Filed pursuant to Rule 424(b)(3)
Registration No. 333-88282

DORCHESTER MINERALS, L.P.
3738 OAK LAWN, SUITE 300
DALLAS, TEXAS 75219

SUPPLEMENT NO. 1 TO
PROXY STATEMENT/PROSPECTUS DATED OCTOBER 30, 2002

THE DATE OF THIS SUPPLEMENT NO. 1 IS DECEMBER13, 2002

Dear Limited Partners,

The following information supplements the proxy statement/prospectus dated October 30, 2002, of Dorchester Minerals, L.P., a Delaware limited partnership, by which the general partners of Dorchester Hugoton, Ltd., Republic Royalty Company and Spinnaker Royalty Company, L.P. are soliciting proxies and written consents, as applicable, in connection with the special meetings of the limited partners of Dorchester Hugoton and Spinnaker and in lieu of a meeting for Republic. The purpose of the special meetings and written consent is to vote upon the combination of the businesses and properties of Dorchester Hugoton, Republic and Spinnaker into Dorchester Minerals, which will result in the limited partners of the combining partnerships receiving common units of Dorchester Minerals.

This supplement includes financial and other information that updates information in the proxy statement/prospectus. You should carefully consider the information in this supplement together with the information in the proxy statement/prospectus.

This supplement does not change the proposals previously submitted for your approval. If you have already properly completed and returned a proxy or consent card, as applicable, it will continue to be valid. If you are a Dorchester Hugoton limited partner, you may obtain more information on voting by calling Dorchester Hugoton's information agent, D.F. King & Co. at (800) 290-6431. In addition, all of the limited partners of Dorchester Hugoton, Republic and Spinnaker may contact the general partners of their respective partnerships for more information.

The combination will not occur unless the limited partners of each of the combining partnerships approve the combination. If you fail to vote by proxy or consent card, as applicable, or in person, it will have the same effect as a vote against the transaction. If you have not already done so, please vote by completing and returning your proxy or consent card, as applicable, so that your vote maybe counted. As discussed in the proxy statement/prospectus, we recommend that you vote FOR the combination.

Sincerely,

P.A. Peak, Inc.
James E. Raley, Inc.
General Partners of
Dorchester Hugoton

SAM Partners, Ltd.
Vaughn Petroleum, Ltd.
General Partners of
Republic

Smith Allen Oil &
Gas, Inc.
General Partner of
Spinnaker

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this supplement and the accompanying supplements are truthful or complete. Any representation to the contrary is a criminal offense.

Please see the sections entitled "Summary—Risk Factors" beginning on page 5 and "Risk Factors" beginning on page 16 of the proxy statement/prospectus for a discussion of the risks involved in the combination.

GENERAL

As previously announced, the special meeting of depositary receipt holders of Dorchester Hugoton will be held at 10:00 a.m. on December 30, 2002 at the Holiday Inn at 11350 LBJ Freeway at Jupiter Road in Dallas, Texas to consider and vote upon the proposed combination with Republic and Spinnaker into Dorchester Minerals, L. P., a new publicly traded limited partnership. The special meeting of limited partners of Spinnaker will be held at 11:00 a.m. on December 30, 2002 at the Holiday Inn at 11350 LBJ Freeway at Jupiter Road in Dallas, Texas to consider and vote upon the combination. Republic's limited partners will act by written consent in lieu of a special meeting of limited partners.

If the combination is approved by more than 50% of the depositary receipt holders of Dorchester Hugoton, all of the limited partners of Republic and limited partners of Spinnaker holding at least 85.9883% of the sharing percentages of Spinnaker, and if all other conditions to the combination have been satisfied by December 31, 2002, then it is anticipated that the combination will close immediately after December 31, 2002. Please see "The Combination Agreement—Conditions" on page 71 of the prospectus for a description of the conditions to the combination.

If the combination closing occurs in the anticipated manner, Dorchester Hugoton expects to distribute its remaining cash, if any, and our common units received in the combination to its general partners and to its non-dissenting depositary receipt holders who are depositary receipt holders at the close of business on December 31, 2002 as a liquidating distribution. Because of the combination, there will not be an "ex-dividend" date for this liquidating distribution as there would be for a regular distribution. If the closing occurs in the anticipated manner and the liquidating distribution is subsequently made, Dorchester Hugoton anticipates that the liquidating distribution will be reported for tax purposes on a 2002 final K-1 tax statement from Dorchester Hugoton. The actual payment of the liquidating distribution will occur in 2003 upon each depositary receipt holder's exchange of Dorchester Hugoton's depositary receipts for our common units. Dorchester Hugoton expects that depositary receipt holders whose depositary receipts are held for them by a broker or similar custodian should receive their share of any liquidating distribution in January 2003 directly from their broker or custodian.

Should the combination close, Dorchester Hugoton now anticipates that the total amount of the cash portion of the liquidating distribution will be slightly more than 99% of Dorchester Hugoton's remaining cash at closing. Based on the financial information contained in this supplement, Dorchester Hugoton's cash available on September 30, 2002 was approximately $18 million. Dorchester Hugoton's remaining cash, if any, that will be included in the liquidating distribution will be increased by subsequent net cash flows and the proceeds of the sale of 128,000 shares of ExxonMobil common stock, which will be sold prior to the closing of the combination, and will be reduced by payments under Dorchester Hugoton's severance plan (estimated to be $2.7 million), combination costs for which Dorchester Hugoton is responsible, payments to depositary receipt holders exercising dissenters' rights, if any, and amounts transferred to us and Dorchester Minerals Operating LP to fund certain obligations of Dorchester Hugoton that we and it will assume in the combination.

OUR INITIAL QUARTERLY DISTRIBUTION

After closing and in the regular ongoing course of our business, we will distribute to our limited partners and general partner according to their respective interests, within 45 days of the end of each fiscal quarter, an amount equal to all "available cash" with respect to that quarter. Available cash means all cash and cash equivalents on hand at the end of that quarter, less any amount of cash reserves that our general partner determines is necessary or appropriate to provide for the conduct of its business or to comply with applicable law or agreements or obligations to which we may be subject. Due to the timing of our receipt of production revenues, our initial quarterly distribution will generally reflect three months of production from the royalty properties and two months of production from properties underlying the Operating ORRIs. This is a one-time occurrence associated with the creation of the Operating ORRIs and the delay in our receipt of revenue. Subsequent quarterly distributions will generally reflect three months of production from the royalty properties and the properties underlying the Operating ORRIs. Our initial quarterly distribution will also reflect payment of costs and expenses for which we are responsible that will be incurred and paid upon the successful consummation of the combination. These costs include Nasdaq listing fees, director and officer insurance premiums, recording and filing fees and legal expenses associated with the closing of the combination.

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THIRD QUARTER RESULTS OF THE COMBINING PARTNERSHIPS

The following sets forth selected financial information and operating data and management's discussion and analysis of financial condition and results of operations for each of the combining partnerships for the period ended September 30, 2002. The unaudited financial statements of each combining partnership for the period ended September 30, 2002 are included in the Appendix to this supplement.

INFORMATION CONCERNING DORCHESTER HUGOTON

Selected Financial and Operating Data

The following table sets forth a summary of selected unaudited financial information and operating data for Dorchester Hugoton for the periods indicated. It should be read in conjunction with the financial statements and related notes included in the Appendix to this document.

	As of and for the Nine Months Ended September 30,	
	2002	2001
(in thousands except per unit and as otherwise indicated)		
Total operating revenues	$ 12,857	$ 23,121
Net earnings	$ 7,215	$ 17,099
Net earnings per unit	$ 0.66	$ 1.57
Cash distributions(1)	$ 8,791	$ 9,876
Book value per unit	$ 3.59	$ 4.03
Net cash provided by operating activities	$ 8,597	$ 19,280
Total assets at book value	$ 38,969	$ 43,695
Cash distributions per unit(1)	$ .81	$ .91
Cash/cash equivalents	$ 18,111	$ 19,701
Increase (decrease) in cash/cash equivalents	$ (328)	$ 3,934
Long-term debt, including current portion	$ —	$ —
Total liabilities	$ 4,218	$ 4,668
General partners' equity	$ 255	$ 288
Unitholders' equity	$ 32,930	$ 36,213
Accumulated other comprehensive income	$ 1,566	$ 2,526
Total partnership capital	$ 34,751	$ 39,027

(1) Because of depletion (which is usually higher in the early years of production), a portion of every distribution of revenues from properties represents a return of a limited partner's original investment. Until a limited partner receives cash distributions equal to his original investment, 100% of such distributions may be deemed to be a return of capital.

Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion is intended to assist in understanding Dorchester Hugoton's financial position and results of operations for the nine months ended September 30, 2002 and 2001. You should refer to Dorchester Hugoton's financial statements and the notes to the financial statements included in the Appendix to this supplement in conjunction with this discussion.

Overview

Dorchester Hugoton's business operations consist of producing, gathering and selling natural gas from the long-established Hugoton gas field in Oklahoma and Kansas. Dorchester Hugoton distributes a large proportion of its net cash flow each year. It has not engaged in exploration activities and has not engaged in development activities except to a very limited extent with respect to replacement or improvement of its existing wells. Its cash flow from operations has historically been sufficient to fund its cash and capital expenditure requirements, and, while it previously maintained a revolving credit arrangement with a bank, borrowings since January 1, 1998 have been minimal.

