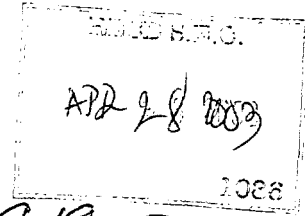




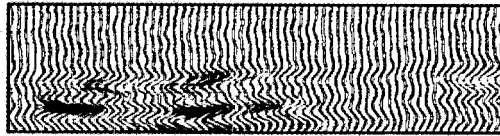
03056947

ARIS

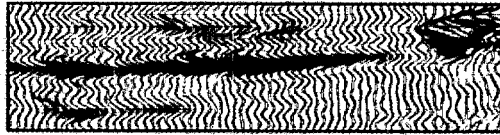
PEI
12-31-02



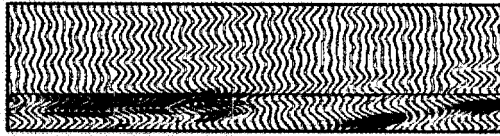
0-19020



PetroQuest Energy Corporation



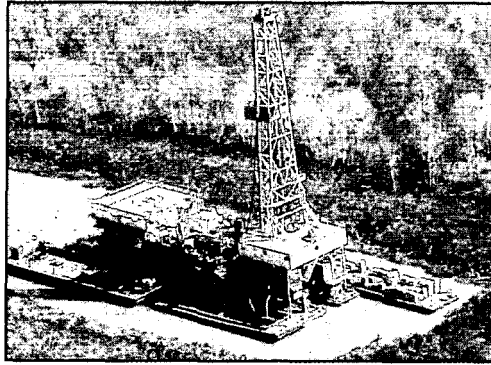
2002 Annual Report



PROCESSED

APR 29 2003

THOMSON
FINANCIAL



Contents

Corporate Profile
1

Letter to Shareholders
2

Financial & Operational Highlights
7

Areas of Operation
8

Form 10-K
9



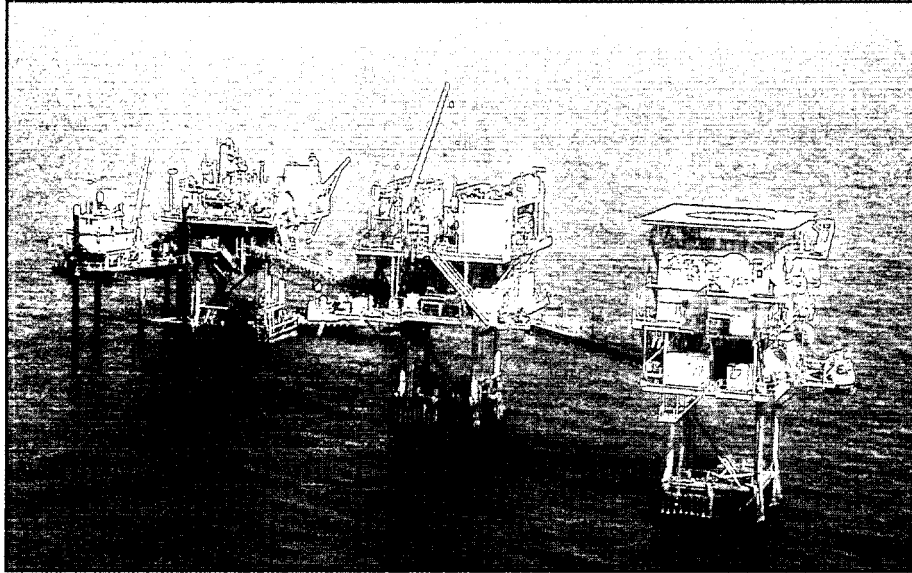
Corporate Profile

PetroQuest Energy, Inc. is an onshore and offshore Gulf of Mexico-based natural gas and oil finder with an emphasis on controlling the entire exploration model—from idea to cash flow. PetroQuest strives to be a top-quartile performer in key industry performance metrics of reserve additions, production growth and per-unit costs for its exploration and operating activities.

The guiding principles that embody PetroQuest's management team and staff are: generate our own exploration ideas, operate more than 80% of our total proved reserves, maintain a dynamic balance sheet and over-deliver on our promises.

PetroQuest Energy, Inc., based in Lafayette, Louisiana, with a Houston exploration office, trades its public common shares on the NASDAQ Stock Market under the symbol PQUE.

Letter To Shareholders



On Jan. 1, 2002, the 12-month forward curve for natural gas prices was \$2.62 per Mcf, well below the \$3.86 per Mcf we received in 2001. Forecasted 2002 industrial demand for natural gas was 15% to 20% lower than peaks of several years ago. Since the beginning of 2001, the Federal Reserve Board cut interest rates a record 12 times in the hope that this would prime the U.S. and world economy engines. We were still coming to grips with the events of September 11, unbelieving for the first time since World War II that we were vulnerable to outside aggression. Against this backdrop, unfazed by conditions that lay outside of our control, and being a growth story, we were emboldened to set new goals for the company.

PetroQuest Energy's backbone is exploration, exploitation and development drilling. We drill and develop the world's cheapest source of energy in arguably one of the best places in the world – in the Gulf Coast Basin, both onshore and in shallow waters offshore. Every day, people rely on more and more of the natural gas that is produced here than anywhere else in the world. The Gulf Coast produces more than 25% of U.S. hydrocarbon consumption and Louisiana is the home of the Henry Hub, the world's most watched natural gas pricing point. In spite of rising prices, production has declined year-over-year on an industry-wide basis.

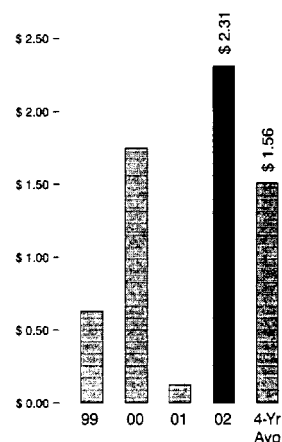
At the end of 2001, our reserves were 82 Bcfe, which represented an 82% compounded annual growth rate (CAGR) since 1999. Management felt that PetroQuest would continue this growth and that it was now of sufficient size to increase its average working interest in its prospects. Unfortunately, we did not realize the success in 2002 previously seen from exploration drilling. We experienced challenges and disappointments not seen in many years. It is accurate to say we were displeased with our 2002 results. The disappointment was doubly hard for me as a shareholder. As you may know, I have not sold a single share of my stock since becoming an officer and director of PetroQuest. In fact, I have continued to add to my position over time through open-market purchases and participation in public offerings. This is how you build a company – through leadership.

This year's results will not dissuade us from our mission. In a year of challenges, we exited 2002 a wiser and more determined company. I've seen much darker days during my 20-plus years in the energy business and I know everyone's resolve here is strong. Our focus is laser sharp. The opportunities before us have never been better than they are now. Whereas, I am not satisfied with our proved reserves at the end of 2002 or our production for the year, I like what we're doing and where we're going. Our employees are among the best in the industry and our prospect inventory is deep.

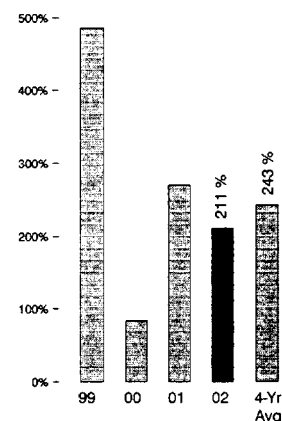
Al Thomas, PetroQuest's president, Ralph Daigle, executive vice president, and I founded PetroQuest's predecessor company in 1986 – a low point for oil prices and the industry. What we learned then serves us well today. We thrived because of the business strategy that we continue to adhere to today. As we learned then, we will gain much from keeping a clear mind, and by practicing patience and perseverance. We intend to resume growth through the drill bit. Our core values are unwavering.

We are Owners

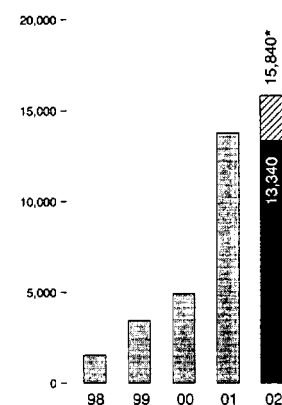
PetroQuest officers and directors purchased shares during 2002, and as a group own more than 25% of the company, one of the highest levels in the industry. We may be the first ones in, but we expect long-term holders will benefit from our life's work well before we do. For the three-year period ended June 28, 2002, investors enjoyed a 68.9% CAGR on their investment. During a five-year period ending June 28, 2002, the result was a 21.3% CAGR. Both of these figures were deemed



Finding & Development Costs, Excluding Revisions (\$/Mcfe)

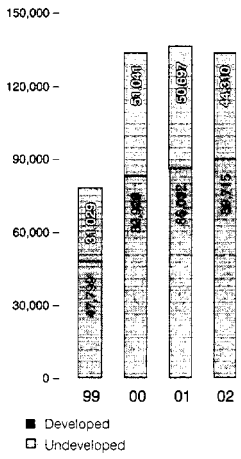


Reserve Replacement, Through the Drill Bit

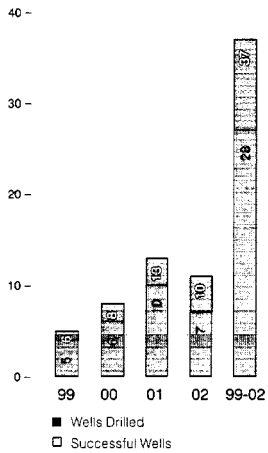


* 2,500 MMcfe related to asset sales and Gulf of Mexico tropical storms

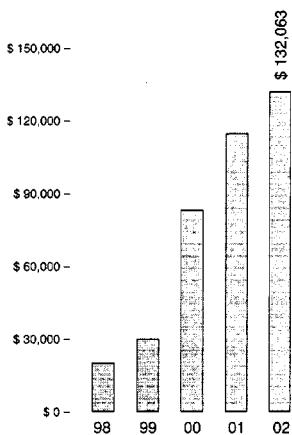
Annual Production (MMcfe)
4-year CAGR 71%



Gross Acreage



Drilling Activity



Total Assets (\$ 000s)
4-Year CAGR 60%

First Quartile in an independent analysis compiled by the energy team at Raymond James & Associates, Inc. (*"Can Investors Outperform the Market With E&P Stocks?"* Jeffrey L. Mobley, CFA, and Wayne Andrews, Sept. 18, 2002). We will not be satisfied until we return to this type of performance.

2002 Results

Oil and gas revenues in 2002 were \$48.1 million. EBITDA was \$32.1 million. Net income was \$2.3 million, or \$0.06 per share. Total assets at December 31, 2002, were \$132 million. Net long-term debt was \$9 million, or 8% of total book capital. Stockholders' equity was \$97.8 million. The future discounted value of our reserves, also called the SEC PV-10 value, was \$166.0 million. We've provided readers of our annual with several comparative tables and graphs of 2002 and preceding years.

Total 2002 production was 13.3 Bcfe, virtually flat to 2001. Reserves at year-end 2002 were 69 Bcfe, which was short of our goal to reach the 100 Bcfe level by year's end. Production and reserves represent our biggest disappointments for 2002. These setbacks would have crippled a less experienced, or time-tested team. Production and reserve growth return with drill bit success. Unfortunately, hydrocarbons do not regenerate themselves. We have to explore, drill and develop our assets in order to increase production and reserves. Despite 2002 results, production and reserves had a four-year CAGR of 71% and 50%, respectively.

Our Business Plan Has a Defined Growth Strategy

PetroQuest's philosophies guide our operations. First, our success comes from extensive knowledge gained through years of experience in our operating area. We own interests in more than 17 producing fields both onshore and offshore, interests in 26 offshore blocks, and 44,310 developed gross acres in hydrocarbon-rich core areas in and along the U.S. Gulf Coast. These areas have characteristics that fit our know-how – seismically identified amplitudes, multi-sand packages, and well-defined infrastructure. We have 8,650 square miles of 3-D seismic data and 400,000 linear miles of 2-D seismic.

We internally generate prospects. PetroQuest has built considerable in-house technological expertise in each of our core areas and has amassed a very large prospect inventory. When combined with our large seismic database and land position, we can efficiently identify and prioritize prospects and pursue exploration and development best suited to our short and long-term objectives. We have more than 500 Bcfe of net unrisks reserve potential included in our prospect inventory. Prospect evaluation is critical to our operations in the past and will continue to be an important focus in the future. Significant growth over the past five years has come from the drill bit. We pursue prospects that offer multi-zone potential, typically at depths less than 15,000 feet. This focus fits our

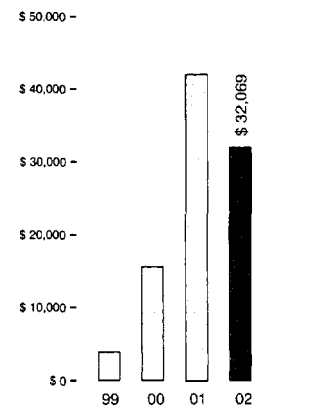
core operating areas and reflects our technological expertise. Of the wells we drilled in 2002, 70% were successful; compared to a 76% success rate since 1999.

PetroQuest prefers to operate the majority of its reserves. This philosophy generates control of infrastructure, pipelines, platforms and other production facilities that are time-critical to bring newly discovered production to market swiftly. We also have greater control over capital requirements and timing, and can better employ our technical expertise. A position of control also allows us to reap greater rewards from our success. We're an exploration story and we'll drill dry holes. The binary risk associated with the drilling of a well does not change how we intend to grow through the drill bit. Our risk profile on a working interest percentage has changed since 1999. Back then, we had about 28 Bcfe of reserves and generated EBITDA of \$4 million, and usually kept about 30% of any one exploration prospect. As revenues and EBITDA grew, our average working interest increased, to 42% in 2000 and 57% in 2001. In 2002, the number was about 70%. We want to drill more wells in 2003, and will do so as we return to working interest levels similar to those seen prior to 2002.

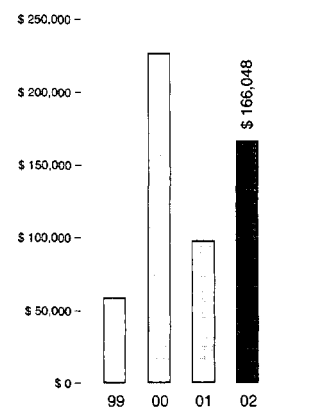
We are in the middle of several exciting opportunities centered towards putting capital to work drilling more wells from our deep and diverse inventory. In 2003, we intend to risk-adjust our working interest percentages, spreading available capital to drill more wells. We will be taking partners on drilling prospects in 2003, in most cases keeping an operating working interest of 25% to 50% per prospect.

Acquisitions complement our drill bit strategy, adding acreage and prospect targets that fit within our existing base of operations. Typically, our acquisitions have not had a large proved producing reserve component. A good example is our Ship Shoal 72 Field. When we acquired the field in Dec. 2000, production was zero. Since becoming the operator and acquiring 100% of the previously fractured working interest, we upgraded the production facilities, reprocessed the 3-D seismic volume using pre-stack time migration, drilled nine wells (all successful) and increased production to 30 MMcfe per day. We have identified another 125+ Bcfe of net unrisksed developmental and mid-depth exploitation potential on seven prospects, and 174+ Bcfe of net unrisksed potential from three deeper pool tests. Later this year we expect to receive additional reprocessed 3-D seismic (pre-stack depth migration), which will further enhance resolution. We anticipate this will result in additional mid-depth and deeper pool prospects. This approach provides latitude for expansion of plays, increasing interests in promising areas, or adding to our prospect inventory with a variety of drilling opportunities with multiple risk characteristics.

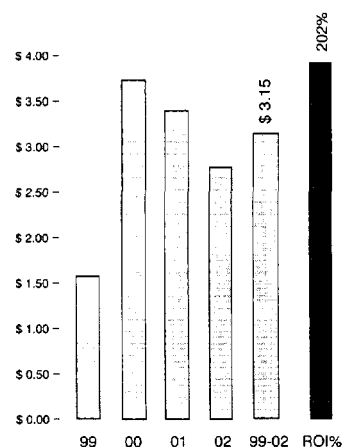
These philosophies have provided a framework for our growth. Adhering to these philosophies generated a strong track record through changing industry conditions. We remain committed to our growth strategy and are confident it will provide shareholders with consistent financial and operational returns.



EBITDA (\$ 000s)
3-Year CAGR 98%



SEC PV-10 (\$ 000s)
3-Year CAGR 57%

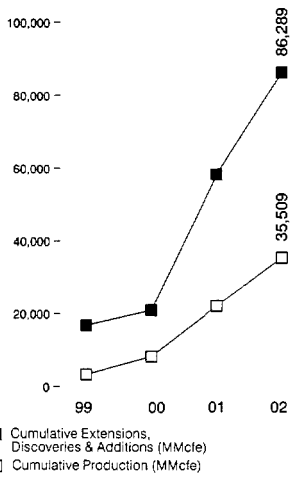


Gross Margin (\$/Mcf)

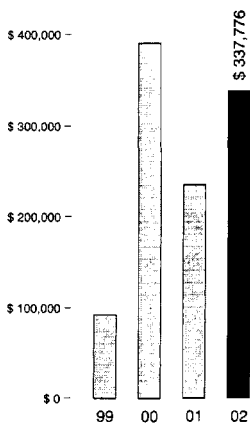
* Weighted average gross margin ROI is 4-year weighted average gross margin divided by 4-year weighted average F&D costs, excluding revisions.

Manageable Bank Debt

We must also have the right-sized balance sheet to be ready to take action when presented with opportunities in our core areas. Having too little equity capital or too much debt impedes a growth story. Maintaining strict control of debt has been fundamental to PetroQuest's success. Over the past five years, and particularly in low commodity price cycles, a prudent debt level has been critical to the strength of our balance sheet and to maintaining financial flexibility to maximize shareholder value. As of the date of this letter, debt as a percentage of total book capital was less than 10%. Commodity swings are shorter and more pronounced, changing the new "mean" for every part of our business. Industry benchmarks are markedly different. Should domestic natural gas prices and world oil prices remain in their present ranges, our current debt level will be considered low by most standards. However, in a lower product pricing environment, our moderate bank debt would be expected to give us flexibility to continue drilling activities.



Gross Ultimate Recovery



Future Revenues (\$ 000s)
3-Year CAGR 54%

A Bright and Challenging Future

The Wall Street Journal reported that the Organization of Petroleum Exporting Countries can no longer suppress a rise in oil prices through the cartel increasing their production. OPEC officials acknowledge that its member countries have little production capacity to increase output. On the other hand, where we once had a natural gas bubble in the U.S., our nation is facing a shortage of supply that could last for years. This elevates the importance of our efforts to find and produce more oil and natural gas for our country.

Success in this business requires strong leadership. Diligently working for the company, their families, communities and our nation are the men and women of PetroQuest – all leaders in their chosen professions. With their continued commitment, we are confident in our direction and in our ability to generate long-term value for our shareholders.

