GULFWEST
ENERGY INC.
A Natural Resource Company

03020447

AR/S

P.E.
12-31-02

ANNUAL REPORT AND 10-K
2002

GULFWEST ENERGY INC.

480 NORTH SAM HOUSTON PARKWAY EAST • SUITE 300 • HOUSTON, TEXAS 77060
281-820-1919 • FAX 281-260-8488

	2002	2001	2000
Proved reserves (SEC year-end prices)			
Oil (MBbls)	5,522	5,872	4,576
Natural Gas (MMcf)	34,159	39,258	24,812
Oil equivalent (MBOE)	11,215	12,415	8,711
Future net revenue from proved reserves (at year end prices):			
Undiscounted ($000)	179,401	$ 98,026	$ 207,639
Discounted at 10% ($000)	98,899	$ 56,499	$ 124,141
Production (net sales volume):			
Oil (MBbls)	278	294	165
Natural Gas (MMcf)	1,487	1,595	1,112
Oil equivalent (MBOE)	526	560	350
Average prices for the year:			
Oil ($/Bbl)	$ 21.05	$ 22.73	$ 26.18
Natural Gas ($/Mcf)	$ 3.09	$ 3.60	3.71
Average prices at year end:			
Oil ($/Bbl)	$ 28.72	$ 17.67	23.81
Natural Gas ($/Mcf)	$ 4.43	$ 2.43	$ 8.45
Total revenues	$ 10,839,800	$ 12,990,600	$ 8,984,200
Less operating and overhead expenses	7,214,300	7,047,400	5,178,300
Income from operations	3,625,300	5,943,200	3,805,900
Less interest income/expense	3,159,400	2,756,900	2,118,600
Income before non-cash and one-time items	466,100	3,186,300	1,687,300
Less non-cash and one-time items	(4,968,400)	1,605,400	(1,334,500)
Income (loss) before income taxes and cumulative effect of change in accounting procedures	(4,502,300)	4,791,700	352,800
Income taxes	0	0	0
Cumulative effect of change in accounting procedures		(3,747,400)	
Net income (loss)	(4,502,300)	1,044,300	352,800
Less dividends on preferred stock	(112,500)	(56,300)	
Net income (loss) for common shareholders	$ (4,614,800)	988,000	352,800
Net income (loss) per common share	$ (.25)	$ .05	$ .02
Total assets	$ 53,088,900	$ 51,379,200	$ 32,374,100
Long-term debt, including current portion	33,523,200	32,830,200	21,491,800
Stockholders' equity	$ 7,823,600	$ 12,344,900	$ 6,701,800
Weighted average shares outstanding	18,492,541	18,464,343	17,293,848

Letter to Shareholders

Dear Fellow Shareholders,

As a part of our annual report, we are providing a few tables and charts summarizing financial and operating data that reflect the status of the company and trends over the last couple of years. We are also providing a synopsis of the last year describing key events that drove the results for the year.

A Look Back at 2002

In early 2002, oil and natural gas prices were down, our production had declined and we needed a capital program to workover several wells and optimize the performance of key fields. In particular, we needed to complete some key workovers, install facility and artificial lift improvements, and drill a key 13,000-foot gas well at our Lacassine field. While these projects were going to increase production in 2002, we were also building an inventory of natural gas drilling locations, which would continue our longer-term growth in natural gas production.

These important development projects were going to be funded in part with the development line of credit we had with our major lender, and in part through the issuance of new equity. We were able to begin our workover program in a few fields and drill our Lacassine gas well. We were also able to acquire a few natural gas wells along the Gulf Coast and successfully increase production from 2 of them. However, at mid-year, our major lender elected to exit the upstream financing business and halted funding of our capital projects and development plan, which were reduced to just a small workover program during the second half of the year. While we were successful in completing our Lacassine gas well and other workovers, the expected results haven't been achieved, as funding required to complete the projects wasn't obtained and we weren't able to complete the projects.

Late in the second quarter, we embarked on a financing process to restructure our debt and obtain funding for our development program. As stated above, our major lender had elected to exit the upstream financing business so our refinancing had to include replacing the line of credit financing arrangement and source of development capital. Since that time, we have been working to negotiate the retirement of our key lender's loan, and the financing of the development plans and projects we have in hand.

Moving Ahead – 2003 Plans

As 2002 ended, we were continuing efforts to refinance our debt, while holding production and our significant development program in tact. We had achieved growth in the previous 3 years and now needed to restructure the company to continue this effort.

We have been working with a short list of financing options to consolidate our debt and fund our development plans. The institutions and markets that had supported the financing needs for small-cap companies, changed dramatically last year. Hence, we have had to be more creative in seeking to finance future growth and increase shareholder value as we go forward. In conjunction with our investment banker, we have been working to select and finalize a refinancing package in the second quarter. Included in our short list of alternatives are restructuring the debt with a significant equity infusion and evaluating a few merger options that would grow the company in a significant step.

As we consider our options, we will be seeking the best alternative to enhance shareholder value, take advantage of the asset base and development opportunities we have assembled, and position the company to compete in the changed business and financial environment of today.

Change in Accounting Reporting as Related to Our Product Hedges

Also in 2002, there was a change in the manner in which we report our fixed price oil and gas hedges. Our auditors determined that the hedges needed to be viewed as derivatives and hence had to be added to the income statement. This new accounting requirement adds significant non-cash gain or loss to our net income and is the result of a hedge agreement we entered into to secure financing. In short, we agreed to hedge a portion of our oil and gas sales at a fixed price for the period May 2000 through June 2004. As mentioned, this agreement meets the definition of SFAS 133 "Accounting for Derivative Instruments and Hedging Activities" and must be accounted for as a derivative instrument. As a result, we have added "Unrealized gain (loss) on derivative instruments" as a new line item in our Statement of Operations. This is a non-cash gain (loss) estimate of the fixed-price hedges, using future oil and gas price forecasts as of December 31, 2002. The past, actual impact of the hedge agreement has been and will continue to be reported in the oil and gas revenue we report in our Statement of Operations. While we don't necessarily agree with this required reporting change, nor do we actively trade in the futures market, we were required to report the hedges as derivative instruments. In 2002, there was an unrealized non-cash loss of $1,596,600 for the year due to the change in the fair value of the derivative instrument.

Closing – A Role Remains for the Domestic E&P Company

As we work through our development and financial plans in 2003, the overall conservative and hesitant nature found in the financial community has slowed our process of refinancing. In our view, with oil and gas demand and corresponding prices remaining strong, there remains a need for domestic oil and gas companies to explore, develop and produce their assets. Therefore, we continue to be optimistic in our role in this industry and in our ability to grow a profitable company. We appreciate your confidence and continued support as we proceed with our plans. We will continue to post company news on our web page (which may be found at www.gulfwestenergy.com) and, should you have any questions, you may contact us at our home office in Houston, at 281-820-1919.

Sincerely;

Thomas R. Kaetzer

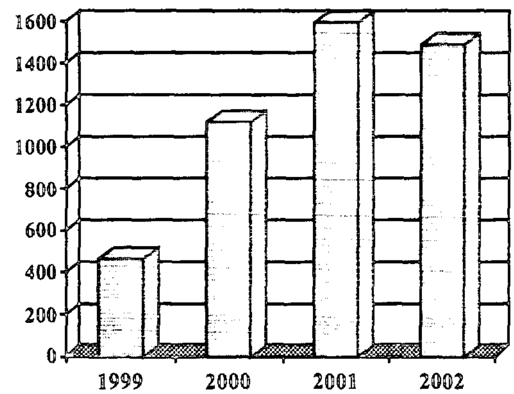
Thomas R. Kaetzer
President and Chief Executive Officer

GULFWEST ENERGY INC.

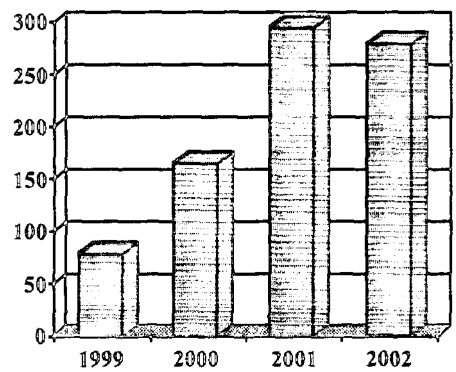
Oil and Gas Annual Production

Production in 2002 dropped slightly as the development program was significantly curtailed in the second half of the year due to the lack of capital funding.

Natural Gas Production (MMcf)

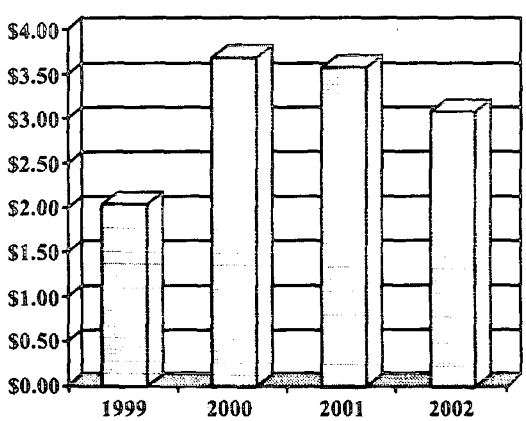


Oil Production (MBbl)

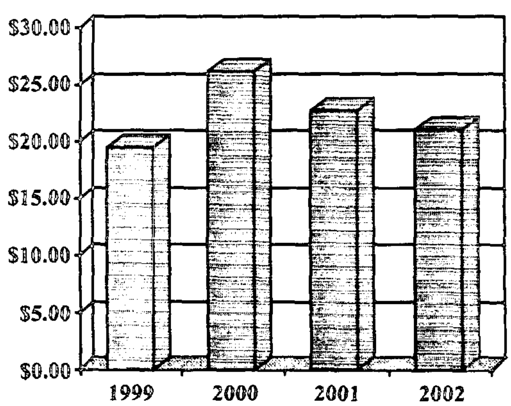


Average Oil and Gas Prices (received by the company)

Average Natural Gas Price



Average Oil Price

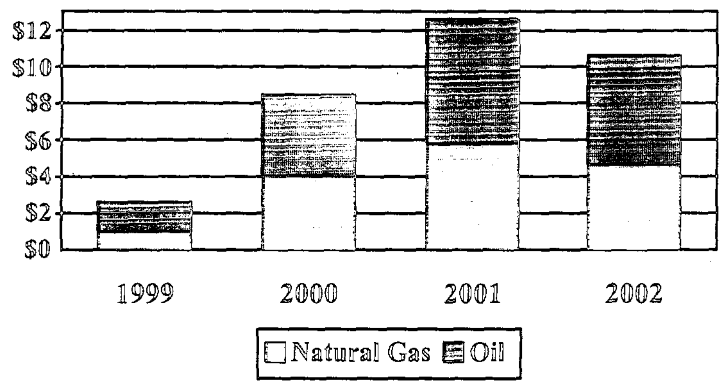


GULFWEST ENERGY INC.

Revenue

Revenue was lower in 2002 as compared to 2001, due to lower prices and production.

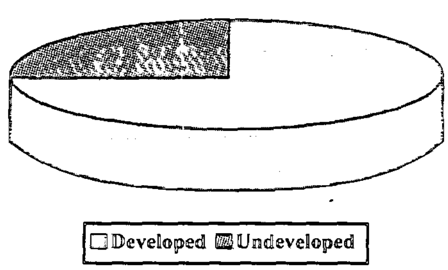
Production Revenue
($Millions)



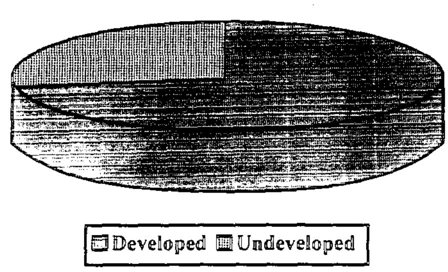
Oil and Gas Reserves

At the end of 2002, in addition to our proved developed producing (PDP) reserves, we had significant proved developed non-producing (PDNP) and proved undeveloped (PUD) reserves, indicating significant growth potential within our existing asset base. These assets and their development potential are providing us the ability to refinance and they are the basis for the future growth of the company.

Proved Reserves
Natural Gas - 34.1 Bcf



Proved Reserves
Oil - 5.5 MMBbl



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

FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2002

or

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ____ to ____.
Commission file number 1-12108.

GulfWest Energy Inc.

(Exact name of registrant as specified in its charter)

Texas **(State or other jurisdiction of incorporation or organization)**	**87-0444770** **(IRS Employer Identification No.)**
480 N. Sam Houston Parkway East, Suite 300 **Houston, Texas** (Address of principal executive offices)	**77060** (Zip Code)

Registrant's telephone number, including area code: (281) 820-1919.

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class

Class A Common Stock, par value of $.001 per share

Securities registered pursuant to Section 12(g) of the Act:

Title of Each Class

Class A Common Stock, par value of $.001 per share

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 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 X No ____

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12-b2 of the Act).

Yes ____ No X

The aggregate market value of voting stock of the Registrant held by non-affiliates, computed by reference to the closing price of such stock on June 28, 2002, was approximately $3,543,451. For purposes of this computation, all executive officers, directors and ten percent (10%) beneficial owners of the Registrant are deemed to be affiliates. Such determination should not be deemed an admission that such executive officers, directors and ten percent (10%) beneficial owners are affiliates.

Indicate the number of shares outstanding of each of the Registrant's classes of common stock: Class A Common Stock $.001 par value: 18,492,541 shares on April 9, 2003.

DOCUMENTS INCORPORATED BY REFERENCE:

The registrant's definitive Proxy Statement pertaining to the 2003 Annual Meeting of Shareholders (the "Proxy Statement") and filed or to be filed not later than 120 days after the end of the fiscal year pursuant to Regulation 14A is incorporated herein by reference into Part III.

PART I

ITEM 1. Business.

Our Business.

We are primarily engaged in the acquisition, development, exploitation and production of crude oil and natural gas. Our focus is on increasing production from our existing properties through further exploitation, development and exploration, and on acquiring additional interests in crude oil and natural gas properties.

Since we made our first significant acquisition in 1993, we have substantially increased our ownership in *producing properties* and the value of our crude oil and natural gas reserves through a combination of acquisitions and the further exploitation and development of our properties. At December 31, 2002, our part of the estimated *proved reserves* these properties contain was approximately 5.5 million barrels (*MBbl)* of oil and 34.1 billion cubic feet *(Bcf)* of natural gas with a *Present Value discounted 10% (PV-10)* of $98.9 million. At present, all of our properties are located on land in Texas, Colorado, Louisiana and Oklahoma, except for the property on Grand Lake, Louisiana. In the future, we plan to expand by acquiring additional properties in those areas, and in similar properties located in other areas of the United States.

Our gross revenues are derived from the following sources:

1. **Oil and gas sales** that are proceeds from the sale of crude oil and natural gas production to midstream purchasers;

2. **Operating overhead and other income** that consists of earnings from operating crude oil and natural gas properties for other *working interest* owners, and marketing and transporting natural gas. This also includes earnings from other miscellaneous activities.

3. **Well servicing revenues** that are earnings from the operation of well servicing equipment under contract to other operators.

Our operations are considered to fall within a single industry segment, which is the acquisition, development, production and servicing of crude oil and natural gas properties. See Item 7. " Management's Discussion and Analysis of Financial Condition and Results of Operations." Certain industry terms are *italicized* and defined in the Glossary beginning on page 28.

Our common stock is traded over-the-counter (OTC) under the symbol "GULF".

Our Company.

We were formed as a corporation under the laws of the State of Utah in 1987 as Gallup Acquisitions, Inc., and subsequently changed our name to First Preference Fund, Inc. and then to GulfWest Energy, Inc. We became a Texas corporation by a merger effected in July 1992, in which our name became GulfWest Oil Company. On May 21, 2001, we changed our name to GulfWest Energy Inc.

Our principal office is located at 480 North Sam Houston Parkway East, Suite 300, Houston, Texas 77060 and our telephone number is (281) 820-1919.

GulfWest Energy Inc. has nine wholly owned subsidiaries:

1. **GulfWest Oil and Gas Company**, a Texas corporation, was organized February 18, 1999 and is the owner of record of interests in certain crude oil and natural gas properties located in Colorado and Texas.

2. **SETEX Oil and Gas Company**, a Texas corporation, was organized August 11, 1998 and is the operator of crude oil and natural gas properties in which we own the majority *working interest*.

3. **LTW Pipeline Co.**, a Texas corporation, was organized April 19, 1999, is the owner and operator of certain natural gas gathering systems and pipelines that we own, and markets the natural gas produced from our properties.

4. **RigWest Well Service, Inc.**, a Texas corporation, was organized September 5, 1996 and operates well servicing equipment for us and under contract for other operators.

5. **Southeast Texas Oil and Gas Company, L.L.C.**, a Texas company, was acquired by us on September 1, 1998 and is the owner of record of interests in certain crude oil and natural gas properties located in three Texas counties.

6. **DutchWest Oil Company**, a Texas corporation, was organized July 28, 1997 and is the owner of record of interests in certain crude oil and natural gas properties located along the Gulf Coast of Texas.

7. **GulfWest Development Company**, a Texas corporation, was organized November 9, 2000 and is the owner of record of interests in certain crude oil and natural gas properties located in Texas, Oklahoma and Mississippi.

8. **GulfWest Texas Company**, a Texas corporation, was organized September 23, 1996 and was the owner of interests in certain crude oil and natural gas properties located in the Vaughn Field, Crockett County, Texas. Effective April 1, 2000, these properties were assigned to GulfWest Oil and Gas Company to facilitate financing.