Dorchester Hugoton's period to period changes in net earnings and cash flows from operating activities are principally determined by changes in natural gas sales volumes and gas prices. Dorchester Hugoton's portion of gas sales volumes (not reduced for the Oklahoma production payment, where applicable) and weighted average sales prices for the periods indicated were:

	Nine Months Ended September 30,	
	2002	2001
Sales Volumes (MMcf):		
Oklahoma	3,660	3,850
Kansas	646	739
Total	4,306	4,589
Weighted Average Sales Prices ($/Mcf):		
Oklahoma	$ 2.98	$ 5.12
Kansas	$ 2.86	$ 5.19
Overall Weighted Average Sales Price	$ 2.96	$ 5.13

It is expected that net operating revenues for 2002 and future years will be benefited by Dorchester Hugoton's acquisition for $5,270,000 in 2001 of a production payment, which had reduced its net operating income and cash flow in prior years. The benefit will be partially offset by increased depletion. Since future payments depend upon future gas prices, the amount of future benefit is not reasonably quantifiable. During the twelve month periods ending March 1, 2001, 2000, and 1999, the production payment to others has been approximately $1,701,000, $730,000, and $646,000, respectively.

Nine Months Ended September 30, 2002 Compared with the Nine Months Ended September 30, 2001

As shown in the table above, Oklahoma nine month 2002 gas sales volumes were 5% lower than the same period of 2001. Oklahoma volumes were influenced by reduced gas pipeline receipts in 2002 because of an explosion unrelated to Dorchester Hugoton and natural reservoir decline. Kansas nine month 2002 gas sales volumes were 13% lower than the same period of 2001 as a result of state well testing and natural reservoir decline.

Natural gas weighted average sales prices in the first nine months of 2002 were down 42% compared to the same period of 2001 due to lower market prices. The significantly lower gas prices and lower gas volumes caused net operating revenues to decrease compared to the first nine months of 2001.

Operating costs during the first nine months of 2002 were lower than the same period of 2001 primarily due to lower production taxes associated with lower natural gas revenues which were partially offset by an increase in depletion costs resulting from the purchase of the Oklahoma production payment during the second quarter of 2001. Legal and other costs associated with the proposed combination with Republic and Spinnaker increased $259,000 compared to the same period of last year, while investment income was down $465,000 due to reduced interest rates in the marketplace.

Liquidity and Capital Resources

On July 19, 1994, Dorchester Hugoton entered into a $15,000,000 unsecured revolving credit facility with Bank One, Texas, NA, which would have expired July 31, 2002. The borrowing base was $6,000,000, which was to be reevaluated by the bank at least annually. As of December 31, 2001, no letters of credit were issued under the credit facility and the amount borrowed was $100,000. Dorchester Hugoton repaid its borrowings on June 4, 2002 and terminated the agreement.

Cash flows from operating activities remain sufficient to meet Dorchester Hugoton's anticipated costs and expenses. Expenses, including combination-related costs, were 31.3% and 19.4% of net operating revenues for the nine months ended September 30, 2002 and 2001, respectively. Capital expenditures, including the acquisition of the Oklahoma production payment in 2001, were 1.4% and 23.8% of net operating revenues for the nine months ended September 30, 2002 and 2001, respectively. Dorchester Hugoton has no current outstanding material commitments for capital expenditures. Cash and cash equivalents at September 30, 2002 and 2001 were $18,111,000 and $19,701,000, respectively.

Dorchester Hugoton does not currently anticipate drilling additional wells as a working interest owner in the Fort Riley zone, the Council Grove formation or elsewhere, but successful activities by others in these formations could prompt a reevaluation by Dorchester Hugoton. Any such drilling is estimated to require $250,000 to $300,000 per well. Dorchester Hugoton anticipates continuing additional fracture treating but is unable to predict the cost until additional engineering studies are done.

Dorchester Hugoton anticipates normal gradual increases in repairs to its Oklahoma gas compression and dehydration facility and gradual increases in Oklahoma field operating costs and expenses as repairs to its 50-year-old pipelines and gas wells become more frequent and as pressures decline. Dorchester Hugoton does not anticipate significant replacement of these items at this time. However, Dorchester Hugoton believes rental field compression units installed at various locations on its Oklahoma gas gathering pipelines may become necessary in 2003 because of lower pressures. The cost of such additional compression could require from $400,000 to $600,000 in capital and require $350,000 to $400,000 per year additional operating costs (primarily compressor rental). While it is believed that the benefits of such compression will more than exceed cost and recover capital, neither the timing of such a project nor the increased gas production are currently predictable.

In 1998, Oklahoma removed production quantity restrictions in the Guymon-Hugoton field, and did not address efforts by third parties to persuade Oklahoma to permit infill drilling in the Guymon-Hugoton field. Both infill drilling and removal of production limits could require considerable capital expenditures. The outcome and the cost of such activities are unpredictable. No additional compression has been installed that affects Dorchester Hugoton's wells since 2000 by operators on adjoining acreage resulting from the relaxed production rules. Such installations by others could require expenditures by Dorchester Hugoton to stay competitive with adjoining operators.

INFORMATION CONCERNING REPUBLIC

Selected Combined Financial and Operating Information

The following table presents a summary of selected unaudited combined financial information and operating data for Republic for the periods indicated, and assumes that the Republic reorganization has occurred. The combined financial information reflects the combined operating results and financial condition of Republic and the Republic ORRIs. Intercompany amounts have been eliminated. It should be read in conjunction with the Republic and Republic ORRI financial statements and related notes included in the Appendix to this document.

	Nine Months Ended September 30,	
	2002	2001
	(in thousands)	
Total operating revenues	$ 12,234	$ 14,299
Net earnings	$ 5,683	$ 9,251
Net earnings per unit (1)	$ 57	$ 93
Cash distributions (2)	$ 8,584	$ 16,101
Cash distributions per unit (1)(2)	$ 86	$ 161
Net cash provided by operating activities	$ 8,946	$ 14,461
Total assets at book value	$ 35,211	$ 29,459
Book value per unit (1)	$ 352	$ 294
Cash/cash equivalents	$ 1,000	$ 667
Increase (decrease) in cash/cash equivalents	$ 421	$ (1,239)
Total liabilities	$ 4,675	$ 3,126
General partners' equity(3)	$ 1,644	$ 1,537
Limited partners' equity(3)	$ 28,892	$ 24,796
Partners' equity	$ 30,536	$ 26,333

(1) Republic's equity structure is based on percentage interests. Per unit disclosures have been prepared on the basis that a unit represents a 1% partnership interest.

(2) Because of depletion (which is usually higher in the early years of production), a portion of every distribution of revenues from properties represents a return of a limited partner's original investment. Until a limited partner receives cash distributions equal to his original investment, 100% of such distributions may be deemed to be a return of capital.

(3) The information presented as general partners' equity includes information with respect to the Affiliated Partnership, while limited partners' equity includes only information with respect to the Unaffiliated ORRI Owners. A portion of the Republic general partners' interest will be converted to a limited partner interest in connection with the Republic reorganization. For the purpose of this presentation, all interests of the Republic general partners have been included as general partners' equity.

Management's Discussion and Analysis of Combined Financial Condition and Results of Operations

The following discussion is intended to assist the reader in understanding Republic's combined financial position and results of operations for the nine months ended September 30, 2002 and 2001. This discussion assumes that the Republic reorganization has occurred. See "The Combination—Preparatory Steps—Reorganization of Republic" beginning on page 65 of the proxy statement/prospectus for a discussion of the Republic reorganization. You should also refer to Republic's financial statements and the notes to the financial statements included in the Appendix to this supplement.

Overview

Republic's business activities consist of the ownership and administration of producing and nonproducing mineral, royalty, overriding royalty and leasehold interests located in 392 counties and parishes in 23 states. Republic owns and produces oil and natural gas reserves almost exclusively in the capacity of a royalty owner. As a royalty owner, Republic's involvement in the operation of producing properties in which it owns an interest is extremely limited and as such, Republic is a passive participant in these activities. In the instances in which

Republic owns the executive rights in nonproducing properties, it is generally able to negotiate certain terms and conditions governing the conduct of its lessees when leasing its interest to third parties who may develop such properties. However, in the event production is established on those properties, Republic's involvement in the operation of such properties is similarly limited and as such Republic becomes a passive participant in such operations. Republic does not engage in oil and gas exploration, development and producing activities as an operator or working interest owner, and except in limited instances, does not bear any cost associated with activity on properties in which it owns an interest. Republic distributes substantially all of its cash flow each year.

Republic's year-to-year changes in net income and net cash flow from operations are principally determined by changes in oil and natural gas sales volumes and oil and natural gas prices. As a royalty owner, Republic essentially has no control over the volumes of oil and natural gas produced and sold from properties in which it owns an interest. Republic's net share of oil and natural gas sales volumes and the corresponding weighted average sales prices for the periods indicated:

	Nine Months Ended September 30,	
	2002	2001
Sales Volumes		
Oil (Bbls)	189,963	213,768
Gas (MMcf)	1,457.4	2,016.3
Weighted Average Price		
Oil ($/Bbl)	22.54	26.13
Gas ($/Mcf)	2.95	5.07

Nine Months Ended September 30, 2002 Compared to the Nine Months Ended September 30, 2001

Oil and natural gas sales volumes of 189,693 Bbls and 1,457.4 MMcf sold during 2002 were 11% and 28% lower, respectively, than 213,768 Bbls and 2,016.3 MMcf sold during 2001. The decrease in oil and natural gas sales volumes were due to natural reservoir declines.

