpine Producer Services, L.P. (formerly Highland Energy Company) and Wagner & Brown, Ltd. accounted for approximately 22% and 19% of total oil and natural gas sales, respectively. No single customer accounted for greater than 10% of the Company's total oil and natural gas sales for the year ended December 31, 2000.

Use of Estimates

Management of the Company has made a number of estimates and assumptions relating to the reporting of assets and liabilities to prepare the financial statements in conformity with generally accepted accounting principles. Actual results could differ from these estimates.

(2) ACQUISITIONS AND DIVESTITURES

On January 30, 2001, the Company acquired 100% of the issued and outstanding stock of Classic Resources Inc. (the "Classic Acquisition") for cash consideration of approximately $53.5 million plus other acquisition costs. The operating results of the Classic Acquisition have been included in the consolidated financial statements since that date. Classic was a privately-held exploration and production company with properties located in East Texas. The Company's estimate of total net proved at the time of the acquisition for Classic's oil and gas properties was 47 Bcfe and net daily production of approximately 11 Mmcfe. The Company financed the acquisition under its existing Credit Facility. The purchase price of the Classic Acquisition was allocated principally to proved properties, with additional amounts allocated to working capital related to amounts recorded for production related receivables and payables in existence and accrued for at January 20, 2001.

On May 31, 2000, we completed the acquisition of the CWR Properties (the "CWR Acquisition") located in East Texas for cash consideration of approximately $51.7 million. The effective date of the acquisition was January 1, 2000, and the operations are included in the Company's consolidated financial statements beginning June 1, 2000. The CWR Acquisition was financed under our existing Credit Facility, which we amended prior to closing the acquisition. The total purchase price was allocated principally to oil and natural gas properties using the purchase method of accounting.

On February 3, 2000, we completed the acquisition of Magellan Exploration LLC (the "Magellan Acquisition"), from certain affiliates of EnCap Investments L.L.C. ("EnCap"), a Delaware limited liability company and an investor in W/E LLC, and other third parties for consideration consisting of (a) 1,085,934 shares of common stock, (b) four year warrants to purchase up to 333,333 shares of common stock at $30.00 per share, (c) 617,009 shares of 5% Series D Convertible Preferred Stock with a redemption value of $24.00 per share and (d) the assignment of a performance based "back-in" working interest of 5% of Magellan's interest in 12 exploration prospects. The total purchase price of approximately $19 million was allocated principally to proved undeveloped oil and natural gas properties using the purchase method of accounting.

The following pro forma data presents the results of the Company for the year ended December 31, 2000, as if the Classic Acquisition and the CWR Acquisition had occurred on January 1, 2000, and the results of the Company for the year ended December 31, 2001 as if the Classic Acquisition had occurred on January 1, 2001. The unaudited pro forma data assumes the acquisition of the respective properties and the debt financing transactions related to these acquisitions. The unaudited pro forma results are presented for comparative purposes only and are not necessarily indicative of the results which would have been obtained had the acquisitions been consummated as presented. (in thousands, except per share amounts):

	Pro Forma Year Ended December 31, 2001	Pro Forma Year Ended December 31, 2000
	(unaudited)	(unaudited)
Total revenues	$121,813	$121,724
Net income attributable to common stockholders	13,958	24,266
Net income per basic share attributable to common stockholders	$ 0.92	$ 2.34

During 2001, the Company completed the sale of certain non-strategic oil and gas properties for net cash proceeds of approximately $36.7 million. In order to defer the tax gain on the sales of the properties, the Company successfully replaced a portion of these properties in accordance with the Like-Kind Exchange regulations of the Internal Revenue Service. At December 31, 2001, the Company had $13.9 million of cash in like-kind escrow accounts. In January 2002, the like-kind replacement term expired in accordance with the Internal Revenue Service regulations and the balance of the escrow accounts were used to reduce borrowings under the Company's Credit Facility.

(3) COMMON STOCK, WARRANT AND SENIOR SUBORDINATED CONVERTIBLE NOTE SALE TO W/E ENERGY COMPANY, L.L.C. ("W/E LLC")

On August 27, 1999, the Company closed a Securities Purchase Agreement (the "Agreement") for a total of $21.4 million with W/E LLC. The Securities Purchase Agreement and contemplated transactions were approved by the stockholders at the Company's annual meeting on August 10, 1999.