9. **GulfWest Oil and Gas Company (Louisiana) LLC**, a Louisiana company, was formed July 31, 2001 and is the owner of record of interests in certain crude oil and natural gas properties in Louisiana.

Our Business Strategy.

We have pursued a business strategy of acquiring interests in crude oil and natural gas *producing properties* where production and reserves can be increased through engineering and development activities. Such activities include *workovers*, development drilling, *recompletion*s, replacement or addition of equipment and *waterflood* or other secondary recovery techniques. We have expanded our business plan to include an increased but controlled emphasis on development drilling for additional crude oil and natural gas reserves. Key elements of our business strategy include:

<u>Continued Acquisition Program.</u> We acquired properties in four crude oil and natural gas fields in Texas and Louisiana in the year 2001. We intend to continue to pursue interests in crude oil and natural gas properties (i) held by small, under-capitalized operators and (ii) being divested by larger independent and major oil and gas companies.

Development and Exploitation of Existing Properties. We intend to increase the development of properties in which we currently own interest by expanding our engineering and geological field studies. Our intent is to increase crude oil and natural gas production and reserves of our existing assets through relatively low-risk development activities, such as *workovers*, *recompletions*, *horizontal drilling* from existing wellbores and infield drilling, as well as the more efficient use of production facilities and the expansion of existing *waterflood* operations.

Significant Operating Control. Currently, we are the operator of all the wells, except two, in which we own *working interests*. This operating control enables us to better manage the nature, timing and costs of development of such wells, and the marketing of the resulting production.

Ownership of Workover Rigs. We currently own three workover service rigs and one swabbing unit that we operate for our own account and under contract for other parties. By owning and operating this equipment, we are better able to control costs, quality of operations and availability of equipment and services. We intend to purchase additional service rigs as needed to accommodate our acquisition and development programs.

Greater Natural Gas Ownership. At December 31, 2002, our reserves were comprised of 49% crude oil and 51% natural gas. We will continue to expand our role in the domestic natural gas industry by (i) acquiring additional interests in natural gas properties, (ii) increasing the production and reserve base of our existing natural gas properties, and (iii) acquiring ownership of more natural gas gathering systems and pipelines. We are presently focusing our *workover* and development efforts on both crude oil and natural gas reserves to take advantage of the higher prices of both commodities. We are also seeking to expand our ownership of gas gathering systems and pipelines located in our main field areas. Our goal is to have greater control of our natural gas transportation and marketing, and an expanded role in the transportation of natural gas produced by other parties in our area of operations.

Expanded Exploration and Exploitation Role. Historically, we have not drilled exploratory wells due to the cost and risk associated with drilling prospective locations. However, since the end of 1998, we have acquired *producing properties* that have included significant acreage for prospective oil and gas exploration. These include producing wells and acreage in Crockett, Grimes, Hardin, Jim Wells, Kimble, Madison, Palo Pinto, Refugio, Sutton, Wharton and Zavala, Counties, Texas; Adams, Arapaho, Elbert and Weld Counties, Colorado; Creek County, Oklahoma; and, Cameron Parish, Louisiana. These acquisitions have added existing natural gas and crude oil production to our asset base and, as importantly, have provided us with immediate geological databases for drilling opportunities. We have expanded our evaluation efforts in these fields and intend to increase our development of reserves, not only through workovers of existing wells, but by drilling additional wells.

Our Employees.

At December 31, 2002, we had 44 full time salaried and contract employees, of whom 32 were field personnel.

Our Executive Officers.

See Item 10 of this report, which information is incorporated herein by reference.

ITEM 2. Our Properties.

At December 31, 2002, we owned an average 92% *working interest* in 291 *gross wells (269 net wells). Gross wells* are the total wells in which we own a *working interest. Net wells* are the sum of the fractional *working interests* we own in *gross wells.* Our part of the estimated *proved reserves* these properties contain was approximately 5.5 million barrels *(MBbl)* of oil and 34.1 billion cubic feet (*Bcf)* of natural gas. Substantially all of our properties are located in Texas, Colorado, Louisiana and Oklahoma.

Proved Reserves.

The following table reflects our estimated *proved reserves* at December 31 for each of the preceding three years.

	2002	2001	2000
Crude Oil (*MBbl*)			
Developed	4,026	3,940	2,884
Undeveloped	1,496	1,932	1,692
Total	5,522	5,872	4,576
Natural Gas (*MMcf*)			
Developed	25,374	21,204	15,142
Undeveloped	8,785	18,054	9,670
Total	34,159	39,258	24,812
Total (*MBOE*)	11,215	12,415	8,711

(a) Approximately 74% of our total *proved reserves* were classified as *proved developed* at December 31, 2002.

(b) *Barrel of Oil Equivalent (BOE)* is based on a ratio of 6,000 cubic feet of natural gas for each barrel of oil.

Standardized Measure of Discounted Future Net Cash Flows.

The following table sets forth as of December 31 for each of the preceding three years, the estimated future net cash flow from and *standardized measure* of discounted future net cash flows of our *proved reserves*, which were prepared in accordance with the rules and regulations of the SEC. Future net cash flow represents future gross cash flow from the production and sale of *proved reserves*, net of crude oil and natural gas production costs (including production taxes, ad valorem taxes and operating expenses) and future development costs. The calculations used to produce the figures in this table are based on current cost and price factors at December 31 for each year. We cannot assure you that the *proved reserves* will all be developed within the periods used in the calculations or that prices and costs will remain constant.

	2002	2001	2000
Future cash inflows	$ 308,381,837	$ 199,162,921	$ 318,504,931
Future production and development costs-			
Production	105,629,872	77,526,278	97,465,972
Development	23,350,811	23,610,596	13,400,359
Future net cash flows before income taxes	179,401,154	98,026,047	207,638,600
Future income taxes	(38,611,577)	(13,281,358)	(56,466,527)
Future net cash flows after income taxes	140,789,577	84,744,689	151,172,073
10% annual discount for estimated timing of cash flows	(63,165,742)	(35,895,306)	(60,790,946)
Standardized measure of discounted Future net cash flows(1)	$ 77,623,835	$ 48,849,383	$ 90,381,127

(1) The average prices of our proved reserves were $28.72 per Bbl and $4.43 per *Mcf*, $17.67 per Bbl and $2.43 per *Mcf*, and $23.81 per Bbl and $8.45 per *Mcf* at December 31, 2002, 2001 and 2000, respectively.

Significant Properties.

Summary information on our properties with *proved reserves* is set forth below as of December 31, 2002.

	Productive Wells		Proved Reserves			Present Value (1)
	Gross Productive Wells	Net Productive Wells	Crude Oil	Natural Gas	Total	Amount
			(MBbl)	*(MMcf)*	*(MBOE)*	($M)
Texas	206	199.76	3,401	19,356	6,627	$ 56,425
Colorado	39	26.57	355	6,180	1,385	9,101
Oklahoma	27	27.00	146	-	146	1,159
Louisiana	17	16.88	1,614	8,623	3,051	32,152
Mississippi	1	.38	6	-	6	62
Total	290	270.59	5,522	34,159	11,215	$ 98,899

(1) The average prices of our proved reserves were $28.72 per Bbl and $4.43 per *Mcf* at December 31, 2002.

All information set forth herein relating to our *proved reserves*, estimated future net cash flows and *present values* is taken from reports prepared by Pressler Petroleum Consultants, independent petroleum engineers. The estimates of these engineers were based upon their review of production histories and other geological, economic, ownership and engineering data provided by and relating to us. No reports on our reserves have been filed with any federal agency. In accordance with the SEC's guidelines, our estimates of *proved reserves* and the future net revenues from which *present values* are derived are made using year end crude oil and natural gas sales prices held constant throughout the life of the properties (except to the extent a contract specifically provides otherwise). Operating costs, development costs and certain production-related taxes were deducted in arriving at estimated future net revenues, but such costs do not include debt service, general and administrative expenses and income taxes.

There are numerous uncertainties inherent in estimating crude oil and natural gas reserves and their values, including many factors beyond our control. The reserve data set forth in this report are based upon estimates. *Reservoir* engineering is a subjective process, which involves estimating the sizes of underground accumulations of crude oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation of that data, and judgment. As a result, estimates of different engineers, including those used by us, may vary. In addition, estimates of reserves are subject to revision based upon actual production, results of future development, exploitation and exploration activities, prevailing crude oil and natural gas prices, operating costs and other factors. Such revisions may be material. Accordingly, reserve estimates are often different from the quantities of crude oil and natural gas that are ultimately recovered and are highly dependent upon the accuracy of the assumptions upon which they are based. We cannot assure you that the estimates contained in this report are accurate predictions of our crude oil and natural gas reserves or their values. Estimates with respect to *proved reserves* that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than upon actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in potentially substantial variations in the estimated reserves.

Production, Revenue and Price History.

The following table sets forth information (associated with our *proved reserves)* regarding production volumes of crude oil and natural gas, revenues and expenses attributable to such production (all net to our interests) and certain price and cost information for the years ended December 31, 2002, 2001 and 2000.

	2002	2001	2000
Production			
Oil (*Bbl*)	278,374	294,276	165,031
Natural gas (*Mcf*)	1,487,048	1,594,899	1,111,639
Total (*BOE*)	526,215	560,092	350,304
Revenue			
Oil production	$ 5,859,568	$ 6,690,338	$ 4,320,943
Natural gas production	4,587,601	5,735,765	4,124,989
Total	$10,447,169	$12,426,103	$ 8,445,932
Operating Expenses	$ 5,430,205	$ 5,155,500	$ 3,377,583
Production Data			
Average sales price			
Per barrel of oil	$ 21.05	$ 22.73	$ 26.18
Per *Mcf* of natural gas	3.09	3.60	3.71
Per *BOE*	19.85	22.19	24.11
Average expenses per *BOE*			
Lease operating	10.32	9.20	9.64
Depreciation, depletion and amortization	5.13	4.45	3.83
General and administrative	$ 3.28	$ 3.05	$ 4.53

Productive Wells at December 31, 2002:

The following table shows the number of productive wells we own by location:

	Gross Oil Wells	Net Oil Wells	Gross Gas Wells	Net Gas Wells
Texas	118	116.11	88	85.65
Colorado	18	11.42	21	15.15
Oklahoma	27	27.00	-	-
Louisiana	14	13.88	3	3.00
Mississippi	1	.38	-	-
Total	178	168.79	112	103.80

Developed Acreage at December 31, 2002.

The following table shows the developed acreage that we own, by location, which is acreage spaced or assigned to productive wells. *Gross acres* are the total acres in which we own a *working interest*. *Net acres* are the sum of the fractional *working interests* we own in *gross acres*.

	Gross Acres	Net Acres
Texas	19,260	14,826
Colorado	5,000	2,700
Louisiana	1,695	1,256
Oklahoma	900	684
Total	26,855	19,466

Undeveloped Acreage at December 31, 2002.

The following table shows the undeveloped acreage that we own, by location. Undeveloped acreage is acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and natural gas.

	Gross Acres	Net Acres
Texas	22,910	17,800
Colorado	10,000	6,000
Louisiana	440	314
Oklahoma	900	684
Total	34,250	24,798

Drilling Results.

In 2002, we drilled one exploratory well, in which we own 18% *working interest,* that resulted in a dry hole and one development well, in which we own 100% *working interest,* that is productive. We drilled three wells in 2001 and six in 2000, all of which were development wells and are currently productive. These development wells included six horizontal wells drilled by sidetracking from existing wellbores in the Madisonville Field, Texas, two new wells drilled on our Colorado acreage; and one well that was deepened in our Leona River Field, Texas.

Risk Factors.

Our success depends heavily upon our ability to market our crude oil and natural gas production at favorable prices.

In recent decades, there have been both periods of worldwide overproduction and underproduction of crude oil and natural gas, and periods of increased and relaxed energy conservation efforts. Such conditions have resulted in excess supply of, and reduced demand for, crude oil on a worldwide basis and for natural gas on a domestic basis. At other times, there has been short supply of, and increased demand for, crude oil and, to a lesser extent, natural gas. These changes have resulted in dramatic price fluctuations.

The degree to which we are leveraged could possibly have important consequences to our shareholders, including the following:

(i) Our indebtedness, acquisitions, working capital, capital expenditures or other purposes may be impaired;

(ii) Funds available for our operations and general corporate purposes or for capital expenditures will be reduced as a result of the dedication of a substantial portion of our consolidated cash flow from operations to the payment of the principal and interest on our indebtedness;

(iii) We may be more highly leveraged than certain of our competitors, which may place us at a competitive disadvantage;

(iv) The agreements governing our long-term indebtedness and bank loans may contain restrictive financial and operating covenants;

(v) An event of default (not cured or waived) under financial and operating covenants contained in our debt instruments could occur and have a material adverse effect;

(vi) Certain of the borrowings under our debt agreements have floating rates of interest, which causes us to be vulnerable to increases in interest rates; and,

(vii) Our substantial degree of leverage could make us more vulnerable to a downturn in general economic conditions.

Our ability to make principal and interest payments under long-term indebtedness and bank loans will be dependent upon our future performance, which is subject to financial, economic and other factors, some of which are beyond our control.

We cannot assure you that our current level of operating results will continue or improve. We believe that we will need to access capital markets in the future in order to provide the funds necessary to repay a significant portion of our indebtedness. We cannot assure you that any such refinancing will be possible or that we can obtain any additional financing, particularly in view of our anticipated high levels of debt. If no such refinancing or additional financing were available, we could default on our debt obligations.

We have incurred net losses in the past and there can be no assurance that we will be profitable in the future.

Our future operating results may fluctuate significantly depending upon a number of factors, including industry conditions, prices of crude oil and natural gas, rates of production, timing of capital expenditures and drilling success. These variables could have a material adverse effect on our business, financial condition, results of operations and the market price of our common stock.

Estimates of crude oil and natural gas reserves depend on many assumptions that may turn our to be inaccurate.

Estimates of our *proved reserves* for crude oil and natural gas and the estimated future net revenues from the production of such reserves rely upon various assumptions, including assumptions as to crude oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating crude oil and natural gas reserves is complex and imprecise.

Actual future production, crude oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable crude oil and natural gas reserves may vary substantially from the estimates we obtain from reserve engineers. Any significant variance in these assumptions could materially affect the estimated quantities and *present value* of reserves we have set forth. In addition, our *proved reserves* may be subject to downward or upward revision due to factors that are beyond our control, such as production history, results of future exploration and development, prevailing crude oil and natural gas prices and other factors.

Approximately 26% of our total estimated *proved reserves* at December 31, 2002 were *proved undeveloped reserves*, which are by their nature less certain.

Recovery of such reserves requires significant capital expenditures and successful drilling operations. The reserve data set forth in the reserve engineer reports assumes that substantial capital expenditures are required to develop such reserves. Although cost and reserve estimates attributable to our crude oil and natural gas reserves have been prepared in accordance with industry standards, we cannot be sure that the estimated costs are accurate, that development will occur as scheduled or that the results of such development will be as estimated.

You should not interpret the *present value* referred to in this report or documents incorporated herein by reference as the current market value of our estimated crude oil and natural gas reserves.

In accordance with SEC requirements, the estimated discounted future net cash flows from *proved reserves* are generally based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower.

The estimates of our *proved reserves* and the future net revenues from which the *present value* of our properties is derived were calculated based on the actual prices of our various properties on a property-by-property basis at December 31, 2002. The average prices of all properties were $28.72 per barrel of oil and $4.43 per thousand cubic feet (*Mcf)* of natural gas at that date.

Actual future net cash flows will also be affected by increases or decreases in consumption by crude oil and natural gas purchasers and changes in governmental regulations or taxation. The timing of both the production and the incurring of expenses in connection with the development and production of crude oil and natural gas properties affect the timing of actual future net cash flows from *proved reserves*. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor. The effective interest rate at various times and the risks associated with our business or the oil and gas industry in general will affect the accuracy of the 10% discount factor.

Except to the extent that we acquire properties containing *proved reserves* or conduct successful development or exploitation activities, our *proved reserves* will decline as they are produced.

In general, the volume of production from crude oil and natural gas properties declines as reserves are depleted. Our future crude oil and natural gas production is highly dependent upon our success in finding or acquiring additional reserves.

The business of acquiring, enhancing or developing reserves requires considerable capital.

Our ability to make the necessary capital investment to maintain or expand our asset base of crude oil and natural gas reserves could be impaired to the extent that cash flow from operations is reduced and external sources of capital become limited or unavailable. In addition, we cannot be sure that our future acquisition and development activities will result in additional *proved reserves* or that we will be able to drill productive wells at acceptable costs.

Crude oil and natural gas drilling and production activities are subject to numerous risks, many of which are beyond our control.

These risks include (i) the possibility that no commercially productive oil or gas reservoirs will be encountered; and, (ii) that operations may be curtailed, delayed or canceled due to title problems, weather conditions, governmental requirements, mechanical difficulties, or delays in the delivery of drilling rigs and other equipment that may limit our ability to develop, produce and market our reserves. We cannot assure you that new wells we drill will be productive or that we will recover all or any portion of our investment in such new wells.

Drilling for crude oil and natural gas may not be profitable.

Any wells that we drill may be dry wells or wells that are not sufficiently productive to be profitable after drilling. Such wells will have a negative impact on our profitability. In addition, our properties may be susceptible to drainage from production by other operators on adjacent properties.

Our industry experiences numerous operating risks that could cause us to suffer substantial losses.

Such risks include fire, explosions, blowouts, pipe failure and environmental hazards, such as oil spills, natural gas leaks, ruptures or discharges of toxic gases. We could also suffer losses due to personnel injury or loss of life; severe damage to or destruction of property; or environmental damage that could result in clean-up responsibilities, regulatory investigation, penalties or suspension of our operations. In accordance with customary industry practice, we maintain insurance policies against some, but not all, of the risks described above. Our insurance policies may not adequately protect us against loss or liability. There is no guarantee that insurance policies that protect us against the many risks we face will continue to be available at justifiable premium levels.