Best regards,

Charles T. Goodson

Chairman of the Board and Chief Executive Officer

February 28, 2003

Financial & Operational Highlights

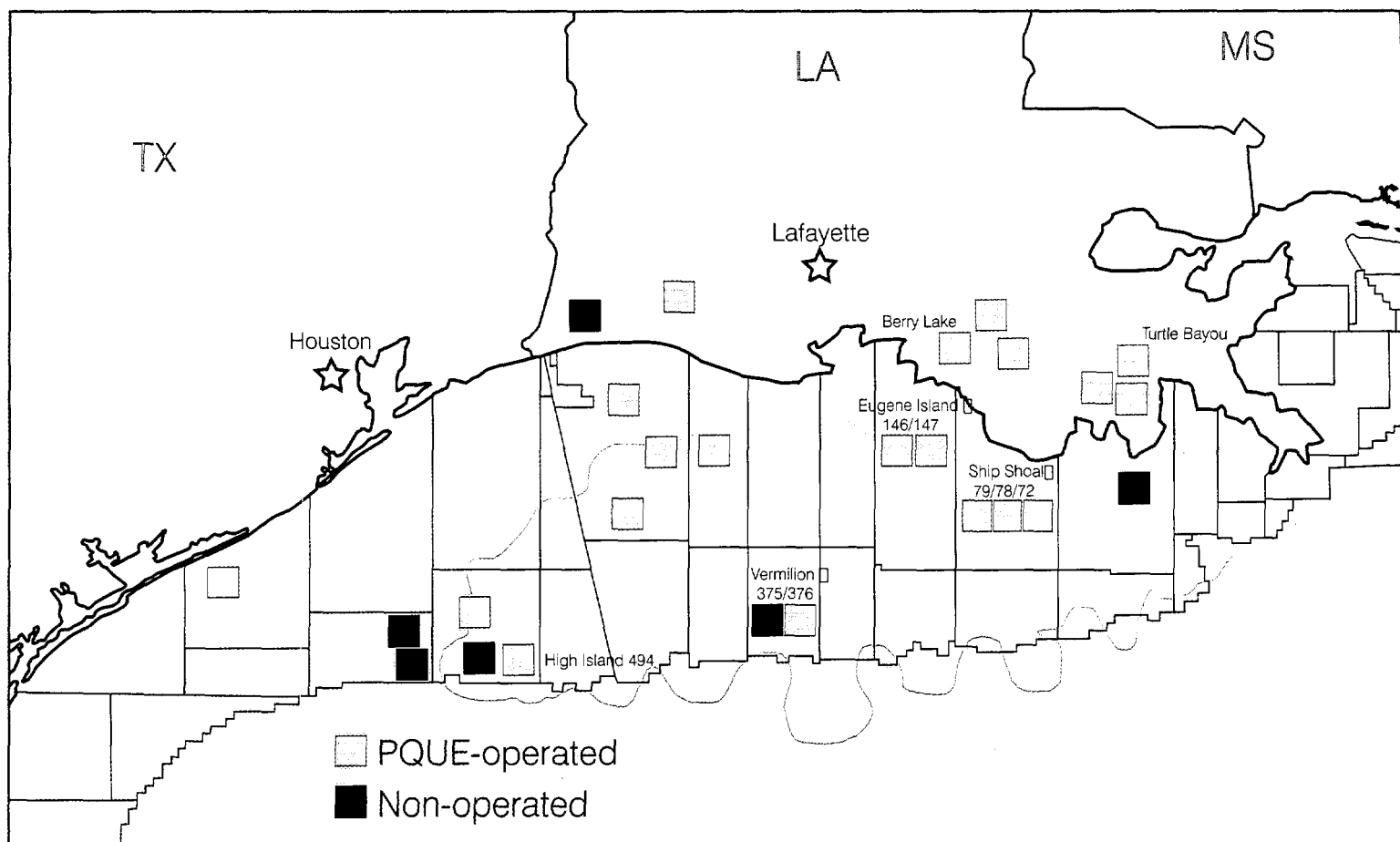
Year-over-Year Review

	1999	2000	2001	2002	3-Year CAGR
Reserves					
Natural Gas, MMcf	15,128	30,135	44,944	37,137	35%
Crude Oil, MBbl	2,194	3,115	6,213	5,258	34%
Natural Gas, Bcfe	28,292	48,824	82,225	68,685	34%
Percent Developed	31%	67%	55%	62%	
Percent Natural Gas	53%	62%	55%	54%	
Percent Offshore	52%	57%	80%	84%	
Future Gross Revenues	\$ 92,788	\$ 391,078	\$ 234,736	\$ 337,776	54%
SEC PV-10	\$ 43,069	\$ 256,867	\$ 88,230	\$ 166,048	57%
Commodity Prices					
Natural Gas, \$/Mcf	\$ 2.33	\$ 4.38	\$ 3.86	\$ 3.20	
Henry Hub Cash Market Average, \$/Mcf	\$ 2.27	\$ 4.15	\$ 3.96	\$ 3.32	Source: Reuters
Crude Oil, \$/Bbl	\$ 18.45	\$ 29.94	\$ 25.49	\$ 25.07	
WTI (Cushing) Spot Average, \$/Bbl	\$ 19.30	\$ 30.35	\$ 25.84	\$ 26.17	Source: Bloomberg
Natural Gas Equivalent, \$/Mcf	\$ 2.46	\$ 4.50	\$ 3.99	\$ 3.61	
Statistics					
Reserve Replacement, Excluding Revisions, %	486%	84%	270%	211%	
4-Year Reserve Replacement, Excluding Revisions%				243%	
Finding & Development Costs, Excluding Revisions, \$/Mcf	\$ 0.77	\$ 1.75	\$ 1.27	\$ 2.31	
4-Year Finding & Development Costs, Excluding Revisions \$/Mcf				\$ 1.56	
\$/Mcf					
Revenues	\$ 2.46	\$ 4.50	\$ 4.01	\$ 3.57	13%
Lease Operating Expense & Production Taxes	\$ 0.88	\$ 0.76	\$ 0.60	\$ 0.79	(4%)
Gross Margin	\$ 1.58	\$ 3.74	\$ 3.41	\$ 2.78	21%
DD&A	\$ 1.29	\$ 1.29	\$ 1.68	\$ 2.11	18%
Net Income	\$ (0.09)	\$ 2.01	\$ 0.85	\$ 0.17	nm

Growth

	2000 Annual	2001 Annual	2002				3-Year CAGR	
			Q1	Q2	Q3	Q4	Annual	
Production								
Natural Gas, MMcf	3,984	9,025	2,385	1,917	1,462	2,001	7,765	40%
Crude Oil, MBbl	161	791	235	217	234	240	929	107%
Natural Gas, MMcf	4,948	13,774	3,792	3,220	2,885	3,444	13,340	57%
\$ thousands, except per share amounts								
Financial								
Total Revenues	\$ 22,561	\$ 55,281	\$ 10,497	\$ 11,102	\$ 11,024	\$ 15,057	\$ 47,680	77%
EBITDA	\$ 15,538	\$ 42,261	\$ 6,746	\$ 7,036	\$ 7,402	\$ 10,885	\$ 32,069	98%
Net Income / Loss	\$ 9,924	\$ 11,645	\$ (364)	\$ 255	\$ 950	\$ 1,466	\$ 2,307	nm
Per Common Share:								
Basic	\$ 0.37	\$ 0.37	\$ (0.01)	\$ 0.01	\$ 0.03	\$ 0.04	\$ 0.06	nm
Diluted	\$ 0.35	\$ 0.34	\$ (0.01)	\$ 0.01	\$ 0.02	\$ 0.03	\$ 0.06	nm

Operations



PetroQuest's operations include its acquisition, development, exploitation and exploration activities in and along the Gulf Coast of Louisiana. Since PetroQuest acquired 100% of Ship Shoal 72, the Company increased production in 2002 to approximately 7 Bcfe net to the Company from nine producing wells. In Addition, the Company has generated seven developmental and exploitation opportunities and three exploration prospects. The Company may seek to obtain a partner in the future development of this property.

As of December 31, 2002, there are four producing wells in the Turtle Bayou field. During 2002, the four producing wells collectively averaged approximately 3,060 Mcf of natural gas and 80 barrels of oil per day net to PetroQuest. PetroQuest acquired a 3-D regional seismic survey shot in 1998, which incorporates the Turtle Bayou field. As a result of studying this data, six additional prospects with multiple objectives were identified. The first five wells were drilled and four completed.

PetroQuest is the operator of Vermilion Block 376 and owns a 43% working interest. The Company and its partners drilled an exploratory well on this property in the fourth quarter of 1999, logging 285 feet of gross hydrocarbon column (136 feet net). An additional well was drilled in the second quarter of 2000 logging 112 feet of gross hydrocarbon pay (74 feet net). During 2000, an approximately 2,500 ton production platform was fabricated and placed in service. During 2002 the field produced at an average rate of approximately 590 Bbls per day of oil and 840 Mcf per day of natural gas, net to the Company.

The Company and its partners drilled a well on the Berry Lake field in the third quarter of 2002 and logged approximately 71 feet of net productive sands. The well came on line during the fourth quarter and produced at an average rate for December of approximately 350 Bbls per day of oil and 560 Mcf per day of natural gas, net to the Company.

PetroQuest initially had a 25% working interest in Eugene Island 147 and acquired the remaining 75% working interest from a major oil and gas company. A 63.5% working interest was subsequently sold to other oil and gas companies. We now hold a 36.5% working interest. During 2000, we drilled two successful wells on this offshore block, and 2002 production averaged approximately 2,060 Mcfe per day net to PetroQuest. Additional exploration opportunities have been identified and are currently being evaluated for future drilling.

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

FORM 10-K

(Mark One)

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: 019020

PETROQUEST ENERGY, INC.

(Exact name of registrant as specified in its charter)

State of incorporation: Delaware I.R.S. Employer Identification No. 72-1440714

400 E. Kaliste Saloom Road, Suite 6000

Lafayette, Louisiana 70508

(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: (337) 232-7028

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

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

Common Stock, Par Value \$.001 Per Share

Preferred Stock Purchase Rights

(Title of Class)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes No

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

Indicate by check mark whether the registrant is an accelerated filer (as defined by Rule 12b-2 of the Act).

Yes No

The aggregate market value of the voting stock held by non-affiliates of the registrant was approximately \$155,451,520 as of June 28, 2002 (based on the last reported sale price of such stock on The Nasdaq National Market System).

As of March 10, 2003, the registrant had outstanding 42,852,394 shares of Common Stock, par value \$.001 per share.

Document incorporated by reference: Proxy Statement of PetroQuest Energy, Inc. relating to the Annual Meeting of Stockholders to be held on May 7, 2003, which is incorporated into Part III of this Form 10-K.

TABLE OF CONTENTS

Page No.

PART I

Item 1.	Business	11
Item 2.	Properties	23
Item 3.	Legal Proceedings.....	24
Item 4.	Submission of Matters to a Vote of Security Holders.....	24

PART II

Item 5.	Market for Registrant's Common Equity and Related Stockholder Matters	25
Item 6.	Selected Financial Data	25
Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	26
Item 7A.	Quantitative and Qualitative Disclosure About Market Risks	31
Item 8.	Financial Statements and Supplementary Data	31
Item 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.....	31

PART III

Item 10.	Directors and Executive Officers of the Registrant.....	32
Item 11.	Executive Compensation	32
Item 12.	Security Ownership of Certain Beneficial Owners and Management	32
Item 13.	Certain Relationships and Related Transactions	32
Item 14.	Controls and Procedures	32

PART IV

Item 15.	Exhibits, Financial Statement Schedules, and Reports on Form 8-K	32
	Index to Financial Statements.....	39

This Form 10-K contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements other than statements of historical facts included in and incorporated by reference into this Form 10-K are forward looking statements. These forward looking statements include, without limitation, statements regarding our estimate of the sufficiency of our existing capital resources and our ability to raise additional capital to fund cash requirements for future operations, and regarding the uncertainties involved in estimating quantities of proved oil and natural gas reserves, in prospect development and property acquisitions and in projecting future rates of production, timing of development expenditures and drilling of wells and the operating hazards attendant to the oil and gas business. Although we believe that the expectations reflected in these forward looking statements are reasonable, we cannot assure you that such expectations reflected in these forward looking statements will prove to have been correct.

When used in this Form 10-K, the words "expect," "anticipate," "intend," "plan," "believe," "seek," "estimate" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain these identifying words. Because these forward-looking statements involve risks and uncertainties, actual results could differ materially from those expressed or implied by these forward-looking statements for a number of important reasons, including those discussed under "Management's Discussions and Analysis of Financial Condition and Results of Operations," "Risk Factors" and elsewhere in this Form 10-K.

You should read these statements carefully because they discuss our expectations about our future performance, contain projections of our future operating results or our future financial condition, or state other "forward-looking" information. Before you invest in our common stock, you should be aware that the occurrence of any of the events described in these risk factors and elsewhere in this Form 10-K could substantially harm our business, results of operations and financial condition and that upon the occurrence of any of these events, the trading price of our common stock could decline, and you could lose all or part of your investment.

We cannot guarantee any future results, levels of activity, performance or achievements. Except as required by law, we undertake no obligation to update any of the forward-looking statements in this Form 10-K after the date of this Form 10-K.

PART I

ITEM 1. BUSINESS

Overview

PetroQuest Energy, Inc. ("PetroQuest" or the "Company") is incorporated in the State of Delaware and is an independent oil and gas company engaged in the generation, exploration, development, acquisition and operation of oil and gas properties onshore and offshore in the Gulf Coast Region. PetroQuest and its predecessors have been active in this area since 1986. The Company's business strategy is to increase production, cash flow and reserves through generation, exploration, development and acquisition of properties located in the Gulf Coast Region.

On September 1, 1998, the Company, formerly known as Optima Petroleum Corporation ("Optima"), completed a merger and reorganization (the "Merger") pursuant to a Plan and Agreement of Merger dated February 11, 1998 by and among Optima, Optima Energy (U.S.) Corporation ("Optima (U.S.)"), Goodson Exploration Company ("Goodson"), NAB Financial, L.L.C. ("NAB") and Dexco Energy, Inc. ("Dexco"), pursuant to which Optima (U.S.) merged into PetroQuest Energy, Inc., a newly formed Louisiana corporation ("PetroQuest Louisiana"). Concurrently, PetroQuest Louisiana, through a merger of PetroQuest Louisiana with Goodson, NAB and Dexco, acquired 100% of the ownership interest of American Explorer L.L.C. ("American Explorer"), all which were owned by Goodson, NAB and Dexco prior to the Merger. Concurrent with the Merger, PetroQuest continued from a Canadian corporation to a Delaware corporation, converted each share of Optima no par value common stock into one share of the Company's \$.001 par value common stock, changed its name to "PetroQuest Energy, Inc." and adopted a new certificate of incorporation. The operating results of American Explorer have been consolidated in the Company's consolidated statement of operations since September 1, 1998.

In addition, management of PetroQuest was changed to the management of American Explorer. The Canadian offices were closed and the Company's headquarters were moved to Lafayette, Louisiana. PetroQuest maintains an offshore exploration office in Houston, Texas.

On December 31, 2000, the Company underwent a corporate reorganization. The Company's subsidiary, PetroQuest Energy, Inc., a Louisiana corporation, was merged into PetroQuest Energy One, L.L.C., a Louisiana limited liability company. In addition, PetroQuest Energy One, L.L.C. changed its name to PetroQuest Energy, L.L.C., a single-member Louisiana limited liability company, and PetroQuest Energy, Inc., a Delaware corporation, continues to be its sole member.

Defined Terms

The Company has provided definitions for some of the oil and natural gas industry terms used in this Form 10-K in "Glossary of Oil and Natural Gas Terms" on page 35.

Our Strategy

Our business strategy is to build shareholder value by increasing per share reserves, production, cash flow and earnings at low finding and development costs through the exploration and development of properties located in the Gulf Coast Basin, either onshore or in shallow waters offshore. We plan to achieve this goal by continuing to:

- *Focus on the Gulf Coast Basin.* We have assembled a large acreage position and 3-D seismic database in the Gulf Coast Basin because we believe this area represents one of the most attractive exploration and development regions in North America. We also believe our management and technical team's expertise and experience developed over the last 25 years will allow us to develop attractive reinvestment opportunities that will permit continuing growth.
- *Target under-exploited fields that have low current production levels.* Using a rigorous prospect selection process that enables us to leverage our experience and knowledge of the Gulf Coast Basin, we target properties with an established production history and existing infrastructure. These fields have often produced from only shallower sands and contain multiple productive horizons that were not targeted during their initial phase of development. By targeting properties with limited current production, our acquisition costs are typically only a small portion of the total capital we will employ over the life of the project.
- *Emphasize and apply technical expertise.* By applying the latest 3-D and other geoscience technologies to under-exploited properties, we believe we can identify opportunities to significantly increase reserves and production from these properties.
- *Operate properties and balance risk.* By operating our properties, we can better control the timing and execution of our exploration and development plans. We also balance the risk and reward potential of our prospects by determining our desired working interest and selling the remainder to industry partners on terms where they often agree to pay a disproportionate share of drilling costs relative to their interests. Our management team has developed many successful relationships with major, integrated and large independent producers. We believe these relationships allow us to allocate our capital spending in a way that maximizes return while reducing the inherent risk of exploration activities.
- *Maintain our financial flexibility.* We seek to maintain unused borrowing capacity under our bank credit facility in order to take advantage of new opportunities. We also evaluate potential property acquisitions and dispositions, and routinely discuss those opportunities with third parties. While dispositions of producing properties reduce current revenues, sales of properties can provide additional capital for exploration and development of properties that are more important to our long-term growth.

Exploration and Development

The Company is engaged in the exploration, development, acquisition and operation of oil and gas properties onshore and offshore in the Gulf Coast Region. As of December 31, 2002, the Company's estimated proved reserves totaled 5,258 MBbl of oil and 37,137 MMcf of natural gas, with pre-tax present value discounted at 10% of the estimated future net revenues based on constant prices in effect at year-end ("discounted cash flow") of \$166,048,000. Approximately 62% of the Company's reserves are proved developed reserves. The Company operates 11 fields representing approximately 95% of the total discounted cash flow attributable to estimated proved reserves.

Significant Properties

Ship Shoal 72, Federal Outer Continental Shelf Waters. PetroQuest acquired an 85% working interest in 14,000 acres in the fourth quarter of 2000 and the remaining 15% working interest in this field during 2001. During 2002, the Company drilled and completed five wells, and the field produced approximately 7 Bcfe net to the Company from 11 producing wells. Additional developmental opportunities and exploration potential in a deeper horizon have been identified and are currently being evaluated for future drilling. Current plans call for seven additional developmental wells and three exploratory wells. We may seek to obtain an industry partner in the future development of this property. Reprocessed 3-D data is currently being reviewed for additional opportunities.

Turtle Bayou Field, Terrebonne Parish, LA. As of December 31, 2002, there are four producing wells in the field in which we hold a working interest. Collectively, the four producing wells averaged approximately 3,060 Mcf of natural gas and 80 barrels of oil per day, net to the Company, for the year ended December 31, 2002. Our working interest varies between 14% and 43% with a weighted average working interest of approximately 34%. PetroQuest acquired a 3-D regional seismic survey shot in 1998, which incorporates the Turtle Bayou Field. As a result of studying this data, six additional prospects with multiple objectives have been identified. The first five wells have been drilled and the Company has completed four of these wells as of December 31, 2002.

Vermilion Block 376, Federal Outer Continental Shelf Waters ("Falcon Prospect"). The Company and its partners drilled a well on this property in the fourth quarter of 1999 and logged 285 feet of gross hydrocarbon column (136 feet net). An additional well was drilled in the second quarter of 2000 logging 112 feet of gross hydrocarbon pay (74 feet net). PetroQuest is the operator of the project and owns a 43% working interest. During 2000, an approximately 2,500 ton production platform was fabricated and placed in service. During 2002 the field produced at an average rate of approximately 590 Bbls per day of oil and 840 Mcf per day of natural gas, net to the Company.

Berry Lake Field, Iberville Parish, LA. The Company and its partners drilled a well on this property in the third quarter of 2002 and logged approximately 71 feet of net productive sands. The well came on line during the fourth quarter and produced at an average rate for December of approximately 350 Bbls per day of oil and 560 Mcf per day of natural gas, net to the Company.

Eugene Island 147, Federal Outer Continental Shelf Waters. PetroQuest initially had a 25% working interest in this lease and acquired the remaining 75% working interest from a major oil and gas company. A 63.5% working interest was subsequently sold to other oil and gas companies and we currently hold a 36.5% working interest. During 2000, we drilled two successful wells on this offshore block, and 2002 production averaged approximately 2,060 Mcfe per day net to PetroQuest. Additional exploration opportunities have been identified and are currently being evaluated for future drilling.