Weighted average oil sales prices of $22.54/Bbl during 2002 were 14% lower than $26.13/Bbl received in 2001 due to average marketplace prices and the effects of a fixed price oil sales contract. Approximately 25% of Republic's total net oil sales volumes were sold under fixed prices of $27.53/Bbl during 2001. Eliminating the effect of this contract results in a weighted average oil sales price of $25.65/Bbl during 2001. This contract was still in effect as of September 30, 2001. Weighted average natural gas prices of $2.95/Mcf were 42% lower in 2002 than $5.07/Mcf received in 2001 due to changes in marketplace prices.

Lease bonus and delay rental income of $10,593 was 42% lower in 2002 than $18,171 received in 2001 due to reduced leasing activity. Other income of $493,348 was 49% higher in 2002 than $330,470 received in 2001 due to non-recurring amounts received in 2002 attributable to litigation settlement proceeds and reduced interest earned on accumulated balances.

Oil and gas production taxes of $1,026,764 were 28% lower in 2002 than $1,428,718 paid in 2001 due primarily to lower production revenue.

General and administrative expenses of $238,834 were 19% higher during 2002 than $200,892 paid in 2001 due primarily to increased rent and to salaries and benefits of employees of the general partners and their affiliates. General and administrative expense reflects general and administrative costs that are reimbursed to the general partner in accordance with Republic's partnership agreement.

Depletion expense of $2,770,011 was 16% higher in 2002 than $2,393,191 recorded in 2001 due to accrued production volumes associated with the settlement of the Salinas litigation.

Other operating costs of $2,455,857 were 293% higher in 2002 than $624,284 paid in 2001 due to increased legal and professional expenses attributable to the proposed combination with Dorchester Hugoton and Spinnaker and to legal expenses and settlement costs associated with the settlement of the Salinas litigation.

As a result, total expenses of $6,550,381 during 2002 were 41% higher than $4,647,085 recorded in 2001, and net income of $5,683,152 during 2002 was 39% lower than $9,250,884 recorded in 2001 due primarily to lower oil and natural gas sales prices.

Liquidity and Capital Resources

Republic's only cash requirements are the distributions pursuant to the Republic ORRIs and the payment of (a) oil and gas production and property taxes not otherwise deducted from gross production revenues, (b) operating expenses associated with the minor working interest properties not otherwise deducted from gross production revenues and (c) general and administrative expenses incurred in its behalf and properly allocated in accordance with its partnership agreement. These cash requirements are funded with oil and natural gas production revenues, lease bonus and delay rental income and nonrecurring income generated from other sources. Since the amounts distributable pursuant to the Republic ORRIs are, by definition, determined after the payment of all expenses actually paid by the partnership, these payments do not represent obligations for which sufficient liquidity is at all times available. As a result, the only cash requirements that may create liquidity concerns for Republic are the payments of taxes and expenses as detailed above. These expenses ranged between 11.5% and 18.9% of total revenues during 1999, 2000 and 2001. Since most of these expenses are dependent upon oil and natural gas prices and sales volumes, sufficient funds are anticipated to be available at all times for payment thereof.

Republic is not liable for the payment of any exploration, development or production costs, with certain limited exceptions, which are both individually and in the aggregate insignificant. Republic does not have any transactions, arrangements or other relationships that could materially affect the partnership's liquidity or the availability of capital resources. Republic had no obligations and commitments to make future contractual payments as of September 30, 2002, other than the September distribution payable to the Republic ORRI Owners in October 2002, as reflected in the financial statements. Republic has not guaranteed the debt of any other party, nor does it have any other arrangements or relationships with other entities that could potentially result in unconsolidated debt.

INFORMATION CONCERNING SPINNAKER

Selected Financial and Operating Information

The following table presents a summary of selected unaudited financial information and operating data for Spinnaker for the periods indicated. It should be read in conjunction with Spinnaker's financial statements and related notes included in the Appendix to this document.

	Nine Months Ended September 30,	
	2002	2001
	(in thousands)	
Total operating revenues	$ 6,096	$ 9,222
Net earnings	$ 3,565	$ 7,030
Net earnings per unit (1)(2)	$ 36	$ 70
Cash distributions (2)	$ 4,490	$ 10,138
Cash distributions per unit (1)	$ 45	$ 101
Net cash provided by operating activities	$ 4,716	$ 9,477
Total assets at book value	$ 13,198	$ 14,704
Book value per unit (1)	$ 131	$ 147
Cash/cash equivalents	$ 597	$ 388
Increase (decrease) in cash/cash equivalents	$ 226	$ (661)
Total liabilities	$ 268	$ 489
General partner's equity	$ (346)	$ (285)
Limited partner's equity	$ 13,276	$ 14,499
Partners' equity	$ 12,930	$ 14,214

(1) Spinnaker's equity structure is based on percentage interests. Per unit disclosures have been prepared on the basis that a unit represents a 1% partnership interest.

(2) Because of depletion (which is usually higher in the early years of production), a portion of every distribution of revenues from properties represents a return of a limited partner's original investment. Until a limited partner receives cash distributions equal to his original investment, 100% of such distributions may be deemed to be a return of capital.

Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion is intended to assist the reader in understanding Spinnaker's financial position and results of operations for the nine months ended September 30, 2002 and 2001. You should refer to Spinnaker's financial statements and the notes to the financial statements included in the Appendix to this supplement in conjunction with this discussion.

Overview

Spinnaker's business activities consist of the ownership and administration of producing and nonproducing mineral, royalty, overriding royalty and leasehold interests located in 352 counties and parishes in 20 states. Spinnaker owns and produces oil and natural gas reserves almost exclusively in the capacity of a royalty owner. As a royalty owner, Spinnaker's involvement in the operation of producing properties in which it owns an interest is extremely limited and as such, Spinnaker is a passive participant in these activities. In the instances in which Spinnaker owns the executive rights in nonproducing properties, it is generally able to negotiate certain terms and conditions governing the conduct of its lessees when leasing its interest to third parties who may develop such properties. However, in the event production is established on those properties, Spinnaker's involvement in the operation of such properties is similarly limited and as such Spinnaker becomes a passive participant in such operations. Spinnaker does not engage in oil and gas exploration, development and producing activities as an operator or working interest owner, and except in limited instances, does not bear any cost associated with activity on properties in which it owns an interest. Spinnaker distributes substantially all of its cash flow each year.

Spinnaker's year-to-year changes in net income, net cash flow from operations and distributions to partners are principally determined by changes in oil and natural gas sales volumes and oil and natural gas prices. As a royalty owner, Spinnaker essentially has no control over the volumes of oil and natural gas produced and sold from properties in which it owns an interest. Spinnaker's net share of oil and natural gas sales volumes and the corresponding weighted average sales prices for the periods indicated were:

	Nine Months Ended September 30,	
	2002	2001
Sales Volumes		
Oil (Bbls)	58,383	63,332
Gas (MMcf)	1,759.6	1,691.4
Weighted Average Price		
Oil ($/Bbl)	21.00	25.61
Gas ($/Mcf)	2.52	4.99

Nine Months Ended September 30, 2002 Compared to the Nine Months Ended September 30, 2001

Oil and natural gas sales volumes of 58,383 Bbls and 1,759.6 MMcf sold during 2002 were 8% and 4% lower and higher, respectively, than 63,332 Bbls and 1,691.4 MMcf sold during 2001. The decrease in oil sales volume was due to natural reservoir declines. The increase in natural gas sales volume was due to receipt of suspended funds attributable to several years of production from certain properties. Eliminating the effects of the receipt of these suspended funds results in natural gas sales volumes of 1,478.2 MMcf sold during 2002.

Weighted average oil sales prices of $21.00/Bbl during 2002 were 18% lower than $25.61/Bbl received in 2002 due to average marketplace prices and the effects of a fixed price oil sales contract. Approximately 28% of Spinnaker's total net oil sales volumes were sold under fixed prices of $27.53/Bbl during 2001. Eliminating the effect of this contract results in a weighted average oil sales price of $24.86/Bbl during 2001. This contract was still in effect as of September 30, 2001. Weighted average natural gas prices of $2.52/Mcf were 49% lower in 2002 than $4.99/Mcf received in 2001 due to changes in marketplace prices and the receipt of suspended funds attributable to several years of production from certain properties. Eliminating the effect of the receipt of these suspended funds results in weighted average natural gas sales prices of $2.78/Mcf.

Lease bonus and delay rental income of $15,000 was 56% lower in 2002 than $34,000 received in 2001 due to reduced leasing activity. Other income of $190,000 was 443% higher in 2002 than $35,000 received in 2001 due primarily to non-recurring amounts received in 2002 attributable to litigation settlement proceeds.

Oil and natural gas production taxes of $467,000 in 2002 were 33% lower than $699,000 paid in 2001 due primarily to lower production revenue.

Management expense of $235,000 during 2002 was 41% higher than $167,000 paid in 2001 due primarily to increased rent and to salaries and benefits of employees of the general partner and its affiliates. Management expense reflects general and administrative costs that are reimbursed to the general partner in accordance with Spinnaker's partnership agreement.

Depletion expense of $1,278,000 in 2002 was 17% higher than $1,094,000 recorded in 2001 due to higher production volumes.

Other operating costs of $551,000 in 2002 were 138% higher than $232,000 paid in 2001 due to increased legal and professional expenses and to expenses attributable to the proposed combination with Dorchester Hugoton and Republic.

As a result, total expenses of $2,531,000 during 2002 were 15% higher than $2,192,000 recorded in 2001, and net income of $3,565,000 during 2002 was 49% lower than $7,030,000 recorded in 2001 due primarily to lower oil and natural gas sales prices.