As owners and operators of crude oil and natural gas properties, we may be liable under federal, state and local environmental regulations for activities involving water pollution, hazardous waste transport, storage, disposal or other activities.

Our past growth has been attributable to acquisitions of producing crude oil and natural gas properties with *proved reserves*. There are risks involved with such acquisitions.

The successful acquisition of properties requires an assessment of recoverable reserves, future crude oil and natural gas prices, operating costs, potential environmental and other liabilities, and other factors beyond our control. Such assessments are necessarily inexact and their accuracy uncertain. In connection with such an assessment, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Such a review, however, will not reveal all existing or potential problems, nor will it permit us, as the buyer, to become sufficiently familiar with the properties to fully assess their capabilities or deficiencies. We may not inspect every well and, even when an inspection is undertaken, structural and environmental problems may not necessarily be observable.

When we acquire properties, in most cases, we are not entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities.

We generally acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. In those circumstances in which we have contractual indemnification rights for pre-closing liabilities, we cannot assure you that the seller will be able to fulfill its contractual obligations. In addition, the competition to acquire producing crude oil and natural gas properties is intense and many of our larger competitors have financial and other resources substantially greater than ours. We cannot assure you that we will be able to acquire producing crude oil and natural gas properties that have economically recoverable reserves for acceptable prices.

We may acquire *royalty, overriding royalty* or *working interests* in properties that are less than the controlling interest.

In such cases, it is likely that we will not operate, nor control the decisions affecting the operations, of such properties. We intend to limit such acquisitions to properties operated by competent parties with whom we have discussed their plans for operation of the properties.

We will need additional financing in the future to continue to fund our developmental and exploitation activities.

We have made and will continue to make substantial capital expenditures in our exploitation and development projects. We intend to finance these capital expenditures with cash flow from operations, existing financing arrangements or new financing. We cannot assure you that such additional financing will be available. If it is not available, our development and exploitation activities may have to be curtailed, which could adversely affect our business, financial condition and results of operations.

The marketing of our natural gas production depends, in part, upon the availability, proximity and capacity of natural gas gathering systems, pipelines and processing facilities.

We could be adversely affected by changes in existing arrangements with transporters of our natural gas since we do not own most of the gathering systems and pipelines through which our natural gas is delivered to purchasers. Our ability to produce and market our natural gas could also be adversely affected by federal, state and local regulation of production and transportation.

The crude oil and natural gas industry is highly competitive in all of its phases.

Competition is particularly intense with respect to the acquisition of desirable *producing properties*, the acquisition of crude oil and natural gas *prospects* suitable for enhanced production efforts, and the hiring of experienced personnel. Our competitors in crude oil and natural gas acquisition, development, and production include the major oil companies, in addition to numerous independent crude oil and natural gas companies, individual proprietors and drilling programs.

Many of these competitors possess and employ financial and personnel resources substantially in excess of those which are available to us and may, therefore, be able to pay more for desirable *producing properties* and *prospects* and to define, evaluate, bid for, and purchase a greater number of *producing properties* and *prospects* than our financial or personnel resources will permit. Our ability to generate reserves in the future will be dependent on our ability to select and acquire suitable *producing properties* and *prospects* while competing with these companies.

The domestic oil industry is extensively regulated at both the federal and state levels. Although we believe we are presently in compliance with all laws, rules and regulations, we cannot assure you that changes in such laws, rules or regulations, or the interpretation thereof, will not have a material adverse effect on our financial condition or the results of our operations.

Legislation affecting the oil and gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden on the industry. There are numerous federal and state agencies authorized to issue rules and regulations affecting the oil and gas industry. These rules and regulations are often difficult and costly to comply with and carry substantial penalties for noncompliance.

State statutes and regulations require permits for drilling operations, drilling bonds, and reports concerning operations. Most states also have statutes and regulations governing conservation matters, including the unitization or pooling of properties, and the establishment of maximum rates of production from wells. Some states have also enacted statutes prescribing price ceilings for natural gas sold within their states.

Our industry is also subject to numerous laws and regulations governing plugging and abandonment of wells, discharge of materials into the environment and other matters relating to environmental protection. The heavy regulatory burden on the oil and gas industry increases the costs of our doing business as an oil and gas company, consequently affecting our profitability.

Our board of directors is authorized, without further shareholder action, to issue preferred stock in one or more series and to designate the dividend rate, voting rights and other rights, preferences and restrictions of each such series.

As of April 9, 2003, we had a total of 8,000 shares of our Series D Preferred Stock and 9,000 shares of our Series E Preferred Stock issued and outstanding, both par value $.01 and liquidation value $500 per share. The 8,000 shares of Series D Preferred Stock are held by Steven M. Morris, a director, and the 9,000 shares of Series E Preferred Stock are held by J. Virgil Waggoner, a director. The Series D and E Preferred Stock are senior to our common stock regarding liquidation. The holders of the preferred stock do not have voting rights or preemptive rights nor are they subject to the benefits of any retirement or sinking fund.

The Series D Preferred Stock is not entitled to dividends, nor is it redeemable, however it is convertible to common stock at anytime following December 31, 2002, the third anniversary of the issue date. Thereafter, the holder may convert any or all of the shares of the Series D Preferred Stock to common stock. The total number of shares of common stock to be issued upon such conversion shall be 500,000.

The Series E Preferred Stock is entitled to receive dividends at the rate of $12.50 per share per annum, payable quarterly. The Series E Preferred Stock is redeemable in whole or in part at any time, at our option, at a price of $500 per share, plus all accrued and undeclared or unpaid dividends; except that, after two years from the date of the original issuance and prior to redemption of remaining shares by the Company, the holders of record shall be given a 60-day written notice of our intent to redeem and the opportunity to convert the Series E Preferred Stock to common stock. The conversion price for the Series E Preferred Stock shall be $2.00 per share of common stock. At April 9, 2003, none of the 9,000 outstanding shares of Series E Preferred Stock had been redeemed or converted. On a fully converted basis, the 9,000 shares of Series E Preferred Stock would convert to 2,250,000 shares of common stock.

We do not pay dividends on our common stock.

Our board of directors presently intends to retain all of our earnings for the expansion of our business, therefore we do not anticipate distributing cash dividends on our common stock in the foreseeable future. Any decision of our board of directors to pay cash dividends will depend upon our earnings, financial position, cash requirements and other factors.

The holders of our common stock do not have cumulative voting rights, preemptive rights or rights to convert their common stock to other securities.

We are authorized to issue 40,000,000 shares of common stock, $.001 par value per share. As of April 9, 2003, there were 18,492,541 shares of common stock issued and outstanding. Since the holders of our common stock do not have cumulative voting rights, the holder(s) of a majority of the shares of common stock present, in person or by proxy, will be able to elect all of the members of our board of directors. The holders of shares of our common stock do not have preemptive rights or rights to convert their common stock into other securities. At December 31, 2002, we had outstanding warrants and options for the purchase of 3,248,754 shares of common stock at prices ranging from $.75 to $6.00 per share, including employee stock options to purchase 1,067,000 shares at prices ranging from $.75 to $1.81 per share. If we issue additional shares, the existing shareholders' percentage ownership of the Company may be further diluted.

Actual results may differ from forward-looking statements.

We make forward-looking statements throughout this report. Whenever you read a statement that is not simply a statement of historical fact, such as when we describe what we "believe," "expect" or "anticipate" will occur, and other similar statements, you must remember that our expectations may not be correct, even though we believe they are reasonable. These forward-looking statements generally relate to our plans and objectives for future operations and are based upon our management's reasonable estimates of future results and trends. We do not guarantee that the transactions and events described will happen as described (or that they will happen at all). In connection with forward-looking statements, you should carefully review the factors set forth in this report under "Risk Factors."

ITEM 3. Legal Proceedings.

From time to time, we are involved in litigation relating to claims arising out of our operations or from disputes with vendors in the normal course of business. As of April 9, 2003, we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on us.

ITEM 4. Submission of Matters to a Vote of Security Holders.

We did not submit any matters to a vote of our security holders during the fourth quarter of the fiscal year ended December 31, 2002.

PART II

ITEM 5. Market for Our Common Stock and Related Stockholder Matters.

Our common stock is traded over-the-counter under the symbol "GULF". The high and low trading prices for the common stock for each quarter in 2002, 2001 and 2000 are set forth below. The trading prices represent prices between dealers, without retail mark-ups, mark-downs, or commissions, and may not necessarily represent actual transactions.

	High	Low
2002		
First Quarter	$.66	$.55
Second Quarter	.60	.46
Third Quarter	.51	.20
Fourth Quarter	.44	.32
2001		
First Quarter	$1.46	$.39
Second Quarter	1.01	.53
Third Quarter	.96	.48
Fourth Quarter	.72	.58
2000		
First Quarter	$1.81	$.75
Second Quarter	2.00	1.25
Third Quarter	1.63	1.13
Fourth Quarter	1.69	.88

We are authorized to issue 40,000,000 shares of Class A common stock, par value $.001 per share (the "common stock"). As of April 9, 2003, there were 18,492,541 shares of common stock issued and outstanding and held by approximately 580 beneficial owners. Our common stock is traded over-the-counter (OTC) under the symbol "GULF". Fidelity Transfer Company, 1800 South West Temple, Suite 301, Box 53, Salt Lake City, Utah 84115, (801) 484-7222 is the transfer agent for the common stock.

Holders of common stock are entitled, among other things, to one vote per share on each matter submitted to a vote of shareholders and, in the event of liquidation, to share ratably in the distribution of assets remaining after payment of liabilities (including preferential distribution and dividend rights of holders of preferred stock). Holders of common stock have no cumulative rights, and, accordingly, the holders of a majority of the outstanding shares of the common stock have the ability to elect all of the directors.

Holders of common stock have no preemptive or other rights to subscribe for shares. Holders of common stock are entitled to such dividends as may be declared by the Board out of funds legally available therefore. We have never paid cash dividends on the common stock and do not anticipate paying any cash dividends in the foreseeable future.

Preferred Stock.

Our board of directors is authorized, without further shareholder action, to issue preferred stock in one or more series and to designate the dividend rate, voting rights and other rights, preferences and restrictions of each such series. As of April 9, 2003, we had a total of 17,000 shares of preferred stock issued and outstanding, including 8,000 of our

Series D and 9,000 of our Series E Preferred Stock. The Series D and E Preferred Stock are senior to our common stock regarding liquidation. The holders of the preferred stock do not have voting rights or preemptive rights nor are they subject to the benefits of any retirement or sinking fund.

The Series D Preferred Stock is not entitled to dividends, nor is it redeemable, however it is convertible to Common Stock at anytime following December 31, 2002, the third anniversary of the date of issue. Thereafter, the holder may convert any or all of the shares of the Series D Preferred Stock to Common Stock. The total number of shares of Common Stock to be issued upon such conversion shall be 500,000.

The Series E Preferred Stock is entitled to receive dividends at the rate of $12.50 per share per annum, payable quarterly. The Series E Preferred Stock is redeemable in whole or in part at any time, at our option, at a price of $500 per share, plus all accrued and undeclared or unpaid dividends; except that, after two years from the date of the original issuance and prior to redemption of remaining shares by the Company, the holders of record shall be given a 60-day written notice of our intent to redeem and the opportunity to convert the Series E Preferred Stock to common stock. The conversion price for the Series E Preferred Stock shall be $2.00 per share of common stock. At April 9, 2003, none of the 9,000 outstanding shares of Series E Preferred Stock had been redeemed or converted. On a fully converted basis, the 9,000 shares of Series E Preferred Stock would convert to 2,225,000 shares of common stock.

Outstanding Options and Warrants.

At April 9, 2003, we had outstanding warrants and options for the purchase 3,398,754 shares of common stock at prices ranging from $.75 to $6.00 per share, including employee stock options to purchase 1,067,000 shares at prices ranging from $.75 to $1.81 per share.

Recent Sales of Unregistered Securities.

During 2002 and to April 9, 2003, we granted warrants or options exercisable for shares of common stock not registered under the Securities Act of 1933, as amended, and exempt under Section 4(2) of the Act. All the grantees were current employees, consultants or accredited investors not affiliated with the company. No underwriters were used, and no underwriting discounts or commissions were paid in connection with the grants.

Date	Derivative	Grantee(s)	Exercisable Shares	Exercise Price	Consideration
02/25/02	Warrant	Director[1]	270,000	$ .75	Compensation
04/30/02	Warrant	Employee	100,000	$ .75	Compensation
07/15/02	Warrant	Accredited Investor	75,000	$ .75	Loan transaction
10/31/02	Option	Employee	35,000	$ .75	Compensation
11/06/02	Warrant	Director	625,000	$ .75	Loan transaction
12/02/02	Warrant	Accredited Investor	75,000	$ .75	Loan transaction
01/24/03	Warrant	Accredited Investor	100,000	$ .75	Loan transaction
02/12/03	Warrant	Accredited Investor	50,000	$ .75	Loan transaction

[1] 200,000, 50,000 and 20,000 warrants originally issued to an officer/director (currently a director) in 1996 at exercise prices of $3.00, $5.00 and $5.75, respectively, were re-priced to $.75 per share.

ITEM 6. Selected Financial Data.

The following table sets forth selected historical financial data of our company as of December 31, 2002, 2001, 2000, 1999 and 1998, and for each of the periods then ended. See "Item 1. Business" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations." The income statement data for the years ended December 31, 2002, 2001 and 2000 and the balance sheet data at December 31, 2002 and 2001 are derived from our audited financial statements contained elsewhere herein. The income statement data for the years ended December 31, 1999 and 1998 and the balance sheet data at December 31, 2000, 1999 and 1998 are derived from our Annual Report on Form 10-K for those periods. You should read this data in conjunction with our consolidated financial statements and the notes thereto included elsewhere herein.

	Year Ended December 31,				
	2002	2001	2000	1999	1998
Income Statement Data					
Operating Revenues	$ 10,839,797	$ 12,990,581	$ 8,984,175	$ 2,812,639	$ 2,403,553
Net income (loss) from operations	927,655	3,451,875	2,464,017	(1,464,094)	(6,329,884)
Net income (loss)	(4,502,313)	1,044,291	352,774	(2,269,506)	(8,387,060)
Dividends on preferred stock	(112,500)	(56,250)	-	(450,684)	(427,173)
Net income (loss) available to Common Shareholders	(4,614,813)	988,401	352,774	(2,720,190)	(8,814,233)
Net income (loss), per share of common stock	$ (.25)	$ .05	$ .02	$ (.34)	$ (3.68)
Weighted average number of shares of common stock outstanding	18,492,541	18,464,343	17,293,848	7,953,147	2,394,866
Balance Sheet Data					
Current assets	$ 2,353,046	$ 2,205,862	$ 2,934,804	$ 1,357,465	$ 820,984
Total assets	53,088,941	51,379,209	32,374,128	20,009,793	8,058,827
Current liabilities	43,998,566	12,492,365	7,594,986	4,650,691	6,559,393
Long-term obligations	1,266,801	26,541,957	18,077,371	11,304,318	3,401,371
Stockholders' Equity (Deficit)	$ 7,823,574	$ 12,344,887	$ 6,701,771	$ 4,054,784	$ (1,901,937)

ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Overview.

We are engaged primarily in the acquisition, development, exploitation, exploration and production of crude oil and natural gas. Our focus is on increasing production from our existing crude oil and natural gas properties through the further exploitation, development and exploration of those properties, and on acquiring additional interests in crude oil and natural gas properties. Our gross revenues are derived from the following sources:

1. **Oil and gas sales** that are proceeds from the sale of crude oil and natural gas production to midstream purchasers;

2. **Operating overhead and other income** that consists of earnings from operating crude oil and natural gas properties for other *working interest* owners, and marketing and transporting natural gas. This also includes earnings from other miscellaneous activities.

3. **Well servicing revenues** that are earnings from the operation of well servicing equipment under contract to other operators.

The following is a discussion of our consolidated financial condition, results of operations, liquidity and capital resources. You should read this discussion in conjunction with the Consolidated Financial Statements of the Company and the Notes thereto contained elsewhere herein. See "Financial Statements."

Results of Operations.

The factors which most significantly affect our results of operations are (1) the sales price of crude oil and natural gas, (2) the level of total sales volumes of crude oil and natural gas, (3) depletion and depreciation of oil and gas property costs and related equipment (4) the level of and interest rates on borrowings and, (5) the level and success of new acquisitions and development of existing properties.

We consider depletion and depreciation of oil and gas properties and related support equipment to be critical accounting estimates, based upon estimates of oil and gas reserves.

The estimates of oil and gas reserves utilized in the calculation of depletion and depreciation are estimated in accordance with guidelines established by the Securities and Exchange Commission and the Financial Accounting Standards Board, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations over prices and costs existing at year end, except by contractual arrangements.

We emphasize that reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. Our policy is to amortize capitalized oil and gas costs on the unit of production method, based upon these reserve estimates. It is reasonably possible the estimates of future cash inflows, future gross revenues, the amount of oil and gas reserves, the remaining estimated lives of the oil and gas properties, or any combination of the above may be increased or reduced in the near term. If reduced, the carrying amount of capitalized oil and gas properties may be reduced materially in the near term.

Comparative results of operations for the periods indicated are discussed below.

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Revenues

Oil and Gas Sales. Our operating revenues from the sale of crude oil and natural gas decreased by 16% from $12,426,000 in 2001 to $10,447,000 in 2002. This decrease resulted from normal oil and gas production declines and the inability to offset those declines through development efforts because of limited development capital.