Markets

PetroQuest's ability to market oil and gas from the Company's wells depends upon numerous factors beyond the Company's control, including:

- the extent of domestic production and imports of oil and gas,
- the proximity of the gas production to gas pipelines,
- the availability of capacity in such pipelines,
- the demand for oil and gas by utilities and other end users,
- the availability of alternative fuel sources,
- the effects of inclement weather,
- state and federal regulation of oil and gas production, and
- federal regulation of gas sold or transported in interstate commerce.

No assurance can be given that PetroQuest will be able to market all of the oil or gas produced by the Company or that favorable prices can be obtained for the oil and gas PetroQuest produces.

In view of the many uncertainties affecting the supply and demand for oil, gas and refined petroleum products, the Company is unable to predict future oil and gas prices and demand or the overall effect such prices and demand will have on the Company. For the year ended December 31, 2002, the Company had three customers who accounted for 25%, 22% and 19% of total revenues, respectively. For the year ended December 31, 2001, the Company had four customers who accounted for 19%, 19%, 15% and 13% of total revenues, respectively. For the year ended December 31, 2000, the Company had three customers who accounted for 58%, 15% and 11% of total revenues, respectively. PetroQuest does not believe that the loss of any of the Company's oil or gas purchasers would have a material adverse effect on the Company's operations due to the availability of other purchasers.

Federal Regulations

Sales and Transportation Of Natural Gas. Historically, the transportation and sales for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938 ("NGA"), the Natural Gas Policy Act of 1978 ("NGPA") and Federal Energy Regulatory Commission ("FERC") regulations. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act deregulated the price for all "first sales" of natural gas. Thus, all sales of gas by the Company may be made at market prices, subject to applicable contract provisions. Sales of natural gas are affected by the availability, terms and cost of pipeline transportation. Since 1985, the FERC has implemented regulations intended to make natural gas transportation more accessible to gas buyers and sellers on an open-access, non-discriminatory basis.

Beginning in April 1992, the FERC issued Order No. 636 and a series of related orders, which required interstate pipelines to provide open-access transportation on a not unduly discriminatory basis for all natural gas shippers. The FERC has stated that it intends for Order No. 636 and its future restructuring activities to foster increased competition within all phases of the natural gas industry. Although Order No. 636 does not directly regulate our production and marketing activities, it does affect how buyers and sellers gain access to the necessary transportation facilities and how we and our competitors sell natural gas in the marketplace.

The courts have largely affirmed the significant features of Order No. 636 and the numerous related orders pertaining to individual pipelines. However, some appeals remain pending and the FERC continues to review and modify its regulations regarding the transportation of natural gas. For example, the FERC issued Order No. 637 which;

- lifts the cost-based cap on pipeline transportation rates in the capacity release market until September 30, 2002, for short-term releases of pipeline capacity of less than one year,
- permits pipelines to file for authority to charge different maximum cost-based rates for peak and off-peak periods,
- encourages, but does not mandate, auctions for pipeline capacity,
- requires pipelines to implement imbalance management services,
- restricts the ability of pipelines to impose penalties for imbalances, overruns and non-compliance with operational flow orders, and
- implements a number of new pipeline reporting requirements.

Order No. 637 also requires the FERC staff to analyze whether the FERC should implement additional fundamental policy changes. These include whether to pursue performance-based or other non-cost based ratemaking techniques and whether the FERC should mandate greater standardization in terms and conditions of service across the interstate pipeline grid.

In April 1999 the FERC issued Order No. 603, which implemented new regulations governing the procedure for obtaining authorization to construct new pipeline facilities. In September 1999, the FERC issued a related policy statement establishing a presumption in favor of requiring owners of new pipeline facilities to charge rates for service on new pipeline facilities based solely on the costs associated with such new pipeline facilities.

We cannot predict what further action the FERC will take on these matters, nor can we accurately predict whether the FERC's actions will achieve the goal of increasing competition in markets in which our natural gas is sold. However, we do not believe that any action taken will affect the Company in a way that materially differs from the way it affects other natural gas producers, gatherers and marketers.

The Outer Continental Shelf Lands Act, which the FERC implements as to transportation and pipeline issues, requires that all pipelines operating on or across the Outer Continental Shelf provide open-access, non-discriminatory service. Historically, the FERC has opted not to impose regulatory requirements under its Outer Continental Shelf Lands Act authority on gatherers and other entities outside the reach of its NGA jurisdiction. However, the FERC in 2000 issued Order No. 639 and 639-A, requiring that virtually all non-proprietary pipeline transporters of natural gas on the Outer Continental Shelf report information on their affiliations, rates and conditions of service. The reporting requirements established by the FERC in Order No. 639 and 639-A may apply, in certain circumstances, to operators of production platforms and other facilities on the Outer Continental Shelf, with respect to gas movements across such facilities. Certain offshore service providers have requested FERC to treat certain information as confidential and not subject to public review. On September 13, 2001, FERC issued an order denying confidential treatment; however, on January 11, 2002, the United States District Court for the District of Columbia granted the motion for summary judgment of the offshore service providers seeking confidential treatment of certain information they are required to report. FERC has indicated that it will appeal. Among the FERC's stated purposes in issuing such rules was the desire to increase transparency in the market, to provide producers and shippers on the Outer Continental Shelf with greater assurance of (a) open-access services on pipelines located on the Outer Continental Shelf and (b) non-discriminatory rates and conditions of service on such pipelines.

The FERC retains authority under the Outer Continental Shelf Lands Act to exercise jurisdiction over gatherers and other entities outside the reach of its NGA jurisdiction if necessary to ensure non-discriminatory access to service on the Outer Continental Shelf. We do not believe that any FERC action taken under its Outer Continental Shelf Lands Act jurisdiction will affect us in a way that materially differs from the way it affects other natural gas producers, gatherers and marketers.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue.

Sales and Transportation Of Crude Oil. Sales of crude oil, condensate and natural gas liquids by the Company are not currently regulated, and are subject to applicable contract provisions made at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to the FERC's jurisdiction under the Interstate Commerce Act. In other instances, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes.

The regulation of pipelines that transport crude oil, condensate and natural gas liquids is generally more light-handed than the FERC's regulation of gas pipelines under the NGA. Regulated pipelines that transport crude oil, condensate, and natural gas liquids are subject to common carrier obligations that generally ensure non-discriminatory access. With respect to interstate pipeline transportation subject to regulation of the FERC under the Interstate Commerce Act, rates generally must be cost-based, although market-based rates or negotiated settlement rates are permitted in certain circumstances. Pursuant to FERC Order No. 561, pipeline rates are subject to an indexing methodology. Under this indexing methodology, pipeline rates are subject to changes in the Producer Price Index for Finished Goods, minus one percent. A pipeline can seek to increase its rates above index levels provided that the pipeline can establish that there is a substantial divergence between the actual costs experienced by the pipeline and the rate resulting from application of the index. A pipeline can seek to charge market-based rates if it establishes that it lacks significant market power. In addition, a pipeline can establish rates pursuant to settlement if agreed upon by all current shippers. A pipeline can seek to establish initial rates for new services through a cost-of-service proceeding, a market-based rate proceeding, or through an agreement between the pipeline and at least one shipper not affiliated with the pipeline. The FERC indicated in Order No. 561 that it will assess in 2000 how the rate-indexing method is operating. The FERC issued a Notice of Inquiry on July 27, 2000 seeking comment on whether to retain or to change the existing index. After consideration of all the initial and reply comments, the FERC concluded on December 14, 2000 that the PPI-1 index has reasonably approximated the actual cost changes in the oil pipeline industry during the preceding five year period, and that it should be continued for the subsequent five year period.

Federal Leases. The Company maintains operations located on federal oil and gas leases, which are administered by the Minerals Management Service pursuant to the Outer Continental Shelf Lands Act. These leases are issued through competitive bidding and contain relatively standardized terms. These leases require compliance with detailed Minerals Management Service regulations and orders that are subject to interpretation and change by the Minerals Management Service.

For offshore operations, lessees must obtain Minerals Management Service approval for exploration, development and production plans prior to the commencement of such operations. In addition to permits required from other agencies such as the Coast Guard, the Army Corps of Engineers and the Environmental Protection Agency, lessees must obtain a permit from the Minerals Management Service prior to the commencement of drilling. The Minerals Management Service has promulgated regulations requiring offshore production facilities located on the Outer Continental Shelf to meet stringent engineering and construction specifications. The Minerals Management Service also has regulations restricting the flaring or venting of natural gas, and has proposed to amend such regulations to prohibit the flaring of liquid hydrocarbons and oil without prior authorization. Similarly, the Minerals Management Service has promulgated other regulations governing the plugging and abandonment of wells located offshore and the installation and removal of all production facilities.

To cover the various obligations of lessees on the Outer Continental Shelf, the Minerals Management Service generally requires that lessees have substantial net worth or post bonds or other acceptable assurances that such obligations will be met. The cost of these bonds or assurances can be substantial, and there is no assurance that they can be obtained in all cases. Under some circumstances, the Minerals Management Service may require operations on federal leases to be suspended or terminated.

The Minerals Management Service also administers the collection of royalties under the terms of the Outer Continental Shelf Lands Act and the oil and gas leases issued under the Act. The amount of royalties due is based upon the terms of the oil and gas leases as well as of the regulations promulgated by the Minerals Management Service. These regulations are amended from time to time, and the amendments can affect the amount of royalties that we are obligated to pay to the Minerals Management Service. However, we do not believe that these regulations or any future amendments will affect the Company in a way that materially differs from the way it affects other oil and gas producers, gatherers and marketers.

Federal, State or American Indian Leases. In the event the Company conducts operations on federal, state or American Indian oil and gas leases, such operations must comply with numerous regulatory restrictions, including various nondiscrimination statutes, and certain of such operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by the Bureau of Land Management ("BLM") or Minerals Management Service or other appropriate federal or state agencies.

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

State Regulations

Most states regulate the production and sale of oil and natural gas, including:

- requirements for obtaining drilling permits,
- the method of developing new fields,
- the spacing and operation of wells,
- the prevention of waste of oil and gas resources, and
- the plugging and abandonment of wells.

The rate of production may be regulated and the maximum daily production allowable from both oil and gas wells may be established on a market demand or conservation basis or both.

The Company may enter into agreements relating to the construction or operation of a pipeline system for the transportation of natural gas. To the extent that such gas is produced, transported and consumed wholly within one state, such operations may, in certain instances, be subject to the jurisdiction of such state's administrative authority charged with the responsibility of regulating intrastate pipelines. In such event, the rates which the Company could charge for gas, the transportation of gas, and the construction and operation of such pipeline would be subject to the rules and regulations governing such matters, if any, of such administrative authority.

Legislative Proposals

In the past, Congress has been very active in the area of natural gas regulation. There are legislative proposals pending in the various state legislatures which, if enacted, could significantly affect the petroleum industry. At the present time it is impossible to predict what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on the Company's operations.

Environmental Regulations

General. The Company's activities are subject to existing federal, state and local laws and regulations governing environmental quality and pollution control. Although no assurances can be made, the Company believes that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, regulations and rules regulating the release of materials in the environment or otherwise relating to the protection of the environment will not have a material effect upon the capital expenditures, earnings or the competitive position of the Company with respect to its existing assets and operations. The Company cannot predict what effect additional regulation or legislation, enforcement policies thereunder, and claims for damages to property, employees, other persons and the environment resulting from the Company's operations could have on its activities.

Activities of PetroQuest with respect to natural gas facilities, including the operation and construction of pipelines, plants and other facilities for transporting, processing, treating or storing natural gas and other products, are subject to stringent environmental regulation by state and federal authorities including the United States Environmental Protection Agency ("EPA"). Such regulation can increase the cost of planning, designing, installation and operation of such facilities. In most instances, the regulatory requirements relate to water and air pollution control measures. Although the Company believes that compliance with environmental regulations will not have a material adverse effect on it, risks of substantial costs and liabilities are inherent in oil and gas production operations, and there can be no assurance that significant costs and liabilities will not be incurred. Moreover it is possible that other developments, such as stricter environmental laws and regulations, and claims for damages to property or persons resulting from oil and gas production, would result in substantial costs and liabilities to the Company.

Solid and Hazardous Waste. The Company owns or leases numerous properties that have been used for production of oil and gas for many years. Although the Company has utilized operating and disposal practices standard in the industry at the time, hydrocarbons or other solid wastes may have been disposed or released on or under these properties. In addition, many of these properties have been operated by third parties. The Company had no control over such entities' treatment of hydrocarbons or other solid wastes and the manner in which such substances may have been disposed or released. State and federal laws applicable to oil and gas wastes and properties have gradually become stricter over time. Under these laws, the Company could be required to remove or remediate previously disposed wastes (including wastes disposed or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators) or to perform remedial plugging operations to prevent future contamination.

The Company generates wastes, including hazardous wastes, that are subject to the federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The EPA has limited the disposal options for certain hazardous wastes. Furthermore, it is possible that certain wastes currently exempt from regulation as "hazardous wastes" generated by the Company's oil and gas operations may in the future be designated as "hazardous wastes" under RCRA or other applicable statutes, and therefore be subject to more rigorous and costly disposal requirements.

Superfund. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on certain persons with respect to the release or threatened release of a "hazardous substance" into the environment. These persons include the owner and operator of a site and persons that disposed or arranged for the disposal of the hazardous substances found at a site. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible persons the costs of such action. Neither the Company nor its predecessors have been designated as a potentially responsible party by the EPA under CERCLA with respect to any such site.

Oil Pollution Act. The Oil Pollution Act of 1990 (the "OPA") and regulations thereunder impose a variety of regulations on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. A "responsible party" includes the owner or operator of a facility or vessel, or the lessee or permittee of the area in which an offshore facility is located. The OPA assigns liability to each responsible party for oil removal costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by the OPA.

The OPA establishes a liability limit for onshore facilities of \$350 million and for offshore facilities of all removal costs plus \$75 million, and lesser limits for some vessels depending upon their size. The regulations promulgated under OPA impose proof of financial responsibility requirements that can be satisfied through insurance, guarantee, indemnity, surety bond, letter of credit, qualification as a self-insurer, or a combination thereof. The amount of financial responsibility required depends upon a variety of factors including the type of facility or vessel, its size, storage capacity, oil throughput, proximity to sensitive areas, type of oil handled, history of discharges and other factors. The Company believes it currently has established adequate financial responsibility. While financial responsibility requirements under OPA may be amended to impose additional costs on the Company, the impact of any change in these requirements should not be any more burdensome to the Company than to others similarly situated.

Clean Water Act. The Clean Water Act ("CWA") regulates the discharge of pollutants to waters of the United States, including wetlands, and requires a permit for the discharge of pollutants, including petroleum, to such waters. Certain facilities that store or otherwise handle oil are required to prepare and implement Spill Prevention, Control and Countermeasure Plans and Facility Response Plans relating to the possible discharge of oil to surface waters. The Company is required to prepare and comply with such plans and to obtain and comply with discharge permits. The Company believes it is in substantial compliance with these requirements and that any noncompliance would not have a material adverse effect on it. The CWA also prohibits spills of oil and hazardous substances to waters of the United States in excess of levels set by regulations and imposes liability in the event of a spill. State laws further provide civil and criminal penalties and liabilities for spills to both surface and groundwaters and require permits that set limits on discharges to such waters.

Air Emissions. The operations of the Company are subject to local, state and federal regulations for the control of emissions from sources of air pollution. Administrative enforcement actions for failure to comply strictly with air regulations or permits may be resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could impose civil and criminal liability for non-compliance. An agency could require the Company to forego construction or operation of certain air emission sources. The Company believes that it is in substantial compliance with air pollution control requirements and that, if a particular permit application were denied, it would have enough permitted or permissible capacity to continue its operations without a material adverse effect on any particular producing field.

OSHA. The Company is subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendments and Reauthorization Act and similar state statutes require the Company to organize and/or disclose information about hazardous materials used or produced in its operations. Certain of this information must be provided to employees, state and local governmental authorities and local citizens.

Management believes that the Company is in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on the Company.

Employees

The Company had 57 employees as of December 31, 2002. In addition to the services of its full time employees, the Company utilizes the services of independent contractors to perform certain services. PetroQuest believes that its relationships with its employees are satisfactory. None of the Company's employees are covered by a collective bargaining agreement.

Internet Website

PetroQuest's Internet website can be found at www.petroquest.com. PetroQuest makes available free of charge, or through the "Financials" section of our Internet website at www.petroquest.com, access to our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after such material is filed, or furnished to the Securities and Exchange Commission.

Risk Factors

Risks Related to Our Business, Industry and Strategy

Our future success depends upon our ability to find, develop and acquire additional oil and natural gas reserves that are economically recoverable.

As is generally the case in the Gulf Coast Basin, many of our producing properties are characterized by a high initial production rate, followed by a steep decline in production. As a result, we must locate and develop or acquire new oil and natural gas reserves to replace those being depleted by production. We must do this even during periods of low oil and natural gas prices when it is difficult to raise the capital necessary to finance our exploration, development and acquisition activities. Without successful exploration, development or acquisition activities, our reserves and revenues will decline rapidly. We may not be able to find and develop or acquire additional reserves at an acceptable cost or have access to necessary financing for these activities.

We may not be able to maintain our historical rates of growth.

We may not be able to maintain the rate of growth in our reserves, production and financial results that we have achieved since our management team acquired its equity interest in PetroQuest. Our growth rates have to a certain extent been unusually high because PetroQuest was a very small company, with total reserves of approximately 14 Bcfe as of December 31, 1998. As a result, as we continue to grow, our growth rates may be lower than those achieved in our recent history.

Oil and natural gas prices are volatile, and a substantial and extended decline in the prices of oil and natural gas would likely have a material adverse effect on us.

Our revenues, profitability and future growth, and the carrying value of our oil and natural gas properties, depend to a large degree on prevailing oil and natural gas prices. Our ability to maintain or increase our borrowing capacity and to obtain additional capital on attractive terms also substantially depend upon oil and natural gas prices. Prices for oil and natural gas are subject to large fluctuations in response to a variety of other factors beyond our control. These factors include:

- relatively minor changes in the supply of and the demand for oil and natural gas;
- market uncertainty;
- the level of consumer product demand;
- weather conditions in the United States;
- the condition of the United States economy;
- the action of the Organization of Petroleum Exporting Countries;
- domestic and foreign governmental regulation, including price controls adopted by the Federal Energy Regulatory Commission;
- political instability in the Middle East and elsewhere;
- the foreign supply of oil and natural gas;
- the price of foreign imports; and
- the availability of alternate fuel sources.

At various times, excess domestic and imported supplies have depressed oil and natural gas prices. We cannot predict future oil and natural gas prices and prices may decline. Declines in oil and natural gas prices may adversely affect our financial condition, liquidity and results of operations. Lower prices may also reduce the amount of oil and natural gas that we can produce economically and require us to record ceiling test write-downs when prices decline. Substantially all of our oil and natural gas sales are made in the spot market or pursuant to contracts based on spot market prices. Our sales are not made pursuant to long-term fixed price contracts.

To attempt to reduce our price risk, we periodically enter into hedging transactions with respect to a portion of our expected future production. We cannot assure you that such transactions will reduce the risk or minimize the effect of any decline in oil or natural gas prices. Any substantial or extended decline in the prices of or demand for oil or natural gas would have a material adverse effect on our financial condition and results of operations.

You should not place undue reliance on reserve information because reserve information represents estimates.