Liquidity and Capital Resources

Spinnaker's only cash requirements are the limited partner distributions pursuant to its partnership agreement and the payment of (a) oil and gas production and property taxes not otherwise deducted from gross production revenues, (b) operating expenses associated with the minor working interest properties not otherwise deducted from gross production revenues and (c) general and administrative expenses incurred in its behalf and properly allocated in accordance with its partnership agreement. These cash requirements are funded with oil and natural gas production revenues, lease bonus and delay rental income and nonrecurring income generated from other sources. Since the limited partner distributions are, by definition, determined after the payment of all expenses actually paid by the partnership, these payments do not represent obligations for which sufficient liquidity is at all times available. As a result, the only cash requirements that may create liquidity concerns for Spinnaker are the payments of taxes and expenses as detailed above. These expenses ranged between 8.4% and 13.2% of total revenues during 1999, 2000 and 2001. Since most of these expenses are dependent upon oil and natural gas prices and sales volumes, sufficient funds are anticipated to be available at all times for payment thereof.

Spinnaker is not liable for the payment of any exploration, development or production costs, with certain limited exceptions, which are both individually and in the aggregate insignificant. Spinnaker does not have any transactions, arrangements or other relationships that could materially affect the partnership's liquidity or the availability of capital resources. Spinnaker had no obligations and commitments to make future contractual payments as of September 30, 2002, other than the September distribution payable to the Spinnaker partners in October 2002, as reflected in the financial statements. Spinnaker has not guaranteed the debt of any other party, nor does it have any other arrangements or relationships with other entities that could potentially result in unconsolidated debt.

ADDITIONAL INFORMATION

See "Where You Can Find More Information" beginning on the inside front cover page of the proxy statement/prospectus for more information on documents incorporated by reference and how to obtain them.

YOU ARE URGED TO READ THE PROXY STATEMENT/PROSPECTUS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION BECAUSE IT CONTAINS IMPORTANT INFORMATION ABOUT THE COMBINATION, INCLUDING INFORMATION ABOUT (1) THE MANNER IN WHICH THE TERMS OF THE COMBINATION WERE DETERMINED AND (2) CONFLICTING INTERESTS OF THE GENERAL PARTNERS OF THE COMBINING PARTNERSHIPS IN RECOMMENDING THE COMBINATION. COPIES OF THE PROXY STATEMENT/PROSPECTUS AND OTHER RELEVANT DOCUMENTS MAY BE OBTAINED WITHOUT CHARGE UPON REQUEST FROM DORCHESTER MINERALS C/O DORCHESTER MINERALS MANAGEMENT GP LLC, 3738 OAK LAWN, SUITE 300, DALLAS, TEXAS 75219. YOU MAY ALSO OBTAIN THE PROXY STATEMENT/PROSPECTUS AND OTHER RELEVANT DOCUMENTS RELATING TO THE COMBINATION FREE THROUGH THE INTERNET WEB SITE THAT THE SEC MAINTAINS AT *WWW.SEC.GOV*.

APPENDIX

TO SUPPLEMENT NO. 1

Index to Financial Statements

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DORCHESTER HUGOTON, LTD.

BALANCE SHEET
(Dollars in Thousands)
(unaudited)

		September 30, 2002
ASSETS		
Current assets:		
Cash and cash equivalents	$	18,111
Investments available for sale		4,083
Accounts receivable		1,880
Prepaid expenses and other current assets		341
Total current assets		24,415
Property and equipment – at cost:		
Natural gas properties (full cost method)		34,039
Other		996
Total		35,035
Less accumulated depreciation, depletion and amortization:		
Full cost depletion		20,120
Other		361
Total		20,481
Net property and equipment		14,554
Total assets	$	38,969
LIABILITIES AND PARTNERSHIP CAPITAL		
Current liabilities:		
Accounts payable	$	599
Production and property taxes payable		318
Royalties payable		370
Distributions payable to Unitholders		2,931
Total liabilities		4,218
Commitments and contingencies (Notes 2 and 3)		
Partnership capital:		
General partners		255
Unitholders		32,930
Accumulated other comprehensive income		1,566
Total partnership capital		34,751
Total liabilities and partnership capital	$	38,969

The financial information included herein
has been prepared by management without
audit by independent public accountants

See Notes to Financial Statements

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DORCHESTER HUGOTON, LTD.

STATEMENTS OF EARNINGS
(Dollars in Thousands)
(unaudited)

	Nine Months Ended September 30, 2002	Nine Months Ended September 30, 2001
Net operating revenues:		
Natural gas sales	$ 12,761	$ 23,535
Other	96	152
Production payment (ORRI)	—	(566)
Total net operating revenues	12,857	23,121
Costs and expenses:		
Operating	2,058	2,348
Production taxes	629	1,489
Depreciation, depletion and amortization	1,616	1,536
General and administrative:		
Tax and regulatory reporting	191	248
Depositary and transfer agent fees	18	17
Other	489	422
Management fees	381	484
Merger costs and related expenses	525	266
Investment income	(300)	(765)
Interest expense	14	28
Other (income) expense, net	21	(51)
Total costs and expenses	5,642	6,022
Net earnings	$ 7,215	$ 17,099
Net earnings per Unit	$ 0.66	$ $1.57

STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in Thousands)
(unaudited)

	Nine Months Ended September 30, 2002	Nine Months Ended September 30, 2001
Net earnings	$ 7,215	$ 17,099
Unrealized holding gain (loss) on available for sale securities	(947)	(521)
Comprehensive income	$ 6,268	$ 16,578

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See Notes to Financial Statements

DORCHESTER HUGOTON, LTD.

STATEMENTS OF CHANGES IN PARTNERSHIP CAPITAL
(Dollars in Thousands)
(unaudited)

	General Partners	Unitholders	Accumulated Other Comprehensive Income	Total
Balance at December 31, 2001	$ 271	$ 34,552	$ 2,513	$ 37,336
Net earnings	73	7,142	—	7,215
Net unrealized holding gain on investments available for sale	—	—	(947)	(947)
Distributions ($0.81 per Unit)	(88)	(8,703)	—	(8,791)
Other	(1)	(61)	—	(62)
Balance at September 30, 2002	$ 255	$ 32,930	$ 1,566	$ 34,751

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DORCHESTER HUGOTON, LTD.

STATEMENTS OF CASH FLOWS
(Dollars in Thousands)
(unaudited)

	Nine Months Ended September 30,	
	2002	2001
Cash flows from operating activities:		
Net earnings	$ 7,215	$ 17,099
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation, depletion and amortization	1,616	1,536
(Gain) loss on sale of property and equipment	25	(11)
Other	(63)	(60)
Changes in operating assets and liabilities:		
Restricted cash	—	(10)
Accounts receivable	(408)	2,513
Prepaid expenses and other current assets	112	(131)
Accounts payable, taxes and royalties payable	100	(1,654)
Net cash provided by operating activities	8,597	19,280
Cash flows from investing activities:		
Capital expenditures	(175)	(5,496)
Cash received on sale of property and equipment	41	26
Net cash used by investing activities	(134)	(5,470)
Cash flows from financing activities:		
Distributions paid to Unitholders	(8,791)	(9,876)
Increase (decrease) in cash and cash equivalents	(328)	3,934
Cash and cash equivalents at beginning of year	18,439	15,767
Cash and cash equivalents at end of year	$ 18,111	$ 19,701
Supplemental cash flow and other information:		
Interest paid (no interest was capitalized)	$ 22	$ 20
Distributions declared but not paid	$ 2,931	$ 2,932

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See Notes to Financial Statements

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DORCHESTER HUGOTON, LTD.

NOTES TO FINANCIAL STATEMENTS
Nine Months Ended September 30, 2002 and 2001 (unaudited)

1. General and Summary of Significant Accounting Policies

Nature of Operations—The Partnership's operations consist principally of the operation of natural gas properties located in Kansas and Oklahoma.

Basis of Presentation—The financial statements reflect all adjustments (consisting only of normal and recurring adjustments) that are, in the opinion of management, necessary for a fair presentation of Dorchester Hugoton, Ltd.'s (the "Partnership's") financial position and operating results for the interim period. Interim period results are not necessarily indicative of the results for the calendar year. Please refer to Management's Discussion and Analysis of Financial Condition and Results of Operations for additional information. Per-Unit information is calculated by dividing the 99% interest owned by Unitholders by the 10,744,380 Units outstanding. Certain amounts in the 2001 financial statements have been reclassified to conform with the 2002 presentation.

Estimates—The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America 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.

Cash and Cash Equivalents—The Partnership's principal banking and short-term investing activities are with major financial institutions. Short-term investments with a maturity of three months or less are considered to be cash equivalents and are carried at cost, which approximates fair value. Cash balances in these accounts may, at times, exceed federally insured limits. The Partnership has not experienced any losses in such cash accounts or investments and does not believe it is exposed to any significant risk on cash and cash equivalents.

Concentration of Credit Risks—The Partnership sells its natural gas to major corporate gas purchasers in the United States and either requires major corporate guarantees, good credit history with the Partnership, letters of credit, or performs on-going credit evaluations or review of financial statements on a regular basis. The Partnership has incurred minimal credit losses.

Investments—The Partnership's investments consist of 128,000 shares of Exxon Mobil Corporation (previously Exxon Corporation) common stock and are classified as available for sale. At September 30, 2002, the carrying value of this stock, based on the quoted market price, was $4,083,200, and the cost was $2,517,455.