Well Servicing Revenues. Revenues from our well servicing operations decreased by 77% from $169,000 in 2001 to $39,000 in 2002. This decrease was due to performing less work for third parties and the sale of one of our workover rigs.

Operating Overhead and Other Income. Revenues from these activities decreased 10% from $395,000 in 2001 to $354,000 in 2002, primarily as a result of the termination of a gas transportation sales contract with a local utility.

Costs and Expenses

Lease Operating Expenses. Lease operating expenses increased 5% from $5,155,000 in 2001 to $5,430,000 in 2002 due to increased vendor prices.

Cost of Well Servicing Operations. Well servicing expenses decreased 69% from $182,000 in 2001 to $56,000 in 2002 due to less work under contract to third parties and the sale of one workover rig.

Depreciation, Depletion and Amortization (DD and A). DD and A increased 8% from $2,491,000 in 2001 to $2,698,000 in 2002, due to our proved reserves being calculated slightly lower at the end of 2001.

General and Administrative (G and A) Expenses. G and A expenses increased only slightly from $1,710,000 in 2001 to $1,728,000 in 2002.

Interest Income and Expense. Interest expense increased 15% from $2,757,000 in 2001 to $3,159,000 in 2002 due to increased debt associated with the funding of acquisitions in August, 2001, capital used in our development program and issuance of warrants associated with working capital loans.

Unrealized Gain (Loss) on Derivative Instruments. The estimated future fair value of derivative instruments at December 31, 2002 resulted in an unrealized loss of $1,596,000 in 2002 compared to an unrealized gain of $4,215,000 in 2001. Also in 2001, an unrealized loss of $3,747,000, resulting from the cumulative effect of adopting SFAS No. 133 "Accounting for Derivative Instruments and Other Hedging Activities," was recorded.

Dry Holes, Abandoned Property, Impaired Assets. The costs of a dry hole in Louisiana of $339,000, abandoned property in Oklahoma of $223,500 and impaired assets in Mississippi of $54,900 totaled $617,400 in 2002 compared to none in 2001.

Dividends on preferred stock due was $112,500 and paid was $112,500 in 2002. Dividends on preferred stock due was $56,250 and paid was $28,125 in 2001.

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Revenues

Oil and Gas Sales. Our operating revenues from the sale of crude oil and natural gas increased by 47% from $8,446,000 in 2000 to $12,426,000 in 2001, due to increased oil and gas production from development projects and acquisitions of additional properties.

Well Servicing Revenues. Revenues from our well servicing operations decreased by 10% from $188,000 in 2000 to $169,000 in 2001. This decrease was due to higher rig utilization on operated properties where the Company has *working interest* partners and less work for third parties.

Operating Overhead and Other Income. Revenues from these activities increased 13% from $350,000 in 2000 to $395,000 in 2000. Major components of the increase included operating overhead $81,800, gathering and marketing $210,900, sale of exploratory leases $96,300 and miscellaneous income $6,000.

Costs and Expenses

Lease Operating Expenses. Lease operating expenses increased 53% from $3,378,000 in 2000 to $5,155,000 in 2001. This increase in operating expenses was due to the acquisitions of additional properties, expanded oil and gas production, and increased vendor prices.

Cost of Well Servicing Operations. Well servicing expenses decreased 14% from $212,000 in 2000 to $182,000 in 2001. This decrease in expenses was due to less utilization of our equipment under contract to third parties.

Depreciation, Depletion and Amortization (DD and A). DD and A increased 86% from $1,342,000 in 2000 to $2,491,000 in 2001, due to significantly higher production resulting from successful field development activities and acquisitions.

General and Administrative (G and A) Expenses. G and A expenses increased 8% from $1,588,000 in 2000 to $1,710,000 in 2001 due to the increased number of properties being managed.

Interest Expense and Dividends on Preferred Stock. Interest expense increased 29% from $2,135,000 in 2000 to $2,757,000 in 2001 due to increased debt associated with the funding of our additional acquisitions and capital development program.

Unrealized Gain (Loss) on Derivative Instruments. The estimated future fair value of derivative instruments at December 31, 2001 resulted in an unrealized gain of $4,215,000 in 2001. Also in 2001, an unrealized loss of $3,747,000, resulting from the cumulative effect of adopting SFAS No. 133 "Accounting for Derivative Instruments and Other Hedging Activities," was recorded. There was no unrealized gain or loss in 2000.

Dividends on preferred stock due was $56,250 and paid was $28,125 in 2001. No dividends were due or paid in 2000.

Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Revenues

Oil and Gas Sales. Our operating revenues from the sale of crude oil and natural gas increased by 233% from $2,533,000 in 1999 to $8,446,000 in 2000, due to increased oil and gas production from development projects, higher oil and gas prices, and acquisitions of additional properties.

Well Servicing Revenues. Revenues from our well servicing operations increased by 61% from $117,000 in 1999 to $188,000 in 2000. This increase was due to higher rig utilization on operated properties where the Company has *working interest* partners and increased work for third parties.

Operating Overhead and Other Income. Revenues from these activities increased 115% from $163,000 in 1999 to $350,000 in 2000. Major components of the change included a decrease of $38,000 in revenues we received for operating properties for other parties (due to our acquiring additional *working interests* in the operated properties); an increase of $117,000 in natural gas marketing and transportation; $52,000 received in damages from a drilling contractor; and, $20,000 received for the assignment of certain deep drilling rights on one of our leases.

Costs and Expenses

Lease Operating Expenses. Lease operating expenses increased 141% from $1,400,000 in 1999 to $3,378,000 in 2000. This increase in operating expenses was due to the acquisitions of additional properties, expanded oil and gas production, and the costs related to such production.

Cost of Well Servicing Operations. Well servicing expenses increased 12% from $190,000 in 1999 to $212,000 in 2000. This increase in expenses was due to less work under contract to third parties.

Depreciation, Depletion and Amortization (DD and A). DD and A increased 91% from $704,000 in 1999 to $1,342,000 in 2000, due to significantly higher production resulting from successful field development activities and acquisitions.

General and Administrative (G and A) Expenses. G and A expenses decreased 20% from $1,983,000 for 1999 to $1,588,000 in 2000. The Company had non-recurring expenses consisting of costs associated with the consolidation of its offices to Houston and non-cash charges of $232,000 related to the issuance of stocks and warrants in 1999 compared to $2,000 in 2000.

Interest Expense and Dividends on Preferred Stock. Interest expense increased 140% from $890,000 in 1999 to $2,135,000 in 2000 due to increased debt associated with additional acquisitions and our capital development program, and higher borrowing rates.

Preferred dividends decreased $451,000 from year-end 1999, since all of the preferred stock entitled to receive dividends had been converted to common stock.

Financial Condition and Capital Resources.

At December 31, 2002, our current liabilities exceeded our current assets by $41,645,520. We had a loss available to common shareholders of $4,614,813 compared to income available to common shareholders of $988,041 at December 31, 2001. This loss included non-cash items of $1,596,600 for unrealized loss on derivative instruments and $617,400 for dry holes, abandoned property and impaired assets.

On April 5, 2000, we entered into an agreement with Aquila Energy Capital, an energy lender, to provide $19,302,000 in financing, of which $13,302,000, less closing costs of $402,000, was funded at closing and $6,000,000 was for future development capital. We used the net proceeds to (i) retire existing debt, including accrued interest, of $10,234,977; (ii) acquire crude oil and natural gas properties in Zavala County, Texas for $2,300,000, including $3,266 in cash and 200,000 shares of common stock; and, (iii) acquire additional interests in the Madisonville Field, Texas. The loan is secured by substantially all of the Company's interests in oil and gas properties, bears interest at prime plus 3.5% and matures May 29, 2004. Monthly payments as to principal and interest are from an 85% net revenue interest in the secured properties. The lender retains a 7% *overriding royalty interest* with payments commencing after the loan is paid in full. On August 16, 2001, the total amount of financing increased by $16,800,000 to $36,102,000. The proceeds were to be used as follows: $10,000,000 for the Goldking Acquisition (see below), $6,630,000 for development of the properties securing the loan and $170,000 for a structuring fee paid to the lender. As a result of the amendment, the net revenue interest payment increased from 85% to 90%. In addition, the amendment requires payments on principal of $1,000,000 in February, 2002, August 2002 and February, 2003

In December, 2002, Aquila sold its loan portfolio, including our loan, to another energy lender. In a subsequent event on February 28, 2003, we entered into an agreement with that lender to buy-out the loan, which has a current balance of $27.9 million for a cash payment of $20 million, under the following terms and conditions:

1. A cash payment of Twenty Million Dollars ($20,000,000), funded at Closing.

2. Cancellation of the Note and Credit Agreement and termination of all debt instruments securing this obligation.

3. Re-assignment to GulfWest O&G of the Overriding Royalty Interest previously conveyed to Aquila and now held by the lender.

4. Cancellation and termination of all fixed price hedges and swap agreements entered into between GulfWest O&G and Aquila. Such cancellation to be effective the first day of the month following the Closing Date.

5. The current reporting and cashflow sweep will remain in effect through the Closing Date. Commencing January 1, 2003, GulfWest O&G will pay interest only due under the Note and no part of the funds retained by lender in the "sweep" shall include any amounts for principal repayment. Therefore, as respects oil and gas sales revenues due GulfWest O&G under the "sweep" for January 2003 production, which is to be paid in March 2003, no funds will be retained by the lender for principal repayment under the Note.

6. Within forty-five (45) days of the date of the lender's written acceptance of this offer, GulfWest will furnish the lender acceptable financial assurance that GulfWest will close the anticipated refinancing within ninety (90) days of the written acceptance of the offer. If within such forty-five (45) day period, GulfWest does not furnish the lender the required financial assurance, then the lender may, at its option, notify GulfWest that it is no longer obligated to the terms of this Agreement, and at the lender's option, re-instate the combined principal and interest payments under the "sweep" arrangement.

7. Should GulfWest not close this transaction within ninety (90) days of the lender's written acceptance of this offer, then GulfWest will, within thirty (30) days, issue to the lender one $1 million of preferred stock convertible at $1.00 per share of common stock. The stock will be in the form of

2,000 shares of a new GulfWest Series F Preferred Stock, par value $.01 and liquidation value $500 per share, with the same terms as the existing GulfWest Preferred E stock (except there will be no net profits interest redemption rights and the conversion price of the GulfWest Preferred Series F stock shall be $1.00 per common share instead of the $2.00 conversion price established for GulfWest's Preferred Series E stock). Provisions will be included in the Preferred Series F Stock Agreement to protect the Preferred Series F stockholder(s) and keep them on par with the Preferred Series E stockholders and other past and future preferred stockholders.

We are currently negotiating with various financial institutions to refinance the loan under the above terms and conditions, as well as providing funds for our $6.4 million capital development plan for 2003.

In a subsequent event on March 3, 2003, the lender notified us we were in default and agreed to forbear from exercising its rights and remedies regarding Events of Default resulting from (1) our most recent Reserve Reporting, as adjusted by the lender, being insufficient to fully amortize the loans by their stated maturity; and, (2 our failure to make the $1,000,000 repayment originally scheduled for August 31, 2002 and deferred to November 30, 2002 and the $1,000,000 repayment scheduled for February 28, 2003. The lender agreed to forebear until the earlier of: (1) May 31, 2003, (2) the occurrence of another Event of Default or Unmatured Event of Default, or (3) the lender learning of another Event of Default or Unmatured Event of Default that has occurred and is continuing, which is not listed above.

On August 17, 2001, we purchased several oil and natural gas properties located in four fields in Texas and Louisiana (the "Goldking Acquisition"). The effective date of the acquisition was July 1, 2001. The acquired properties are currently producing an aggregate 600 barrels of oil and 1,200 Mcf of natural gas per day, with total proved reserves (net to the acquired interests) estimated at 1.2 million barrels of oil and 9.5 billion cubic feet of natural gas. There are additional possible reserves estimated at 10 billion cubic feet of natural gas. The purchase price of the acquisition was $15 million in a combination of notes payable, preferred stock, cash, warrants and common stock. Financing was arranged through an existing credit facility and included expanding the company's credit line to continue the development of its properties through the year 2002.

Effective December 1, 2001 and amended August 16, 2002, we entered into an Oil and Gas Property Acquisition, Exploration and Development Agreement (the "Summit Agreement") with Summit Investment Group-Texas, L.L.C., an unrelated party, ("Summit"). Under the agreement, Summit will provide or makes available to us payments in the aggregate of $1,200,000 in advanced funds (the Advanced Funds") for our use in the acquisition of oil and gas leases and other mineral and royalty interests in order that we may conduct specified oil and gas exploration and production activities. We will pay Summit a sourcing fee of $100,000 and expenses of $100,000 from the Advanced Funds. We agree to drill four (4) wells located on oil and gas properties acquired under the Summit Agreement (the "Obligation Wells") and to commence such drilling prior to the expiration of two (2) years from the effective date of the Summit Agreement. We will pay Summit $150,000 on or before the date of commencement of drilling of each Obligation Well and Summit shall assign us its interest in the applicable oil and gas leases attributable to the production unit for such well. We further agree to conduct well workover operations on certain existing wells acquired by us, which are located on lands described in the Summit Agreement, all such well workover operations to be completed within nine (9) months of the Effective Date. Summit will reserve a 2.5% *overriding royalty interest* in the drilling *prospect* leases and a 25% net profits interest in the *workover* leases.

The Advanced Funds shall be recouped by Summit in the following manner:

(a) A total of $600,000 shall be repaid out of an undivided 40% of the "Summit Net Profits Interest", defined as twenty five percent (25%) of the monthly net sale proceeds of all oil and gas production allocable to our interest in the pertinent oil and gas properties, as more fully defined in the Summit Agreement. Summit will retain an 8.5% *working interest* in the *workover* leases after payment of the $600,000.

(b) We shall pay $150,000 in cash to Summit on the date we commence drilling each Obligation Well; or

(c) By virtue of a lump sum production payment by us.

If, at the expiration of two (2) years from the Effective Date, Summit has not completely recouped the Advanced Funds from the payments referred to in (a), (b) and (c) above, then Summit, at its sole election, may require that we issue to it a quantity of our Common Stock equivalent to the quotient of the outstanding Advanced Funds (numerator) and $2.00 per share (denominator). Upon issuance of such stock to Summit, Summit shall assign to us all its interest in the remaining oil and gas properties within the subject area, reserving its *overriding royalty interest* in the properties.

Inflation and Changes in Prices.

While the general level of inflation affects certain costs associated with the petroleum industry, factors unique to the industry result in independent price fluctuations. Such price changes have had, and will continue to have a material effect on our operations; however, we cannot predict these fluctuations.

The following table indicates the average crude oil and natural gas prices received over the last three years by quarter. Average prices per barrel of oil equivalent, computed by converting natural gas production to crude oil equivalents at the rate of 6 *Mcf* per barrel, indicate the composite impact of changes in crude oil and natural gas prices.

	Average Prices		
	Crude Oil And Liquids (per Bbl)	Natural Gas (per Mcf)	Per Equivalent Barrel
2002			
First	$ 19.40	$ 2.81	$ 18.31
Second	20.75	3.16	19.83
Third	22.04	2.87	19.67
Fourth	22.38	3.56	22.11
2001			
First	$ 24.15	$ 5.27	$ 27.87
Second	24.14	3.88	23.71
Third	23.25	3.08	21.08
Fourth	19.94	2.62	17.96
2000			
First	$ 26.06	$ 2.73	$ 21.23
Second	25.14	3.19	21.89
Third	25.79	3.90	24.42
Fourth	27.38	4.68	27.74

ITEM 7a. Qualitative and Quantitative Disclosures About Market Risk.

Information with respect to qualitative disclosures about material risk is contained in Item 1 "Risk Factors".

Information with respect to quantitative disclosures about material risk follow:

All of the Company's financial instruments are for purposes other than trading. The Company only enters derivative financial instruments in conjunction with its oil and gas hedging activities.

Hypothetical changes in interest rates and prices chosen for the following stimulated sensitivity effects are considered to be reasonably possible near-term changes generally based on consideration of past fluctuations for each risk category. It is not possible to accurately predict future changes in interest rates and product prices. Accordingly, these hypothetical changes may not be an indicator of probable future fluctuations.

Interest Rate Risk

The Company is exposed to interest rate risk on debt with variable interest rates. At December 31, 2002, the Company carried variable rate debt of $38,598,511. Assuming a one percentage point change at December 31, 2002 on the Company's variable rate debt, the annual pretax income (loss) would change by $385,985.

Commodity Price Risk

The Company hedges a portion of its price risks associated with its oil and natural gas sales which are classified as derivative instruments. As of December 31, 2002, these derivative instruments' assets had a fair value of $(1,128,993). Fair value was estimated based upon the net present value of expected future cash flows, comparing prices for oil and gas in the hedge contract with quoted oil and gas futures prices. A hypothetical change in oil and gas prices could have an effect on oil and gas futures prices, which are used to estimate the fair value of our derivative instrument. However, it is not practicable to estimate the resultant change, in any, in the fair value of our derivative instrument.

ITEM 8. Financial Statements and Supplementary Data.

Information with respect to this Item 8 is contained in our financial statements beginning on Page F-1 of this Annual Report.

ITEM 9. Changes In and Disagreements With Accountants and Accounting and Financial Disclosure.

None

PART III

ITEM 10. Directors and Executive Officers of the Registrant.