The controlling person of W/E LLC was EnCap. The sole member of EnCap is El Paso Field Services Company, a Delaware corporation ("El Paso Field Services"). The controlling person of El Paso Field Services is El Paso Corporation, a Delaware corporation. The Company received $9.8 million in cash and properties valued at $875,000 for 1,585,185 shares of common stock and 1,200,000 warrants (the "Warrants") and $10.7 million for a 5-year senior subordinated convertible note with a face value of $10.7 million (See Note 6).

On November 28, 2001, W/E LLC was dissolved and all shares of common stock and warrants of the Company held by W/E LLC were distributed to its members.

(4) RELATED PARTY TRANSACTIONS

David B. Miller and D. Martin Phillips, directors of the Company, are managing directors of EnCap, which was the controlling person of W/E LLC. Floyd C. Wilson, Chairman and Chief Executive Officer of the Company, was also a member of W/E LLC. Gary R. Christopher, a shareholder and director of the Company until December 31, 2001, is employed by Kaiser-Francis Oil Co., which owns approximately 7% of the common stock of the Company as of December 31, 2001.

In 2000, the Company paid EnCap a fee of $500,000 in connection with a private equity shelf facility related to the CWR Acquisition. As required by the Company's Credit Facility, the private equity shelf facility would have allowed the Company to require EnCap Investments to purchase up to $20 million of a new class of exchangeable preferred stock from the Company. Upon completion of the Company's public offering of common stock on June 30, 2000, the shelf facility expired.

The Company has a $250 million credit facility (the "Credit Facility") with Bank One, NA, as administrative agent, Bank of Montreal, as syndication agent, and Union Bank of California, N.A., Wells Fargo Bank Texas, National Association, CIBC, Inc., Comerica Bank, Fleet National Bank and The Bank of Nova Scotia as participating lenders. The borrowing base is redetermined semi-annually and as of December 31, 2001, was $145 million. In addition, the Company is a party to certain derivative contracts that Bank One, NA is the counter-party to. These derivative contracts cover a portion of the Company's anticipated natural gas production for 2002. Larry L. Helm, a director of the Company, is responsible for the nationwide Middle Market Banking Group of Bank One Corporation.

(5) LONG-TERM DEBT

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

	2001	2000
$250 million Credit Facility	$108,000	$63,000
Less current maturities	—	—
Long-term debt excluding current maturities	$108,000	$63,000

The Company's Credit Facility with Bank One, NA as agent and seven other banks. The Credit Facility as amended, matures May 31, 2003. As of December 31, 2001, the borrowing base was set at $145 million. The borrowing base is to be redetermined semi-annually on May 1 and November 1 and provides for interest as revised under the Credit Facility to accrue at a rate calculated at the Company's option as either the bank's prime rate plus a low of zero to a high of 50 basis points or LIBOR plus basis points increasing from a low of 150 to a high of 212.5 as loans outstanding increase as a percentage of the borrowing base. As of December 31, 2001, the Company was paying an average of 3.68% per annum interest on the principal balance of $108 million under the Credit Facility. Prior to maturity, no payments of principal are required so long as the borrowing base exceeds the loan balance. The borrowings under the Credit Facility are secured by substantially all of the Company's oil and natural gas properties. At December 31, 2001, the amount available to be borrowed under the Credit Facility was approximately $37 million. Additionally, at December 31, 2001, the Company had approximately $13.9 million in cash held in like-kind exchange escrow accounts. The Company used these funds to repay borrowings under the Credit Facility in January, 2002. At March 7, 2002, borrowings under the Credit Facility totaled $97 million.

The Credit Facility is governed by various financial and other covenants, including requirements to maintain a current ratio of one to (1:1), and an interest rate coverage ratio. Additionally, limitations on asset dispositions, declaration and payment of cash dividends and the entering into hedge transactions without the bank's consent are included. Aggregate amounts of expected required repayments of long term debt at December 31, 2001 are as follows (in thousands):