This document contains estimates of oil and natural gas reserves, and the future net cash flows attributable to those reserves, prepared by Ryder Scott Company, L.P., our independent petroleum and geological engineers. There are numerous uncertainties inherent in estimating quantities of proved reserves and cash flows from such reserves, including factors beyond our control and the control of Ryder Scott. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of an estimate of quantities of reserves, or of cash flows attributable to these reserves, is a function of:

- the available data;
- assumptions regarding future oil and natural gas prices;
- estimated expenditures for future development and exploitation activities; and
- engineering and geological interpretation and judgment.

Reserves and future cash flows may also be subject to material downward or upward revisions based upon production history, development and exploitation activities and oil and natural gas prices. Actual future production, revenue, taxes, development expenditures, operating expenses, quantities of recoverable reserves and the value of cash flows from those reserves may vary significantly from the assumptions and estimates in this document. In addition, reserve engineers may make different estimates of reserves and cash flows based on the same available data. In calculating reserves on a Mcfe basis, oil was converted to natural gas equivalent at the ratio of six Mcf of natural gas to one Bbl of oil. While this ratio approximates the energy equivalency of natural gas to oil on a Btu basis, it may not represent the relative prices received by us from the sale of our oil and natural gas production.

Approximately 38% of our estimated proved reserves are undeveloped. Estimates of undeveloped reserves, by their nature, are less certain. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of our oil and natural gas reserves and the costs associated with these reserves in accordance with industry standards, we cannot assure you that the estimated costs are accurate, that development will occur as scheduled or that the actual results will be as estimated.

You should not assume that the present value of future net revenues referred to in this document and the information incorporated by reference is the current market value of our estimated oil and natural gas reserves. In accordance with Securities and Exchange Commission 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 than the prices and costs as of the date of the estimate. Any changes in consumption by natural gas purchasers or in governmental regulations or taxation may also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the Securities and Exchange Commission to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor. The effective interest rate at various times and the risks associated with our operations or the oil and natural gas industry in general will affect the accuracy of the 10% discount factor.

Lower oil and natural gas prices may cause us to record ceiling test write-downs.

We use the full cost method of accounting to account for our oil and natural gas operations. Accordingly, we capitalize the cost to acquire, explore for and develop oil and natural gas properties. Under full cost accounting rules, the net capitalized costs of oil and natural gas properties may not exceed a "ceiling limit" which is based upon the present value of estimated future net cash flows from proved reserves, discounted at 10%, plus the lower of cost or fair market value of unproved properties. If net capitalized costs of oil and natural gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling test write-down." This charge does not impact cash flow from operating activities, but does reduce our stockholders' equity. The risk that we will be required to write down the carrying value of oil and natural gas properties increases when oil and natural gas prices are low or volatile. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves.

Factors beyond our control affect our ability to market oil and natural gas.

The availability of markets and the volatility of product prices are beyond our control and represent a significant risk. The marketability of our production depends upon the availability and capacity of natural gas gathering systems, pipelines and processing facilities. The unavailability or lack of capacity of these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Our ability to market oil and natural gas also depends on other factors beyond our control. These factors include:

- the level of domestic production and imports of oil and natural gas;
- the proximity of natural gas production to natural gas pipelines;
- the availability of pipeline capacity;
- the demand for oil and natural gas by utilities and other end users;
- the availability of alternate fuel sources;
- the effect of inclement weather;
- state and federal regulation of oil and natural gas marketing; and
- federal regulation of natural gas sold or transported in interstate commerce.

If these factors were to change dramatically, our ability to market oil and natural gas or obtain favorable prices for our oil and natural gas could be adversely affected.

We face strong competition from larger oil and natural gas companies that may negatively affect our ability to carry on operations.

We operate in the highly competitive areas of oil and natural gas exploration, development and production. Factors that affect our ability to compete successfully in the marketplace include:

- the availability of funds and information relating to a property;
- the standards established by us for the minimum projected return on investment; and
- the intermediate transportation of natural gas.

Our competitors include major integrated oil companies, substantial independent energy companies, affiliates of major interstate and intrastate pipelines and national and local natural gas gatherers, many of which possess greater financial and other resources than we do.

Risks Relating to Financing Our Business

We may not be able to obtain adequate financing to execute our operating strategy.

We have historically addressed our long-term liquidity needs through the use of credit facilities, the issuance of equity securities and the use of cash provided by operating activities. We continue to examine the following alternative sources of long-term capital:

- borrowings from banks or other lenders;
- the issuance of debt securities;
- the sale of common stock, preferred stock or other equity securities;
- joint venture financing; and
- production payments.

The availability of these sources of capital will depend upon a number of factors, some of which are beyond our control. These factors include general economic and financial market conditions, oil and natural gas prices and our market value and operating performance. We may be unable to execute our operating strategy if we cannot obtain capital from these sources.

We may not be able to fund our planned capital expenditures.

We spend and will continue to spend a substantial amount of capital for the development, exploration, acquisition and production of oil and natural gas reserves. If low oil and natural gas prices, operating difficulties or other factors, many of which are beyond our control, cause our revenues or cash flows from operations to decrease, we may be limited in our ability to spend the capital necessary to complete our drilling program. We may be forced to raise additional debt or equity proceeds to fund such expenditures. We cannot assure you that additional debt or equity financing or cash generated by operations will be available to meet these requirements.

Leverage may materially affect our operations.

We presently have and may incur from time to time debt under our bank credit facility. The borrowing base limitation on our bank credit facility is periodically redetermined and upon such redetermination, we could be forced to repay a portion of our bank debt. We may not have sufficient funds to make such repayments.

Our level of debt affects our operations in several important ways, including the following:

- a portion of our cash flow from operations is used to pay interest on borrowings;
- the covenants contained in the agreements governing our debt limit our ability to borrow additional funds or to dispose of assets;
- the covenants contained in the agreements governing our debt may affect our flexibility in planning for, and reacting to, changes in business conditions;
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes;
- our leveraged financial position may make us more vulnerable to economic downturns and may limit our ability to withstand competitive pressures;
- any debt that we incur under our credit facilities will be at variable rates, which could make us vulnerable to increases in interest rates; and
- a high level of debt will affect our flexibility in planning for or reacting to changes in market conditions.

In addition, we may significantly alter our capitalization in order to make future acquisitions or develop our properties. These changes in capitalization may significantly increase our level of debt. A higher level of debt increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of debt depends on our future performance. General economic conditions and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control.

If we are unable to repay our debt at maturity out of cash on hand, we could attempt to refinance such debt, or repay such debt with the proceeds of an equity offering. We cannot assure you that we will be able to generate sufficient cash flow to pay the interest on our debt or that future borrowings or equity financing will be available to pay or refinance such debt. The terms of our bank credit facility may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions and our market value and operating performance at the time of such offering or other financing. We cannot assure you that any such offering or refinancing can be successfully completed.

Risks Relating to Our Ongoing Operations

The loss of key personnel could adversely affect our ability to operate.

Our operations are dependent upon a relatively small group of key management and technical personnel. We cannot assure you that such individuals will remain with us for the immediate or foreseeable future. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on our operations.

Operating hazards may adversely affect our ability to conduct business.

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

- unexpected drilling conditions including blowouts, cratering and explosions;
- uncontrollable flows of oil, natural gas or well fluids;
- equipment failures, fires or accidents;
- pollution and other environmental risks; and
- shortages in experienced labor or shortages or delays in the delivery of equipment.

These risks could result in substantial losses to us from injury and loss of life, damage to and destruction of property and equipment, pollution and other environmental damage and suspension of operations. Our offshore operations are also subject to a variety of operating risks peculiar to the marine environment, such as hurricanes or other adverse weather conditions and more extensive governmental regulation. These regulations may, in certain circumstances, impose strict liability for pollution damage or result in the interruption or termination of operations.

Losses and liabilities from uninsured or underinsured drilling and operating activities could have a material adverse effect on our financial condition and operations.

We maintain several types of insurance to cover our operations, including maritime employer's liability and comprehensive general liability. Amounts over base coverages are provided by primary and excess umbrella liability policies with maximum limits of \$50 million. We also maintain operator's extra expense coverage, which covers the control of drilled or producing wells as well as redrilling expenses and pollution coverage for wells out of control.

We may not be able to maintain adequate insurance in the future at rates we consider reasonable, or we could experience losses that are not insured or that exceed the maximum limits under our insurance policies. If a significant event that is not fully insured or indemnified occurs, it could materially and adversely affect our financial condition and results of operations.

Compliance with environmental and other government regulations is costly and could negatively impact production.

Our operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may:

- require the acquisition of permits before drilling commences;
- restrict the types, quantities and concentration of various substances that can be released into the environment from drilling and production activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas;
- require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells; and
- impose substantial liabilities for pollution resulting from our operations.

The recent trend toward stricter standards in environmental legislation and regulation is likely to continue. The enactment of stricter legislation or the adoption of stricter regulations could have a significant impact on our operating costs, as well as on the oil and natural gas industry in general.

Our operations could result in liability for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. We could also be liable for environmental damages caused by previous property owners. As a result, substantial liabilities to third parties or governmental entities may be incurred which could have a material adverse effect on our financial condition and results of operations. We maintain insurance coverage for our operations, including limited coverage for sudden and accidental environmental damages, but this insurance may not extend to the full potential liability that could be caused by sudden and accidental environmental damages and further may not cover environmental damages that occur over time. Accordingly, we may be subject to liability or may lose the ability to continue exploration or production activities upon substantial portions of our properties if certain environmental damages occur.

The Oil Pollution Act of 1990 imposes a variety of regulations on "responsible parties" related to the prevention of oil spills. The implementation of new, or the modification of existing, environmental laws or regulations, including regulations promulgated pursuant to the Oil Pollution Act, could have a material adverse impact on us.

Ownership of working interests and overriding royalty interests in certain of our properties by certain of our officers and directors may create conflicts of interest.

Certain of our executive officers and directors or their respective affiliates are working interest owners or overriding royalty interest owners in particular properties. In their capacity as working interest owners, they are required to pay their proportionate share of all costs and are entitled to receive their proportionate share of revenues in the normal course of business. As overriding royalty interest owners they are entitled to receive their proportionate share of revenues in the normal course of business. A conflict of interest may exist between us and such officers and directors with respect to the drilling of additional wells or other development operations with respect to these properties.

Risks Relating to Our Common Stock Outstanding

Our management controls a significant percentage of our outstanding common stock and their interests may conflict with those of our stockholders.

Our directors and executive officers and their affiliates beneficially own about 25% of our outstanding common stock at March 7, 2003. If these persons were to act in concert, they would, as a practical matter, be able to effectively control our affairs. This concentration of ownership could also have the effect of delaying or preventing a change in control of or otherwise discouraging a potential acquiror from attempting to obtain control of us. This could have a material adverse effect on the market price of our common stock or prevent our stockholders from realizing a premium over the then prevailing market prices for their shares of our common stock.

Our stock price could be volatile, which could cause you to lose part or all of your investment.

The stock market has from time to time experienced significant price and volume fluctuations that may be unrelated to the operating performance of particular companies. In particular, the market price of our common stock, like that of the securities of other energy companies, has been and may be highly volatile. Factors such as announcements concerning changes in prices of oil and natural gas, the success of our exploration and development drilling program, the availability of capital, and economic and other external factors, as well as period-to-period fluctuations and financial results, may have a significant effect on the market price of our common stock.

From time to time, there has been limited trading volume in our common stock. In addition, there can be no assurance that there will continue to be a trading market or that any securities research analysts will continue to provide research coverage with respect to our common stock. It is possible that such factors will adversely affect the market for our common stock.

Provisions in our corporate documents could delay or prevent a change in control of our company, even if that change would be beneficial to our stockholders.

Certain provisions of our certificate of incorporation and bylaws may delay, discourage, prevent or render more difficult an attempt to obtain control of our company, whether through a tender offer, business combination, proxy contest or otherwise. These provisions include:

- the charter authorization of "blank check" preferred stock;
- provisions that directors may be removed only for cause, and then only on approval of holders of a majority of the outstanding voting stock; and
- a restriction on the ability of stockholders to take actions by written consent.

In November 2001, our board of directors adopted a shareholder rights plan, pursuant to which uncertificated preferred stock purchase rights were distributed to our stockholders at a rate of one right for each share of common stock held of record as of November 19, 2001. The rights plan is designed to enhance the board's ability to prevent an acquirer from depriving stockholders of the long-term value of their investment and to protect stockholders against attempts to acquire us by means of unfair or abusive takeover tactics. However, the existence of the rights plan may impede a takeover not supported by our board, including a takeover that may be desired by a majority of our stockholders or involving a premium over the prevailing stock price.

Notice Regarding Consent Of Arthur Andersen LLP

On June 15, 2002, Arthur Andersen LLP, our former independent auditors, was convicted of federal obstruction of justice. On June 28, 2002, our Board of Directors, upon the approval of its Audit Committee, engaged Ernst & Young, LLP as independent auditors and dismissed Arthur Andersen LLP. After reasonable efforts, we have not been able to obtain the consent of Arthur Andersen LLP to the incorporation by reference of its audit report dated March 7, 2002 into our registration statements on Form S-3 and Form S-8. As permitted under Rule 437a promulgated under the Securities Act of 1933, we have not filed the written consent of Arthur Andersen LLP that would otherwise be required by the Securities Act. Because Arthur Andersen LLP has not consented to the incorporation of reference of their report in these registration statement, you may not be able to recover amounts from Arthur Andersen LLP under Section 11(a) of the Securities Act for any untrue statement of a material fact or any omission to state a material fact, if any, contained in or omitted from our financial statements included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2001, which are incorporated by reference in these registration statements.

ITEM 2. PROPERTIES

For a description of the Company's exploration and development activities and its significant properties, see Item 1. Business-Exploration and Development and - Significant Properties.

Oil and Gas Reserves

The following table sets forth certain information about the estimated proved reserves of the Company as of December 31, 2002.

	Oil (MBbls)	Gas (MMcf)
Proved developed:	4,201	17,409
Proved undeveloped:	1,057	19,728
Total proved:	5,258	37,137
Estimated pre-tax future net cash flows	\$ 216,934,286	
Discounted pre-tax future net cash flows	\$ 166,047,752	
Standardized measure of discounted future net cash flows	\$ 139,415,797	

Ryder Scott Company, L.P. prepared the estimates of proved reserves and future net cash flows (and present value thereof) attributable to such proved reserves at December 31, 2002. Reserves were estimated using oil and gas prices and production and development costs in effect at December 31, 2002 without escalation, and were prepared in accordance with Securities and Exchange Commission regulations regarding disclosure of oil and gas reserve information. The product prices used in developing the above estimates averaged \$30.44 per Bbl of oil and \$4.48 per MMBtu of gas. Because of the high Btu content of the Company's Gulf Coast gas, this equates to an average price realized of approximately \$4.79 per Mcf.

The Company has not filed any reports with other federal agencies which contain an estimate of total proved net oil and gas reserves.

Oil and Gas Drilling Activity

The following table sets forth the wells drilled and completed by the Company during the periods indicated. All such wells were drilled in the continental United States:

	2002		2001		2000	
	Gross	Net	Gross	Net	Gross	Net
Exploration:						
Productive	2	1.72	1	0.41	3	1.32
Non-productive	1	0.50	2	0.68	1	0.40
Total	3	2.22	3	1.09	4	1.72
Development:						
Productive	5	4.02	9	5.78	3	1.23
Non-productive	2	0.77	1	0.54	1	0.40
Total	7	4.79	10	6.32	4	1.63

The Company owned working interests in 31 gross (15.7 net) producing oil and gas wells at December 31, 2002. At December 31, 2002, the Company had one well in progress.

Leasehold Acreage

The following table shows the approximate developed and undeveloped (gross and net) leasehold acreage of the Company as of December 31, 2002:

	Leasehold Acreage			
	Developed		Undeveloped	
	Gross	Net	Gross	Net
Mississippi (onshore)	721	458	6,678	4,768
Louisiana (onshore)	4,297	1,027	9,118	7,254
Texas (offshore)	1,440	636	-	-
Federal Waters	37,852	16,236	73,919	49,577
Total	44,310	18,357	89,715	61,599

Title to Properties

The Company believes that the title to its oil and gas properties is good and defensible in accordance with standards generally accepted in the oil and gas industry, subject to such exceptions which, in the opinion of the Company, are not so material as to detract substantially from the use or value of such properties. The Company's properties are typically subject, in one degree or another, to one or more of the following:

- royalties and other burdens and obligations, express or implied, under oil and gas leases,
- overriding royalties and other burdens created by the Company or its predecessors in title,
- a variety of contractual obligations (including, in some cases, development obligations) arising under operating agreements, farmout agreements, production sales contracts and other agreements that may affect the properties or their titles,
- back-ins and reversionary interests existing under purchase agreements and leasehold assignments,
- liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing obligations to unpaid suppliers and contractors and contractual liens under operating agreements,
- pooling, unitization and communitization agreements, declarations and orders, and
- easements, restrictions, rights-of-way and other matters that commonly affect property

To the extent that such burdens and obligations affect the Company's rights to production revenues, they have been taken into account in calculating the Company's net revenue interests and in estimating the size and value of the Company's reserves. The Company believes that the burdens and obligations affecting its properties are conventional in the industry for properties of the kind owned by the Company.

ITEM 3. LEGAL PROCEEDINGS

There are no legal proceedings to which the Company or its subsidiaries is a party or by which any of its property is subject, other than ordinary and routine litigation due to the business of producing and exploring for oil and natural gas, except as follows:

PetroQuest Energy, Inc. f/k/a Optima Energy (U.S.) Corp. v. The Meridian Resource & Exploration Company f/k/a Texas Meridian Resources Exploration, Inc., bearing Civil Action No. 99-2394 of the United States District Court for the Western District of Louisiana was filed on February 24, 2000. The Company asserts a claim for damages against Meridian resulting from Meridian's activities as operator of the Southwest Holmwood property, Calcasieu Parish, Louisiana. Meridian's activities as operator resulted in a final judgment of the United States District Court for the Western District of Louisiana ordering cancellation of the Company's rights to a productive oil and gas lease and the associated joint exploration agreement, forfeiture to two producing wells on the lease and substantial damages against Meridian causing the Company the loss of its investment and profits.

The Meridian Resource & Exploration Company v. PetroQuest Energy, Inc., bearing Docket No. 996192A of the 15th Judicial District Court in and for the Parish of Lafayette, Louisiana was filed on December 17, 1999. Meridian asserts that the Company is responsible as an investor under its participation agreement with Meridian for \$530,004 of the losses, costs, expense and liability of Meridian resulting from the final judgment that was rendered in favor of Amoco and against Meridian in legal proceedings relative to the Southwest Holmwood Field, Calcasieu Parish, Louisiana in the matter "*Amoco Production Company v. Texas Meridian Resource & Exploration Company*," bearing Civil Action No. 96-1639 in the United States District Court for the Western District of Louisiana (Civil Action No. 98-30724 in the United States Court of Appeals for the Fifth Circuit). Although the Company accrued \$555,000 when the district court decision was rendered against Meridian in December 1997, the Company denies liability to Meridian for losses sustained by Meridian as operator as a result of the Amoco litigation and is vigorously defending the lawsuit. Meridian initially withheld \$737,620 from production revenues due the Company from other properties. On January 9, 2002 Meridian released to the Company \$211,476 of the withheld revenues. The Company is pursuing recovery of the balance of the withheld revenues from Meridian as discussed in *PetroQuest Energy, Inc. f/k/a Optima Energy (U.S.) Corp. v. The Meridian Resource & Exploration Company f/k/a Texas Meridian Resources Exploration, Inc.*

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

There were no matters submitted to a vote of security holders during the fourth quarter of 2002.