The following table sets forth information on our directors and executive officers:

Name	Age	Position	Year First Elected Director or Officer
J. Virgil Waggoner(1)(2)(3)	75	Chairman of the Board	1997
Thomas R. Kaetzer(3)	44	Chief Executive Officer President and Director	1998
Jim C. Bigham	67	Executive Vice President and Secretary	1991
Richard L. Creel	54	Vice President of Finance and Controller	1998
Marshall A. Smith III(3)	55	Director	1989
John E. Loehr(1)(2)(3)	57	Director	1992
William T. Winston	36	Director	2000
Steven M. Morris(1)(2)	51	Director	2000
John P. Boylan(1)	36	Director	2001

(1) Member of the Audit Committee.
(2) Member of the Compensation Committee.
(3) Member of the Executive Committee.

J. Virgil Waggoner has served as a director of GulfWest since December 1, 1997 and was elected Chairman of the Board in May, 2002. Mr. Waggoner's career in the petrochemical industry began in 1950 and included senior management positions with Monsanto Company and El Paso Products Company, the petrochemical and plastics unit of El Paso Company. He served as president and chief executive officer of Sterling Chemicals, Inc. from the firm's inception in 1986 until its sale and his retirement in 1996. He is currently chief executive officer of JVW Investments, Ltd., a private company.

Thomas R. Kaetzer was appointed senior vice president and chief operating officer of GulfWest on September 15, 1998 and on December 21, 1998 became president and a director. On March 20, 2001, he was appointed chief executive officer. Mr. Kaetzer has 17 years experience in the oil and gas industry, including 14 years with Texaco Inc., which involved the evaluation, exploitation and management of oil and gas assets. He has both onshore and offshore experience in operations and production management, asset acquisition, development, drilling and *workovers* in the continental U.S., Gulf of Mexico, North Sea, Colombia, Saudi Arabia, China and West Africa. Mr. Kaetzer has a Masters Degree in Petroleum Engineering from Tulane University and a Bachelor of Science Degree in Civil Engineering from the University of Illinois.

Jim C. Bigham has served as secretary since 1991 and as executive vice president of GulfWest since 1996. Prior to joining GulfWest, he held management and sales positions in the real estate and printing industries. Mr. Bigham is also a retired United States Air Force Major. During his military career, he served in both command and staff officer positions in the operational, intelligence and planning areas.

Richard L. Creel has served as controller of GulfWest since May 1, 1997 and was elected vice president of finance on May 28, 1998. Prior to joining GulfWest, Mr. Creel served as Branch Manager of the Nashville, Tennessee office of Management Reports and Services, Inc. He has also served as controller of TLO Energy Corp. He has extensive experience in general accounting, petroleum accounting, and financial consulting and income tax preparation.

Marshall A. Smith III founded GulfWest and served as an officer in various capacities, including president, chief executive officer and chairman of the board, from July 1989 until his resignation in May 2002. He is currently a paid consultant and remains a director.

John E. Loehr has served as a director of GulfWest since 1992, was chairman of the board from September 1, 1993 to July 8, 1998 and was chief financial officer from November 22, 1996 to May 28, 1998. He is also currently president and sole shareholder of ST Advisory Corporation, an investment company, and vice-president of Star-Tex Trading Company, also an investment company. He was formerly president of Star-Tex Asset Management, a commodity-trading advisor, and a position he held from 1988 until 1992 when he sold his ownership interest. Mr. Loehr is a CPA and a member of the American Institute of Certified Public Accountants.

William T. Winston joined GulfWest in April 1999 and served as vice president from May 2000 until March 29, 2002. He became a director in August 2001. While vice president, he was responsible for business development, including identifying and evaluating pipeline and gathering system acquisitions, and assisting in the evaluation for production acquisitions. Before joining GulfWest, Mr. Winston was in charge of field operations and project planning for Eagle Natural Gas Co., a privately held natural gas gathering company based in Houston. He served six years in the United States Army and Texas National Guard and holds a Bachelor of Arts Degree in Government from the University of Texas at Austin.

Steven M. Morris was appointed a director of GulfWest on January 6, 2000. He was the president of Pozo Resources, Inc., an oil and gas production company, until its asset were sold to GulfWest on December 31, 1999. Mr. Morris is a certified public accountant and president of Pentad Enterprises, Inc., a private investment firm in Houston, Texas. He is currently a director of the Bank of Tanglewood, Houston, Texas, and Quicksilver Resources, Inc., a publicly traded oil and gas exploration and production company with offices in Ft. Worth, Texas. In a subsequent event, Mr. Morris resigned as a director for personal reasons effective January 7, 2003.

John P. Boylan was appointed a director of GulfWest on August 7, 2001. Mr. Boylan has served as Managing Partner and Chief Executive Officer of Birdwell Partners, L.P., the parent company and General Partner of Five Star Transportation, Superior Trucking Company and American Pipe Inspection Company since 1999. He began his career in the oil and gas industry in 1993 providing venture funding for lease acquisition and drilling projects, and from 1996 to present has been actively involved in the management of an independent exploration and production company. He has had experience in all of the major producing trends covering the Texas Gulf Coast and South Texas. He received the degree of Bachelor of Business Administration, with a major in Accounting, from the University of Texas in 1988 and the degree of Master of Business Administration, with majors in Finance, Economics and International Business from the Leonard N. Stern Graduate School of Business of New York University in 1995. Mr. Boylan has been a Certified Public Accountant in the State of Texas since 1991.

Our directors are elected annually and hold office until the next annual meeting of shareholders and until their successors are duly elected and qualified. The board of directors met six times during the calendar year ended December 31, 2002.

Committees of the Board of Directors.

Our board of directors has established an audit committee and a compensation committee. The functions of these committees, their current members, and the number of meetings held during 2002 are described below.

The audit committee was established to review and appraise the audit efforts of our independent auditors, and monitor the company's accounts, procedures and internal controls. The committee is comprised of Mr. John E. Loehr (Chairman), Mr. J. Virgil Waggoner, Mr. John P. Boylan and Mr. Steven M. Morris. The committee met twice in 2002.

The function of the compensation committee is to fix the annual salaries and other compensation for the officers and key employees of the Company. The committee is comprised of Mr. J. Virgil Waggoner (Chairman), Mr. John E. Loehr and Mr. Steven M. Morris. The committee met twice in 2002.

Compensation of Directors.

The shareholders approved an amended and restated Employee Stock Option Plan on May 28, 1998, which included a provision for the payment of reasonable fees in cash or stock to directors. No fees were paid to directors in 2002 or 2001.

ITEM 11. **Executive Compensation.**

Information regarding executive compensation is incorporated herein by reference to our Proxy Statement.

ITEM 12. **Security Ownership of Certain Beneficial Owners and Management.**

Information regarding security ownership of certain beneficial owners and management is incorporated herein by reference to our Proxy Statement.

ITEM 13. **Certain Relationships and Related Transactions.**

Information regarding certain relationships and related transactions is incorporated herein by reference to our Proxy Statement.

ITEM 14. Controls and Procedures

Within ninety days of the date of this Report, we carried out an evaluation, under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, of our disclosure controls and procedures (as defined in Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934). Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective in timely alerting them to material information required to be included in periodic filings with the Securities and Exchange Commission. There were no significant changes in our internal controls or in other factors that could significantly affect these internal controls subsequent to the date of our most recent evaluation.

GLOSSARY OF INDUSTRY TERMS AND ABBREVIATIONS

The following are definitions of certain industry terms and abbreviations used in this report:

Bbl. Barrel.

BOE. Barrel of oil equivalent, based on a ratio of 6,000 cubic feet of natural gas for each barrel of oil.

Gross Acres or Gross Wells. The total acres or wells, as the case may be, in which a *working interests* is owned.

Horizontal Drilling. High angle directional drilling with lateral penetration of one or more productive *reservoirs*.

Mcf. One thousand cubic feet.

Net Acres or Net Wells. The sum of the fractional *working interests* owned in *gross acres* or *gross wells.*

Overriding Royalty Interest. The right to receive a share of the *proceeds of production* from a well, free of all costs and expenses, except transportation.

Present Value. The pre-tax present value, discounted at 10%, of future net cash flows from estimated proved reserves, calculated holding prices and costs constant at amounts in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions) and otherwise in accordance with the Commission's rules for inclusion of oil and gas reserve information in financial statements filed with the Commission.

Proceeds of Production. Money received (usually monthly) from the sale of oil and gas produced from *producing properties.*

Producing Properties. Properties that contain one or more wells that produce oil and/or gas in paying quantities (i.e., a well for which proceeds from production exceed operating expenses).

Productive Well. A well that is producing oil or gas or that is capable of production.

Prospect. A lease or group of leases containing possible reserves, capable of producing crude oil, natural gas, or natural gas liquids in commercial quantities, either at the time of acquisition, or after vertical or horizontal drilling, completion of *workovers*, *recompletions*, or operational modifications.

Proved Reserves. Estimated quantities of crude 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 conditions; i.e., prices and costs as of the date the estimate is made. *Reservoirs* are considered proved if either actual production or a conclusive formation test supports economic production.

The area of a *reservoir* considered proved includes:

a. That portion delineated by drilling and defining by gas-oil or oil-water contacts, if any; and

b. The immediately adjoining portions not yet drilled but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Proved Reserves do not include:

a. Oil that may become available from known *reservoir*s but is classified separately as "indicated additional reserves";

b. Crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, *reservoir* characteristics, or economic factors;

c. Crude oil, natural gas, and natural gas liquids that may occur in undrilled *prospect*s; and

d. Crude oil, natural gas, and natural gas liquids that may be recovered from oil shales and other sources.

Proved Developed Reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as *proved developed* only after testing by a pilot project or after operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved Undeveloped Reserves. Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for *recompletion*. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other units that have not been drilled can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for *proved undeveloped reserves* be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proven effective by actual tests in the area and in the same *reservoir*.

Recompletion. The completion for production of an existing wellbore in another formation from that in which the well has previously been completed.

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

Royalty. The right to a share of production from a well, free of all costs and expenses, except transportation.

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

Standardized Measure. The present value, discounted at 10%, of future net cash flows from estimated proved reserves, after income taxes, calculated holding prices and costs constant at amounts in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions) and otherwise in accordance with the Commission's rules for inclusion of oil and gas reserve information in financial statements filed with the Commission.

Waterflood. An engineered, planned effort to inject water into an existing oil *reservoir* with the intent of increasing oil reserve recovery and production rates.

Working Interest. The operating interest under a lease, the owner of which has the right to explore for and produce oil and gas covered by such lease. The full working interest bears 100 percent of the costs of exploration, development, production, and operation, and is entitled to the portion of gross revenue from the *proceeds of production* which remains after proceeds allocable to *royalty* and *overriding royalty interests* or other lease burdens have been deducted.

Workover. Rig work performed to restore an existing well to production or improve its production from the current existing *reservoir*.

PART III

ITEM 15. **Exhibits, Financial Statement Schedules, and Reports on Form 8-K.**

(a) The following documents are filed as part of this Report:

(1) Financial Statements:
Consolidated Balance Sheets at December 31, 2002 and 2001.
Consolidated Statements of Operations for the years ended December 31, 2002, 2001 and 2000.
Consolidated Statements of Stockholders' Equity for the years ended December 31, 2002, 2001 and 2000.
Consolidated Statements of Cash Flows for the years ended December 31, 2002, 2001 and 2000.
Notes to Consolidated Financial Statements, December 31, 2002, 2001 and 2000.

(2) Financial Statement Schedule:
Schedule II - Valuation and Qualifying Accounts

(3) Exhibits:

Number	Description
*3.1	Articles of Incorporation of the Registrant and Amendments thereto.
*3.2	Bylaws of the Registrant.
%10.1	GulfWest Oil Company 1994 Stock Option and Compensation Plan, amended and restated as of April 1, 2001 and approved by the shareholders on May 18, 2001.
22.1	Subsidiaries of the Registrant (included on page 3 of this Annual Report.
25	Power of Attorney (included on signature page of this Annual Report).

---

* Previously filed with the Company's Registration Statement (on Form S-1, Reg. No. 33-53526), filed with the Commission on October 21, 1992.

% Previously filed with the Company's Proxy Statement on Form DEF 14A, filed with the Commission on April 16, 2001.

(b) Reports on Form 8-K.

None.

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 on its behalf by the undersigned, thereunto duly authorized.

GULFWEST ENERGY INC.

Date: April 9, 2003

By \s\ Thomas R. Kaetzer
Thomas R. Kaetzer, President

POWER OF ATTORNEY

Know all men by these presents, that each person whose signature appears below constitutes and appoints Thomas R. Kaetzer as his true and lawful attorney-in-fact and agent, with full power of substitution, for him and in his name, place, and stead, in any and all capacities to sign any and all amendments or supplements to this Annual Report on Form 10-K, and to file the same, and with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent or his substitute or substitutes, may lawfully 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\ J. Virgil Waggoner J. Virgil Waggoner	Chairman of the Board	April 9, 2003
\s\ Thomas R. Kaetzer Thomas R. Kaetzer	President, Chief Executive Officer and Director	April 9, 2003
\s\ Jim C. Bigham Jim C. Bigham	Executive Vice President and Secretary	April 9, 2003
\s\ Richard L. Creel Richard L. Creel	Vice President of Finance, Controller	April 9, 2003
\s\ William T. Winston William T. Winston	Director	April 9, 2003
\s\ Marshall A. Smith III Marshall A. Smith III	Director	April 9, 2003
\s\ John E. Loehr John E. Loehr	Director	April 9, 2003
\s\ John P. Boylan John P. Boylan	Director	April 9, 2003
\s\ Steven M.Morris Steven M. Morris	Director	April 9, 2003

This page is intentionally left blank

GULFWEST ENERGY INC.

FINANCIAL REPORT

DECEMBER 31, 2002

CONTENTS

	Page
INDEPENDENT AUDITOR'S REPORT ON THE FINANCIAL STATEMENTS	F-1
FINANCIAL STATEMENTS	
Consolidated balance sheets	F-2
Consolidated statements of operations	F-4
Consolidated statements of stockholders' equity	F-5
Consolidated statements of cash flows	F-7
Notes to consolidated financial statements	F-8
INDEPENDENT AUDITOR'S REPORT ON THE FINANCIAL STATEMENT SCHEDULE	F-30
FINANCIAL STATEMENT SCHEDULE	
Schedule II - Valuation and Qualifying Accounts	F-31

All other Financial Statement Schedules have been omitted because they are either inapplicable or the information required is included in the financial statements or the notes thereto.

INDEPENDENT AUDITOR'S REPORT

To the Stockholders and
Board of Directors
GULFWEST ENERGY INC.

We have audited the accompanying consolidated balance sheets of GulfWest Energy Inc. (a Texas Corporation) and Subsidiaries as of December 31, 2002 and 2001, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2002. 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 consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of GulfWest Energy Inc. and Subsidiaries as of December 31, 2002 and 2001, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As shown in the consolidated financial statements, the Company incurred a net loss of $4,502,313 during the year ended December 31, 2002, and, as of that date, had a working capital deficiency of $41,645,520. Those conditions raise substantial doubt about the Company's ability to continue as a going concern. Management's plans regarding those matters described in Note 2, "Operations and Management Plans". The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

\s\WEAVER AND TIDWELL, L.L.P
WEAVER AND TIDWELL, L.L.P.

Dallas, Texas
March 24, 2003

GULFWEST ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

DECEMBER 31, 2002 AND 2001

ASSETS

	2002	2001
CURRENT ASSETS		
Cash and cash equivalents	$ 687,694	$ 689,030
Accounts receivable – trade, net of allowance for doubtful accounts of $-0- in 2002 and 2001	1,361,446	1,392,751
Prepaid expenses	303,906	124,081
Total current assets	2,353,046	2,205,862
OIL AND GAS PROPERTIES, using the successful efforts method of accounting	56,786,043	52,045,178
OTHER PROPERTY AND EQUIPMENT	2,121,410	2,352,166
Less accumulated depreciation, depletion and amortization	(8,498,497)	(6,235,251)
Net oil and gas properties and other property and equipment	50,408,956	48,162,093
OTHER ASSETS		
Deposits	37,442	37,442
Debt issue cost, net	289,497	506,230
Derivative instruments		467,582
Total other assets	326,939	1,011,254
TOTAL ASSETS	$53,088,941	$51,379,209

The Notes to Consolidated Financial Statements are an integral part of these statements.

LIABILITIES AND STOCKHOLDERS' EQUITY

	2002	2001
CURRENT LIABILITES		
Notes payable	$ 4,936,088	$ 2,821,020
Notes payable – related parties	1,290,000	40,000
Current portion of long-term debt	33,128,447	6,065,588
Current portion of long-term debt – related parties	256,967	222,687
Accounts payable – trade	3,928,477	3,099,399
Accrued expenses	458,587	243,671
Total current liabilities	43,998,566	12,492,365
NONCURRENT LIABILITIES		
Long-term debt, net of current portion	126,552	26,330,589
Long-term debt – related parties	11,256	211,368
Total noncurrent liabilities	137,808	26,541,957
OTHER LIABILITES		
Derivative instruments	1,128,993	
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' EQUITY		
Preferred stock	170	170
Common stock	18,493	18,493
Additional paid-in capital	28,258,212	28,164,712
Retained deficit	(20,453,301)	(15,838,488)
Total stockholders' equity	7,823,574	12,344,887
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$53,088,941	$ 51,379,209

The Notes to Consolidated Financial Statements are an integral part of these statements.