2002	$ —
2003	108,000
2004	—
Thereafter	—
Total	$108,000

(6) SENIOR SUBORDINATED CONVERTIBLE NOTES

On August 27, 1999, senior subordinated convertible promissory notes (the "Senior Subordinated Notes") were sold to W/E LLC and affiliates of Alvin V. Shoemaker ("Shoemaker"), a former director and significant shareholder, for $10.7 million and $0.2 million, respectively. On October 19, 1999, $2.4 million of Senior Subordinated Notes were sold to The Prudential Insurance Company of America ("Prudential"). The Senior Subordinated Notes bore interest at an annual rate of 9%. Interest was payable beginning on December 31, 1999, every March 31, June 30, September 30 and December 31, until maturity on August 27, 2004. The Company may defer payment of fifty percent (50%) of the first eight quarterly interest payments. The Senior Subordinated Notes could be prepaid, without premium or penalty, in whole or in part, at any time after August 27, 2001. The holders of the Senior Subordinated Notes could convert all or any portion of outstanding principal and accrued interest at any time into shares of Company common stock at a conversion price of $9.00 per common share, a total of 1,469,316 common shares. The conversion price could be adjusted from time to time based on the occurrence of certain events. In the event of a change in control, the entire outstanding principal balance and all accrued but unpaid interest is immediately due and payable.

The Senior Subordinated Notes ranked senior in right of payment to all Company notes and indebtedness other than the Credit Facility.

During the second quarter of 2001, the Company received notice of an election by Shoemaker to convert approximately $0.2 million of Senior Subordinated Notes. The conversion resulted in the retirement of $0.2 million in senior subordinated debt and the issuance of an additional 16,666 shares of common stock of the Company.

During the third quarter of 2001, the Company sent notice of an election to W/E LLC to prepay the $10.7 million of Senior Subordinated Notes. Pursuant to the terms of the convertible note agreement, W/E LLC elected instead to exercise its right to convert the principal and accrued interest outstanding into common shares of the Company. Under the terms of the convertible note agreement, the balance of the note plus any accrued interest was to be converted at $9.00 per share. The conversion by W/E LLC resulted in the retirement of approximately $10.7 million in senior subordinated debt and the issuance of an additional 1,206,127 shares of common stock of the Company.

During the fourth quarter of 2001, the Company received notice of an election by Prudential to convert approximately $2.4 million of Senior Subordinated Notes. The conversion resulted in the retirement of $2.4MM in senior subordinated debt and the issuance of an additional 265,013 shares of common stock of the Company.

(7) INCOME TAXES

The components of income tax expense for the years ended December 31, 2001 and 2000 consisted of the following (in thousands):

	2001			2000		
	Federal	State	Total	Federal	State	Total
Current	$1,143	$ 479	$ 1,622	$ 6,120	$1,842	$ 7,962
Deferred	7,582	1,436	9,018	6,224	256	6,480
Total	$8,725	$1,915	$10,640	$12,344	$2,098	$14,442

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

	December 31, 2001	December 31, 2000
Income tax provision at statutory rate	$ 9,800	$16,137
State income taxes, net of federal benefit	1,224	1,364
Decrease in valuation allowance	—	(2,523)
Utilization of Sec. 29 tax credits	(500)	(400)
Other	116	(136)
Total	$10,640	$14,442

The Company's net deferred tax liability at December 31, 2001 and 2000 is as follows (in thousands):

	2001	2000
Deferred tax liability		
Oil and natural gas properties	$47,563	$ 9,547
Deferred tax asset		
NOL carryforward	(5,237)	(5,812)
AMT tax credit carryforward	(327)	(36)
Other	(430)	(495)
	(5,994)	(6,343)
Valuation allowance	3,566	3,566
Net deferred tax liability	$45,135	$ 6,770

In connection with the Classic Acquisition, the Company recorded $29.3 million in deferred taxes for the future tax impact of the difference between the allocated book basis and the historical tax basis of the Classic Properties.

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax asset will not be realized. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income, and tax planning strategies in making this assessment. Based upon projections for future taxable income over the periods in which the deferred tax assets are deductible and the Section 382 limitation discussed below, management believes it is more likely than not that the Company will realize the benefits of these deductible differences, net of the existing valuation allowances at December 31, 2001 and 2000. The net change in the total valuation allowance for the years ended December 31, 2001 and 2000 was $-0- and $2.5 million and the amount remaining at December 31, 2001 is $3.6 million.

The Enex acquisition caused an ownership change pursuant to Section 382 in March 1998. As a result of this ownership change, the Company's use of its net operating loss carryforwards subsequent to that date will be limited. The Floyd Oil Acquisition in November 1999 also caused an ownership change pursuant to Section 382. As a result of these changes, the Company's use of its net operating loss carryforwards subsequent to that date will be limited. In February 2000, Enex had an ownership change pursuant to Section 382 with respect to its net operating losses.