PART II

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

Market Price of and Dividends on Common Stock

The Company's common stock trades on The Nasdaq Stock Market under the symbol "PQUE." On January 19, 2001, the Company voluntarily delisted its common stock from the Toronto Stock Exchange ("TSE") where it formally traded under the symbol "PQU." The Company delisted its stock from the TSE because it no longer had Canadian operations and substantially all of its trading volume was on The Nasdaq Stock Market. The following table lists high and low sales prices per share for the periods indicated:

Quarter Ended	Nasdaq Stock Market		Toronto Stock Exchange	
	High (U.S.\$)	Low (U.S.\$)	High (CDN \$)	Low (CDN \$)
2001				
1st Quarter	5.63	3.69	6.50	5.05
2nd Quarter	8.99	4.00	N/A	N/A
3rd Quarter	7.34	3.95	N/A	N/A
4th Quarter	7.35	4.66	N/A	N/A
2002				
1st Quarter	6.49	4.20	N/A	N/A
2nd Quarter	6.85	5.20	N/A	N/A
3rd Quarter	5.75	3.65	N/A	N/A
4th Quarter	5.05	3.61	N/A	N/A

As of March 10, 2003, there were approximately 572 common stockholders of record.

The Company has not paid dividends on the common stock and intends to retain its cash flow from operations for the future operation and development of its business. In addition, the Company's credit facility with a group of three banks restricts the declaration or payment of any dividends or distributions without prior written consent of certain members of the bank group.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth, as of the dates and for the periods indicated, selected financial information for the Company. The financial information for each of the five years in the period ended December 31, 2002 have been derived from the audited Consolidated Financial Statements of the Company for such periods. The information should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Consolidated Financial Statements and notes thereto. The following information is not necessarily indicative of future results of the Company. All amounts are stated in U.S. dollars unless otherwise indicated.

	Years Ended December 31,				
	2002	2001 (a)	2000 (a)	1999 (a)	1998 (a)
	(in thousands except share data)				
Revenues	\$ 48,141	\$ 55,281	\$ 22,561	\$ 8,607	\$ 3,377
Net Income (Loss)	2,307	11,645	9,924	(310)	(16,240)
Net Income (Loss) per share:					
Basic	0.06	0.37	0.37	(0.01)	(1.20)
Diluted	0.06	0.34	0.35	(0.01)	(1.20)
Oil and Gas Properties, net	120,746	101,029	56,344	21,490	17,423
Total Assets	132,063	114,639	83,072	29,901	20,066
Long-term Debt	2,400	33,000	6,804	2,927	1,300
Stockholders' Equity	97,770	54,215	41,456	18,105	13,336

(a) The Company's financial statements for 1998-2001 were audited by Arthur Andersen LLP, who has ceased operations.

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

General

PetroQuest is an independent oil and gas company engaged in the exploration, development, acquisition and operation of oil and gas properties onshore and offshore in the Gulf Coast Region. We have been active in this area since 1986, which gives us extensive geophysical, technical and operational expertise in this area. Our business strategy is to increase production, cash flow and reserves through exploration, development and acquisition of properties located in the Gulf Coast Region.

New Accounting Standards

In June 2001, the Financial Accounting Standards Board issued SFAS 143, "Accounting for Asset Retirement Obligations," which requires recording the fair value of an asset retirement obligation associated with tangible long-lived assets in the period incurred. Retirement obligations associated with long-lived assets included within the scope of SFAS 143 are those for which there is a legal obligation to settle under existing or enacted law, statute, written or oral contract or by legal construction under the doctrine of promissory estoppel. We will record the fair value of these obligations on January 1, 2003, and will record the related additional assets. The estimated fair value of the obligations at January 1, 2003 is approximately \$9,500,000. The net difference between our previously recorded abandonment liability and the amounts estimated under SFAS 143, after taxes, is expected to total a gain of approximately \$850,000, which will be recognized as a cumulative effect of a change in accounting principle.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure – an amendment of SFAS No. 123." SFAS No. 148 amends SFAS No. 123 to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, this statement amends the disclosure requirements of SFAS No. 123 to require disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on the reported results. SFAS No. 148 is effective for the year ended December 31, 2002 and for interim financial statements commencing in 2003. Our adoption of this pronouncement did not have an impact on financial condition or results of operations.

Critical Accounting Policies

Full Cost Method of Accounting

We use the full cost method of accounting for our investments in oil and gas properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs, incurred for the purpose of exploring for and developing and oil and natural gas are capitalized. Acquisition costs include costs incurred to purchase, lease or otherwise acquire property. Exploration costs include the costs of drilling exploratory wells, including those in progress and geological and geophysical service costs in exploration activities. Development costs include the costs of drilling development wells and costs of completions, platforms, facilities and pipelines. Costs associated with production and general corporate activities are expensed in the period incurred. Sales of oil and gas properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas.

The costs associated with unevaluated properties are not initially included in the amortization base and related to unevaluated leasehold acreage and delay rentals, seismic data and capitalized interest. These costs are either transferred to the amortization base with the costs of drilling the related well or are assessed quarterly for possible impairment or reduction in value.

We compute the provision for depletion of oil and gas properties using the unit-of-production method based upon production and estimates of proved reserve quantities. Unevaluated costs and related carrying costs are excluded from the amortization base until the properties associated with these costs are evaluated. In addition to costs associated with evaluated properties, the amortization base includes estimated future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values. Our depletion expense is affected by the estimates of future development costs, unevaluated costs and proved reserves, and changes in these estimates could have an impact on our future earnings.

We capitalize certain internal costs that are directly identified with the acquisition, exploration and development activities. The capitalized internal costs include salaries, employee benefits, costs of consulting services and other related expenses and do not include costs related to production, general corporate overhead or similar activities. We also capitalize a portion of the interest costs incurred on our debt. Capitalized interest is calculated using the amount of our unevaluated property and our effective borrowing rate.

Capitalized costs of oil and gas properties, net of accumulated DD&A and related deferred taxes, are limited to the estimated future net cash flows from proved oil and gas reserves, discounted at 10 percent, plus the lower of cost or fair value of unproved properties, as adjusted for related income tax effects (the full cost ceiling). If capitalized costs exceed the full cost ceiling, the excess is charged to write-down of oil and gas properties in the quarter in which the excess occurs.

Given the volatility of oil and gas prices, it is probable that our estimate of discounted future net cash flows from proved oil and gas reserves will change in the near term. If oil or gas prices decline, even for only a short period of time, or if we have downward revisions to our estimated proved reserves, it is possible that write-downs of oil and gas properties could occur in the future.

Future Abandonment Costs

Future abandonment costs include costs to dismantle and relocate or dispose of our production platforms, gathering systems, wells and related structures and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon the type of production structure, depth of water, reservoir characteristics, depth of the reservoir, market demand for equipment, currently available procedures and consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. The accounting for future abandonment costs changed on January 1, 2003, with the adoption of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations." See New Accounting Standards in the Notes to Consolidated Financial Statements for a further discussion of this accounting standard.

Reserve Estimates

Our estimates of oil and gas reserves are, by necessity, projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable oil and gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effect of regulations by governmental agencies, and assumptions governing future oil and gas prices, future operating costs, severance taxes, development costs and workover costs, all of which may in fact vary considerably from actual results. The future drilling costs associated with reserves assigned to proved undeveloped locations may ultimately increase to the extent that these reserves may be later determined to be uneconomic. For these reasons, estimates of the economically recoverable quantities of expected oil and gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of our oil and gas properties and/or the rate of depletion of such oil and gas properties. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variance may be material.

Derivative Instruments

The estimated fair values of our commodity derivative instruments are recorded in the consolidated balance sheet. All of our commodity derivative instruments represent hedges of the price of future oil and gas production. The changes in fair value of those derivative instruments that qualify for treatment due to being highly effective are recorded to Other Comprehensive Income until the hedged oil or natural gas quantities are produced.

Estimating the fair values of hedging derivatives requires complex calculations incorporating estimates of future prices, discount rates and price movements. Instead, we choose to obtain the fair value of our commodity derivatives from the counter parties to those contracts. Since the counter parties are market makers, they are able to provide us with a literal market value, or what they would be willing to settle such contracts for as of the given date.

Results of Operations

The following table sets forth certain operating information with respect to our oil and gas operations for the years ended December 31, 2002, 2001 and 2000:

	Year Ended December 31,		
	2002	2001	2000
Production:			
Oil (Bbls)	929,181	791,405	160,631
Gas (Mcf)	7,765,142	9,025,240	3,984,461
Total Production (Mcf)	13,340,228	13,773,670	4,948,246
Sales:			
Total oil sales	\$ 23,294,514	\$ 20,171,659	\$ 4,809,382
Total gas sales	24,846,723	34,794,876	17,457,307
Average sales prices:			
Oil (per Bbl)	\$ 25.07	\$ 25.49	\$ 29.94
Gas (per Mcf)	3.20	3.86	4.38
Per Mcfe	3.61	3.99	4.50

The above sales include income related to gas hedges of (\$733,000) and \$1,247,000 and oil hedges of (\$128,000) and \$384,000 for the years ended December 31, 2002 and 2001, respectively. We were not hedged during 2000.

Comparison of Results of Operations for the Years Ended December 31, 2002 and 2001

Net income totaled \$2,307,000 and \$11,645,000 for the years ended December 31, 2002 and 2001, respectively. The results are attributable to the following components:

Production

Oil production in 2002 increased 17% over the year ended December 31, 2001. Natural gas production in 2002 decreased 14% over the year ended December 31, 2001. On a Mcfe basis, total production for the year ended December 31, 2002 decreased 3% over the same period in 2001. The decrease in 2002 total production volumes, as compared to 2001, was due to the consistent decline of our Gulf Coast production partially offset by the drilling success during 2002.

Prices

Average oil prices per Bbl during 2002 were \$25.07 as compared to \$25.49 for the same period in 2001. Average gas prices per Mcf were \$3.20 during 2002 as compared to \$3.86 for the same period in 2001. Stated on a Mcfe basis, unit prices received during 2002 were 10% lower than the prices received during 2001.

Revenue

Oil and gas sales during 2002 decreased 12% to \$48,141,000 as compared to 2001 revenues of \$54,967,000. The slight decrease in production volumes and reduced commodity prices resulted in the decrease in revenue.

Expenses

Lease operating expenses for 2002 increased to \$9,988,000 from \$7,172,000 during 2001. On a Mcfe basis, lease operating expenses increased from \$0.52 per Mcfe in 2001 to \$0.75 in 2002. The increase during 2002 is primarily due to increased insurance costs and an increase in the repairs and maintenance at the Ship Shoal 72 Field.

General and administrative expenses during 2002 totaled \$5,009,000 as compared to expenses of \$4,752,000 during 2001, net of amounts capitalized of \$3,664,000 and \$2,651,000, respectively. The increases in general and administrative expenses are primarily due to an increase in staffing levels and rent expense related to the generation of prospects, exploration for oil and gas reserves and operation of properties. We recognized \$345,000 and \$765,000 of non-cash compensation expense during 2002 and 2001, respectively.

Depreciation, depletion and amortization ("DD&A") expense for 2002 increased 22% to \$28,196,000 as compared to \$23,094,000 in 2001. On a Mcfe basis, which reflects the changes in production, the DD&A rate for 2002 was \$2.11 per Mcfe as compared to \$1.68 per Mcfe for 2001. The increase in 2002 as compared to 2001 is due primarily to costs in excess of previous estimates during the previous twelve months and unsuccessful exploration drilling results during 2002.

Interest expense, net of amounts capitalized on unevaluated prospects, decreased \$1,833,000 during 2002 as compared to 2001. The decrease is the result of an decrease in the average debt levels and interest rates during 2002. We capitalized \$619,000 and \$1,001,000 of interest during 2002 and 2001, respectively.

Income tax expense of \$1,288,000 was recognized during 2002 as compared to \$5,411,000 being recorded during 2001. The decrease is due to a decrease in operating profit during the current year. We provide for income taxes at a statutory rate of 37% adjusted for permanent differences expected to be realized, primarily statutory depletion.

Comparison of Results of Operations for the Years Ended December 31, 2001 and 2000

Net income totaled \$11,645,000 and \$9,924,000 for the years ended December 31, 2001 and 2000, respectively. The positive results are attributable to the following components:

Production

Oil production in 2001 increased 393% over the year ended December 31, 2000. Natural gas production in 2001 increased 127% over the year ended December 31, 2000. On a Mcfe basis, production for the year ended December 31, 2001 increased 178% over the same period in 2000. The increase in 2001 production volumes, as compared to 2000, was due to our successful drilling program, which had a 77% success rate completing 10 of 13 wells drilled in 2001.

Prices

Average oil prices per Bbl during 2001 were \$25.49 as compared to \$29.94 for the same period in 2000. Average gas prices per Mcf were \$3.86 during 2001 as compared to \$4.38 for the same period in 2000. Stated on a Mcfe basis, unit prices received during 2001 were 11% lower than the prices received during 2000.

Revenue

Oil and gas sales during 2001 increased 147% to \$54,967,000 as compared to 2000 revenues of \$22,267,000. The significant growth in production volumes partially offset by reduced commodity prices resulted in significant increases in revenue.

Expenses

Lease operating expenses for 2001 increased to \$7,172,000 from \$2,831,000 during 2000. The increase during 2001 is primarily due to the 178% increase in production on a Mcfe basis. On a Mcfe basis, lease operating expenses decreased from \$0.57 per Mcfe in 2000 to \$0.52 in 2001.

General and administrative expenses during 2001 totaled \$4,752,000 as compared to expenses of \$3,248,000 during 2000, net of amounts capitalized of \$2,651,000 and \$2,084,000, respectively. The increases in general and administrative expenses are primarily due to an 33% increase in staffing levels related to the generation of prospects, exploration for oil and gas reserves and operation of properties. Additionally, we have recognized \$765,000 of non-cash compensation expense during 2001. As a result of extending the life of two directors' options, we recognized \$413,000 of non-cash compensation expense during the fourth quarter. We also recognized \$352,000 of non-cash compensation expense related to the amortization of unearned deferred compensation.

Depreciation, depletion and amortization ("DD&A") expense for 2001 increased 265% to \$23,094,000 as compared to \$6,386,000 in 2000. The rise in DD&A is primarily due to increased production from bringing new wells on-line since the first quarter of 2000. On a Mcfe basis, which reflects the changes in production, the DD&A rate for 2001 was \$1.68 per Mcfe as compared to \$1.29 per Mcfe for 2000. The increase in 2001 as compared to 2000 is due primarily to the significant capital and future development costs related to our offshore projects.

Interest expense, net of amounts capitalized on unevaluated prospects, increased \$2,033,000 during 2001 as compared to 2000. The increase is the result of an increase in debt levels during 2001 resulting from property acquisitions and a higher capital budget, which has been partially funded by borrowings. We capitalized \$1,001,000 and \$439,000 of interest during 2001 and 2000, respectively.

Income tax expense of \$5,411,000 was recognized during 2001 as compared to an \$850,000 benefit being recorded during 2000. The increase is the result of fully reversing the valuation allowance on our deferred tax asset during 2000. We provide for income taxes at a statutory rate of 37% adjusted for permanent differences expected to be realized, primarily statutory depletion.

Liquidity and Capital Resources

We have financed our exploration and development activities to date principally through cash flow from operations, bank borrowings, private and public offerings of common stock and sales of properties.

Source of Capital: Operations

Net cash flow from operations during the year decreased from \$40,869,000 in 2001 to \$29,178,000 in 2002. This decrease resulted primarily from a decrease in the average realized commodity prices. Working capital (before considering debt) increased from \$(10.4) million at December 31, 2001 to \$(9.2) million at December 31, 2002. This was caused primarily by the reduction of payables from our fourth quarter 2002 common stock offering.

Source of Capital: Debt

PetroQuest and our subsidiary PetroQuest Energy, L.L.C. (the "Borrower") have a \$100 million revolving credit facility with a group of three banks which permits us to borrow amounts from time to time based on our available borrowing base as determined in the credit facility. The credit facility is secured by a mortgage on substantially all of the Borrower's oil and gas properties, a pledge of the membership interest of the Borrower and PetroQuest's corporate guarantee of the indebtedness of the Borrower. The borrowing base under this credit facility is based upon the valuation on March 31 and September 30 of the Borrower's mortgaged properties, projected oil and gas prices, and any other factors deemed relevant by the lenders. We or the lenders may also request additional borrowing base redeterminations. On September 30, 2002, the borrowing base under the credit facility was adjusted to \$25 million and is subject to quarterly reductions of \$5 million commencing on January 31, 2003.

Outstanding balances on the revolving credit facility bear interest at either the prime rate (plus 0.375% per year whenever the borrowing base usage under the credit facility is greater than or equal to 90%) or the Eurodollar rate plus a margin (based on a sliding scale of 1.625% to 2.375% depending on borrowing base usage). The credit facility also allows us to use up to \$10 million of the borrowing base for letters of credit for fees of 2% per annum. At December 31, 2002, we had \$9 million of borrowings and a \$2.6 million letter of credit issued pursuant to the credit facility.

The credit facility contains covenants and restrictions common to borrowings of this type, including maintenance of certain financial ratios. We were in compliance with all of our covenants at December 31, 2002. The credit facility matures on June 30, 2004.

Source of Capital: Issuance of Equity Securities

We have an effective universal shelf registration statement relating to the potential public offer and sale by PetroQuest of any combination of debt securities, common stock, preferred stock, depositary shares, and warrants from time to time or when financing needs arise. The registration statement does not provide assurance that we will or could sell any such securities.

During October and November 2002, we completed the offering of 5,000,000 shares of our common stock. The shares were sold to the public for \$4.25 per share. After underwriting discounts, we realized proceeds of approximately \$20.4 million.

During February and March 2002, we completed the offering of 5,193,600 shares of our common stock. The shares were sold to the public for \$4.40 per share. After underwriting discounts, we realized proceeds of approximately \$21.9 million.

Source of Capital: Sales of Properties

On March 1, 2002, we closed the sale of our interest in Valentine Field for \$18.6 million. The transaction had an effective date of January 1, 2002. At December 31, 2001, our independent reservoir engineering firm attributed 7.3 Bcfe of proved reserves net to our interest in this field. Consistent with the full cost method of accounting, we did not recognize any gain or loss as a result of this sale. The proceeds were treated as a reduction of the full cost pool.

Use of Capital: Exploration and Development

We have an exploration and development program budget for the year 2003 which will require significant capital. Our capital budget for direct capital for new projects in 2003 is approximately \$25 million. Our management believes the cash flows from operations and available borrowing capacity under our credit facility, after the March 31 and September 30 regularly scheduled redeterminations, will be sufficient to fund planned 2003 exploration and development activities. Currently, the borrowing base is scheduled to be reduced to \$5 million as of December 31, 2003. Management believes that the regularly scheduled redeterminations will generate an increased borrowing capacity above such amount at year-end. In the future, our exploration and development activities could require additional financings, which may include sales of additional equity or debt securities, additional bank borrowings, sales of properties, or joint venture arrangements with industry partners. We cannot assure you that such additional financings will be available on acceptable terms, if at all. If we are unable to obtain additional financing, we could be forced to delay or even abandon some of our exploration and development opportunities or be forced to sell some of our assets on an untimely or unfavorable basis.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISKS

The Company experiences market risks primarily in two areas: interest rates and commodity prices. The Company believes that its business operations are not exposed to significant market risks relating to foreign currency exchange risk.

The Company's revenues are derived from the sale of its crude oil and natural gas production. Based on projected annual sales volumes for 2003, a 10% decline in the estimated average 2003 prices the Company receives for its crude oil and natural gas production would have an approximate \$5.7 million impact on the Company's revenues.