Property and Equipment—The Partnership follows the full cost method of accounting prescribed by the United States Securities and Exchange Commission under which all costs relating to the acquisition, exploration and development of natural gas properties (both productive and nonproductive) are capitalized (not to exceed estimated discounted future net cash flows) by the country (United States) in which the costs are incurred. Natural gas properties are being depleted on the unit-of-production method using estimates of proved gas reserves. Other assets are being depreciated or amortized using straight-line methods for financial reporting purposes over estimated useful lives of 3 to 40 years.

Gains or losses are recognized upon the disposition of natural gas properties involving a significant portion of the Partnership's reserves. Proceeds from other dispositions of natural gas properties are credited to the full cost account.

Income Taxes—The Partnership is treated as a partnership for income tax purposes and, as a result, income or loss of the Partnership is includible in the tax returns of the individual Unitholders. Accordingly, no recognition has been given to income taxes in the financial statements.

2. Contingencies

In January 2002, some individuals and an association called Rural Residents for Natural Gas Rights, referred to as RRNGR, filed a lawsuit against the Partnership, Anadarko Petroleum Corporation, Conoco, Inc., XTO Energy Inc., ExxonMobil Corporation, Phillips Petroleum Company, Incorporated and Texaco Exploration and Production, Inc. ("defendants"). The individuals and RRNGR consist primarily of Texas County, Oklahoma residents who use natural gas at their own risk, free of cost from gas wells in residences located on leases. The plaintiffs seek declaration that their domestic gas use is not limited to stoves and inside lights and is not limited to a principal dwelling as provided in the oil and gas lease agreements entered into in the 1930's through the 1950's. Plaintiffs also assert defendants conspired to restrain trade by warning of dangers of natural gas use and using such warnings to induce some plaintiffs to release their domestic gas rights. Plaintiffs also seek certification of class action against defendants. Additionally, plaintiffs seek accounting of fuel use by defendants. Dorchester Hugoton believes plaintiffs' claims are completely without merit as to Dorchester Hugoton and has filed an answer. In July 2002 the defendants won a motion for summary judgment removing RRNGR as a plaintiff. Based upon past measurements of such gas usage and current natural gas prices, Dorchester Hugoton believes the damages sought by plaintiffs to be minimal.

The Partnership is involved in several other legal and/or administrative proceedings arising in the ordinary course of its gas business, none of which have predictable outcomes and none of which are believed to have any significant effect on the financial position or operating results of the Partnership.

3. Commitments

The Partnership adopted a severance policy during the first quarter of 1998. Benefits are generally payable to employees and General Partner(s) in the event the Partnership incurs reduction in force or the elimination of a position or group of positions. The policy provides for up to approximately $2.8 million in severance payments if such obligations occur. Pursuant to agreements related to the combination, such severance payments, estimated to be $2.7 million, will be paid by the Partnership prior to closing of the transaction.

4. Debt

Between 1994 and 2002 the Partnership maintained an unsecured revolving credit facility for $15,000,000 with Bank One, Texas, N.A. While the latest borrowing base was $6,000,000, since August 1997 only $100,000 had been outstanding. On June 4, 2002 the Partnership repaid its borrowings and terminated the agreement.

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REPUBLIC ROYALTY COMPANY
AND AFFILIATED PARTNERSHIP

COMBINED BALANCE SHEET
September 30, 2002 (unaudited)

Assets	
Current assets:	
Cash and cash equivalents	$ 999,554
Accounts receivable–ORRI	3,159,552
Total current assets	4,159,106
Oil and gas properties, at cost (full-cost method of accounting):	
Proved producing royalty interests	4,299,814
Less accumulated depletion	(3,002,154)
Net oil and gas properties	1,297,660
Total assets	$ 5,456,766
Liabilities and Owners' Capital	
Current liabilities:	
Accounts payable	$ 1,009,008
Nonaffiliated ORRI Owner payable	2,803,554
Total current liabilities	3,812,562
Owners' capital	1,644,204
Contingencies (note 4)	
Total liabilities and owners' capital	$ 5,456,766

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See accompanying notes to combined financial statements

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REPUBLIC ROYALTY COMPANY AND AFFILIATED PARTNERSHIP

COMBINED STATEMENTS OF OPERATIONS
Nine months ended September 30, 2002 and 2001 (unaudited)

	September 30, 2002 (unaudited)	September 30, 2001 (unaudited)
Revenues:		
Royalty income	$ 1,700,791	2,022,803
Lease bonus income	1,536	2,635
Other income	71,535	47,918
Total revenues	1,773,862	2,073,356
Expenses:		
Oil and gas production tax	148,881	207,164
Depletion expense	127,247	74,101
Other operating expenses	364,191	156,148
Total expenses	640,319	437,413
Net income	$ 1,133,543	1,635,943

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See Notes to Financial Statements

REPUBLIC ROYALTY COMPANY
AND AFFILIATED PARTNERSHIP

COMBINED STATEMENTS OF OWNERS' CAPITAL
Nine months ended September 30, 2002 (unaudited)

Balance at December 31, 2001	$ 1,822,077
Distributions to owners (unaudited)	(1,311,416)
Net income (unaudited)	1,133,543
Balance at September 30, 2002 (unaudited)	$ 1,644,204

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See Notes to Financial Statements

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REPUBLIC ROYALTY COMPANY
AND AFFILIATED PARTNERSHIP

COMBINED STATEMENTS OF CASH FLOWS
Nine months ended September 30, 2002 and 2001 (unaudited)

	September 30, 2002 (unaudited)	September 30, 2001 (unaudited)
Cash flow from operating activities:		
Net income	$ 1,133,543	1,635,943
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion expense	127,247	74,101
(Increase) decrease in accounts receivable	(873,138)	1,728,075
Increase (decrease) in accounts and royalty owners payable	1,285,549	(2,357,525)
Net cash provided by operating activities	1,673,201	1,080,594
Cash flows from investing activities – facilitation amount	58,915	401,038
Cash flows from financing activities – distribution to owners	(1,311,416)	(2,721,061)
Net increase (decrease) in cash and cash equivalents	420,700	(1,239,429)
Cash and cash equivalents at beginning of year	578,854	1,906,903
Cash and cash equivalents at end of year	$ 999,554	667,474

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See Notes to Financial Statements

REPUBLIC ROYALTY COMPANY
AND AFFILIATED PARTNERSHIP

NOTES TO COMBINED FINANCIAL STATEMENTS
September 30, 2002 and 2001 (unaudited)

(1) Organization and Nature of Business

Republic Royalty Company (RRC or the Partnership) is a general partnership formed in September 1993 for the exclusive purpose of acquiring producing and nonproducing mineral and royalty interests and working interests in five exploratory prospects (Properties) from multiple parties. SAM Partners, Ltd. (50% interest) (SAM) and Vaughn Petroleum, Inc. (50% interest) (VPI) are the sole partners of RRC.

Initial capitalization of RRC was comprised of certain contract and management rights of the partners and properties contributed by VPI. Total cash consideration of $61.9 million was paid to the sellers of the Properties, which amount was funded with proceeds derived from the simultaneous sale of Overriding Royalty Interests (ORRI) to certain investors (Nonaffiliated ORRI Owners) and to RRC NPI Holdings, L.P. (Affiliated Partnership or Affiliated ORRI Owner), a limited partnership. RRC is the general partner to the Affiliated Partnership, and various affiliates of SAM and VPI own 100% of the Affiliated Partnership interests. In accordance with the applicable agreements governing these sales (ORRI Conveyance Agreements), RRC receives all revenues and pays all expenses attributable to the Properties and pays amounts to the owners of the ORRI. The ORRI Conveyance Agreements state that the Nonaffiliated ORRI Owners (and/or their successors) and the Affiliated ORRI Owner are entitled to payment of amounts equal to 95.0% and 0.9%, respectively, of Net Proceeds as defined in the ORRI Conveyance Agreements until the aggregate of all payments equals their investment (Payout No. 1), at which time their percentages are reduced to 85.5% and 0.81%. The percentages of Net Proceeds payable to the Affiliated ORRI Owner and the Nonaffiliated ORRI Owners will reduce to 76.95% and 0.73%, respectively, when the aggregate of all payments equals a 14% annual return on their investment (Payout No. 2) as set forth in the ORRI Conveyance Agreements ($83,659,226 at December 31, 2001). Payout No. 1 was reached in August 2000. The percentages remained at 85.5% during 2002.

RRC recorded its interest in the Properties at fair values based on the amounts paid by the Nonaffiliated ORRI Owners and the Affiliated Partnership for the ORRI.

(2) Basis of Presentation

(a) Basis of Combination

The accompanying combined financial statements include the Partnership’s share and the Affiliated Partnership’s share of revenues, expenses, and distributions for the nine months ended September 30, 2002 and 2001. The revenues, expenses, and amounts payable by and/or due to these parties varied during this time in accordance with the ORRI Conveyance Agreements. Significant interaffiliate balances and transactions have been eliminated in combination. Revenues, expenses, and distributions attributable to the Nonaffiliated ORRI Owners are excluded from the accompanying combined financial statements.

In the opinion of management, the unaudited financial statements of the Partnership as of September 30, 2002 and for the nine months ended September 30, 2002 and 2001 include the adjustments and accruals which are necessary for a fair presentation of the results for the interim periods. These results are not necessarily indicative of results for a full year.

(3) Summary of Significant Accounting Policies

A summary of the significant accounting policies followed by RRC and the Affiliated Partnership is as follows:

(a) Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America 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 periods. Oil and gas reserve estimates are used in the calculation of depletion expense and the full-cost ceiling limitation for oil and gas properties and are inherently imprecise. Actual results could differ from those estimates.