As of December 31, 2001, the Company had net operating loss carryforwards of approximately $14.9 million, expiring beginning in 2009 through 2019.

(8) RETIREMENT PLAN AND EMPLOYEE INCENTIVE PLAN

All of the employees of the Company are eligible to participate in a defined contribution plan that provides for maximum employee contributions of 15% of total wages paid to employees for the year and Company contributions. Company contributions made to the plan for the years ending December 31, 2001 and 2000 were $462,763 and $135,225, respectively.

(9) STOCK OPTION PLANS

The Company's stock option plans authorize the granting of options to key employees and non-employee directors at prices equivalent to the market value at the date of grant. Options generally become exercisable in the following manner: 50% upon the date of grant with the remaining 50% exercisable in three annual installments commencing one year after the date of grant and, if not exercised, expire 10 years from the date of grant. The Company accounts for employee stock-based compensation using the intrinsic value method and since the exercise price of the options granted is equal to the quoted market price of the Company's stock at the grant date, no compensation costs have been recognized for its stock option plans. Had compensation cost for the Company's Plans been determined based on the fair value at the grant date for stock options granted for the years ending December 31, 2001 and 2000, the Company's net income and income per share would have been adjusted to the pro forma amounts listed below (in thousands, except per share amounts):

	December 31, 2001	December 31, 2000
Net Income attributable to Common Stockholders		
As Reported	$16,137	$30,176
Pro Forma	$13,446	$21,889
Net Income per common share, diluted		
As Reported	$ 0.91	$ 2.28
Pro Forma	$ 0.77	$ 1.58

The fair value of grants was estimated on the date of grant using the Black Scholes option pricing model with the following weighted-average assumptions used in 2001 and 2000, respectively: risk free interest rates of 3.96% and 6.48%, expected volatility of 69% and 72%, no dividend yield, and an expected life of the option of 3 years in 2001 and 2000. The weighted average fair value of stock options granted in 2001 and 2000 was $7.02 and $5.72 per share, respectively.

A summary of the status of the Company's plans as of December 31, 2001 and 2000, and changes during the years ended on those dates is presented below:

	Shares	Average Exercise Price Per Share
Options outstanding at January 1, 2000	335,922	$15.00
Granted in 2000	2,898,500	$11.07
Exercised in 2000	(95,190)	$ 6.83
Forfeited in 2000	(248,160)	$16.39
Options outstanding at December 31, 2000	2,891,072	$11.15
Granted in 2001	502,835	$14.67
Exercised in 2001	(81,682)	$ 9.12
Forfeited in 2001	(36,729)	$18.53
Options outstanding at December 31, 2001	3,275,496	$11.66
Options outstanding at December 31, 2000	2,891,072	$11.15
Options exercisable at December 31, 2001	2,058,765	11.45
Options exercisable at December 31, 2000	1,442,995	11.16
Options available for grant at December 31, 2001	1,012,527	
Options available for grant at December 31, 2000	275,298	

At December 31, 2001, the range of exercise prices and weighted average remaining contractual life of options outstanding was $4.50 to $18.56 and 8.78 years, respectively.

Warrants to purchase 1,216,822 shares and 266,226 shares of common stock at $3.00 per share were issued on August 27, 1999 and October 19, 1999, respectively, and warrants to purchase 333,333 shares of common stock at $30.00 per share were issued on February 3, 2000, are excluded from the table above because the warrants were issued in conjunction with the sales of stock and are not stock-based compensation. During 2001, warrants to purchase 283,047 shares of common stock at $3.00 were exercised.

(10) STOCKHOLDERS' EQUITY

Preferred Stock—Series B

In connection with the merger of Shore Oil Company, effective June 30, 1997, the Company issued 266,667 shares of Series B Preferred Stock ("Series B"). The Series B is nonvoting and pays no dividends. The Series B has a liquidation value of $7.50 a share. Until December 31, 2002, any holder of the Series B may convert all or any portion of Series B shares into shares of Company Common Stock ("Common"). The number of shares of Common into which the total number of Series B shares may be converted is 88,889 shares plus the result of multiplying (i) (the value of approximately 40,000 net mineral acres owned by the Company in South Louisiana (the "Mineral Acres") minus $2,000,000) divided by $8,000,000 times (ii) 355,555. In no event shall the aggregate total number of shares of Common into which the Series B are converted exceed 444,444 shares. Unless the Company has given notice to redeem the Series B shares, any outstanding shares of Series B shall be automatically be converted on December 31, 2002.