In a typical hedge transaction, the Company will have the right to receive from the counterparts to the hedge, the excess of the fixed price specified in the hedge over a floating price based on a market index, multiplied by the quantity hedged. If the floating price exceeds the fixed price, the Company is required to pay the counterparts this difference multiplied by the quantity hedged. The Company is required to pay the difference between the floating price and the fixed price (when the floating price exceeds the fixed price) regardless of whether the Company has sufficient production to cover the quantities specified in the hedge. Significant reductions in production at times when the floating price exceeds the fixed price could require the Company to make payments under the hedge agreements even though such payments are not offset by sales of production. Hedging will also prevent the Company from receiving the full advantage of increases in oil or gas prices above the fixed amount specified in the hedge. As of December 31, 2002, the Company had open fixed price swap contracts with third parties, whereby a fixed price has been established for a certain period. These agreements in effect for 2003 are for oil volume of 1,000 barrels per day at a weighted average price of \$25.75, and gas volume of 7,000Mmbtu per day at a weighted average price of \$4.02. At December 31, 2002, the Company recognized a liability of \$1,841,000 related to these derivative instruments, which have been designated as cash flow hedges.

We currently have two interest rate swaps covering \$5 million of our floating rate debt. The swaps which expire in November 2003 and 2004 have fixed interest rates of 4.56% and 4.25%-5.665%, respectively. The swaps are stated at their fair value and are marked-to-market through other income in our income statement. As of December 31, 2002, the fair value of the open interest rate swaps was a liability of \$477,000.

The Company also evaluated the potential effect that reasonably possible near term changes may have on the Company's credit facility. Debt outstanding under the facility is subject to a floating interest rate and represents 100% of the Company's total debt as of December 31, 2002. Based upon an analysis utilizing the actual interest rate in effect and balances outstanding as of December 31, 2002 and assuming a 10% increase in interest rates and no changes in the amount of debt outstanding, the potential effect on interest expense for 2003 is approximately \$34,000.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information concerning this Item begins on page F-1.

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

Previously reported on Form 8-K, dated July 1, 2002.

PART III

ITEMS 10, 11, 12 & 13

For information concerning Item 10. Directors and Executive Officers of the Registrant, Item 11. Executive Compensation, Item 12. Security Ownership of Certain Beneficial Owners and Management and Item 13. Certain Relationships and Related Transactions, see the definitive Proxy Statement of PetroQuest Energy, Inc. relating to the Annual Meeting of Stockholders to be held May 7, 2003, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

ITEM 14. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Within 90 days prior to the filing date of this Form 10-K, our principal executive officer ("CEO") and principal financial officer ("CFO") carried out an evaluation of the effectiveness of PetroQuest's disclosure controls and procedures. Based on those evaluations, the CEO and CFO believe

- i. that our disclosure controls and procedures are designed to ensure that information required to be disclosed by PetroQuest in the reports it files under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to the PetroQuest's management, including the CEO and CFO, as appropriate to allow timely decisions regarding required disclosure; and
- ii. that our disclosure controls and procedures are effective.

Changes in Internal Controls

There have been no significant changes in our internal controls or in other factors that could significantly affect our internal controls subsequent to the evaluation referred to above, nor have there been any corrective actions with regard to significant deficiencies or material weaknesses.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) 1. FINANCIAL STATEMENTS

The following financial statements of the Company and the Report of the Company's Independent Public Accountants thereon are included on pages F-1 through F-19 of this Form 10-K.

Report of Independent Auditors
Report of Independent Public Accountants
Consolidated Balance Sheets as of December 31, 2002 and 2001
Consolidated Statements of Operations for the three years ended December 31, 2002
Consolidated Statements of Stockholder's Equity for the three years ended December 31, 2002
Consolidated Statements of Cash Flows for the three years ended December 31, 2002
Notes to Consolidated Financial Statements

2. FINANCIAL STATEMENT SCHEDULES:

All schedules are omitted because the required information is inapplicable or the information is presented in the Financial Statements or the notes thereto.

3. EXHIBITS:

- 2.1 Plan and Agreement of Merger by and among Optima Petroleum Corporation, Optima Energy (U.S.) Corporation, its wholly-owned subsidiary, and Goodson Exploration Company, NAB Financial L.L.C., Dexco Energy, Inc., American Explorer, L.L.C. (incorporated herein by reference to Appendix G of the Proxy Statement on Schedule 14A filed July 22, 1998).
- 3.1 Certificate of Incorporation of the Company (incorporated herein by reference to Exhibit 4.1 to Form 8-K dated September 16, 1998)
- 3.2 Bylaws of the Company (incorporated herein by reference to Exhibit 4.2 to Form 8-K dated September 16, 1998).
- 3.3 Certificate of Domestication of Optima Petroleum Corporation (incorporated herein by reference to Exhibit 4.4 to Form 8-K dated September 16, 1998).

- 3.4 Certificate of Designations, Preferences, Limitations And Relative Rights of The Series a Junior Participating Preferred Stock of PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit A of the Rights Agreement attached as Exhibit 1 to Form 8-A filed November 9, 2001).
- 4.1 Form of Certificate of Contingent Stock Issue Right (incorporated herein by reference to Exhibit 4.3 to Form 8-K dated September 16, 1998).
- 4.2 Form of Warrant to Purchase Shares of Common Stock of PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 4.1 to Form 8-K dated August 9, 1999)
- 4.3 Form of Placement Agent Warrant to Purchase Shares of Common Stock of PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 4.2 to Form 8-K dated August 9, 1999)
- 4.4 Rights Agreement dated as of November 7, 2001 between PetroQuest Energy, Inc. and American Stock Transfer & Trust Company, as Rights Agent, including exhibits thereto (incorporated herein by reference to Exhibit 1 to Form 8-A filed November 9, 2001).
- 4.5 Form of Rights Certificate (incorporated herein by reference to Exhibit C of the Rights Agreement attached as Exhibit 1 to Form 8-A filed November 9, 2001).
- 10.1 PetroQuest Energy, Inc. 1998 Incentive Plan, as amended and restated effective December 1, 2000 (incorporated herein by reference to Appendix A to Proxy Statement on Schedule 14A filed April 20, 2001).
- 10.2 Amended and Restated Credit Agreement dated as of May 11, 2001, by and among PetroQuest Energy, L.L.C., a Louisiana limited liability company, PetroQuest Energy, Inc., a Delaware corporation, and Hibernia National Bank, and the Financial Institutions named therein as Lenders, and Hibernia National Bank as Administrative Agent (incorporated herein by reference to Exhibit 10.3 to Form 10-Q filed May 15, 2001).
- 10.3 Revolving Note dated May 11, 2001 in the principal amount of \$50,000,000.00 payable to Hibernia National Bank (incorporated herein by reference to Exhibit 10.4 to Form 10-Q filed May 15, 2001).
- 10.4 Revolving Note dated May 11, 2001 in the principal amount of \$25,000,000.00 payable to Union Bank of California, N.A. (incorporated herein by reference to Exhibit 10.5 to Form 10-Q filed May 15, 2001).
- 10.5 Revolving Note dated May 11, 2001 in the principal amount of \$25,000,000.00 payable to Royal Bank of Canada (incorporated herein by reference to Exhibit 10.6 to Form 10-Q filed May 15, 2001).
- 10.6 Commercial Guaranty made as of May 11, 2001, by PetroQuest Energy, Inc., a Delaware corporation, in favor of Hibernia National Bank (incorporated herein by reference to Exhibit 10.7 to Form 10-Q filed May 15, 2001).
- 10.7 Subordination Agreement effective as of May 11, 2001, by and among Hibernia National Bank, EnCap Energy Capital Fund III, L.P., PetroQuest Energy, L.L.C., a Louisiana limited liability company, and PetroQuest Energy, Inc., a Delaware corporation (incorporated herein by reference to Exhibit 10.8 to Form 10-Q filed May 15, 2001).
- 10.8 First Amendment to Amended and Restated Credit Agreement dated and effective as of July 20, 2001, among PetroQuest Energy, L.L.C., PetroQuest Energy, Inc., Royal Bank of Canada, Union Bank of California, N.A., and Hibernia National Bank, a national banking association, individually as a lender and as Administrative Agent (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed February 15, 2002).
- 10.9 Second Amendment to Amended and Restated Credit Agreement dated as of December 24, 2001, among PetroQuest Energy, L.L.C., PetroQuest Energy, Inc., Royal Bank of Canada, Union Bank of California, N.A., and Hibernia National Bank, a national banking association, individually as a lender and as Administrative Agent (incorporated herein by reference to Exhibit 10.2 to Form 8-K filed February 15, 2002).
- 10.10 Third Amendment to Amended and Restated Credit Agreement dated as of March 1, 2002, among PetroQuest Energy, L.L.C., PetroQuest Energy, Inc., Royal Bank of Canada, Union Bank of California, N.A., and Hibernia National Bank, a national banking association, individually as a lender and as Administrative Agent (incorporated herein by reference to Exhibit 10.10 to Form 10-K filed March 13, 2002).
- 10.11 Fourth Amendment to Amended and Restated Credit Agreement dated as of November 13, 2002, but effective as of September 20, 2002, among PetroQuest Energy, L.L.C., PetroQuest Energy, Inc., Royal Bank of Canada, Union Bank of California, N.A., and Hibernia National Bank, a national banking association, individually as a lender and as Administrative Agent (incorporated herein by reference to Exhibit 10.1 to Form 10-Q filed November 14, 2002).
- 10.12 Employment Agreement dated September 1, 1998, between PetroQuest Energy, Inc. and Charles T. Goodson (incorporated herein by reference to Exhibit 10.2 to Form 8-K dated September 16, 1998).
- 10.13 Employment Agreement dated September 1, 1998, between PetroQuest Energy, Inc. and Alfred J. Thomas, II (incorporated herein by reference to Exhibit 10.3 to Form 8-K dated September 16, 1998).
- 10.14 Employment Agreement dated September 1, 1998, between PetroQuest Energy, Inc. and Ralph J. Daigle (incorporated herein by reference to Exhibit 10.4 to Form 8-K dated September 16, 1998).
- 10.15 First Amendment to Employment agreement dated September 1, 1998 between PetroQuest Energy, Inc. and Charles T. Goodson dated July 30, 1999 (incorporated herein by reference to Exhibit 10.1 to For 8-K dated August 9, 1999)
- 10.16 First Amendment to Employment Agreement dated September 1, 1998 between PetroQuest Energy, Inc. and Alfred J. Thomas, II dated July 30, 1999 (incorporated herein by reference to Exhibit 10.2 to Form 8-K dated August 9, 1999).
- 10.17 First Amendment to Employment Agreement dated September 1, 1998 between PetroQuest Energy, Inc. and Ralph J. Daigle dated July 30, 1999 (incorporated herein by reference to Exhibit 10.3 to Form 8-K dated August 9, 1999).
- 10.18 Employment Agreement dated May 8, 2000 between PetroQuest Energy, Inc. and Michael O. Aldridge (incorporated by reference to Exhibit 10.1 to the Form 10-Q filed August 14, 2000).

- 10.19 Employment Agreement dated December 15, 2000 between PetroQuest Energy, Inc. and Arthur M. Mixon, III. (incorporated herein by reference to Exhibit 10.12 to Form 10-K filed March 30, 2001).
- 10.20 Employment Agreement dated April 20, 2001 between PetroQuest Energy, Inc. and Daniel G. Fournerat (incorporated herein by reference to Exhibit 10.1 to Form 10-Q filed May 15, 2001).
- * 10.21 Employment Agreement dated April 20, 2001 between PetroQuest Energy, Inc. and Dalton F. Smith III.
- 10.22 Form of Termination Agreement Between PetroQuest Energy, Inc. and each of its executive officers, including Charles T. Goodson, Alfred J. Thomas, II, Ralph J. Daigle, Michael O. Aldridge, Arthur M. Mixon, III, Daniel G. Fournerat and Dalton F. Smith III (incorporated herein by reference to Exhibit 10.20 to Form 10-K filed March 13, 2002).
- 10.23 Form of Indemnification Agreement between PetroQuest Energy, Inc. and each of its directors and executive officers, including Charles T. Goodson, Alfred J. Thomas, II, Ralph J. Daigle, Daniel G. Fournerat, E. Wayne Nordberg, Jay B. Langner, William W. Rucks, IV, Michael O. Aldridge, Arthur M. Mixon, III and Dalton F. Smith III (incorporated herein by reference to Exhibit 10.21 to Form 10-K filed March 13, 2002).
- 21.1 Subsidiaries of the Company (incorporated herein by reference to Exhibit 21.1 to Form 10-K filed March 30, 2001).
- * 23.1 Consent of Independent Auditors.
- 23.2 Consent of Arthur Andersen LLP (omitted pursuant to Rule 437a under the Securities Act of 1933, as amended).
- * 23.3 Consent of Ryder Scott Company, L.P.
- * 99.1 Certification Pursuant To 18 U.S.C. Section 1350, As Adopted Pursuant To Section 906 Of The Sarbanes-Oxley Act of 2002.
- * 99.2 Certification Pursuant To 18 U.S.C. Section 1350, As Adopted Pursuant To Section 906 Of The Sarbanes-Oxley Act of 2002

* Filed herewith.

REPORTS ON FORM 8-K

- (i) The Company filed a report on Form 8-K on October 30, 2002, relating to an underwritten public offering.
- (ii) The Company filed a report on Form 8-K on November 4, 2002, relating to the closing of an underwritten public offering.
- (iii) The Company filed a report on Form 8-K on November 6, 2002, relating to third quarter 2002 results.
- (iv) The Company filed a report on Form 8-K on November 21, 2002, relating to gas hedges for 2003 and operations updates.

GLOSSARY OF OIL AND NATURAL GAS TERMS

The following is a description of the meanings of some of the oil and natural gas used in this Form 10-K.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, of crude oil or other liquid hydrocarbons.

Bcf. Billion cubic feet of natural gas.

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

Block. A block depicted on the Outer Continental Shelf Leasing and Official Protraction Diagrams issued by the U.S. Minerals Management Service or a similar depiction on official protraction or similar diagrams issued by a state bordering on the Gulf of Mexico.

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

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

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

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

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

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

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

Farm-in or farm-out. An agreement under which the owner of a working interest in a natural gas and oil lease assigns the working interest or a portion of the working interest to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a "farm-in" while the interest transferred by the assignor is a "farm-out."

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

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Lead. A specific geographic area which, based on supporting geological, geophysical or other data, is deemed to have potential for the discovery of commercial hydrocarbons.

MBbls. Thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. Thousand cubic feet of natural gas.

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

MMBls. Million barrels of crude oil or other liquid hydrocarbons.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

MMcfe. Million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or wells, as the case may be.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

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

Proved developed non-producing reserves. Proved developed reserves expected to be recovered from zones behind casing in existing wells.

Proved developed producing reserves. Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and capable of production to market.

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

Proved reserves. The 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 and operating conditions.

Proved undeveloped reserves. Proved 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.

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

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

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

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 13, 2003.

PETROQUEST ENERGY, INC.

By: /s/ Charles T. Goodson
CHARLES T. GOODSON
Chairman of the Board and Chief
Executive Officer

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 indicated on March 13, 2003.

By: /s/ Charles T. Goodson
CHARLES T. GOODSON
Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)

By: /s/ Alfred J. Thomas, II
ALFRED J. THOMAS, II
President, Chief Operating Officer and Director

By: /s/ Ralph J. Daigle
RALPH J. DAIGLE
Executive Vice President and Director

By: /s/ Michael O. Aldridge
MICHAEL O. ALDRIDGE
Senior Vice President, Chief Financial Officer, Treasurer and Director (Principal Financial and Accounting Officer)

By: /s/ Jay B. Langner
JAY B. LANGNER
Director

By: /s/ E. Wayne Nordberg
E. WAYNE NORDBERG
Director

By: /s/ William W. Rucks, IV
WILLIAM W. RUCKS, IV
Director

CERTIFICATIONS

I, Charles T. Goodson, certify that:

1. I have reviewed this annual report on Form 10-K of PetroQuest Energy, Inc.;
2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;
3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:
 - a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
 - b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and
 - c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;
5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
 - a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and
6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 13, 2003

/s/ Charles T. Goodson
CHARLES T. GOODSON
Chairman and Chief Executive Officer

CERTIFICATIONS

I, Michael O. Aldridge, certify that:

1. I have reviewed this annual report on Form 10-K of PetroQuest Energy, Inc.;
2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;
3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:
 - a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
 - b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and
 - c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;
5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
 - d) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and
 - e) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and
6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 13, 2003

/s/ Michael O. Aldridge
MICHAEL O. ALDRIDGE
Senior Vice President, Chief Financial Officer
and Treasurer

INDEX TO FINANCIAL STATEMENTS

Report of Independent Auditors	40
Report of Independent Public Accountants	41
Consolidated Balance Sheets of PetroQuest Energy, Inc. as of December 31, 2002 and 2001.	42
Consolidated Statements of Operations of PetroQuest Energy, Inc. <i>for the years ended December 31, 2002, 2001 and 2000.</i>	43
Consolidated Statements of Stockholders' Equity of PetroQuest Energy, Inc. <i>for the years ended December 31, 2002, 2001 and 2000.</i>	44
Consolidated Statements of Cash Flows of PetroQuest Energy, Inc. <i>for the years ended December 31, 2002, 2001 and 2000.</i>	45
Notes to Consolidated Financial Statements	46

REPORT OF INDEPENDENT AUDITORS

To the Stockholders of
PetroQuest Energy, Inc.:

We have audited the accompanying consolidated balance sheet of PetroQuest Energy, Inc. (a Delaware corporation) as of December 31, 2002, and the related consolidated statements of operations, stockholders' equity and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit. The financial statements of PetroQuest Energy, Inc. for the years ended December 31, 2001 and 2000, were audited by other auditors who have ceased operations and whose report dated March 7, 2002, expressed an unqualified opinion on those statements and included an explanatory paragraph that disclosed the change in the Company's method of accounting for derivative instruments and hedging activities discussed in Note 2 to these financial statements.

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

In our opinion, the 2002 financial statements referred to above present fairly, in all material respects, the consolidated financial position of PetroQuest Energy, Inc. as of December 31, 2002, and the consolidated results of its operations and its cash flow for the year then ended in conformity with accounting principles generally accepted in the United States.

ERNST&YOUNG LLP

New Orleans, Louisiana
February 11, 2003

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Stockholders of
PetroQuest Energy, Inc.:

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

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of PetroQuest Energy, Inc. and subsidiaries as of December 31, 2001 and 2000, and the consolidated results of their operations and their cash flow for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As discussed in Note 2 to the consolidated financial statements effective January 1, 2001, the Company adopted SFAS 133, "Accounting for Derivatives Instruments and Hedging Activities."

ARTHUR ANDERSEN LLP

New Orleans, Louisiana
March 7, 2002

NOTE: The report of Arthur Andersen LLP presented above is a copy of a previously issued Arthur Andersen LLP report and said report has not been reissued by Arthur Andersen LLP nor has Arthur Andersen LLP provided a consent to the inclusion of its report in this Form 10-K.

PETROQUEST ENERGY, INC.
Consolidated Balance Sheets
(Amounts in Thousands)

	December 31, 2002	December 31, 2001
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 1,137	\$ 1,063
Oil and gas revenue receivable	6,500	5,582
Joint interest billing receivable	2,165	4,609
Other current assets	310	135
Total current assets	10,112	11,389
Oil and gas properties:		
Oil and gas properties, full cost method	214,543	150,726
Unevaluated oil and gas properties	15,653	14,682
Accumulated depreciation, depletion and amortization	(109,450)	(64,379)
Oil and gas properties, net	120,746	101,029
Plugging and abandonment escrow	-	1,034
Other assets, net of accumulated depreciation and amortization of \$2,851 and \$2,144, respectively	1,205	1,187
Total Assets	\$ 132,063	\$ 114,639
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	\$ 18,337	\$ 19,749
Advances from co-owners	940	2,044
Current portion of long-term debt	6,600	329
Total current liabilities	25,877	22,122
Long-term debt	2,400	19,000
Debt subsequently refinanced	-	14,000
Deferred income taxes	5,461	4,690
Other liabilities	555	612
Commitments and contingencies	-	-
Stockholders' equity:		
Common stock, \$.001 par value; authorized 75,000 shares; issued and outstanding 42,852 and 32,530 shares, respectively	43	33
Paid-in capital	106,173	64,083
Unearned deferred compensation	(337)	(682)
Other comprehensive income	(1,197)	-
Accumulated deficit	(6,912)	(9,219)
Total stockholders' equity	97,770	54,215
Total Liabilities and Stockholders' Equity	\$ 132,063	\$ 114,639

See accompanying Notes to Consolidated Financial Statements.