(b) Capitalization Policy for Oil and Gas Activities

RRC and the Affiliated Partnership utilize the full-cost method of accounting for its oil and gas properties. Under the full cost method, all productive and nonproductive costs incurred in connection with the acquisition, exploration, and development of oil and gas reserves are capitalized and amortized on the units-of-production method based upon total proved reserves of the underlying properties. Conveyances of properties, including gains or losses on abandonments of properties, are treated as adjustments to the cost of oil and gas properties, with no gain or loss recognized.

Pursuant to the full cost method of accounting, the excess of the facilitation amount (management fees) over actual general and administrative expenses incurred by the Partnership is credited to the full cost pool. During the nine months ended September 30, 2002 and 2001, the full cost pool was reduced by $58,915 and $401,038, respectively, for the excess of the facilitation amount over actual general and administrative expenses incurred.

Under the full cost method, the net book value of oil and gas properties may not exceed the estimated future net revenues from proved oil and gas properties, discounted at 10% per year (the ceiling limitation). In arriving at estimated future net revenues, estimated lease operating expenses, development costs, abandonment costs, and certain production-related and ad valorem taxes are deducted. In calculating future net revenues, prices and costs in effect at the time of the calculation are held constant indefinitely, except for changes which are fixed and determinable by existing contracts. The net book value is compared to the ceiling limitation on an annual basis. The excess, if any, of the net book value above the ceiling limitation is required to be written off as a noncash expense. There can be no assurance that there will not be writedowns in future periods under the full cost method of accounting as a result of sustained decreases in oil and gas prices or other factors.

(c) Depletion

RRC and the Affiliated ORRI Owner provide for depletion of proved producing oil and gas properties on a unit-of-production method, based upon studies by independent engineers for proved oil and gas reserves.

(d) Cash Equivalents

RRC and the Affiliated Partnership consider all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

(e) Concentration of Credit Risk

Accounts receivable balances represent revenue accruals from companies which operate primarily in the oil and gas industry. RRC and the Affiliated Partnership do not require collateral for their receivable balances. RRC and the Affiliated Partnership, as well as the companies they do business with, are subject to fluctuations and trends in the oil and gas industry.

(f) Revenue Recognition

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

REPUBLIC ROYALTY COMPANY
AND AFFILIATED PARTNERSHIP

NOTES TO COMBINED FINANCIAL STATEMENTS—(Continued)

Revenue is recognized when earned and reasonably assured of collection. Royalty revenue in legal suspense is recorded when the legal dispute is settled.

(g) Income Taxes

RRC and the Affiliated Partnership are not subject to federal income taxes because the tax effect of their activities accrues to the partners and owners. Taxable income or loss of RRC and the Affiliated Partnership is allocated to each partner and owner in accordance with the applicable Partnership and ORRI Conveyance Agreements, respectively. Accordingly, there is no provision for federal income taxes reflected in the accompanying combined financial statements.

(h) Derivative Instruments

Effective January 1, 2001, RRC and Affiliated Partnership adopted the provisions of statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* (Statement 133). Statement 133, as amended, standardizes the accounting for derivative instruments, including certain derivative instruments embedded in other contracts. Under the standard, entities are required to report all derivative instruments in the statement of financial position at fair value. The accounting for changes in the fair value (i.e., gains or losses) of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship and, if so, on the reason for holding the instrument. If certain conditions are met, entities may elect to designate a derivative instrument as a hedge of exposures to changes in fair value, cash flows, or foreign currencies. RRC and Affiliated Partnerships held no fair value hedge or foreign currency hedge derivative instruments at September 30, 2002 and 2001.

(4) Litigation Settlements

RRC is or was a party to litigation concerning various contracts and other claims. At December 31, 2001, RRC and Affiliated Partnership were defendants in a proceeding referred to as Salinas Litigation. The litigation involved claims of trespass to try title and adverse possession claim to a portion of a 180 acre tract of land, among other things, in which substantial mineral interests exist and with respect to which all royalties from the tract have been deposited into an escrow account. In May 2002, RRC and Affiliated Partnership reached a settlement on the Salinas litigation whereby RRC and Affiliated Partnership were awarded record title to the mineral interest, cash proceeds from royalty income previously held in legal suspense, and agreed to make certain payments to the plaintiffs. Included in the accompanying unaudited combined statement of operations for the nine months ended September 30, 2002 are royalty income, interest income, and legal and settlement costs, which are included in other operating costs, of $446,000, $37,000, and $181,000, respectively.

(5) Commitments and Contingencies

In the normal course of business, RRC and the Affiliated Partnership are involved in various lawsuits and claims related to their royalty properties. In the opinion of RRC's management, the ultimate resolution of such matters will not have a material adverse effect on the combined financial position or results of operations of RRC and Affiliated Partnership.

(6) Recent Accounting Pronouncements

In July 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 141, *Business Combinations*, and No. 142, Goodwill and Other Intangible Assets. Statement 141

REPUBLIC ROYALTY COMPANY
AND AFFILIATED PARTNERSHIP

NOTES TO COMBINED FINANCIAL STATEMENTS—(Continued)

requires that all business combinations initiated after June 30, 2001 be accounted for under the purchase method, and Statement 142 requires that goodwill no longer be amortized to earnings, but instead be reviewed for impairment. RRC and the Affiliated Partnership believe there is no impact of adopting this standard on their financial statements.

In June 2001, the FASB issued Statement No. 143, *Accounting for Asset Retirement Obligations*, which establishes requirements for the accounting of removal-type costs associated with asset retirements. The standard is effective for fiscal years beginning after June 15, 2002, with earlier application encouraged. RRC and the Affiliated Partnership are currently assessing the impact on their financial statements.

In August 2001, the FASB issued Statement No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, which establishes requirements for the accounting for the impairment or disposal of long-lived assets. The standard is effective for fiscal years beginning after December 15, 2001. RRC and Affiliated Partnership believe there will be no impact on their financial statements from adopting this standard.

In April 2002, the FASB issued SFAS No. 145, Rescission of SFAS Nos. 4, 44, and 64, Amendment of SFAS No. 13, and Technical Corrections. SFAS No. 145 eliminates SFAS No. 4, *Reporting Gains and Losses from Extinguishment of Debt*, and thus allows for only those gains or losses on the extinguishment of debt that meet the criteria of extraordinary items to be treated as such in the financial statements. SFAS No. 45 also amends SFAS No. 13, *Accounting for Leases*, to require sale-leaseback accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. The provisions of this statement relating to the rescission of SFAS No. 4 are effective for fiscal years beginning after May 15, 2002. The provisions of this statement relating to the amendment of SFAS No. 13 are effective for transactions occurring after May 15, 2002, and all provisions of this statement are effective for financial statements issued on or after May 15, 2002. Management believes the adoption of this statement will have no material effect on its financial position or results of operations.

The Company will be required to adopt SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities on January 1, 2003.* SFAS 146 requires that costs associated with exit or disposal activities be recorded at their fair values when a liability has been incurred. Under previous guidance, certain exit costs were accrued upon management's commitment to an exit plan, which is generally before an actual liability has been incurred. Management is currently evaluating the impact of this Statement.

REPUBLIC UNAFFILIATED ORRI OWNERS

INTERIM BALANCE SHEET
September 30, 2002 (unaudited)

Assets	
Current assets:	
Accounts receivable—ORRI	$ 2,803,554
Oil and gas properties, at cost (full-cost method of accounting):	
Proved producing royalty interests	64,961,084
Less accumulated depletion	(38,010,284)
Net oil and gas properties	26,950,800
Total assets	$ 29,754,354
Liabilities and ORRI Owners' Equity	
Current liabilities—accounts payable	$ 862,702
ORRI owner' equity	28,891,652
Contingencies	
Total liabilities and ORRI owner' equity	$ 29,754,354

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See accompanying notes to combined financial statements

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REPUBLIC UNAFFILIATED ORRI OWNERS

STATEMENTS OF OPERATIONS
Nine months ended September 30, 2002 and 2001 (unaudited)

	September 30, 2002 (unaudited)	September 30, 2001 (unaudited)
Revenues:		
Royalty income	$ 10,028,801	11,927,563
Lease bonus income	9,057	15,536
Other income	421,813	282,552
Total revenues	10,459,671	12,225,651
Expenses:		
Oil and gas production tax	877,883	1,221,554
Facilitation amount	297,749	601,930
Depletion	2,642,764	2,319,090
Other operating expenses	2,091,666	468,136
Total expenses	5,910,062	4,610,710
Net income	$ 4,549,609	7,614,941

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See accompanying notes to combined financial statements

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REPUBLIC UNAFFILIATED ORRI OWNERS

STATEMENTS OF ORRI OWNERS' EQUITY
Nine months ended September 30, 2002 (unaudited)

Balance at December 31, 2001	$	31,614,479
Distributions to ORRI owners (unaudited)		(7,272,436)
Net income (unaudited)		4,549,609
Balance at September 30, 2002 (unaudited)	$	28,891,652

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See accompanying notes to combined financial statements

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REPUBLIC UNAFFILIATED ORRI OWNERS

STATEMENTS OF CASH FLOWS
Nine months ended September 30, 2002 and 2001 (unaudited)

	September 30, 2002 (unaudited)	September 30, 2001 (unaudited)
Cash flow from operating activities:		
Net income	$ 4,549,609	7,614,941
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion	2,642,764	2,319,090
(Increase) decrease in accounts receivable	(549,370)	2,849,231
Increase (decrease) in accounts payable and accrued expenses and other	629,433	596,800
Net cash provided by operating activities	7,272,436	13,380,062
Cash flows from investing activities—distributions to ORRI owners	(7,272,436)	(13,380,062)
Net increase in cash	—	—
Cash, beginning of period	—	—
Cash, end of period	$ —	—

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REPUBLIC UNAFFILIATED ORRI OWNERS
NOTES TO FINANCIAL STATEMENT

September 30, 2002 and 2001 (unaudited)

(1) Organization and Nature of Business

Effective September 27, 1993, certain investors (Republic Unaffiliated ORRI Owners) represented by UBS Asset Management (New York) Inc. acquired a net profits interest (ORRI) in certain oil and gas minerals owned by Republic Royalty Company (RRC) pursuant to an ORRI Conveyance Agreement (Agreement).