At December 31, 2001, the value of the Mineral Acres had increased to a level that resulted in the 266,667 shares of Series B being convertible into 154,591 shares of Common. At December 31, 2001, none of the Series B had been converted.

Preferred Stock—Series C

On August 31, 2000, the Company sent notices to the holders of its Series C Preferred Stock (the "Series C") advising that the Series C would be redeemed on September 30, 2000. The Series C had a redemption price of $5.00 per share and the holders had the right to convert their Series C shares into Company common stock at a ratio of one share of common for three shares of Series C prior to September 30, 2000. A total of 2,101,827 shares of the Series C were outstanding on September 30, 2000 with 1,293,521 (62%) held by the Company's then 80% owned subsidiary, Enex. 109,580 Series C shares were converted to 36,527 shares of common stock and approximately 1,992,247 Series C shares were redeemed. On a consolidated basis, the Company's initial liability for the Series C redemption was approximately $4.8 million. As a result of the Series C redemption, the Company recognized a charge to dividend expense in 2000 of $498,706. At December 31, 2001, $1.3 million remained to be funded.

Preferred Stock—Series D

On February 3, 2000, we completed the Magellan Acquisition, from certain affiliates of EnCap and an investor in W/E LLC, and other third parties for consideration consisting of (a) 1,085,934 shares of common stock, (b) four year warrants to purchase up to 333,333 shares of common stock at $30.00 per share, (c) 617,009 shares of 5% Series D Convertible Preferred Stock with a redemption value of $24.00 per share and (d) the assignment of a performance based "back-in" working interest of 5% of Magellan's interest in 12 exploration prospects. The total purchase price of approximately $19 million was allocated principally to proved undeveloped oil and natural gas properties. During 2001, 7,154 shares of the Series D were converted to common stock.

Common Stock

On June 30, 2000, the Company completed its public offering of 8.05 million shares of the Company's common stock (priced at $9.00 per share). The net proceeds, approximately $66.6 million, were used primarily to repay a portion of the outstanding debt under the amended Credit Facility.

On January 14, 2000, the Company's stockholders voted to affect a one-for-three reverse split of the Company's common stock for the stockholders of record on December 9, 1999. The par value of these shares was transferred to additional paid-in capital. All common share and earnings per common share amounts have been retroactively restated in the accompanying consolidated financial statements to reflect the reverse stock split.

On August 27, 1999, the Company sold to W/E LLC 1,585,185 shares of common stock and five-year warrants to purchase 1,200,000 shares of common stock for $9.8 million in cash and oil and natural gas properties valued at $0.9 million. On the same date, the Company sold 22,222 shares of common stock and five-year warrants to purchase 16,822 shares of common stock to Shoemaker for $0.2 million (See Notes 3 and 6).

On October 19, 1999, the Company closed a private placement of securities to Prudential. The economic terms and conditions of the private placement are similar to those of the securities purchase agreement with W/E LLC and Shoemaker entered into on July 1, 1999. The private placement consisted of the sale of 351,681 shares of common stock and five-year warrants to purchase 266,226 shares at $3.00 per share of common stock for $2.4 million and a five-year senior subordinated convertible note for $2.4 million (See Note 6).

The warrants issued to W/E LLC, Shoemaker and Prudential are exercisable for $3.00 per share and expire five years from the issue date. Sixty percent of the warrants were immediately exercisable, in whole or in part at any time until the expiration date. An additional 10% of the warrants may be exercised at each anniversary of the grant date until expiration. At December 31, 2001, 1,200,000 warrants were exercisable. As a result of the conversion of the entire principal balance of the Senior Subordinated Notes during 2001, all of the warrants became immediately exercisable. During 2001, warrants to purchase 283,047 shares of common stock at $3.00 were exercised.

(11) COMMITMENTS AND CONTINGENCIES

On November 18, 1999, the Company's shareholders approved a reincorporation of the Company from Alabama to Delaware (See Note 1). The Alabama Code has a shareholder dissent provision that allows a shareholder to dissent from the reincorporation and demand cash payment equal to the fair value of the common stock owned at the date of the reincorporation. Before the November 18 meeting, the Company received shareholder dissents representing ownership of 99,438 shares of common stock. Over the period December 15, 1999 to January 25, 2000, the Company received formal demands for payment from the dissenting shareholders (the "dissenters"). At December 31, 1999 the Company had accrued the estimated cash payment to the dissenters of approximately $1.1 million. The Company made an offer to the dissenters on March 14, 2000 and the dissenters made a counteroffer in late March. On May 26, 2000, the Company agreed to a settlement with the dissenters for them to surrender 62,549 shares of common stock for a total of $980,800, including interest. The settlement closed on June 30, 2000 and the shares are held by the Company as treasury stock. A shareholder holding 36,889 shares of common stock agreed to withdraw his dissent.