This page is intentionally left blank

GULFWEST ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000

	2002	2001	2000
OPERATING REVENUES			
Oil and gas sales	$ 10,447,169	$ 12,426,103	$ 8,445,932
Well servicing revenues	39,116	169,167	188,052
Operating overhead and other income	353,512	395,311	350,191
Total Operating Revenues	10,839,797	12,990,581	8,984,175
OPERATING EXPENSES			
Lease operating expenses	5,430,205	5,155,500	3,377,583
Cost of well servicing operations	56,295	182,180	212,286
Depreciation, depletion and amortization	2,697,784	2,491,385	1,341,890
General administrative	1,727,858	1,709,641	1,588,399
Total Operating Expenses	9,912,142	9,538,706	6,520,158
INCOME FROM OPERATIONS	927,655	3,451,875	2,464,017
OTHER INCOME AND EXPENSE			
Interest income			16,082
Interest expense	(3,159,381)	(2,756,912)	(2,134,718)
Gain (loss) on sale of assets	(56,647)	(118,254)	7,393
Unrealized gain (loss) on derivative instruments	(1,596,575)	4,215,017	
Dry holes, abandoned property and impaired assets	(617,365)		
Total Other Income and (Expense)	5,429,968	1,339,851	(2,111,243)
INCOME (LOSS) BEFORE INCOME TAXES AND CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLES	(4,502,313)	4,791,726	352,774
INCOME TAXES			
INCOME (LOSS) BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLES	(4,502,313)	4,791,726	352,774
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLES, NET OF INCOME TAXES		(3,747,435)	
NET INCOME (LOSS)	$ (4,502,313)	$ 1,044,291	$ 352,774
DIVIDENDS ON PREFERRED STOCK (PAID 2002-$112,500; 2001-$28,125; 2000-$76,992)	(112,500)	(56,250)	
NET INCOME (LOSS) AVAILABLE TO COMMON SHAREHOLDERS	$ (4,614,813)	$ 988,041	$ 352,774
NET INCOME (LOSS) PER SHARE, BASIC BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLES	$ (.25)	$ .25	$ .02
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLES		(.20)	
NET INCOME (LOSS) PER SHARE BASIC	$ (.25)	$ .05	$ .02
NET INCOME (LOSS) PER SHARE, DILUTED BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLES	$ (.25)	$ .23	$ .02
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLES		(.18)	
NET INCOME (LOSS) PER SHARE, DILUTED	$ (.25)	$ .05	$ .02

GULFWEST ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000

	Number of Shares	
	Preferred Stock	Common Stock
BALANCE, December 31, 1999	8,815	15,696,882
Conversion of 815 shares of AAA preferred stock and unpaid dividends to 538,222 shares of common stock	(815)	538,322
Issuance of 2,209,837 shares of common stock, net of offering costs (1,143,837 through private placement, 200,000 for acquisition of assets, 866,000 in exchange for debt)		2,209,837
Issuance of warrants and options for services and additional financing		
Netting of related party receivables and payables		
Provision for bad debts – receivables from related parties		
Net income		
BALANCE, December 31, 2000	8,000	18,445,041
Issuance of 9,000 shares of Series E preferred stock for the acquisition of assets	9,000	
Issuance of 47,500 shares of common stock for the acquisition of assets		47,500
Issuance of warrants for the acquisition of assets		
Net income		
Dividends paid on preferred stock		
BALANCE, December 31, 2001	17,000	18,492,541
Issuance of warrants for additional financing		
Net loss		
Dividends paid on preferred stock		
BALANCE, December 31, 2002	17,000	18,492,541

The Notes to Consolidated Financials are an integral part of these statements.

Common Stock	Preferred Stock	Additional Paid-In Capital	Retained Deficit	Receivables from Related Parties
$ 15,697	$ 88	$ 21,321,909	$ (17,130,436)	$ (152,474)
538	(8)	76,463	(76,992)	
2,210		2,123,868		
		15,660		
				112,226
				40,248
			352,774	
$ 18,445	$ 80	$ 23,537,900	$ (16,854,654)	$ -
	90	4,499,910		
48		35,402		
		91,500		
			1,044,291	
			(28,125)	
$ 18,493	$ 170	$ 28,164,712	$ (15,838,488)	$ -
		93,500		
			(4,502,313)	
			(112,500)	
$ 18,493	$ 170	$ 28,258,212	$ (20,453,301)	$ -

The Notes to Consolidated Financials are an integral part of these statements.

GULFWEST ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000

	2002	2001	2000
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (4,502,313)	$ 1,044,291	$ 352,774
Adjustments to reconcile net income (loss) to net cash			
Provide by (used in) operating activities:			
Depreciation, depletion and amortization	2,697,784	2,491,385	1,341,890
Common stock and warrants issued and charged to operations	93,500		15,660
(Gain) loss on sale of assets	56,647	118,254	(7,393)
Dry holes, abandoned property, impaired assets	617,365		
Unrealized (gain) loss on derivative instruments	1,596,575	(4,215,017)	
Cumulative effect of accounting change		3,747,435	
Other non-operating income			(5,780)
Provision for bad debts			40,248
(Increase) decrease in accounts receivable – trade, net	(109,437)	765,939	(1,344,767)
(Increase) decrease in prepaid expenses	(179,825)	(40,730)	(3,588)
Increase (decrease) in accounts payable and accrued expenses	1,043,994	797,800	1,710,769
Net cash provided by operating activities	1,314,290	4,709,357	2,099,813
CASH FLOWS FROM INVESTING ACTIVITIES:			
Deposits		(9,804)	
Proceeds from sale of property and equipment	675,440	394,423	14,915
Purchase of property and equipment	(5,861,969)	(6,962,650)	(6,126,817)
Net cash used in investing activities	(5,186,529)	(6,578,031)	(6,111,902)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from sale of common stock, net			795,378
Payments on debt	(3,410,778)	(6,577,928)	(1,733,513)
Proceeds from debt issuance	7,394,181	8,530,269	5,694,510
Debt issue cost		(29,544)	(368,554)
Dividends paid	(112,500)	(28,125)	
Net cash provided by financing activities	3,870,903	1,894,672	4,387,821
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(1,336)	25,998	375,732
CASH AND CASH EQUIVALENTS, Beginning of year	689,030	663,032	287,300
CASH AND CASH EQUIVALENTS, End of year	$ 687,694	$ 689,030	$ 663,032
CASH PAID FOR INTEREST	$ 3,004,015	$ 2,811,677	$ 2,041,630

The Notes to Consolidated Financial Statements are an integral part of these statements.

GULFWEST ENERGY INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Summary of Significant Accounting Policies

The following is a summary of the significant accounting policies consistently applied by management in the preparation of the accompanying consolidated financial statements.

Organization/Concentration of Credit Risk

GulfWest Energy Inc. and our subsidiaries intend to pursue the acquisition of quality oil and gas prospects, which have proved developed and undeveloped reserves and the development of prospects with third party industry partners.

The accompanying consolidated financial statements include our company and its wholly-owned subsidiaries: RigWest Well Service, Inc. ("RigWest"), GulfWest Texas Company ("GWT"), both formed in 1996; DutchWest Oil Company formed in 1997; SETEX Oil and Gas Company ("SETEX") formed August 11, 1998; Southeast Texas Oil and Gas Company, L.L.C. ("Setex LLC") acquired September 1, 1998; GulfWest Oil and Gas Company formed February 18, 1999; LTW Pipeline Co. formed April 19, 1999; GulfWest Development Company ("GWD") formed November 9, 2000 and GulfWest Oil and Gas Company (Louisiana) LLC, formed July 31, 2001. All material intercompany transactions and balances are eliminated upon consolidation.

We grant credit to independent and major oil and gas companies for the sale of crude oil and natural gas. In addition, we grant credit to joint owners of oil and gas properties, which we, through our subsidiary, SETEX, operate. Such amounts are secured by the underlying ownership interests in the properties. We also grant credit to various third parties through RigWest for well servicing operations.

We maintain cash on deposit in interest and non-interest bearing accounts, which, at times, exceed federally insured limits. We have not experienced any losses on such accounts and believe we are not exposed to any significant credit risk on cash and equivalents.

Statement of Cash Flows

We consider all highly liquid investment instruments purchased with remaining maturities of three months or less to be cash equivalents for purposes of the consolidated statements of cash flows.

Non-Cash Investing and Financing Activities:

During the twelve month period ended December 31, 2002, we acquired $74,653 in property and equipment through notes payable to financial institutions. We also acquired $182,742 of oil producing properties in exchange of accounts receivable from a related party. In addition, we sold property and equipment, which included an account receivable of $42,000. This receivable was collected in January 2003.

During the twelve month period ended December 31, 2001, we acquired $15,068,774 in property and equipment through $10,441,824 in notes payable to financial institutions and related parties, by issuing 9,000 shares of preferred stock valued at $4,500,000, by issuing 47,500 shares of common stock valued at $35,450 and by issuing 150,000 warrants valued at $91,500. Also, debt issue costs increased $170,000 in notes payable.

Note 1. Summary of Significant Accounting Policies (continued)

Statement of Cash Flows – Non-cash Investing and Financing Activities – continued

During the twelve month period ended December 31, 2000, we acquired $5,434,161 in property and equipment through notes payable to financial institutions and related parties of $4,958,163, in exchange of accounts receivable of $169,798 and by issuing 200,000 shares of common stock valued at $306,200. In addition, accounts payable and accrued expenses decreased $312,791, debt issue costs increased $206,875 through notes payable to financial institutions. During the period, 815 shares of preferred stock, along with unpaid dividends of $76,992, were converted to 538,322 shares of common stock, notes payable of $975,000 (including $750,000 to a director) were converted to 800,000 shares of common stock and accounts payable of $49,352 were converted to 66,000shares of common stock. Also, related party receivables of $112,226 and accounts receivable of $26,950 were exchanged for related party notes payable of $75,000 and for accounts payable of $64,176.

Use of Estimates in the Preparation of Financial Statements

The preparation of consolidated financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Oil and Gas Properties

We use the successful efforts method of accounting for oil and gas producing activities. Costs to acquire mineral interests in oil and gas properties, to drill and equip exploratory wells that find proved reserves, and to drill and equip development wells are capitalized. Costs to drill exploratory wells that do not find proved reserves, and geological and geophysical costs are expensed.

As we acquire significant oil and gas properties, any unproved property that is considered individually significant is periodically assessed for impairment of value, and a loss is recognized at the time of impairment by providing an impairment allowance. Capitalized costs of producing oil and gas properties and support equipment, after considering estimated dismantlement and abandonment costs and estimated salvage values, are depreciated and depleted by the unit-of-production method.

On the sale of an entire interest in an unproved property, gain or loss on the sale is recognized, taking into consideration the amount of any recorded impairment if the property has been assessed individually. If a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained. On the sale of an entire or partial interest in a proved property, gain or loss is recognized, based upon the fair values of the interests sold and retained.

Other Property and Equipment

The following tables set forth certain information with respect to our other property and equipment. We provide for depreciation and amortization using the straight-line method over the following estimated useful lives of the respective assets:

Assets	Years
Automobiles	3-5
Office equipment	7
Gathering system	10
Well servicing equipment	10

GULFWEST ENERGY INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Summary of Significant Accounting Policies - continued

Other Property and Equipment – continued

Capitalized costs relating to other properties and equipment:

	2002	2001
Automobiles	$ 420,776	$ 446,055
Office equipment	137,362	126,690
Gathering system	529,486	529,486
Well servicing equipment	1,033,786	1,249,935
	2,121,410	2,352,166
Less accumulated depreciation	(1,037,076)	(937,488)
Net capitalized cost	$ 1,084,334	$ 1,414,678

Revenue Recognition

We recognize oil and gas revenues on the sales method as oil and gas production is sold. Differences between sales and production volumes during the years ended December 31, 2002, 2001, and 2000 were not significant. Well servicing revenues are recognized as the related services are performed. Operating overhead income is recognized based upon monthly contractual amounts for lease operations and other income is recognized as earned.

Fair Value of Financial Instruments

At December 31, 2002 and 2001, our financial instruments consist of notes payable and long-term debt. Interest rates currently available to us for notes payable and long-term debt with similar terms and remaining maturities are used to estimate fair value of such financial instruments. Accordingly, the carrying amounts are a reasonable estimate of fair value.

Debt Issue Costs

Debt issue costs incurred are capitalized and subsequently amortized over the term of the related debt on a straight-line basis.

Earnings (Loss) Per Share

Earnings (loss) per share are calculated based upon the weighted-average number of outstanding common shares. Diluted earnings (loss) per share are calculated based upon the weighted-average number of outstanding common shares, plus the effect of dilutive stock options, warrants, convertible preferred stock and convertible debentures.

Trade Accounts Receivable

Trade accounts receivable are reported in the consolidated balance sheet at the outstanding principal adjusted for any chargeoffs. An allocation for doubtful accounts is recognized by management based upon a review of specific customer balances, historical losses and general economic conditions.

Note 1. Summary of Significant Accounting Policies - continued

Earnings (Loss) Per Share - continued

We have adopted Statement of Financial Accounting Standards (SFAS) No. 128 "Earnings Per Share", which requires that both basic earnings (loss) per share and diluted earnings (loss) per share be presented on the face of the statement of operations. All per-share amounts are presented on a diluted basis, that is, based upon the weighted-average number of outstanding common shares and the effect of all potentially diluted common shares.

Impairments

Impairments, measured using fair market value, are recognized whenever events or changes in circumstances indicate that the carrying amount of long-lived assets (other than unproved oil and gas properties discussed above) may not be recoverable and the future undiscounted cash flows attributable to the asset are less than its carrying value.

Stock Based Compensation

In October 1995, SFAS No. 123, "Stock Based Compensation," (SFAS 123) was issued. This statement requires that we choose between two different methods of accounting for stock options and warrants. The statement defines a fair-value-based method of accounting for stock options and warrants but allows an entity to continue to measure compensation cost for stock options and warrants using the accounting prescribed by APB Opinion No. 25 (APB 25), "Accounting for Stock Issued to Employees." Use of the APB 25 accounting method results in no compensation cost being recognized if options are granted at an exercise price at the current market value of the stock or higher. We will continue to use the intrinsic value method under APB 25 but are required by SFAS 123 to make pro forma disclosures of net income (loss) and earnings (loss) per share as if the fair value method had been applied in its 2002, 2001 and 2000 financial statements.

During 2002, 2001 and 2000, we issued options and warrants totaling: 2002 – 405,000 (all exercisable); 2001 – 184,000 (all exercisable); and 2000 – 354,000 (all exercisable), respectively, to employees and directors as compensation. If we had used the fair value method required by SFAS 123, our net income (loss) and per share information would approximate the following amounts:

	2002		2001		2000	
	As Reported	ProForma	As Reported	ProForma	As Reported	ProForma
SFAS 123 compensation cost	$	$ 38,300		$ 99,360	$	$ 265,620
APB 25 compensation cost	$	$		$	$	
Net income (loss)	$(4,614,813)	$(4,653,113)	$ 988,041	$ 888,681	$ 352,774	$ 87,154
Income (loss) per common share–basic	$ (.25)	$ (.25)	$ .05	$ .05	$ .02	$ .00
Income (loss) per common share-diluted	$ (.25)	$ (.25)	$ .05	$ .04	$ .02	$ .00

Note 1. Summary of Significant Accounting Policies - continued

Stock Based Compensation - continued

The effects of applying SFAS 123 as disclosed above are not indicative of future amounts. We anticipate making additional stock based employee compensation awards in the future.

We use the Black-Sholes option-pricing model to estimate the fair value of the options and warrants (to employee and non-employees) on the grant date. Significant assumptions include (1) 5.75% risk free interest rate; (2) weighted average expected life of 2002 – 3.6; 2001 - 5.0; 2000 – 4.8; (3) expected volatility of 2002 – 101.73%; 2001 – 103.27%; 2000 – 99.82%; and (4) no expected dividends.

Implementation of New Financial Accounting Standards

Effective January 1, 2001, we adopted SFAS No. 133 "Accounting for Derivative Instruments and Other Hedging Activities", as amended by SFAS No. 137 and No. 138. As a result of a financing agreement with an energy lender, we were required to enter into an oil and gas hedging agreement with the lender. It has been determined this agreement meets the definition of SFAS 133 "Accounting for Derivative Instruments and Hedging Activities" and is accounted for as a derivative instrument.

The estimated change in fair value of the derivatives is reported in Other Income and Expense as unrealized (gain) loss on derivative instruments. The estimated fair value of the derivatives is reported in Other Assets (or Other Liabilities) as derivative instruments.

The estimated fair value of the derivative instruments at January 1, 2001, the date of initial application of SFAS 133, of $3,747,435 is reported in the Statement of Operations as the cumulative effect of a change in accounting principle.

In June, 2001, SFAS No. 141 "Business Combinations" and SFAS No. 142 "Goodwill and Other Intangible Assets were issued. We presently have no goodwill or intangible assets and are thus not affected by SFAS No. 142.

Effective January 1, 2002, we adopted SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." This statement requires the following three-step approach for assessing and recognizing the impairment of long-lived assets: (1) consider whether indicators of impairment of long-lived assets are present; (2) if indicators of impairment are present, determine whether the sum of the estimated undiscounted future cash flows attributable to the assets in question is less than their carrying amount; and (3) if less, recognize an impairment loss based on the excess of the carrying amount of the assets over their respective fair values. In addition, SFAS No. 144 provides more guidance on estimating cash flows when performing a recoverability test, requires that a long-lived asset to be disposed of other than by sale (such as abandoned) be classified as "held and used" until it is disposed of, and establishes more restrictive criteria to classify an asset as "held for sale". The adoption of SFAS No. 144 did not have a material impact on our financial statements since it retained the fundamental provisions of SFAS No. 121, "Accounting for the Impairment or Disposal of Long-Lived Assets and for Long-Lived Assets to be Disposed Of," related to the recognition and measurement of the impairment of long-lived assets to be "held and used".