(2) Basis of Presentation

The accompanying financial statements include the Republic Unaffiliated ORRI Owners' share of the acquired overriding royalty interests and related revenues and expenses.

The Agreement provides for the establishment of a net proceeds account for the purpose of providing a means of computing the amount of the net proceeds overriding royalty interest payments due to the Republic Unaffiliated ORRI Owners from RRC in connection with the Agreement. Generally, the net proceeds account is increased for all cash generated from the subject minerals, as defined in the Agreement (gross proceeds) and decreased for direct operating costs and certain additional costs (production costs).

Cash is distributed as received by the Republic Unaffiliated ORRI Owners to its group members; accordingly, there is no cash balance maintained.

(3) Summary of Significant Accounting Policies

A summary of the significant accounting policies followed by Republic Unaffiliated ORRI Owners are as follows:

(a) Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America 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 periods. Oil and gas reserve estimates are used in the calculation of depletion expense and the full-cost ceiling limitation for oil and gas properties and are inherently imprecise. Actual results could differ from those estimates. In the opinion of management, the unaudited financial statements of Republic Unaffiliated ORRI Owners as of September 30, 2002 and for the nine months ended September 30, 2002 and 2001 include the adjustments and accruals which are necessary for a fair presentation of the results for the interim periods. These results are not necessarily indicative of results for a full year.

(b) Capitalization Policy for Oil and Gas Activities

Republic Unaffiliated ORRI Owners utilize the full cost method of accounting for its ORRI. Under the full cost method, all productive and nonproductive costs incurred in connection with the acquisition, exploration, and development of crude oil and natural gas reserves are capitalized and amortized on the units-of-production method based upon total proved reserves of the underlying properties. Conveyances of properties, including gains or losses on abandonments of properties, are treated as adjustments to the cost of crude oil and natural gas properties, with no gain or loss recognized.

Under the full cost method, the net book value of the ORRI, may not exceed the estimated future net revenues from proved oil and natural gas properties, discounted at 10% per year (the ceiling limitation). In arriving at estimated future net revenues, estimated lease operating expenses, development costs, abandonment

REPUBLIC UNAFFILIATED ORRI OWNERS

NOTES TO FINANCIAL STATEMENTS—(Continued)

costs, and certain production related and ad-valorem taxes are deducted. In calculating future net revenues, prices and costs in effect at the time of the calculation are held constant indefinitely, except for changes which are fixed and determinable by existing contracts. The net book value is compared to the ceiling limitation on an annual basis. The excess, if any, of the net book value above the ceiling limitation is required to be written off as a noncash expense. There can be no assurance that there will not be writedowns in future periods under the full cost method of accounting as a result of sustained decrease in oil and natural gas prices or other factors.

(c) Depletion

Republic Unaffiliated ORRI Owners provide for depletion of the proved producing royalty interest on a unit-of-production method, based upon studies by independent engineers of the proved oil and gas reserves burdened by the net proceeds ORRI.

(d) Concentration of Credit Risk

Accounts receivable balances represent revenue accruals from companies (flow through from RRC) which operate primarily in the oil and gas industry. Republic Unaffiliated ORRI Owners do not require collateral for its receivable balances. Republic Unaffiliated ORRI Owners as well as the companies it does business with are subject to fluctuations and trends in the oil and gas industry.

(e) Revenue Recognition

Republic Unaffiliated ORRI Owners use the sales method of accounting for oil and gas revenues. Under the sales method, revenues are recognized based on actual volumes of oil and gas sold to purchasers. Revenue is recognized when earned and reasonably assured of collection. Royalty revenue in legal suspense is recorded when the legal dispute is settled.

(f) Income Taxes

Republic Unaffiliated ORRI Owners are not subject to federal income taxes because the tax effect of its activities accrues to the individual owners. Taxable income or loss of Republic Unaffiliated ORRI Owners is allocated to each ORRI owner in accordance with their respective ownership percentages. Accordingly, there is no provision for income taxes reflected in the accompanying financial statements.

(g) Derivative Instruments

Effective January 1, 2001, Republic Unaffiliated ORRI Owners adopted the provisions of Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* (Statement 133). Statement 133, as amended, standardizes the accounting for derivative instruments, including certain derivative instruments embedded in other contracts. Under the standard, entities are required to report all derivative instruments in the statement of financial position at fair value. The accounting for changes in the fair value (i.e., gains or losses) of a derivative instrument depends on whether it has been designated and qualifies as a part of a hedging relationship and, if so, on the reason for holding the instrument. If certain conditions are met, entities may elect to designate a derivative instrument as a hedge of exposures to changes in fair value, cash flows, or foreign currencies. Republic Unaffiliated ORRI Owners held no fair value hedge or foreign currency hedge derivative instruments at September 30, 2002 or 2001.

(4) Litigation Settlements

RRC is or was a party to litigation concerning various contracts and other claims. At December 31,2001, RRC and the Republic Unaffiliated ORRI Owners were defendants in a proceeding referred to as Salinas

REPUBLIC UNAFFILIATED ORRI OWNERS

NOTES TO FINANCIAL STATEMENTS—(Continued)

Litigation. The litigation involved claims of trespass to try title and adverse possession claim to a portion of a 180-acre tract of land, among other things, in which substantial mineral interests exists and with respect to which all royalties from the tract were deposited into an escrow account. In May 2002, RRC and the Republic Unaffiliated ORRI Owners reached a settlement on the Salinas litigation whereby RRC and the Republic Unaffiliated ORRI Owners were awarded record title to the mineral interest, cash proceeds from royalty income previously held in legal suspense, and agreed to make certain payments to the plaintiffs. Included in the accompanying unaudited combined statement of operations for the nine months ended September 30, 2002 are royalty income, interest income, and legal and settlement costs, which are included in other operating costs, of $2,268,000, $217,000, and $1,065,000, respectively.

(5) Commitments and Contingencies

In the normal course of business, RRC is involved in various lawsuits and claims, related to its Royalty properties. In the opinion of RRC's management, the ultimate resolution of such matters will not have a material adverse effect on the financial position or results of operations of RRC or the ORRI interests.

(6) Recent Accounting Pronouncements

In July 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 141, *Business Combinations*, and No. *142, Goodwill and Other Intangible Assets.* Statement 141 requires that all business combinations initiated after June 30, 2001 be accounted for under the purchase method, and Statement 142 requires that goodwill no longer be amortized to earnings, but instead be reviewed for impairment. Republic Unaffiliated ORRI Owners believe there is no current impact on their financial statements.

In June 2001, the FASB issued Statement No. 143, *Accounting for Asset Retirement Obligations*, which establishes requirements for the accounting of removal-type costs associated with asset retirements. The standard is effective for fiscal years beginning after June 15, 2002, with earlier application encouraged. Republic Unaffiliated ORRI Owners are currently assessing the impact on their financial statements.

In August 2001, the FASB issued Statement No. *144, Accounting for the Impairment or Disposal of Long-Lived Assets*, which establishes requirements for the accounting for the impairment or disposal of long-lived assets. The standard is effective for fiscal years beginning after December 15, 2001. Republic Unaffiliated ORRI Owners believe there will be no impact on their financial statements from adopting this standard.

In April 2002, the FASB issued SFAS No. 145, Rescission of SFAS Nos. 4, 44, and 64, Amendment of SFAS No. 13, and Technical Corrections. SFAS No. 145 eliminates SFAS No. 4, *Reporting Gains and Losses from Extinguishment of Debt,* and thus allows for only those gains or losses on the extinguishment of debt that meet the criteria of extraordinary items to be treated as such in the financial statements. SFAS No. 45 also amends SFAS No. 13, *Accounting for Leases*, to require sale-leaseback accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. The provisions of this statement relating to the rescission of SFAS No. 4 are effective for fiscal years beginning after May 15, 2002. The provisions of this statement relating to the amendment of SFAS No. 13 are effective for transactions occurring after May 15, 2002, and all provisions of this statement are effective for financial statements issued on or after May 15, 2002. Management believes the adoption of this statement will have no material effect on its financial position or results of operations.

The Company will be required to adopt SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities on January 1, 2003.* SFAS No. 146 requires that costs associated with exit or disposal activities be recorded at their fair values when a liability has been incurred. Under previous guidance, certain exit costs were accrued upon management's commitment to an exit plan, which is generally before an actual liability has been incurred. Management is currently evaluating the impact of this Statement.

SPINNAKER ROYALTY COMPANY, L.P.

INTERIM BALANCE SHEET
September 30, 2002 (unaudited)

Assets		
Current assets:		
Cash and cash equivalents	$	597,000
Accounts receivable		1,184,000
Total current assets		1,781,000
Oil and gas properties, at cost (full-cost method of accounting):		
Proved and producing royalty interests		30,540,000
Unproved royalty interests		—
		30,540,000
Less accumulated depletion		(19,123,000)
Net oil and gas properties		11,417,000
Total assets	$	13,198,000
Liabilities and Partners' Capital		
Current liabilities—accounts payable and accrued expenses	$	268,000
Partners' capital (deficit):		
General partner		(346,000)
Limited partner		13,276,000
Total partners' capital		12,930,000
Contingencies		
Total liabilities and partners' capital	$	13,198,000

The financial information included herein
has been prepared by management without
audit by independent public accountants

See accompanying notes to combined financial statements

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SPINNAKER ROYALTY COMPANY, L.P.