Commitments and Contingencies

The Company has commitments for operating leases (primarily for office space) in Houston, Texas. Rental expense for office space was $670,842 in 2001 and $390,452 in 2000. Future minimum lease commitments at December 31, 2001 are $1,141,980 in 2002; $1,308,336 in 2003; $1,342,046 in 2004; $889,263 in 2005; $847,822 in 2006; and $1,769,192 in years thereafter.

The Company is a defendant in various legal proceedings which are considered routine litigation incidental to the Company's business, the disposition of which management believes will not have a material effect on the financial position or results of operations of the Company.

(12) ACCOUNTING PRONOUNCEMENTS

In October, 2001, the FASB issued SFAS 144, Accounting for the Impairment or Disposal of Long-Lived Assets, which addresses financial accounting and reporting for the impairment or disposal of long-lived assets. While SFAS 144 supersedes SFAS 121, Accounting for the Impairment of Long-Lived Assets and for Long Lived Assets to Be Disposed Of, it retains many of the fundamental provisions of that Statement.

SFAS 144 also supersedes the accounting and reporting provisions of APB Opinion No. 30, Reporting the Results of Operations—Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions, for the disposal of a segment of business. However, it retains the requirement in Opinion 30 to report separately discontinued operations and extends that reporting to a component of an entity that either has been disposed of (by sale, abandonment, or in a distribution to owners) or is classified as held for sale. By broadening the presentation of discontinued operations to include more disposal transactions, the FASB has enhanced managements ability to provide information that helps financial statement users to assess the effects of a disposal transaction on the ongoing operations of an entity.

Statement No. 144 is effective for fiscal years beginning after December 15, 2001 and interim periods within those fiscal years. The Company does not anticipate the adoption of SFAS 144 to have a material adverse impact on its financial position or results of operations.

In August, 2001, the FASB issued SFAS 143, "Accounting for Asset Retirement Obligations". SFAS 143 addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. The standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and (or) normal use of the asset. SFAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset and this additional carrying amount is depreciated over the life of the asset. The liability is accreted at the end of each period through charges to operating expense. If the obligation is settled for other than the carrying amount of the liability, the Company will recognize a gain or loss on settlement.

Implementation of SFAS 143 is required for fiscal year 2003. To accomplish this, the Company must identify all legal obligations for asset retirement obligations, if any, and determine the fair value of these obligations on the date of adoption. The determination of fair value is complex and will require the Company to gather market information and develop cash flow models. Additionally, the Company will be required to develop processes to track and monitor theses obligations. Due to the effort necessary to comply with the adoption of SFAS 143, it is not practicable for management to estimate the impact of adopting SFAS 143 at the date of this report.

In July 2001, the FASB issued SFAS 141, "Business Combinations' and SFAS 142, "Goodwill and Other Intangible Assets". SFAS 141 requires that all business combinations be accounted for under the purchase method and that certain intangible assets in a business combination be recognized as assets apart from goodwill. The company is required to implement SFAS 141 for all business combinations for which the date of acquisition is July 1, 2001 or later. SFAS 142 requires that ratable amortization of goodwill be replaced with periodic tests of the impairment of goodwill and that intangible assets other than goodwill should be amortized over their useful lives. Implementation of SFAS 142 is required for fiscal year 2002. The Company does not anticipate the adoption of SFAS 142 to have a material adverse impact on its financial position or results of operations.

(13) FINANCIAL INSTRUMENTS

Oil and Natural Gas Derivatives

At December 31, 2001, the Company has a collar on 40,000 Mmbtu of daily natural gas production for the NYMEX contract period of January through March of 2002, with a floor of $2.67/Mmbtu and a ceiling of $3.15/Mmbtu. Additionally, 3TEC has placed 56,000 Mmbtu of daily natural gas production from April through October of 2002 into a collar with a floor of $2.90/Mmbtu and an average ceiling of $3.38/Mmbtu. The fair value of these contracts at December 31, 2001 was approximately $3.1 million. The Company did not designate these derivative instruments as hedges as such these contracts have been marked-to-market through earnings at December 31, 2001 and will be during each quarter that the contract is outstanding.