Note 1. Summary of Significant Accounting Policies - continued

Implementation of New Financial Accounting Standards - continued

In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." SFAS No. 146 addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies EITF Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." SFAS No. 146 requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred. Under EITF Issue No. 94-3, a liability for an exit cost as defined was recognized at the date of an entity's commitment to an exit plan. SFAS No. 146 also establishes that the fair value is the objective for the initial measurement of the liability. SFAS No. 146 is effective for exit and disposal activities that are initiated after December 31, 2002. This statement will impact the timing of our recognition of liabilities for costs associated with exit or disposal activities.

Note 2. Operations and Management Plans

At December 31, 2002, our current liabilities exceeded our current assets by $41,645,520. We had a net loss available to common shareholders of $4,614,813 compared to a net income available to common shareholders of $988,041 at December 31, 2001. This loss included non-cash items of $1,596,600 for unrealized loss on derivative instruments and $617,400 for dry holes, abandoned property and impaired assets.

On April 5, 2000, we entered into an agreement with Aquila Energy Capital ("Aquila"), an energy lender, to provide $19,302,000 in financing, of which $13,302,000, less closing costs of $402,000, was funded at closing and $6,000,000 was for future development capital. We used the net proceeds to (i) retire existing debt, including accrued interest, of $10,234,977; (ii) acquire crude oil and natural gas properties in Zavala County, Texas for $2,300,000, including $3,266 in cash and 200,000 shares of common stock; and, (iii) acquire additional interests in the Madisonville Field, Texas. The loan is secured by substantially all of the Company's interests in oil and gas properties, bears interest at prime plus 3.5% and matures May 29, 2004. Monthly payments as to principal and interest are from an 85% net revenue interest in the secured properties. The lender retains a 7% *overriding royalty interest* with payments commencing after the loan is paid in full.

On August 16, 2001, the total amount of financing increased by $16,800,000 to $36,102,000. The proceeds were to be used as follows: $10,000,000 for the Goldking Acquisition (see below), $6,630,000 for development of the properties securing the loan and $170,000 for a structuring fee paid to the lender. As a result of the amendment, the net revenue interest payment increased from 85% to 90%. In addition, the amendment requires payments on principal of $1,000,000 in February, 2002, August 2002 and February, 2003.

In December, 2002, Aquila sold its loan portfolio, including our loan, to another energy lender. In a subsequent event on February 28, 2003, we entered into an agreement with that lender to buy-out the loan, which has a current balance of $27.9 million for a cash payment of $20 million, under the following terms and conditions:

1. A cash payment of Twenty Million Dollars ($20,000,000), funded at Closing.

2. Cancellation of the Note and Credit Agreement and termination of all debt instruments securing this obligation.

3. Re-assignment to us of the *Overriding Royalty Interest* previously conveyed to Aquila and now held by the lender.

Note 2. Operations and Management Plans - continued

4. Cancellation and termination of all fixed price hedges and swap agreements entered into between Aquila and us. Such cancellation to be effective the first day of the month following the Closing Date.

5. We will pay interest only due under the Note.

6. By April 14, 2003, we furnish the lender acceptable financial assurance that we will close the anticipated refinancing by May 29, 2003. If by April 14, 2003 we do not furnish the lender the required financial assurance, then the lender may, at its option, notify us that it is no longer obligated to the terms of this Agreement, and at the lender's option, re-instate the combined principal and interest payments.

7. Should we not close this transaction within ninety (90) days of the lender's written acceptance of this offer, then we will, within thirty (30) days, issue to the lender one $1 million of preferred stock convertible at $1.00 per share of common stock. The stock will be in the form of 2,000 shares of a new GulfWest Series F Preferred Stock, par value $.01 and liquidation value $500 per share, with the same terms as the existing GulfWest Preferred E stock (except there will be no net profits interest redemption rights and the conversion price of the GulfWest Preferred Series F stock shall be $1.00 per common share instead of the $2.00 conversion price established for GulfWest's Preferred Series E stock). Provisions will be included in the Preferred Series F Stock Agreement to protect the Preferred Series F stockholder(s) and keep them on par with the Preferred Series E stockholders and other past and future preferred stockholders.

We are currently negotiating with various financial institutions to refinance the loan under the above terms and conditions, as well as providing funds for our $6.4 million capital development plan for 2003.

In a subsequent event on March 3, 2003, the lender notified us we were in default and agreed to forbear from exercising its rights and remedies regarding Events of Default resulting from (1) our most recent Reserve Reporting, as adjusted by the lender, being insufficient to fully amortize the loans by their stated maturity; and, (2 our failure to make the $1,000,000 repayment originally scheduled for August 31, 2002 and deferred to November 30, 2002 and the $1,000,000 repayment scheduled for February 28, 2003. The lender agreed to forebear until the earlier of: (1) May 31, 2003, (2) the occurrence of another Event of Default or Unmatured Event of Default, or (3) the lender learning of another Event of Default or Unmatured Event of Default that has occurred and is continuing, which is not listed above. Because of the defaults, the long term portion of this debt was reclassified to current.

On August 17, 2001, we purchased several oil and natural gas properties located in four fields in Texas and Louisiana (the "Goldking Acquisition"). The effective date of the acquisition was July 1, 2001. The acquired properties are currently producing an aggregate 600 barrels of oil and 1,200 Mcf of natural gas per day, with total proved reserves (net to the acquired interests) estimated at 1.2 million barrels of oil and 9.5 billion cubic feet of natural gas. There are additional possible reserves estimated at 10 billion cubic feet of natural gas. The purchase price of the acquisition was $15 million in a combination of notes payable, preferred stock, cash, warrants and common stock. Financing was arranged through an existing credit facility and included expanding the company's credit line to continue the development of its properties through the year 2002.

Effective December 1, 2001 and amended August 16, 2002, we entered into an Oil and Gas Property Acquisition, Exploration and Development Agreement (the "Summit Agreement") with Summit Investment Group-Texas, L.L.C., an unrelated party, ("Summit"). Under the agreement, Summit will provide or makes available to us payments in the aggregate of $1,200,000 in advanced funds (the Advanced Funds") for our use in the acquisition of oil and gas leases and other mineral and royalty interests in order that we may conduct specified

Note 2. Operations and Management Plans - continued

oil and gas exploration and production activities. We will pay Summit a sourcing fee of $100,000 and expenses of $100,000 from the Advanced Funds. We agree to drill four (4) wells located on oil and gas properties acquired under the Summit Agreement (the "Obligation Wells") and to commence such drilling prior to the expiration of two (2) years from the effective date of the Summit Agreement. We will pay Summit $150,000 on or before the date of commencement of drilling of each Obligation Well and Summit shall assign us its interest in the applicable oil and gas leases attributable to the production unit for such well. We further agree to conduct well workover operations on certain existing wells acquired by us, which are located on lands described in the Summit Agreement, all such well workover operations to be completed within nine (9) months of the Effective Date. Summit will reserve a 2.5% *overriding royalty interest* in the drilling *prospect* leases and a 25% net profits interest in the *workover* leases.

The Advanced Funds shall be recouped by Summit in the following manner:

(a) A total of $600,000 shall be repaid out of an undivided 40% of the "Summit Net Profits Interest", defined as twenty five percent (25%) of the monthly net sale proceeds of all oil and gas production allocable to our interest in the pertinent oil and gas properties, as more fully defined in the Summit Agreement. Summit will retain an 8.5% *working interest* in the *workover* leases after payment of the $600,000.

(b) We shall pay $150,000 in cash to Summit on the date we commence drilling each Obligation Well; or

(c) By virtue of a lump sum production payment by us.

If, at the expiration of two (2) years from the Effective Date, Summit has not completely recouped the Advanced Funds from the payments referred to in (a), (b) and (c) above, then Summit, at its sole election, may require that we issue to it a quantity of our Common Stock equivalent to the quotient of the outstanding Advanced Funds (numerator) and $2.00 per share (denominator). Upon issuance of such stock to Summit, Summit shall assign to us all its interest in the remaining oil and gas properties within the subject area, reserving its *overriding royalty interest* in the properties.

Note 3. Cost of Oil and Gas Properties

The following tables set forth certain information with respect to our oil and gas producing activities for the periods presented:

Capitalized Costs Relating to Oil and Gas Producing Activities:

	2002	2001
Unproved oil and gas properties	$ 439,926	$ 440,033
Proved oil and gas properties	52,847,625	48,702,656
Support equipment and facilities	3,498,492	2,902,489
	56,786,043	52,045,178
Less accumulated depreciation, depletion and		
Amortization	(7,461,421)	(5,297,763)
Net capitalized costs	$ 49,324,622	$ 46,747,415

Results of Operations for Oil and Gas Producing Activities:

	2002	2001	2000
Oil and gas sales	$ 10,447,169	$ 12,426,103	$ 8,445,932
Production costs	(5,430,205)	(5,155,500)	(3,377,583)
Depreciation, depletion and amortization	(2,187,036)	(2,018,890)	(1,030,635)
Income tax expense	-	–	–
Results of operations for oil and gas producing activities - income	$ 2,829,928	$ 5,251,713	$ 4,037,714

Costs Incurred in Oil and Gas Producing Activities:

	2002	2001	2000
Property Acquisitions			
Proved	$ 562,760	$ 15,236,808	$ 5,874,199
Unproved	14,401	154,076	122,837
Development Costs	5,141,075	6,317,527	4,814,317
	$ 5,718,236	$ 21,708,411	$ 10,811,353

Note 3. Cost of Oil and Gas Properties - continued

Effective July 1, 2001, we acquired interests in oil and gas properties located in Texas and Louisiana from an unrelated party, Grand Goldking L.L.C. The acquisition cost was $15,077,358, consisting of 9,000 shares of Series E preferred stock valued at $4,500,000 and $10,000,000 in debt. In addition, we paid $545,300 in commissions to unrelated parties. The commissions were paid by issuing 10,000 shares of common stock valued at $8,800, 150,000 warrants valued at $91,500 and $445,000 in cash. We incurred additional cash costs of $33,058 related to the acquisition. On the same date, we transferred its ownership interest in these properties to our wholly owned subsidiary, GulfWest Oil and Gas Company.

Supplemental unaudited pro forma information (under the purchase method of accounting) presenting the results of operations for the years ended December 31, 2001 and 2000, as if the Grand Goldking acquisition had occurred as of January 1, 2001 and 2000:

	Year Ended December 31, 2001	Year Ended December 31, 2000
Operating revenues	$ 15,649,329	$ 16,343,559
Operating expenses	10,652,222	9,027,278
Income from operations	4,997,107	7,316,281
Other income and expense	(3,325,166)	(3,011,243)
Income taxes	-	-
Net income	1,671,941	4,305,038
Preferred dividends	(112,500)	(112,500)
Net income to common shareholders	$ 1,559,441	$ 4,192,538
Earnings per share		
Basic	$ 0.08	$ 0.24
Diluted	$ 0.07	$ 0.21

Effective January 1, 2002, we acquired oil and gas properties located in Louisiana from a related party for $182,742. The acquisition price was the amount of accounts receivable due us.

Note 4. Accrued Expenses

Accrued expenses consisted of the following:

	December 31, 2002	December 31, 2001
Payroll and payroll taxes	$ 1,863	$ 3,910
Interest	414,724	194,761
Professional fees	42,000	45,000
	$ 458,587	$ 243,671

Note 5. Notes Payable and Long-Term Debt

Notes payable is as follows:

	2002	2001
Non-interest bearing note payable to an unrelated party; payable out of 50% of the net transportation revenues from a certain natural gas pipeline; no due date.	$ 40,300	$ 40,300
Note payable to a bank with monthly principal payments of $13,889; interest at prime plus 1%; due March 2002; secured by the guaranty of three of our directors; retired September, 2002.		374,999
Promissory note payable to one of our directors at 8%; due May, 2001; unsecured.	40,000	40,000
Promissory note payable to an unrelated party at 10%; payable on demand; unsecured.	45,000	115,000
Line of credit (up to $2,500,000) to a bank; due October, 2002; secured by guaranty of a director; interest at prime rate, less.25% (prime rate 4.25% at December 31, 2001). Line of credit increased to $3,000,000 and due date extended to April, 2003	2,995,488	2,251,192
Promissory note to an unrelated party at 10%; due and retired in January, 2002.		39,529
Note payable to a bank; due March, 2003; interest at prime rate plus 1% (prime rate 4.25% at December 31, 2002); secured by guaranty of three of our directors	500,000	
Promissory note payable to an unrelated party; payable on demand; interest at 8%; secured by certain oil and gas properties.	300,000	
Line of credit payable to a bank; due April, 2003; secured by guaranty of a director; interest at prime rate (prime rate 4.25% at December 31, 2002 with a floor of 5.5% and a ceiling of 8.5%.	1,000,000	
Promissory note payable to unrelated party; interest at 6%; due June, 2003.	55,300	
Promissory note payable to one of our directors; interest at 8%; due on demand; unsecured.	50,000	
Promissory note payable to one of our directors; interest at prime rate (prime rate 4.25% at December 31, 2002); due May, 2003; secured by common stock of DutchWest Oil Company, our wholly owned subsidiary.	1,200,000	
	$ 6,226,088	$ 2,861,020

The weighted average interest rate for notes payable at December 31, 2002 and 2001 was 4.7% and 5.0%, respectively.

GULFWEST ENERGY INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 5. Notes Payable and Long-Term Debt

Long-term debt is as follows:

	2002	2001
Line of credit (up to $3,000,000) to a bank; due July, 2003; secured by the guaranty of a director; interest at prime rate (prime rate 4.25% at December 31, 2002).	$ 2,999,515	$ 2,939,515
Subordinated promissory notes to various individuals at 9.5% interest per annum; amounts include $50,000 ($100,000 – 2001) due to related parties; past due.	150,000	200,000
Notes payable to finance vehicles, payable in aggregate monthly installments of approximately $6,000, including interest of 9% to 13% per annum; secured by the related equipment; due various dates through 2007.	116,721	96,024
Note payable to related party to finance equipment with monthly installments of $5,200, including interest at 13.76% per annum; final payment due October, 2003; secured by related equipment.	48,850	100,591
Promissory note to a director; interest at 8.5%; due December 31, 2003.	95,670	88,814
Note payable to a related party to finance equipment with monthly installments of $2,300, including interest at 11% per annum; final payment due March, 2002; secured by related equipment.		6,871
Note payable to a related party to finance equipment with monthly installments of $1,100, including interest at 11% per annum; final payment due September, 2002; secured by related equipment.		9,453
Note payable to a bank with monthly principal payments of $2,300; interest at 9.5%; due May, 2003; secured by related equipment.	11,630	39,543
Note payable to an energy lender; interest at prime plus 3.5% (prime rate 4.25% at December 31, 2002) payable monthly out of 85% (90% beginning July, 2001) net profits from certain oil and gas properties; final payment due May, 2004; secured by related oil and gas properties.	27,907,509	26,679,770

Note 5. Notes Payable and Long-Term Debt

Long-term debt is as follows – continued:

	2002	2001
Note payable to a bank with monthly principal payments of $15,000; interest at prime plus 1% (prime rate 4.75% at December 31, 2002); in October, 2001 monthly principal payments became $36,000 and interest prime plus 1% with a minimum prime rate of 5.5%; final payment due November, 2003; secured by related oil and gas properties.	$ 1,996,000	$ 2,392,000
Note payable to unrelated party to finance saltwater disposal well with monthly installments of $4,540, including interest at 10% per annum; final payment due January, 2005; secured by related well.	123,624	149,325
Note payable to related party to finance equipment with monthly installments of $5,109, including interest at 13.75% per annum; final payment due February, 2004; secured by related equipment.	65,743	114,324
Note payable to related party to finance equipment with monthly installments of $608, including interest at 11% per annum; final payment due February, 2004; secured by related equipment.	7,960	14,002
	33,523,222	32,830,232
Less current portion	(33,385,414)	(6,288,275)
Total long-term debt	$ 137,808	$ 26,541,957

Estimated annual maturities for long-term debt are as follows:

2003	$ 33,385,414
2004	102,008
2005	27,291
2006	7,150
2007	1,359
	$ 33,523,222

Note 6. Stockholders' Equity

Common Stock

	2002	2001
Par value $.001; 40,000,000 shares authorized; 18,492,541 shares issued and outstanding as of December 31, 2002 and 2001, respectively	$ 18,493	$ 18,493

Preferred Stock

	2002	2001
Series D, par value $.01; 12,000 shares authorized; 8,000 shares issued and outstanding at December 31, 2002 and 2001. The Series D preferred stock does not pay dividends and is not redeemable. The liquidation value is $500 per share. After three years from the date of issue, and thereafter, the shares are convertible to common stock based upon a value of $500 per Series D share divided by $8 per share of common stock.	80	80
Series E, par value $.01; 9,000 shares authorized; 9,000 shares issued and outstanding at December 31, 2002 and 2001. The Series E preferred stock pays dividends, as declared, at a rate of 2.5% per anum, has a liquidation value of $500 per share, may be redeemed at our and, if not redeemed after two years, is convertible to common stock based upon a value of $500 per Series E share divided by $2 per share of common stock.	90	90
	$ 170	170

All classes of preferred shareholders have liquidation preference over common shareholders of $500 per preferred share, plus accrued dividends. There were no dividends in arrears at December 31, 2002.

Stock Options

We maintain a Non-Qualified Stock Option Plan (as amended and restated, the "Plan"), which authorizes the grant of options of up to 2,000,000 shares of common stock. Under the Plan, options may be granted to any of our key employees (including officers), employee and nonemployee directors, and advisors. A committee appointed by the Board administers the Plan. Prior to 1999, options granted under the Plan had been granted at an option price of $3.13 and $1.81 per share. In July 1999, the Board authorized that all then current employee and director options under the plan be reduced to a price of $.75 per share. Following is a schedule by year of the activity related to stock options, including weighted-average ("WTD AVG") exercise prices of options in each category.