PETROQUEST ENERGY, INC.
Consolidated Statements of Operations
(Amounts in Thousands, Except Per Share Data)

	Year Ended December 31,		
	2002	2001	2000
Revenues:			
Oil and gas sales	\$ 48,141	\$ 54,967	\$ 22,267
Interest and other income	(461)	314	294
	47,680	55,281	22,561
Expenses:			
Lease operating expenses	9,988	7,172	2,831
Production taxes	614	1,096	944
Depreciation, depletion and amortization	28,196	23,094	6,386
General and administrative	5,009	4,752	3,248
Interest expense	278	2,111	78
	44,085	38,225	13,487
Income from operations	3,595	17,056	9,074
Income tax expense (benefit)	1,288	5,411	(850)
Net income	\$ 2,307	\$ 11,645	\$ 9,924
Earnings per common share:			
Basic	\$ 0.06	\$ 0.37	\$ 0.37
Diluted	\$ 0.06	\$ 0.34	\$ 0.35
Weighted average number of common shares:			
Basic	37,871	31,818	26,919
Diluted	39,997	34,271	28,249

See accompanying Notes to Consolidated Financial Statements.

PETROQUEST ENERGY, INC.
Consolidated Statements of Stockholders' Equity
(Amounts in Thousands, Except Share Data)

	Common Stock	Paid-In Capital	Unearned Deferred Compensation	Other Comprehensive Income	Retained Deficit	Total Stockholders' Equity
December 31, 1999	\$ 24	\$ 48,869	\$ -	\$ -	\$ (30,788)	\$ 18,105
Options and warrants exercised	1	1,586	-	-	-	1,587
Stock based employee compensation (221,500 shares)	-	555	-	-	-	555
Sale of common stock	5	11,280	-	-	-	11,285
Net income	-	-	-	\$ -	9,924	9,924
December 31, 2000	\$ 30	\$ 62,290	-	-	\$ (20,864)	\$ 41,456
Options and warrants exercised	3	1,510	(1,034)	-	-	479
Amortization of deferred compensation	-	413	352	-	-	765
Tax effect of deferred compensation	-	(130)	-	-	-	(130)
Cumulative effect of change in accounting principle, net of taxes	-	-	-	(383)	-	(383)
Amortization of derivative fair value adjustment	-	-	-	383	-	383
Net income	-	-	-	-	11,645	11,645
December 31, 2001	\$ 33	\$ 64,083	\$ (682)	\$ -	\$ (9,219)	\$ 54,215
Options and warrants exercised	-	178	-	-	-	178
Sale of common stock	10	42,040	-	-	-	42,050
Amortization of deferred compensation	-	-	345	-	-	345
Tax effect of deferred compensation	-	(128)	-	-	-	(128)
Derivative fair value adjustment	-	-	-	(1,197)	-	(1,197)
Net income	-	-	-	-	2,307	2,307
December 31, 2002	\$ 43	\$ 106,173	\$ (337)	\$ (1,197)	\$ (6,912)	\$ 97,770

See accompanying Notes to Consolidated Financial Statements.

PETROQUEST ENERGY, INC.
Consolidated Statements of Cash Flows
(Amounts in Thousands)

	Year Ended December 31,		
	2002	2001	2000
Cash flows from operating activities:			
Net income	\$ 2,307	\$ 11,645	\$ 9,924
Adjustments to reconcile net income to net cash provided by operating activities:			
Deferred tax expense (benefit)	1,288	5,411	(850)
Amortization of debt issuance costs	261	1,369	-
Compensation expense	345	765	555
Depreciation, depletion and amortization	28,196	23,094	6,386
Derivative mark to market	416	61	-
Plugging and abandonment costs	-	(28)	(89)
Changes in working capital accounts:			
Accounts receivable	(918)	(434)	(2,811)
Joint interest billing receivable	2,443	5,542	(7,961)
Accounts payable and accrued liabilities	(3,862)	(61)	15,870
Other assets	(725)	(1,011)	(1,744)
Advances from co-owners	(1,376)	(5,253)	4,140
Plugging and abandonment escrow	1,034	(539)	(240)
Other	(231)	308	(345)
Net cash provided by operating activities	29,178	40,869	22,835
Cash flows from investing activities:			
Investment in oil and gas properties	(64,324)	(66,678)	(40,972)
Sale of oil and gas properties, net	17,321	-	-
Net cash used in investing activities	(47,003)	(66,678)	(40,972)
Cash flows from financing activities:			
Exercise of options and warrants	178	671	1,587
Proceeds from borrowing	23,000	28,000	22,620
Repayment of debt	(47,329)	(9,348)	(12,812)
Issuance of common stock	42,050	-	11,285
Net cash provided by financing activities	17,899	19,323	22,680
Net increase (decrease) in cash and cash equivalents	74	(6,486)	4,543
Cash and cash equivalents balance beginning of period	1,063	7,549	3,006
Cash and cash equivalents balance end of period	\$ 1,137	\$ 1,063	\$ 7,549
Supplemental disclosure of cash flow information			
Cash paid during the period from:			
Interest	\$ 736	\$ 1,464	\$ 409
Income taxes	\$ -	\$ -	\$ -

See accompanying Notes to Consolidated Financial Statements.

PETROQUEST ENERGY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 – Organization

PetroQuest Energy, Inc. (a Delaware Corporation) ("PetroQuest" or the "Company") is an independent oil and gas company headquartered in Lafayette, Louisiana with an exploration office in Houston, Texas. It is engaged in the exploration, development, acquisition and operation of oil and gas properties onshore and offshore in the Gulf Coast Region. PetroQuest and its predecessors have been active in this area since 1986.

On December 31, 2000, the Company underwent a corporate reorganization. The Company's subsidiary, PetroQuest Energy, Inc., a Louisiana corporation, was merged into PetroQuest Energy One, L.L.C., a Louisiana limited liability company. In addition, PetroQuest Energy One, L.L.C. changed its name to PetroQuest Energy, L.L.C., a single-member Louisiana limited liability company, and PetroQuest Energy, Inc., a Delaware corporation, continues to be its sole member.

A new single-member Louisiana limited liability company called PetroQuest Oil & Gas, L.L.C. was created on December 31, 2000. PetroQuest Energy, Inc. (a Delaware corporation) is the sole member of PetroQuest Oil & Gas, L.L.C.

Note 2 – Summary of Significant Accounting Policies

Principles of Consolidation

The Consolidated Financial Statements include the accounts of the Company and its subsidiaries, PetroQuest Energy, L.L.C. and PetroQuest Oil & Gas, L.L.C. All intercompany accounts and transactions have been eliminated.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States 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 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

The Company utilizes the full cost method of accounting, which involves capitalizing all acquisition, exploration and development costs incurred for the purpose of finding oil and gas reserves including the costs of drilling and equipping productive wells, dry hole costs, lease acquisition costs and delay rentals. The Company also capitalizes the portion of general and administrative costs, which can be directly identified with acquisition, exploration or development of oil and gas properties. Unevaluated property costs are transferred to evaluated property costs at such time as wells are completed on the properties, the properties are sold, or management determines these costs to have been impaired. Interest is capitalized on unevaluated property costs.

Depreciation, depletion and amortization of oil and gas properties is computed using the unit-of-production method based on estimated proved reserves. All costs associated with evaluated oil and gas properties, including an estimate of future development, restoration, dismantlement and abandonment costs associated therewith, are included in the computation base. The costs of investments in unproved properties are excluded from this calculation until the project is evaluated and proved reserves established or impaired. Oil and gas reserves are estimated annually by independent petroleum engineers. Additionally, the capitalized costs of proved oil and gas properties cannot exceed the present value of the estimated net cash flow from its proved reserves (the full cost ceiling). Transactions involving sales of reserves in place, unless significant, are recorded as adjustments to accumulated depreciation, depletion and amortization.

Upon the acquisition or discovery of oil and gas properties, management estimates the future net costs to be incurred to dismantle, abandon and restore the property using geological, engineering and regulatory data available. Such cost estimates are periodically updated for changes in conditions and requirements. Such estimated amounts are considered as part of the full cost pool for purposes of amortization upon acquisition or discovery. Such costs are capitalized as oil and gas properties as the actual restoration, dismantlement and abandonment activities take place.

Other Assets

Other Assets consist primarily of furniture and fixtures (net of accumulated depreciation) which are depreciated over their useful lives ranging from 3-7 years and loan costs which are amortized over the life of the related loan.

Cash and Cash Equivalents

The Company considers all highly liquid investments in overnight securities made through its commercial bank accounts, which result in available funds the next business day, to be cash and cash equivalents.

Income Taxes

The Company accounts for income taxes in accordance with Statement of Financial Accounting Standards (SFAS) No. 109. Provisions for income taxes include deferred taxes resulting primarily from temporary differences due to different reporting methods for oil and gas properties for financial reporting purposes and income tax purposes. For financial reporting purposes, all exploratory and development expenditures are capitalized and depreciated, depleted and amortized on the unit-of-production method. For income tax purposes, only the equipment and leasehold costs relative to successful wells are capitalized and recovered through depreciation or depletion. Generally, most other exploratory and development costs are charged to expense as incurred; however, the Company may use certain provisions of the Internal Revenue Code which allow capitalization of intangible drilling costs where management deems appropriate. Other financial and income tax reporting differences occur as a result of statutory depletion.

Revenue Recognition

The Company records natural gas and oil revenue under the sales method of accounting. Under the sales method, the Company recognizes revenues based on the amount of natural gas or oil sold to purchasers, which may differ from the amounts to which the Company is entitled based on its interest in the properties. Gas balancing obligations as of December 31, 2002, 2001 and 2000 were not significant.

Certain Concentrations

During 2002, 66% of the Company's oil and gas production was sold to three customers. During 2001, 66% of the Company's oil and gas production was sold to four customers. During 2000, 84% of the Company's oil and gas production was sold to three customers. Based on the current demand for oil and gas, the Company does not believe the loss of any of these customers would have a significant financially disruptive effect on its business or financial condition.

Fair Value of Financial Instruments

The fair value of accounts receivable and accounts payable approximate book value at December 31, 2002 and 2001 due to the short-term nature of these accounts. The fair value of the note payable and non-recourse financing approximates book value due to the variable rate of interest charged.

Derivative Instruments

On January 1, 2001, the Company adopted Statement of Financial Accounting Standards No. 133, as amended (SFAS 133) pertaining to the accounting for derivative instruments and hedging activities. SFAS 133 requires an entity to recognize all of its derivatives as either assets or liabilities on its balance sheet and measure those instruments at fair value. If the conditions specified in SFAS 133 are met, those instruments may be designated as hedges. Changes in the value of hedge instruments would not impact earnings, except to the extent that the instrument is not perfectly effective as a hedge.

The Company recognized \$861,000 and \$1,630,000 in oil and gas revenues during the years ended December 31, 2002 and 2001, respectively as a result of the settlement of costless collars. As of December 31, 2002, the Company had open fixed price swap contracts with third parties, whereby a fixed price has been established for a certain period. These agreements in effect for 2003 are for oil volume of 1,000 barrels per day at a weighted average price of \$25.75, and gas volume of 7,000Mmbtu per day at a weighted average price of \$4.02. At December 31, 2002, the Company recognized a liability of \$1,841,000 related to these derivative instruments, which have been designated as cash flow hedges.

The Company currently has two interest rate swaps covering \$5 million of our floating rate debt. The swaps which expire in November 2003 and 2004 have fixed interest rates of 4.56% and 4.25%-5.665%, respectively. The swaps are stated at their fair value and are marked-to-market through other income in the Company's income statement. As of December 31, 2002, the fair value of the open interest rate swaps was a liability of \$477,000.

New Accounting Standards

In June 2001, the Financial Accounting Standards Board issued SFAS 143, "Accounting for Asset Retirement Obligations," which requires recording the fair value of an asset retirement obligation associated with tangible long-lived assets in the period incurred. Retirement obligations associated with long-lived assets included within the scope of SFAS 143 are those for which there is a legal obligation to settle under existing or enacted law, statute, written or oral contract or by legal construction under the doctrine of promissory estoppel. The

Company will record the fair value of these obligations on January 1, 2003, and will record the related additional assets. The estimated fair value of the obligations at January 1, 2003 is approximately \$9,500,000. The net difference between the Company's previously recorded abandonment liability and the amounts estimated under SFAS 143, after taxes, is expected to total a gain of approximately \$850,000, which will be recognized as a cumulative effect of a change in accounting principle.

Earnings per Common Share Amounts

Basic earnings or loss per common share was computed by dividing net income or loss by the weighted average number of shares of common stock outstanding during the year. Diluted earnings or loss per common share is determined on a weighted average basis using common shares issued and outstanding adjusted for the effect of stock options considered common stock equivalents computed using the treasury stock method.

Options to purchase 273,667 shares of common stock at \$5.56 to \$7.65 per share were outstanding during 2002 but were not included in the computation of diluted earnings per share because the options' exercise prices were greater than the average market price of the common shares. Options to purchase 180,000 shares of common stock at \$5.89 to \$7.65 per share were outstanding during 2001 but were not included in the computation of diluted earnings per share because the options' exercise prices were greater than the average market price of the common shares. Options to purchase 682,500 shares of common stock at \$3.13 to \$3.44 per share were outstanding during 2000 but were not included in the computation of diluted earnings per share because the options' exercise prices were greater than the average market price of the common shares. The contingent stock rights assigned in connection with a Company merger (see Note 3) were also excluded from the calculation of diluted earnings per share prior to their issuance.

Stock-based Compensation

The Company accounts for its stock-based compensation plans under the principles prescribed by the Accounting Principles Board's Opinion No. 25 ("APB No. 25"), "Accounting for Stock Issued to Employees." See Note 10 for the Company's disclosure of stock-based compensation under SFAS No. 123.

Note 3 – Equity

Other Comprehensive Income

The following table presents a recap of the Company's comprehensive income for years ended December 31, 2002 and 2001 (in thousands):

	Year Ended December 31,	
	2002	2001
Net income	\$ 2,307	\$ 11,645
Cumulative effect of change in accounting principle, net of taxes	-	(383)
Change in fair value of derivative instrument, accounted for as hedges, net of taxes	(1,197)	383
Comprehensive income	\$ 1,110	\$ 11,645

The Company accounts for derivatives in accordance with Statement of Financial Accounting Standards No. 133, as amended (SFAS 133). When the conditions specified in SFAS 133 are met, the Company may designate these derivatives as hedges. As of December 31, 2002, the Company had fixed price swap contracts with third parties, whereby a fixed price has been established for a certain period. At December 31, 2002, the effect of derivative financial instruments is net of deferred income tax benefit of \$644,000.

Unearned Deferred Compensation

In April 2001, the Original Owners of American Explorer L.L.C. entered into an agreement with an officer of the Company whereby the Original Owners granted to the officer an option to acquire, at a fixed price, certain of the original shares the Original Owners were issued in the Merger. As the fixed price of the April grant was below the market price as of the date of grant, the Company is recognizing non-cash compensation expense over the three-year vesting period of the option. In addition, the Original Owners granted to the officer an interest in a portion of the Common Stock issuable pursuant to the CSIRs, if any, that might be issued. This agreement is similar to agreements previously entered into with two other officers of the Company. Non-cash compensation expense is being recognized for the Common Stock issuable pursuant to the CSIRs granted to the three officers over the three-year vesting period based on the fair value of the Common Stock issuable pursuant to the CSIRs in May 2001, when the Common Stock issuable pursuant to the CSIRs was issued to the Original Owners. The Company has recorded the effects of the transactions as deferred compensation until fully amortized. We recognized \$345,000 and \$765,000, respectively of non-cash compensation expense during the years ended December 31, 2002 and 2001.

Common Stock Issue Rights

Pursuant to a Company merger, the Company issued to the original owners of American Explorer L.L.C. and their respective affiliates, certain of whom currently serve as officers and directors of the Company, 7,335,001 shares of the Company's common stock, par value \$.001 per share (the "Common Stock"), and 1,667,001 Contingent Stock Issue Rights (the "CSIRs"). The CSIRs entitled the holders to receive an additional 1,667,001 shares of Common Stock at such time within three years of the anniversary date of the issuance of the CSIRs if the trading price for the Common Stock closed at \$5.00 or higher for 20 consecutive trading days. On May 3, 2001 the Common Stock closed higher than \$5.00 for the twentieth consecutive trading day, and 1,667,001 shares of Common Stock were issued under the terms of the CSIRs.

Note 4 – Debt

PetroQuest and our subsidiary PetroQuest Energy, L.L.C. (the "Borrower") have a \$100 million revolving credit facility with a group of three banks which permits us to borrow amounts from time to time based on our available borrowing base as determined in the credit facility. The credit facility is secured by a mortgage on substantially all of the Borrower's oil and gas properties, a pledge of the membership interest of the Borrower and PetroQuest's corporate guarantee of the indebtedness of the Borrower. The borrowing base under this credit facility is based upon the valuation on March 31 and September 30 of the Borrower's mortgaged properties, projected oil and gas prices, and any other factors deemed relevant by the lenders. We or the lenders may also request additional borrowing base redeterminations. On September 30, 2002, the borrowing base under the credit facility was adjusted to \$25 million and is subject to quarterly reductions of \$5 million commencing on January 31, 2003. As of December 31, 2002, \$9 million is outstanding under the credit facility and \$2.4 million is classified as long term reflecting the remaining borrowing base at December 31, 2003.

Outstanding balances on the revolving credit facility bear interest at either the prime rate (plus 0.375% per year whenever the borrowing base usage under the credit facility is greater than or equal to 90%) or the Eurodollar rate plus a margin (based on a sliding scale of 1.625% to 2.375% depending on borrowing base usage). The credit facility also allows us to use up to \$10 million of the borrowing base for letters of credit for fees of 2% per annum. At December 31, 2002, we had \$9 million of borrowings and a \$2.6 million letter of credit issued pursuant to the credit facility.

The credit facility contains covenants and restrictions common to borrowings of this type, including maintenance of certain financial ratios. We were in compliance with all of our covenants at December 31, 2002. The credit facility matures on June 30, 2004.

Note 5 – Related Party Transactions

Certain of the Company's executive officers and directors or their affiliates are working interest owners or overriding royalty interest owners in particular properties operated by the Company. In their capacity as working interest owners, they are required to pay their proportionate share of all costs and are entitled to receive their proportionate share of revenues in the normal course of business. As overriding royalty interest owners they are entitled to receive their proportionate share of revenues in the normal course of business.

Note 6 – Common Stock and Warrants

During October and November 2002, the Company completed the offering of 5,000,000 shares of its common stock. The shares were sold to the public for \$4.25 per share. After underwriting discounts, the Company realized proceeds of approximately \$20.4 million.

During February and March 2002, the Company completed the offering of 5,193,600 shares of its common stock. The shares were sold to the public for \$4.40 per share. After underwriting discounts, the Company realized proceeds of approximately \$21.9 million.

On July 20, 2000, the Company completed a private placement of 4.89 million shares of common stock to accredited investors at a purchase price of \$2.50 per share for a total consideration of \$12,225,000 before fees and expenses. After fees and expenses, including \$644,168 in commissions, proceeds to the Company were \$11,294,000. The Company subsequently registered the resale of the common stock with the Securities and Exchange Commission on Form S-3.