During February 2002, the Company unwound the April through October 2002 collar for net proceeds of approximately $5.8 million ($.48 per Mmbtu), and then swapped 56,000 Mmbtu of daily natural gas production at $2.56/Mmbtu. Also during February 2002, the Company put in place a collar on 20,000 Mmbtu of daily gas production from November 2002 to March 2003 with a floor of $3.20/Mmbtu and a weighted average ceiling of $3.53/Mmbtu.

At December 31, 2000, the Company had no open derivative instruments.

In February 2000, the Company entered into fixed swap agreements covering 2,000 barrels of oil per day for the period March through October 2000 at a weighted average NYMEX West Texas Intermediate price of $25.96 per barrel. During the year ended December 31, 2000, the Company's oil revenues were reduced by the effect of the hedge by $2.1 million.

Fair value of cash, receivables and payables approximates carrying value. Fair value of long-term debt also approximates carrying value due to the nature of the Credit Facility, whereby the interest rates are floating rates which reflect market rates.

Counterparty Risk

The Company's couterparties to the derivative contracts open at December 31, 2001 are Bank One, NA and Bank of Montreal, both commercial banks who are also participants in the Company's Credit Facility. We feel the credit-worthiness of our current counterparties is sound and do not anticipate any non-performance of contractual obligations.

(14) QUARTERLY FINANCIAL DATA (Unaudited)

The following unaudited summarized quarterly financial data is presented in thousands, except per share data.

	2001			
	1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.
Total Revenues	$44,731	$40,332	$ 17,995	$ 19,721
Operating Income (loss)	26,294	21,495	(766)	(19,024)
Net Income (loss)	16,177	13,209	(915)	(11,623)
Net Income (loss) per share (fully-diluted)	$ 0.86	$ 0.70	$ (0.07)	$ (0.72)
	2000			
	1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.
Total Revenues	$17,609	$22,130	$ 27,308	$ 37,776
Operating Income	4,764	7,505	13,852	20,290
Net Income	3,116	4,914	9,085	14,549
Net Income per share (fully-diluted)	$ 0.35	$ 0.50	$ 0.50	$ 0.93

The financial results of the Company have been restated for the first and second quarters of 2001. The changes reflect adjustments to oil and natural gas production and revenues as a result of the Company's overaccrual of revenue related to these quarters. The impact of the adjustments decreased the previously reported amounts as follows:

	2001	
	1st Qtr.	2nd Qtr.
Total Revenues	$4,345	$3,494
Cost and operating expenses	693	961
Operating Income	3,652	2,533
Net Income	2,272	1,571
Net Income per share, (fully-diluted)	0.12	0.08

(15) SUBSEQUENT EVENTS

During January 2002, the $13.9 million of cash being held in like-kind escrow accounts was returned to the Company and used to pay down borrowings under the Company's Credit Facility.

During February 2002, the Company unwound the April through October 2002 collar for net proceeds of approximately $5.8 million ($.48 per Mmbtu), and then swapped 56,000 Mmbtu of daily natural gas production at $2.56/Mmbtu. Also during February 2002, the Company put in place a collar on 20,000 Mmbtu of daily gas production from November 2002 to March 2003 with a floor of $3.20/Mmbtu and a weighted average ceiling of $3.53/Mmbtu.

(16) SUPPLEMENTAL OIL AND NATURAL GAS INFORMATION (UNAUDITED)

Capitalized Costs and Costs Incurred

The following tables present the capitalized costs related to oil and natural gas producing activities and the related depreciation, depletion, amortization and impairment as of December 31, 2001 and 2000 and costs incurred in oil and natural gas property acquisition, exploration and development activities (in thousands) for the years ended December 31, 2001 and 2000.

	2001	2000
Capitalized Costs		
Proved properties	$374,449	$263,801
Nonproducing leasehold	10,974	6,477
Accumulated depreciation, depletion, amortization and impairment	(70,299)	(54,260)
Net capitalized costs	$315,124	$216,018
Costs Incurred		
Proved properties	$ 75,765	$ 79,770
Unproved properties	8,560	95
Exploration costs	19,731	695
Development costs	63,358	25,346
Total	$167,414	$105,906
Depletion, depreciation, amortization and impairment	$ 32,982	$ 18,459

Estimated Quantities of Reserves

The Company has interests in oil and natural gas properties that are located principally in Texas, Louisiana, Oklahoma and New Mexico. The Company does not own or lease any oil and natural gas properties outside the United States. There are no quantities of oil and natural gas subject to long-term supply or similar agreements with any governmental agencies.