	2002		2001		2000	
	Wtd Avg Prices	Number	Wtd Avg Prices	Number	Wtd Avg Prices	Number
Balance, January 1	$ 1.03	1,097,000	$ 1.09	923,000	$ 1.07	717,000
Options issued	$ .75	35,000	$ .83	184,000	$ 1.17	206,000
Options expired	$ 3.00	(65,000)	$ 3.00	(10,000)	-	-
Balance, December 31	$ .90	1,067,000	$ 1.03	1,097,000	$ 1.09	923,000

Note 6. Stockholders' Equity – continued

All options were exercisable at December 31, 2002. Following is a schedule by year and by exercise price of the expiration of our stock options issued as of December 31, 2002:

	2003	2004	2005	2006	2007	Thereafter	Total
$ .75		432,000			35,000	150,000	617,000
$ .83				184,000			184,000
$1.13			100,000				100,000
$1.20			106,000				106,000
$1.81						60,000	60,000
	-	432,000	206,000	184,000	35,000	210,000	1,067,000

Stock Warrants

We have issued a significant number of stock warrants for a variety of reasons, including compensation to employees, additional inducements to purchase our common or preferred stock, inducements related to the issuance of debt and for payment of goods and services. Following is a schedule by year of the activity related to stock warrants, including weighted-average exercise prices of warrants in each category:

	2002		2001		2000	
	Wtd Avg Prices	Number	Wtd Avg Prices	Number	Wtd Avg Prices	Number
Balance, January 1	$ 2.15	1,306,754	$ 2.31	1,392,254	$ 2.53	1,369,754
Warrants issued	$ .75	1,145,000	$ .75	150,000	$ 1.86	170,000
Warrants exercised or expired	$ 3.57	(270,000)	$ 2.22	(235,500)	$ 2.65	(147,500)
Balance, December 31	$ 1.24	2,181,754	$ 2.15	1,306,754	$ 2.31	1,392,254

Included in the "warrants issued" and "warrants exercised/expired" columns in 2002 were 270,000 warrants whose price was reduced in 2002 to $.75.

Following is a schedule by year and by exercise price of the expiration of our stock warrants issued as of December 31, 2002:

	2003	2004	2005	2006	2007	Total
$ .75	166,754		75,000	1,590,000		1,831,754
.875			150,000			150,000
6.00	200,000					200,000
	366,754	-	225,000	1,590,000	-	2,181,754

Warrants outstanding to our officers, directors and employees at December 31, 2002 and 2001 were approximately 1,682,000 and 957,000, respectively. The exercise prices on these warrants range from $.75 to $.88 and expire various dates through 2006.

Note 7. Income (Loss) Per Common Share

The following is a reconciliation of the numerators and denominators used in computing income (loss) per share:

	2002	2001	2000
Net income (loss)	$ (4,502,313)	$ 1,044,291	$ 352,774
Preferred stock dividends	(112,500)	(56,250)	-
Income (loss) available to common shareholders (numerator)	$ (4,614,813)	$ 988,041	$ 352,774
Weighted-average number of shares of common stock – basic (denominator)	18,492,541	18,464,343	17,293,848
Income (loss) per share - basic	$ (.25)	$ .05	$ .02

Potential dilutive securities (stock options, stock warrants and convertible preferred stock) in 2002 have not been considered since we reported a net loss and, accordingly, their effects would be antidilutive. Potential dilutive securities (stock options, stock warrants and convertible preferred stock) totaling 2,780,520 weighted average shares in 2001 and 1,102,960 weighted average shares in 2000 have been considered but there is no effect on income per common share.

Note 8. Related Party Transactions

On December 1, 1992, Ray Holifield and Associates, Inc. executed an unsecured promissory note to us for $118,645 with interest at 10% per annum, due on October 1, 1993. At December 31, 1993, the note was still outstanding. During 1994, we entered into an agreement with the Holifield Trust in which Holifield will make payments on the past due note from future oil and gas revenue. During 1995, $10,995 of interest payments were received. At December 31, 2001 the unsecured promissory note had been fully reserved. At December 31, 2002, the unsecured promissory note had been fully written off.

On December 1, 1992, Parkway Petroleum Company, a Ray Holifield related company, executed an unsecured promissory note to us for $54,616 with interest at 10% per annum, due on October 1, 1993. The note was issued for amounts due from contract drilling services we provided Parkway Petroleum Company. At December 31, 1993, the note was still outstanding. During 1994, we entered into an agreement with the Holifield Trust in which Holifield will make payments on the past due note from future oil and gas revenue. During 1995, $6,250 of interest payments were received. At December 31, 2001, the unsecured promissory note had been fully reserved. At December 31, 2002, the unsecured promissory note had been fully written off.

On January 10, 1994, we entered into a consulting agreement with Williams Southwest Drilling Company, Inc. ("Williams") whereby we would provide management and accounting services for $25,000 per month for a period of one year. We accrued the consulting fees with an offset to deferred income until payment of the fees is actually received. During 1994, $172,140 was recorded as consulting fee income. Beginning in the second quarter 1994, we began recognizing consulting income only as cash payments were received. Prior to the second quarter, $75,000 in consulting fee revenue was accrued. We received $97,140 in consulting fee payments. As of December 31, 1994, the receivable from Williams of $202,860 for consulting fees has been offset by deferred income of $127,860 and a provision for doubtful accounts of $75,000. Effective January 1, 1995, we received a promissory note from Williams in the amount of $202,860, bearing interest at the rate of 10% per annum, and payable in quarterly installments of principal and interest of $15,538.87. At December 31, 2001, the unsecured promissory note had been fully reserved. At December 31, 2002, the unsecured promissory note had been fully written off.

Note 8. Related Party Transactions (continued)

From July 22 to August 13, 1998, we advanced sums totaling $102,000 to Gulf Coast Exploration, Inc. At December 31, 2001, the debt had been fully reserved. At December 31, 2002, the debt had been fully written off.

On October 1, 1998, Toro Oil Company executed an unsecured promissory note to us for the purchase of 100% of WestCo for $150,000, with interest at the prime rate per annum and due September 30, 1999. To date, no principal payments have been received. At December 31, 2001, the promissory note had been fully reserved. At December 31, 2002, the debt had been fully written off.

Interest expensed on related party notes totaled approximately $53,000, $128,000 and $186,000 for the years ended December 31, 2002, 2001 and 2000, respectively.

Note 9. Income Taxes

The components of the net deferred federal income tax assets (liabilities) recognized in our consolidated balance sheets were as follows:

	December 31, 2002	December 31, 2001
Deferred tax assets		
Provision for bad debts	$	$ 251,763
Net operating loss carryforwards	5,236,485	3,843,135
Oil and gas properties	542,131	617,780
Capital loss carryforwards	93,211	114,997
Derivative instruments	383,858	
Deferred tax liability		
Derivative instruments		(158,978)
Net deferred tax assets before valuation allowance	6,255,685	4,668,697
Valuation allowance	(6,255,685)	(4,668,697)
Net deferred tax assets (liabilities)	$ -	$ -

As of December 31, 2002 and 2001, we did not believe it was more likely than not that the net operating loss carryforwards would be realizable through generation of future taxable income; therefore, they were fully reserved.

Note 9. Income Taxes - continued

The following table summarizes the difference between the actual tax provision and the amounts obtained by applying the statutory tax rate of 34% to the income (loss) before income taxes for the years ended December 31, 2002, 2001 and 2000.

	2002	2001	2000
Tax (benefit) calculated at statutory rate	$ (1,530,786)	$ 355,059	$ 119,943
Increase (reductions) in taxes due to:			
Effect of net operating loss carryforwards			(45,176)
Effect on non-deductible expenses	65,174	18,157	43,133
Change in valuation allowance	1,586,988	(345,754)	(60,422)
Other	(121,376)	(27,462)	(57,478)
Current federal income tax provision	$ -	$ -	$ -

As of December 31, 2002 we had net operating loss carryforwards of approximately $15,400,000 and capital loss carryforwards of approximately $274,000, which are available to reduce future taxable income and capital gains, respectively, and the related income tax liability. The capital loss carryforward expires in 2003. The net operating loss carryforward expires at various dates through 2022.

Note 10. Commitments and Contingencies

Oil and Gas Hedging Activities

We entered into an agreement with an energy lender commencing in May, 2000, to hedge a portion of our oil and gas sales for the period of May, 2000 through April, 2004. The agreement called for initial volumes of 7,900 barrels of oil and 52,400 Mmbtu of gas per month, declining monthly thereafter. We entered into a second agreement with the energy lender, commencing September, 2001, to hedge an additional portion of our oil and gas sales for the periods of September, 2001 through July, 2004 and September, 2001 through December 2002, respectively. The agreement called for initial volumes of 15,000 barrels of oil and 50,000 Mmbtu of gas per month, declining monthly thereafter. Volumes at December 31, 2002 had declined to 9,800 barrels of oil and 26,500 Mmbtu of gas. As a result of these agreements, we realized a reduction in revenues of $368,776, $762,480 and $1,200,794 for the twelve-month periods ended December 31, 2002, 2001 and 2000, respectively, which is included in oil and gas sales.

Lease Obligations

We lease office space at one location under a sixty-four (64) month lease, which commenced December 1, 2001 and was amended May 30, 2002 after expansion. Annual commitments under the lease are: 2003 - $126,536, 2004 – $130,051, 2005 – $132,980, 2006 - $135,241 and 2007 - $33,977. Total rent expense for the years ended December 31, 2002, 2001 and 2000 were approximately $91,000, $60,000 and $54,000, respectively.

Litigation

From time to time, we are involved in litigation arising out of our operations or from disputes with vendors in the normal course of business. As of April 9, 2003, we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material effect on our consolidated financial statements.

Note 11. Oil and Gas Reserves Information (Unaudited)

The estimates of proved oil and gas reserves utilized in the preparation of the financial statements are estimated in accordance with guidelines established by the Securities and Exchange Commission and the Financial Accounting Standards Board, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations over prices and costs existing at year end except by contractual arrangements.

We emphasize that reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. Our policy is to amortize capitalized oil and gas costs on the unit of production method, based upon these reserve estimates. It is reasonably possible that, because of changes in market conditions or the inherent imprecision of these reserve estimates, that the estimates of future cash inflows, future gross revenues, the amount of oil and gas reserves, the remaining estimated lives of the oil and gas properties, or any combination of the above may be increased or reduced in the near term. If reduced, the carrying amount of capitalized oil and gas properties may be reduced materially in the near term.

Note 11. Oil and Gas Reserves Information (Unaudited) - continued

The following unaudited table sets forth proved oil and gas reserves, all within the United States, at December 31, 2002, 2001, and 2000, together with the changes therein.

	Crude Oil (BBls)	Natural Gas (*Mcf*)
QUANTITIES OF PROVED RESERVES:		
Balance December 31, 1999	3,314,908	19,186,865
Revisions	433,409	1,478,834
Extensions, discoveries and additions	501,293	1,509,014
Purchase	490,600	3,748,845
Sales	-	
Production	(165,031)	(1,111,639)
Balance December 31, 2000	4,575,179	24,811,919
Revisions	(386,078)	238,595
Extensions, discoveries and additions	5,676	895,333
Purchase	2,078,561	14,905,837
Sales	(107,225)	1,122
Production	(294,276)	(1,594,899)
Balance December 31, 2001	5,871,837	39,257,907
Revisions	(125,468)	(4,959,229)
Extensions, discoveries and additions	22,129	1,090,024
Purchase	52,480	1,090,025
Sales	(20,698)	(837,856)
Production	(278,374)	(1,487,048)
Balance December 31, 2002	5,521,906	34,158,823
PROVED DEVELOPED RESERVES:		
December 31, 2000	2,883,641	15,141,979
December 31, 2001	3,939,593	21,203,989
December 31, 2002	4,025,552	25,374,113

Note 11. Oil and Gas Reserves Information (Unaudited) - continued

STANDARDIZED MEASURE:

Standardized measure of discounted future net cash flows relating to proved reserves:

	2002	2001	2000
Future cash inflows	$ 308,381,837	$ 199,162,921	$ 318,504,931
Future production and development costs			
Production	105,629,872	77,526,278	97,465,972
Development	23,350,811	23,610,596	13,400,359
Future cash flows before income taxes	179,401,154	98,026,047	207,638,600
Future income taxes	(38,611,577)	(13,281,358)	(56,466,527)
Future net cash flows after income taxes	140,789,577	84,744,689	151,172,073
10% annual discount for estimated timing of cash flows	(63,165,742)	(35,895,306)	(60,790,946)
Standardized measure of discounted future net cash flows	$ 77,623,835	$ 48,849,383	$ 90,381,127

The following reconciles the change in the standardized measure of discounted future net cash flows:

	2002	2001	2000
Beginning of year	$ 48,849,383	$ 90,381,127	$ 30,955,399
Changes from:			
Purchases	3,054,793	27,032,359	18,483,582
Sales	(953,159)	(443,324)	
Extensions, discoveries and improved recovery, less related costs	2,002,176	427,192	10,727,329
Sales of oil and gas produced net of production costs	(5,016,964)	(7,270,603)	(5,068,349)
Revision of quantity estimates	(9,974,557)	(1,783,276)	7,365,348
Accretion of discount	5,649,945	12,414,073	3,765,842
Change in income taxes	(13,624,917)	26,109,535	(27,056,577)
Changes in estimated future development costs	(5,254,561)	(6,360,990)	(504,445)
Development costs incurred that reduced future development costs	5,569,881	5,945,369	4,359,405
Change in sales and transfer prices, net of production costs	46,903,282	(89,573,528)	38,543,222
Changes in production rates (timing) and other	418,533	(8,028,551)	8,810,371
End of year	$ 77,623,835	$ 48,849,383	$ 90,381,127

GULFWEST ENERGY INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 12. Quarterly Results (Unaudited)

Summary data relating to the results of operations for each quarter for the years ended December 31, 2002 and 2001 follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
2002				
Net sales	$ 2,648,873	$ 2,951,798	$ 2,641,626	$ 2,597,500
Gross profit	239,912	450,255	100,527	136,961
Net income (loss)	(1,964,010)	(305,060)	(924,750)	(1,420,993)
Income (loss) per common share – basic and diluted	$ (0.11)	$ (0.02)	$ (0.05)	$ (0.07)
2001				
Net sales	$ 3,057,739	$ 3,455,882	$ 3,669,203	$ 2,807,757
Gross profit	930,784	1,219,002	1,083,789	218,300
Net income (loss)	(2,409,567)	1,919,735	1,671,994	(194,121)
Income (loss) per common share – basic	$ (0.13)	$ 0.10	$ 0.09	$ (0.01)
- diluted	$ (0.13)	$ 0.10	$ 0.08	$ (0.01)

INDEPENDENT AUDITOR'S REPORT

Stockholders and Board of Directors
GULFWEST ENERGY INC.

Our report on the consolidated financial statements of GulfWest Energy Inc. and Subsidiaries as of December 31, 2002 and 2001 and for each of the three years in the period ended December 31, 2002, is included on page F-1. In connection with our audit of such consolidated financial statements, we have also audited the related financial statement schedule for the years ended December 31, 2002, 2001 and 2000 on page F-31.

In our opinion, the financial statement schedule referred to above, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information required to be included therein.

\s\ WEAVER AND TIDWELL, L.L.P.
WEAVER AND TIDWELL, L.L.P.

Dallas, Texas
March 24, 2003

GULFWEST ENERGY INC. AND SUBSIDIARIES
SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000

DECRIPTION	BALANCE AT BEGINNING OF PERIOD	PROVISIONS/ ADDITIONS	RECOVERIES/ DEDUCTIONS	BALANCE AT END OF PERIOD
For the year ended				
December 31, 2000				
Accounts and notes receivable related parties	$ 700,230	$ 40,248	$	$ 740,478
Valuation allowance for Deferred tax assets	$ 5,074,873	$ (60,422)	$	$ 5,014,451
For the year ended				
December 31, 2001				
Accounts and notes receivable related parties	$ 740,478	$	$	$ 740,478
Valuation allowance for Deferred tax assets	$ 5,014,451	$ (345,754)	$	$ 4,668,697
For the year ended				
December 31, 2002				
Accounts and notes receivable related parties	$ 740,478	$	$ (740,478)	$
Valuation allowance for Deferred tax assets	$ 4,668,697	$ 1,586,988	$	$ 6,255,685

Board of Directors

J. Virgil Waggoner
Chairman of the Board

Thomas R. Kaetzer

John E. Loehr

Marshall A. Smith III

Steven M. Morris

William T. Winston

John P. Boylan

Officers

Thomas R. Kaetzer
President and Chief Executive Officer

Jim C. Bigham
Executive Vice President and Secretary

Richard L. Creel
Vice President of Finance and Controller

Corporate Information

Corporate Office:	**GulfWest Energy Inc.** **480 N. Sam Houston Parkway E.** **Suite 300** **Houston, Texas 77060** **(281) 820-1919**
Transfer Agent:	**Fidelity Transfer Company** **1800 South West Temple** **Suite 301, Box 53** **Salt Lake City, Utah 84115**
Auditors:	**Weaver & Tidwell, L.L.P.** **Three Forest Plaza** **12221 Merit Drive, Suite 1700** **Dallas, Texas 75251**
Common Stock Information:	**The Common Stock is traded over the counter under the symbol "GULF".**
Form 10-K:	**Additional copies of the Company's Form 10-K as filed with the Securities and Exchange Commission are available without charge by writing to Mr. Jim C. Bigham, Secretary, GulfWest Energy Inc., 480 N. Sam Houston Parkway E., Suite 300, Houston, Texas 77060.**