STATEMENTS OF OPERATIONS
Nine months ended September 30, 2002 and 2001 (unaudited)

	September 30, 2002 (unaudited)	September 30, 2001 (unaudited)
Revenues:		
Royalty income	$ 5,891,000	9,153,000
Lease bonus income	15,000	34,000
Interest and other income	190,000	35,000
Total revenues	6,096,000	9,222,000
Expenses:		
Oil and gas production taxes and ad valorem taxes	467,000	699,000
Depletion	1,278,000	1,094,000
Management expense	235,000	167,000
Other operating expenses	551,000	232,000
Total expenses	2,531,000	2,192,000
Net income	$ 3,565,000	7,030,000

The financial information included herein
has been prepared by management without
audit by independent public accountants

See accompanying notes to combined financial statements

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SPINNAKER ROYALTY COMPANY, L.P.

STATEMENTS OF PARTNERS' CAPITAL
Nine months ended September 30, 2002 (unaudited)

	Limited partners	General partner	Total
Balance at December 31, 2001	$ 14,158,000	(303,000)	13,855,000
Distribution to partners (unaudited)	(4,270,000)	(220,000)	(4,490,000)
Net income (unaudited)	3,388,000	177,000	3,565,000
Balance at September 30, 2002 (unaudited)	$ 13,276,000	(346,000)	12,930,000

The financial information included herein
has been prepared by management without
audit by independent public accountants

See accompanying notes to combined financial statements

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SPINNAKER ROYALTY COMPANY, L.P.

STATEMENTS OF CASH FLOWS
Nine months ended September 30, 2002 and 2001 (unaudited)

	September 30, 2002 (unaudited)	September 30, 2001 (unaudited)
Cash flow from operating activities:		
Net income	$ 3,565,000	7,030,000
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion expense	1,278,000	1,094,000
(Increase) decrease in accounts receivable	(206,000)	967,000
Increase (decrease) in accounts payable, accrued expenses, and other	79,000	386,000
Net cash provided by operating activities	4,716,000	9,477,000
Cash flows from financing activities—distributions to partners	(4,490,000)	(10,138,000)
Net increase (decrease) in cash and cash equivalents	226,000	(661,000)
Cash and cash equivalents at beginning of year	371,000	1,049,000
Cash and cash equivalents at end of year	$ 597,000	388,000

The financial information included herein
has been prepared by management without
audit by independent public accountants

See accompanying notes to combined financial statements

SPINNAKER ROYALTY COMPANY, L.P.

NOTES TO FINANCIAL STATEMENTS
September 30, 2002 and 2001 (unaudited)

(1) Organization and Nature of Business

On September 4, 1997, Spinnaker Royalty Company and others formed Spinnaker Royalty Company, L.P. (the Partnership) by contributing certain oil and gas mineral and royalty interests to the Partnership. Smith Allen Oil & Gas, Inc., is the Partnership’s general partner. The primary business of the Partnership is to acquire, own, and manage oil and gas properties.

(2) Summary of Significant Accounting Policies

A summary of the significant accounting policies followed by the Partnership is as follows:

(a) Capitalization Policy for Oil and Gas Activities

The Partnership utilizes the full cost method of accounting for its oil and gas properties. Under the full cost method, all productive and nonproductive costs incurred in connection with the acquisition, exploration, and development of oil and gas reserves are capitalized and amortized on the units-of-production method based upon total proved reserves. Conveyances of properties, including gains or losses on abandonments of properties, are treated as adjustments to the cost of oil and gas properties, with no gain or loss recognized.

Under the full cost method, the net book value of oil and gas properties may not exceed the estimated future net revenues from proved oil and gas properties, discounted at 10% per year (the ceiling limitation). In arriving at estimated future net revenues, estimated lease operating expenses, development costs, abandonment costs, and certain production-related and ad-valorem taxes are deducted. In calculating future net revenues, prices and costs in effect at the time of the calculation are held constant indefinitely, except for changes which are fixed and determinable by existing contracts. The net book value is compared to the ceiling limitation on an annual basis. The excess, if any, of the net book value above the ceiling limitation is required to be written off as a noncash expense. The Partnership did not incur ceiling limitation writedowns during 2001, 2000 and 1999. There can be no assurance that there will not be writedowns in future periods under the full cost method of accounting as a result of sustained decreases in oil and gas prices or other factors.

(b) Depletion

The Partnership provides for depletion of proved and producing oil and gas properties on a unit-of production method, based upon studies by independent engineers for proved oil and gas reserves.

(c) Cash Equivalents

The Partnership considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

(d) Revenue Recognition

The Partnership uses the sales method of accounting for oil and gas revenues. Under the sales method, revenues are recognized based on actual volumes of oil and gas sold to purchasers. Revenue is recognized when earned and reasonably assured of collection. Royalty revenue in legal suspense is recorded when the legal dispute is settled.

SPINNAKER ROYALTY COMPANY, L.P.

NOTES TO FINANCIAL STATEMENTS—(Continued)

(e) Concentration of Credit Risk

Accounts receivable balances represent revenue accruals from companies which operate primarily in the oil and gas industry. The Partnership does not require collateral for its receivable balances. The Partnership as well as the companies it does business with are subject to fluctuations and trends in the oil and gas industry.

(f) Income Taxes

The Partnership is not subject to federal income taxes because the tax effect of its activities accrues to the partners. Taxable income or loss of the Partnership is allocated to each partner in accordance with the Partnership agreement. Accordingly, there is no provision for income taxes reflected in the accompanying financial statements.

(g) Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America 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 periods. Oil and gas reserve estimates are used in the calculation of depletion expense and the full-cost ceiling limitation for oil and gas properties and are inherently imprecise. Actual results could differ from those estimates. In the opinion of management, the unaudited financial statements of the Partnership as of September 30, 2002 and for the nine months ended September 30, 2002 and 2001 include the adjustments and accruals which are necessary for a fair presentation of the results for the interim periods. These results are not necessarily indicative of results for a full year.

(h) Derivative Instruments

Effective January 1, 2001, the Partnership adopted the provisions of statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* (Statement 133). Statement 133, as amended, standardizes the accounting for derivative instruments, including certain derivative instruments embedded in other contracts. Under the standard, entities are required to report all derivative instruments in the statement of financial position at fair value. The accounting for changes in the fair value (i.e., gains or losses) of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship and, if so, on the reason for holding the instrument. If certain conditions are met, entities may elect to designate a derivative instrument as a hedge of exposures to changes in fair value, cash flows, or foreign currencies. The Partnership held no fair value hedge or foreign currency hedge derivative instruments at September 30, 2002 or 2001.

(3) Recent Accounting Pronouncements

In July 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 141, *Business Combinations*, and No. *142, Goodwill and Other Intangible Assets.* Statement 141 requires that all business combinations initiated after June 30, 2001 be accounted for under the purchase method, and Statement 142 requires that goodwill no longer be amortized to earnings, but instead be reviewed for impairment. The Partnership is not currently impacted by these statements.

In June 2001, the FASB issued Statement No. 143, *Accounting for Asset Retirement Obligations*, which establishes requirement for the accounting of removal-type costs associated with asset retirements. The standard

SPINNAKER ROYALTY COMPANY, L.P.

NOTES TO FINANCIAL STATEMENTS—(Continued)

is effective for fiscal years beginning after June 15, 2002, with earlier application encouraged. The Partnership is currently assessing the impact of its financial statements.

In August 2001, the FASB issued Statement No. *144, Accounting for the Impairment or Disposal of Long-Lived Assets*, which establishes requirements for the accounting for the impairment or disposal of long-lived assets. The standard is effective for fiscal years beginning after December 15, 2001. The Partnership believes there will be no impact on their financial statements from adopting this standard.

In April 2002, the FASB issued SFAS No. 145, Rescission of SFAS Nos. 4, 44, and 64, Amendment of SFAS No. 13, and Technical Corrections. SFAS No. 145 eliminates SFAS No. 4, *Reporting Gains and Losses from Extinguishment of Debt*, and thus allows for only those gains or losses on the extinguishment of debt that meet the criteria of extraordinary items to be treated as such in the financial statements. SFAS No. 45 also amends SFAS No. 13, *Accounting for Leases*, to require sale-leaseback accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. The provisions of this statement relating to the rescission of SFAS No. 4 are effective for fiscal years beginning after May 15, 2002. The provisions of this statement relating to the amendment of SFAS No. 13 are effective for transactions occurring after May 15, 2002, and all provisions of this statement are effective for financial statements issued on or after May 15, 2002. Management believes the adoption of this statement will have no material effect on its financial position or results of operations.

The Company will be required to adopt SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities on January 1, 2003.* SFAS 146 requires that costs associated with exit or disposal activities be recorded at their fair values when a liability has been incurred. Under previous guidance, certain exit costs were accrued upon management’s commitment to an exit plan, which is generally before an actual liability has been incurred. Management is currently evaluating the impact of this Statement.

(4) Commitments and Contingencies

In the normal course of business, the Partnership is involved in various lawsuits and claims related to its royalty properties. In the opinion of the Partnership’s management, the ultimate resolution of such matters will not have a material adverse effect on the financial position or results of operations of the Partnership.