The Company retains independent engineering firms to provide year-end estimates of the Company's future net recoverable oil, natural gas and natural gas liquids reserves. In 2001 and 2000, such estimates were prepared by Ryder Scott Company. The reserve information was prepared in accordance with guidelines established by the Securities and Exchange Commission.

Estimated proved net recoverable reserves as shown below include only those quantities that can be expected to be commercially recoverable at prices and costs in effect at the balance sheet dates under existing regulatory practices and with conventional equipment and operating methods. Proved developed reserves represent only those reserves expected to be recovered through existing wells. Proved undeveloped reserves include those reserves expected to be recovered from new wells or on undrilled acreage or from existing wells on which a relatively major expenditure is required for recompletion.

Net quantities of proved developed and undeveloped reserves of oil, including condensate and natural gas liquids, for the years ended December 31, 2001 and 2000 are summarized as follows:

	2001		2000	
	Oil (MBbls) (1)	Gas (MMcf)	Oil (MBbls) (1)	Gas (MMcf)
Proved Reserves Beginning of year	10,672	237,693	9,835	159,699
Purchases of reserves in place	211	33,712	1,981	85,437
Extensions and discoveries	308	11,547	51	2,699
Revisions of previous estimates	(1,520)	(18,822)	659	8,698
Sales of reserves in place	(3,382)	(10,512)	(715)	(1,076)
Production for the year	(952)	(22,352)	(1,139)	(17,764)
End of year	5,337	231,266	10,672	237,693
Proved Developed Reserves				
Beginning of year	9,895	177,252	9,358	122,914
End of year	4,705	175,659	9,895	177,252

(1) Includes oil, condensate and plant product barrels.

Standardized Measure of Discounted Future Net Cash Flows From Proved Reserves

The following is a summary of the standardized measure of discounted future net cash flows related to the Company's proved oil and natural gas reserves. For these calculations, estimated future cash flows from estimated future production of proved reserves are computed using oil and natural gas prices as of the end of each period presented. Future development and production costs attributable to the proved reserves were estimated assuming that existing conditions would continue over the economic lives of the individual leases and costs were not escalated for the future. Estimated future income taxes were calculated by applying statutory tax rates (based on current law adjusted for permanent differences and tax credits) to the estimated future pre-tax net cash flows related to proved oil and natural gas reserves, less the tax basis of the properties involved.

The Company cautions against using this data to determine the value of its oil and natural gas properties. To obtain the best estimate of the fair value of the oil and natural gas properties, forecasts of future economic conditions, varying discount rates, and consideration of other than proved reserves would have to be incorporated into the calculation. In addition, there are significant uncertainties inherent in estimating quantities of proved reserves and in projecting rates of production that impair the usefulness of the data.

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves for the years ended December 31, 2001 and 2000 are summarized as follows (in thousands):

	2001	2000
Future cash inflows	$ 628,537	$2,349,534
Future production costs and development costs	(243,201)	(352,703)
Future income tax expenses	(58,051)	(676,227)
Future net cash flows	327,285	1,320,604
10% discount to reflect timing of cash flows	(145,686)	(627,930)
Standardized measure of discounted future net cash flows	$ 181,599	$ 692,674

The following are the principal sources of changes in the standardized measure of discounted future net cash flows for the years ended December 31, 2001 and 2000 (in thousands):

	2001	2000
Sales of oil and natural gas, net of production cost	$ (89,410)	$ (78,969)
Net changes in prices and production cost	(765,134)	467,920
Extensions and discoveries	11,388	15,393
Purchases of reserves	26,461	397,280
Sales of reserves	(22,682)	(8,789)
Revisions of previous quantity estimates	(24,809)	39,442
Net change in income taxes	322,700	(304,816)
Accretion of discount	104,736	19,843
Changes in production rates (timing) and other	(74,325)	(3,371)
Change for year	$(511,075)	$ 543,933

The period end prices of oil and natural gas at December 31, 2001 and 2000, used in the above table were \$19.84 and \$25.31 per barrel of oil and \$2.57 and \$9.40 per thousand cubic feet of natural gas, respectively.