In August 1999, the Company received the funding of a private placement of 5 million units at a purchase price of \$1.00 per unit for a total consideration of \$5,000,000 before fees and expenses. Each unit sold in the private placement consisted of one share of the Company's common stock and one warrant exercisable to purchase one-half a share of the Company's common stock. Each warrant is exercisable at any time through the fourth year after issuance to purchase one-half of a share of the Company's common stock at a per share purchase price of \$1.25. At December 31, 2002, there were 1,647,500 warrants outstanding.

Note 7 – Investment in Oil and Gas Properties

The following table discloses certain financial data relative to the Company's evaluated oil and gas producing activities, which are located onshore and offshore the continental United States:

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities
(amounts in thousands)

	2002	2001	2000
Acquisition costs:			
Proved	\$ 1,023	\$ 11,928	\$ 6,154
Unproved	6,052	1,250	4,670
Exploration costs	16,183	7,280	9,625
Development costs	37,247	43,424	18,000
Other costs	4,283	3,652	2,523
Total costs incurred	\$ 64,788	\$ 67,534	\$ 40,972

Other costs for the year ended December 31, 2002 include \$3,664,000 and \$619,000 of capitalized general and administrative costs and interest costs respectively. Other costs for the year ended December 31, 2001 include \$2,651,000 and \$1,001,000 of capitalized general and administrative costs and interest costs respectively. Other costs for the year ended December 31, 2000 include \$2,084,000 and \$439,000 of capitalized general and administrative costs and interest costs respectively.

At December 31, 2002 and 2001, unevaluated oil and gas properties with capitalized costs of \$15,653,000 and \$14,682,000 respectively, were not subject to depletion. Of the \$15,653,000 of unevaluated oil and gas property costs at December 31, 2002, not subject to depletion, \$6,730,000 was incurred in 2002, \$3,932,000 was incurred in 2001 and \$4,991,000 was incurred in prior years. Of the \$14,682,000 of unevaluated oil and gas property costs at December 31, 2001, not subject to depletion, \$6,485,000 was incurred in 2001 and \$8,197,000 was incurred in prior years. Management expects that these properties will be evaluated over the next one to three years.

Note 8 – Income Taxes

The Company follows the provisions of SFAS No. 109, "Accounting For Income Taxes," which provides for recognition of a deferred tax asset for deductible temporary timing differences, operating loss carryforwards, statutory depletion carryforwards and tax credit carryforwards net of a "valuation allowance." An analysis of the Company's deferred taxes follows (amounts in thousands):

	December 31,	
	2002	2001
Net operating loss carryforwards	\$ 13,829	\$ 12,205
Percentage depletion carryforward	1,291	1,161
Alternative minimum tax credit	4	16
Deferred Compensation	(258)	(130)
Temporary differences:		
Oil and gas properties - full cost	(21,126)	(18,096)
Derivative mark to market	644	-
Compensation expense	153	153
	\$ (5,463)	\$ (4,691)

For tax reporting purposes, the Company had operating loss carryforwards of \$37,376,000 and \$32,986,000 at December 31, 2002 and 2001 respectively. If not utilized, such carryforwards would begin expiring in 2009 and would completely expire by the year 2022. The Company had available for tax reporting purposes \$3,688,000 in statutory depletion deductions that may be carried forward indefinitely.

Income tax expense (benefit) for each of the years ended December 31, 2002, 2001 and 2000 (amounts in thousands) was different than the amount computed using the Federal statutory rate (35%) for the following reasons:

	For the Year-Ended December 31,		
	2002	2001	2000
Amount computed using the statutory rate	\$ 1,258	\$ 5,970	\$ 3,176
Increase (reduction) in taxes resulting from:			
State & local taxes	79	341	120
Percentage depletion carryforward	(129)	(720)	-
Other	80	(180)	-
Increase (decrease) in deferred tax asset valuation allowance	-	-	(4,146)
Income tax expense (benefit)	\$ 1,288	\$ 5,411	\$ (850)

Note 9 – Commitments and Contingencies

PetroQuest Energy, Inc. f/k/a Optima Energy (U.S.) Corp. v. The Meridian Resource & Exploration Company f/k/a Texas Meridian Resources Exploration, Inc., bearing Civil Action No. 99-2394 of the United States District Court for the Western District of Louisiana was filed on February 24, 2000. The Company asserts a claim for damages against Meridian resulting from Meridian's activities as operator of the Southwest Holmwood property, Calcasieu Parish, Louisiana. Meridian's activities as operator resulted in a final judgment of the United States District Court for the Western District of Louisiana ordering cancellation of the Company's rights to a productive oil and gas lease and the associated joint exploration agreement, forfeiture to two producing wells on the lease and substantial damages against Meridian causing the Company the loss of its investment and profits. The Company is unable to predict with certainty the outcome of the lawsuit at this time.

The Meridian Resource & Exploration Company v. PetroQuest Energy, Inc., bearing Docket No. 996192A of the 15th Judicial District Court in and for the Parish of Lafayette, Louisiana was filed on December 17, 1999. Meridian asserts that the Company is responsible as an investor under its participation agreement with Meridian for \$530,004 of the losses, costs, expense and liability of Meridian resulting from the final judgment that was rendered in favor of Amoco and against Meridian in legal proceedings relative to the Southwest Holmwood Field, Calcasieu Parish, Louisiana in the matter "*Amoco Production Company v. Texas Meridian Resource & Exploration Company*," bearing Civil Action No. 96-1639 in the United States District Court for the Western District of Louisiana (Civil Action No. 98-30724 in the United States Court of Appeals for the Fifth Circuit). Although the Company accrued \$555,000 when the district court decision was rendered against Meridian in December 1997, the Company denies liability to Meridian for losses sustained by Meridian as operator as a result of the Amoco litigation and is vigorously defending the lawsuit. Meridian initially withheld \$737,620 from production revenues due the Company from other properties. On January 9, 2002 Meridian released to the Company \$211,476 of the withheld revenues. The Company is pursuing recovery of the balance of the withheld revenues from Meridian as discussed in *PetroQuest Energy, Inc. f/k/a Optima Energy (U.S.) Corp. v. The Meridian Resource & Exploration Company f/k/a Texas Meridian Resources Exploration, Inc.* The Company is unable to predict with certainty the outcome of the lawsuit at this time.

The Company is a party to other ongoing litigation in the normal course of business. While the outcome of lawsuits or other proceedings against the Company cannot be predicted with certainty, management believes that the effect on its financial condition, results of operations and cash flows, if any, will not be material.

Abandonment

The Company has made, and will continue to make, expenditures for the protection of the environment. Present and future environmental laws and regulations applicable to the Company's operation could require substantial capital expenditures or could adversely affect its operations in other ways that cannot be predicted at this time. As of December 31, 2002 and 2001, total estimated site restoration, dismantlement and abandonment costs were approximately \$13,684,000 and \$14,056,000 respectively, net of expected salvage value.

Lease Commitments

The Company has operating leases for office space, which expire on various dates through 2010.

Future minimum lease commitments as of December 31, 2002 under these operating leases are as follows (in thousands):

2003	\$	615
2004		635
2005		647
2006		572
2007		546
Thereafter		1,258
	\$	4,273

Total rent expense under operating leases was approximately \$577,000, \$411,000 and \$345,000 in 2002, 2001 and 2000, respectively.

Note 10 - Employee Benefit Plans

The Company currently has one stock option plan. The stock options generally become exercisable over a three-year period, must be exercised within 10 years of the grant date and may be granted only to employees, directors and consultants. The exercise price of each option may not be less than 100% of the fair market value of a share of Common Stock on the date of grant. Upon a change in control of the Company, all outstanding options become immediately exercisable.

A summary of the Company's stock options as of December 31, 2002, 2001 and 2000 and changes during the years ended on those dates is presented below:

	Year Ended December 31,					
	2002		2001		2000	
	Number of Options	Wgtd. Avg. Price	Number of Options	Wgtd. Avg. Price	Number of Options	Wgtd. Avg. Price
Outstanding at beginning of year	2,238,766	\$ 2.94	1,861,900	\$ 1.92	1,126,200	\$ 0.95
Granted	112,000	6.17	622,500	5.32	1,027,500	2.67
Expired/cancelled/forfeitures	(66,910)	3.75	(14,500)	6.17	(24,866)	1.04
Exercised	(86,503)	1.44	(231,134)	0.89	(266,934)	0.85
Outstanding at end of year	2,197,353	3.14	2,238,766	2.94	1,861,900	1.92
Options exercisable at year-end	1,453,166	2.36	1,030,608	1.64	800,733	0.97
Options available for future grant	770,208		268,081		182,166	
Weighted average fair value of options granted during the year		\$ 3.93		\$ 3.18		\$ 1.99

The fair value of each option granted during the periods presented is estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions: (a) divided yield of 0% (b) expected volatility ranges of 74.50%-74.90%, 65.14% - 67.87% and 56.99% - 59.88% in 2002, 2001 and 2000, respectively (c) risk-free interest rate ranges of 4.17% - 4.54%, 4.03% - 5.10% and 5.39% - 6.96% in 2002, 2001 and 2000, respectively, and (d) expected life of 5 years for all 2002 and 2001 grants and 10 years for all 2000 grants.

The following table summarizes information regarding stock options outstanding at December 31, 2002:

Range of Exercise Price	Options Outstanding At 12/31/02	Wgtd. Avg. Remaining Contractual Life	Wgtd. Avg. Exercise Price	Options Exercisable At 12/31/02	Wgtd. Avg. Exercise Price
\$0.85 - \$0.94	410,100	6 years	\$0.89	410,100	\$0.89
\$1.44 - \$1.88	461,666	7.68 years	\$1.67	428,666	\$1.68
\$3.13 - \$3.75	689,167	8.09 years	\$3.20	441,342	\$3.17
\$4.25 - \$7.65	636,420	9.18 years	\$5.61	173,059	\$5.49
	2,197,353	7.93 years	\$3.14	1,453,167	\$2.36

If the compensation cost for the Company's 2002, 2001 and 2000 grants for stock-based compensation plans had been determined consistent with the expense recognition provisions of SFAS No. 123, the Company's 2002, 2001 and 2000 net income and basic and diluted earnings per common share would have approximated the pro forma amounts below (in thousands, except per share amounts):

	Year Ended December 31,					
	2002		2001		2000	
	As Reported	Pro Forma	As Reported	Pro Forma	As Reported	Pro Forma
Net income	\$ 2,307	\$,320	\$ 11,645	\$ 10,882	\$ 9,924	\$ 9,112
Earnings per common share						
Basic	\$ 0.06	\$ 0.03	\$ 0.37	\$ 0.34	\$ 0.37	\$ 0.34
Diluted	\$ 0.06	\$ 0.03	\$ 0.34	\$ 0.32	\$ 0.35	\$ 0.32

Note 11 – Oil and Gas Reserve Information - Unaudited

The Company's net proved oil and gas reserves at December 31, 2002 have been estimated by independent petroleum consultants in accordance with guidelines established by the Securities and Exchange Commission ("SEC"). Accordingly, the following reserve estimates are based upon existing economic and operating conditions at the respective dates.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in providing the future rates of production and timing of development expenditures. The following reserve data represents estimates only and should not be construed as being exact. In addition, the present values should not be construed as the current market value of the Company's oil and gas properties or the cost that would be incurred to obtain equivalent reserves.

The following table (amounts in thousands) sets forth an analysis of the Company's estimated quantities of net proved and proved developed oil (including condensate) and gas reserves, all located onshore and offshore the continental United States:

	Oil in MBbls	Natural Gas in MMcf
Proved reserves as of December 31, 1999	2,194	15,128
Revisions of previous estimates	(760)	6,638
Extensions, discoveries and other additions	110	3,476
Purchase of producing properties	1,732	8,865
Production	(161)	(3,972)
Proved reserves as of December 31, 2000	3,115	30,135
Revisions of previous estimates	(522)	(2,631)
Extensions, discoveries and other additions	3,805	14,409
Purchase of producing properties	606	12,170
Sale of producing properties	-	(114)
Production	(791)	(9,025)
Proved reserves as of December 31, 2001	6,213	44,944
Revisions of previous estimates	(1,204)	(8,955)
Extensions, discoveries and other additions	1,438	19,453
Purchase of producing properties	-	-
Sale of producing properties	(260)	(10,540)
Production	(929)	(7,765)
Proved reserves as of December 31, 2002	5,258	37,137
Proved developed reserves:		
As of December 31, 2000	2,355	18,679
As of December 31, 2001	3,104	26,847
As of December 31, 2002	4,201	17,409

The following tables (amounts in thousands) present the standardized measure of future net cash flows related to proved oil and gas reserves together with changes therein, as defined by the FASB. Future production and development costs are based on current costs with no escalations. Estimated future cash flows have been discounted to their present values based on a 10% annual discount rate.

Standardized Measure

	December 31,		
	2002	2001	2000
Future cash flows	\$ 337,776	\$ 234,736	\$ 391,078
Future production and development costs	(120,842)	(118,700)	(66,095)
Future income taxes	(36,687)	(18,226)	(98,190)
Future net cash flows	180,247	97,810	226,793
10% annual discount	(40,831)	(22,763)	(48,470)
Standardized measure of discounted future net cash flows	\$ 139,416	\$ 75,047	\$ 178,323

Changes in Standardized Measure

	Year Ended December 31,		
	2002	2001	2000
Standardized measure at beginning of year	\$ 75,047	\$ 178,323	\$ 43,069
Sales and transfers of oil and gas produced, net of production costs	(38,400)	(45,068)	(18,492)
Changes in price, net of future production costs	78,648	(188,513)	104,695
Extensions and discoveries, net of future production and development costs	83,005	33,067	27,575
Changes in estimated future development costs, net of development costs incurred during this period	19,059	16,333	2,801
Revisions of quantity estimates	(56,166)	(7,742)	12,818
Accretion of discount	8,823	25,687	4,307
Net change in income taxes	(13,448)	65,361	(78,544)
Purchase of reserves in place	-	12,730	67,052
Sale of reserves in place	(12,899)	(864)	-
Changes in production rates (timing) and other	(4,253)	(14,267)	13,042
Standardized measure at end of year	\$ 139,416	\$ 75,047	\$ 178,323

The weighted average prices of oil and gas used with the above tables at December 31, 2002, 2001 and 2000 were \$30.44, \$18.49 and \$25.29 respectively, per barrel and \$4.79, \$2.69 and \$10.35, respectively, per Mcf.

Note 13 – Summarized Quarterly Financial Information – Unaudited

Summarized quarterly financial information is as follows (amounts in thousands except per share data):

	Quarter Ended			
	March-31	June-30	September-30	December-31
2002:				
Revenues	\$ 10,497	\$ 11,102	\$ 11,024	\$ 15,057
Expenses	10,861	10,847	10,074	13,591
Net income (loss)	(364)	255	950	1,466
Earnings (loss) per share:				
Basic	\$ (0.01)	\$ 0.01	\$ 0.03	\$ 0.04
Diluted	\$ (0.01)	\$ 0.01	\$ 0.02	\$ 0.03
2001:				
Revenues	\$ 12,553	\$ 14,888	\$ 15,468	\$ 12,372
Expenses	8,412	11,034	12,960	11,230
Net income (1)	4,141	3,854	2,508	1,142
Earnings per share: (2)				
Basic	\$ 0.14	\$ 0.12	\$ 0.08	\$ 0.04
Diluted	\$ 0.13	\$ 0.11	\$ 0.07	\$ 0.03

- (1) Included in net income for the quarter ended December 31, 2001 is a tax benefit of \$759,000 primarily attributable to a revision in the Company's estimated effective income tax rate.
- (2) The above quarterly earnings per share may not total to the full year per share amount, as the weighted average number of shares outstanding for each quarter fluctuated as a result of the assumed exercise of stock options.

Exhibit 23.1

CONSENT OF INDEPENDENT AUDITORS

We consent to the incorporation by reference in the Registration Statements (File Nos. 333-67578, 333-63920, 333-52700, 333-42520, 333-65401, 333-102758, 333-88846 and 333-89961) of PetroQuest Energy, Inc., of our report dated February 11, 2003, with respect to the 2002 consolidated financial statements of PetroQuest Energy, Inc. included in Form 10-K for the year ended December 31, 2002.

/s/ Ernst & Young, LLP
New Orleans, Louisiana
March 14, 2003

Exhibit 23.3

CONSENT OF RYDER SCOTT COMPANY, L.P.

We hereby consent to the incorporation by reference in this Annual Report on Form 10-K prepared by PetroQuest Energy, Inc. (the "Company") for the year ending December 31, 2002, and to the incorporation by reference thereof into the Company's previously filed Registration Statements on Form S-3 (File Nos. 333-63920, 333-42520 and 333-89961) and Form S-8 (File Nos. 333-102758, 333-88846, 333-67578, 333-52700 and 333-65401), of information contained in our reports relating to certain estimated quantities of the Company's proved reserves of oil and gas, future net income and discounted future net income, effective December 31, 1999, 2000, 2001 and 2002. The referenced reserve reports were dated February 28, 2000, February 16, 2001, March 18, 2002 and February 21, 2003, respectively. We further consent to references to our firm under the headings "Risk Factors" and "Oil and Gas Reserves."

/s/RYDER SCOTT COMPANY, L.P.
Houston, Texas
March 14, 2003

Board of Directors

Charles T. Goodson
Chairman of the Board and
Chief Executive Officer,
PetroQuest Energy, Inc.

Alfred J. Thomas, II
President and Chief Operating Officer,
PetroQuest Energy, Inc.

Ralph J. Daigle
Executive Vice President
PetroQuest Energy, Inc.

Michael O. Aldridge
Senior Vice President and
Chief Financial Officer,
PetroQuest Energy, Inc.

Jay B. Langner *#
Honorary Chairman of the Board,
Hudson General Corporation

E. Wayne Nordberg *#
Ingalls & Snyder, LLC

William W. Rucks, IV *#
Private Investments

* - Members of the Compensation Committee

- Members of the Audit Committee

Senior Management

Charles T. Goodson
Chairman of the Board and
Chief Executive Officer

Alfred J. Thomas, II
President and Chief Operating Officer

Ralph J. Daigle
Executive Vice President

Michael O. Aldridge
Senior Vice President and
Chief Financial Officer

Art M. Mixon
Senior Vice President - Operations

Daniel G. Fournierat
Senior Vice President, General Counsel and Secretary

Dalton F. Smith III
Senior Vice President - Business Development and Land

Stephen H. Green
Senior Vice President - Exploration

Robert R. Brooksher
Vice President - Corporate Communications

Corporate Address

PetroQuest Energy, Inc.
400 East Kaliste Saloom Road, Suite 6000
Lafayette, Louisiana 70508
(337) 232-7028
Fax: (337) 232-0044
Web: www.petroquest.com

Exploration Office

PetroQuest Energy, Inc.
10333 Richmond Avenue, Suite 750
Houston, Texas 77042
(713) 784-8300
Fax: (713) 784-8327

Transfer Agent and Registrar

American Stock Transfer & Trust Company
59 Maiden Lane
New York, New York 10038
(718) 921-8145

Independent Auditors

Ernst & Young LLP
New Orleans, Louisiana 70170

Legal Counsel

Onebane, Bernard, Torian, Diaz,
McNamara & Abell
Lafayette, Louisiana 70502

Porter & Hedges, L.L.P.
Houston, Texas 77002

Annual Meeting

The Company's Annual Meeting of Stockholders will be held at 9 a.m. on May 7, 2003 at the City Club at River Ranch at 1100 Camellia Boulevard, Lafayette, Louisiana 70508

Form 10-K

Copies of the Company's Annual Report on Form 10-K may be obtained, without charge, by writing to our Corporate Secretary at our Corporate Address.

Common Stock Listing



PQUE
NASDAQ
LISTED



PetroQuest Energy Corporation

400 East Kaliste Saloom Road, Suite 6000

Lafayette, Louisiana 70508

(337) 232-7028

Fax: (337) 232-0044

Web: www.petroquest.com